ENERGY LAW JOURNAL

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ARTICLES

BOOK REVIEW

NOTES

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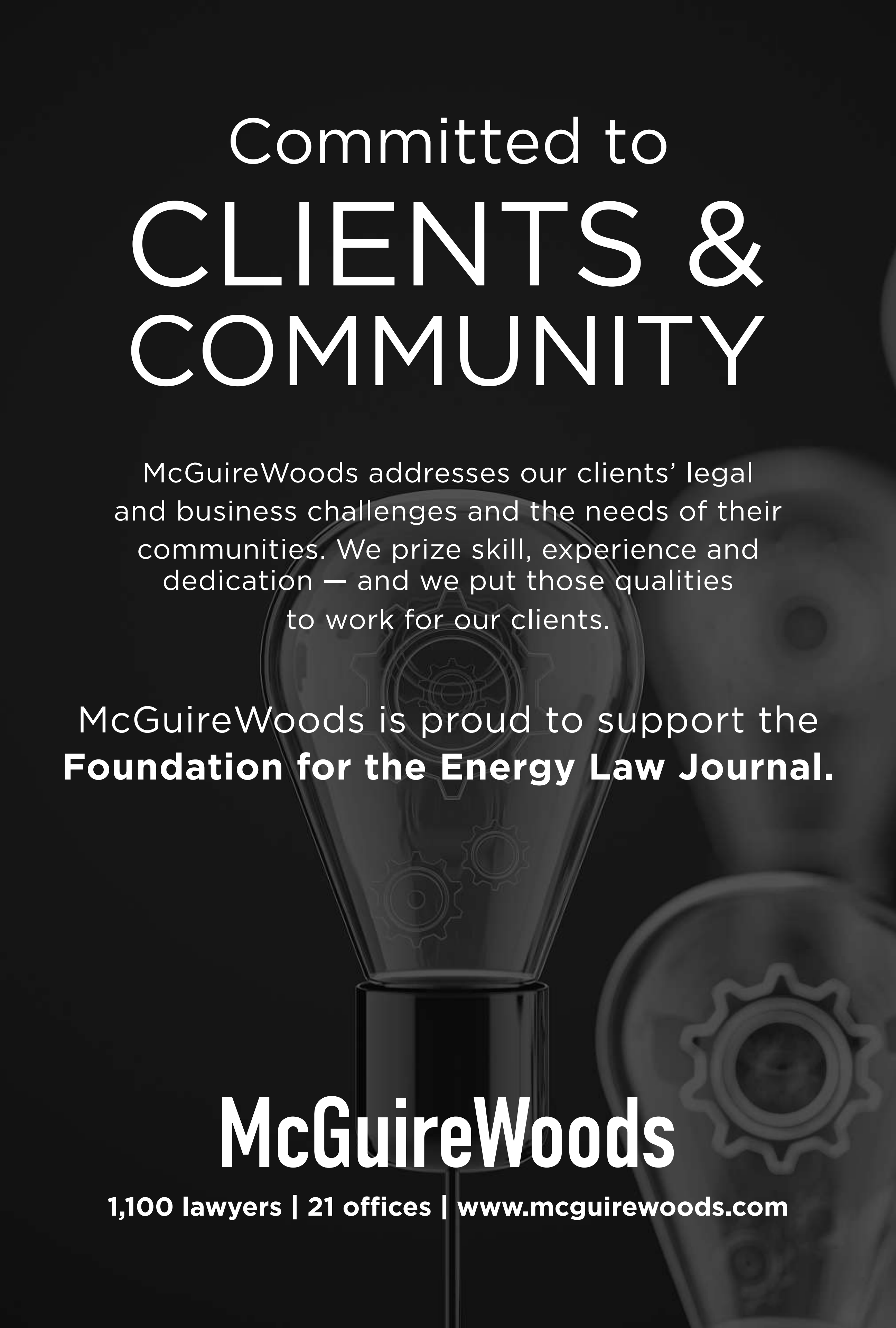
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Energy Law Journal
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COMMITTEE REPORTS

Neither the reports of the Energy Bar Association Committees nor the review of Canadian energy law developments are included in the print version of the Journal. Rather they are published online on the EBA's website at https://www.eba-net.org/energy-sector-reports/. Persons citing to the reports should use the following format: [Title of Report], 45 Energy Law Journal [page number] Online (2024), [link to report]. Included in the full electronic version of the Energy Law Journal, Volume 45, No. 2, are the following reports:

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The Rising Star in Energy Award is given to a member in recognition of outstanding contributions to the EBA, CFEBA, and/or FELJ early in their careers, with demonstrated engagement through leadership or other proactive efforts. Award winners are in their first ten years of practice as an attorney or energy professional. This award honors and recognizes a substantial commitment to the practice of energy law through their work, in addition to a commitment to EBA, its mission and core values, such as EBA's diversity and inclusion policy and pro bono efforts.

2024	Andrew DeVore
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2001	Congressman John D. Dingell

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This Award was created in memory of Paul Nordstrom, a past President of the Energy Bar Association (EBA) and motivating force in the organization of the Charitable Foundation of the EBA (CFEBA). The first award was given to Paul posthumously. It is an award to honor and to recognize exemplary long-term service or a particularly significant example of public service by a current or past member to the community through the EBA, the CFEBA, or the Foundation of the Energy Law Journal. Exemplary community service outside of these organizations may also be considered as a criterion for the Award.

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2015	Stephen H. Watts, II
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2013	Jeff Genzer
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2010	James Van Nostrand

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This Award was created in memory of Jason F. Leif, a past President of the Energy Bar Association (EBA), a past President of the Houston Chapter of the EBA, and a motivating force in the revitalization of the Houston Chapter. This award honors and recognizes exemplary long-term service, or one or more particularly significant examples of service, by an EBA member to one or more of the EBA Chapters, enhancing the role of the EBA Chapters in representing EBA's values and character at the regional level. Exemplary service to the community in connection with EBA Chapter activities may also be considered. The EBA Board created this award in 2018, and voted unanimously to honor Jason as the first recipient of the Award.

2024	Freddi L. Greenberg
2023	Kelli Cole
2022	Jason Marshall
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2019	Daniel T. Pancamo
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The Champion for Diversity and Inclusion Award, is given to a Member who has embodied the principles of the Diversity and Inclusion Policy through their actions in the Associations and/or their professional career. The award is granted as deemed warranted by the EBA Board and may, or may not, be granted annually. Emma Hand was named as the first recipient of this award.

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2021	Sherry Quirk
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And we gratefully acknowledge those EBA members and others who have so generously contributed in the past.

The Energy Bar Association is an international, non-profit association. Founded in 1946 as the Federal Power Bar Association, the Association currently has approximately 2000 members. The Association's voluntary membership is comprised of government, corporate, and private attorneys, as well as energy professionals from across the globe, and includes law students interested in energy law. The mission of the Association is to promote the professional excellence and ethical integrity of its members in the practice, administration, and development of energy laws, regulations, and policies. In addition to publishing the *Energy Law Journal*, the Association organizes and sponsors a number of activities, including two national conferences a year, and numerous continuing legal education (CLE) programs each year. The Association also sponsors eight formal chapters in the United States and Canada and committees that monitor and report to the membership on developments of interest. Complete membership and subscription information can be obtained from the Association at 2000 M Street, NW, Suite 715, Washington, DC 20036, or by contacting us at (202) 223-5625 or by visiting EBA-Net.org.

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DIVERSITY AND INCLUSION POLICY

The Energy Bar Association (EBA), the Charitable Foundation of the Energy Bar Association (CFEBA), and the Foundation of the Energy Law Journal (FELJ) are committed to the goals of fostering an inclusive and diverse membership and increasing diversity across all levels of the Associations. Attorneys, energy professionals and students with varied and diverse characteristics practicing in the energy field are welcome to join our ranks, regardless of race, creed, color, ethnicity, Native American, Alaska, or Hawaiian Native tribal membership or descendance, gender (including gender identity or expression), sexual orientation, family and marital status (including pregnancy), family responsibilities, religion, national origin, age, personal appearance, political affiliation, veterans status, disability, source of income (government, solo, corporate, firm practice), or place of residence or business (geographic diversity) and are encouraged to become active participants in the Associations' activities.

PRESIDENT'S MESSAGE

For just under forty-five years, the *Journal* has provided members with thoughtful analysis of the day's pressing energy law and policy issues. This edition stays true to that heritage, addressing important questions relating to the cost, equity, and innovation of energy as the nation's generation mix continues to evolve. CeCe Coffey explores the development of organized electricity markets outside of Regional Transmission Organizations and Independent System Operators, highlighting guidance from the Federal Energy Regulatory Commission. Rachel Neuburger reviews the 2019 all-requirements contracts imposed by the Tennessee Valley Authority upon its distribution utility customers in the context of market, economic, and political conditions at the time. Emma Shumway discusses recent efforts by state utility regulators to improve rate designs and their ratemaking procedures to reduce energy insecurity. In the context of climate policies adopted by states, utilities, or other stakeholders, Joshua Macey and Jacob Mays discuss the allocation of transmission costs and make their case for the "beneficiary pays" approach. Lawrence Luong also provides an informative discussion of utility smart grid innovation, with a case study of the "SmartSacramento" project. The diversity of topics presented in this edition reconfirms that the Journal remains a key benefit of EBA membership.

In order to maximize the value of membership, the EBA will kick off a new strategic planning exercise in January of 2025—the first since before the COVID pandemic. Suffice it to say that much has changed. Yet, EBA remains as committed as ever to its mission of promoting the professional excellence and ethical integrity of its members. I look forward to collaborating with the Board of Directors, as well as leadership from the Foundation for the Energy Law Journal and the Charitable Foundation for the Energy Bar Association, to ensure that EBA meets and exceeds the needs of its members.

Finally, on behalf of the EBA Board of directors and Staff, I would like to thank the various people who have contributed to this edition of the *Energy Law Journal*. In addition to the authors, editors, and members, we are especially grateful to the Journal's Editor-in-Chief, Harvey Reiter, Executive Editor, Caileen Gamache, and Administrative Editor, Nicholas Cicale, who continue to provide exemplary leadership.

Sincerely,

Conor B. Ward
President, Energy Bar Association

EDITOR IN CHIEF'S PAGE

If any of you follow baseball, you may have guessed that I would start my semi-annual Editor in Chief's Page with a reference to the baseball team I've followed since childhood — the Detroit Tigers. At the July 30 trading deadline, the Tigers, muddling along at 52-57 and out of the playoff picture, engaged in what looked like a fire sale. They traded their second-best starting pitcher, Jack Flaherty, to the Dodgers for several minor league players, traded their veteran backup catcher Carson Kelly for another two minor leaguers, and traded trustworthy left-handed reliever Andrew Chafin for yet some other minor league prospects. Then, inexplicably, improbably, miraculously, with but two uninjured starting pitchers — likely Cy Young winner Tarik Skubal and rookie Keider Montero — and five other rookies regularly in the starting lineup, the Tigers became the hottest team in all of baseball. From August 11, when the Tigers were *ten* games out of the last wild card spot until September 27, the Tigers won thirty-one of their next forty-three games, clinching the last wild card slot with two games left in the regular season. They went on to sweep the Houston Astros in two road games, and even managed to take a two game to one lead over Central Division winner Cleveland, before succumbing to the Guardians in game five of their second round series.

I could not talk about the surprises of baseball without mentioning September 19 — the day that Shohei Otani etched a huge mark in baseball history. On that day he became the first player in major league baseball history to amass six hits — five of them for extra bases (three of those were homeruns) — knock in ten runs, and steal two bases in a single game. And in doing so, he also became the first player in major league baseball history to hit over fifty home runs and steal over fifty bases in a single season. For good measure, his performance that day also clinched a playoff spot for his team, the Los Angeles Dodgers. He finished his season as part of the World Series Champion Dodgers. But can he pitch? Well yes, but not until next season.[1]

In previous Editor-in-Chief Pages, I have noted — no, marveled at — how many significant domestic and international events have been packed into each six-month period between Journal editions. The last six months have been no different. The thirty-day period from late June to late July was particularly remarkable. Not as remarkable as the Tigers' comeback in August and September. But still pretty remarkable.

At the start of that thirty-day period the Supreme Court finished its 2023-24 term with decisions that profoundly changed the legal landscape. That was particularly the case in the field of administrative law in which most EBA members practice.

1. Tony Cloninger, a pitcher for the Atlanta Braves, probably set the mark for greatest pitching and hitting performance in a single game when, in July 1966, he both pitched his team to victory and hit two grand slams, knocking in nine runs altogether. *Tony Cloninger Sets Grand Slam Record*, THIS DAY IN BASEBALL (July 3, 1966), https://thisdayinbaseball.com/tony-cloninger-sets-grand-slam-record/.

Over only a several day period, the Court reversed the forty-year old *Chevron* doctrine,[2] declared that administrative agency decisions affirmed by the courts decades ago could still be challenged under the six-year federal state of limitations — even by affiliates of losing parties — because the clock would not start running for such parties until they were harmed,[3] and ruled that ninety years after its creation, the SEC could no longer seek penalties for securities fraud before ALJs because fraud is a common law tort, giving alleged perpetrators the constitutional right to jury trials in federal court.[4]

What impact the demise of *Chevron* will have on FERC practice is hard to predict. For many decades before *Chevron*, FERC and its predecessor did big things under arguably ambiguous statutory language ("just and reasonable rates") — they established area rates for natural gas;[5] assumed jurisdiction over most electric transmission services, including transmission agreements between entities located wholly within a single state;[6] and established original cost ratemaking.[7] And *Loper-Bright* suggests that, even without deference, FERC and other agencies given statutory authority to decide what is "reasonable" or "appropriate" will be given wider berth:

> In a case involving an agency, of course, the statute's meaning may well be that the agency is authorized to exercise a degree of discretion. Congress has often enacted such statutes. For example, some statutes "expressly delegate[]" to an agency the authority to give meaning to a particular statutory term. Others empower an agency to prescribe rules to "fill up the details" of a statutory scheme, or to regulate subject to the limits imposed by a term or phrase that "leaves agencies with flexibility," such as "appropriate" or "reasonable."[8]

Jarkesy was a ruling that may threaten FERC's ability to pursue penalties for fraud claims under the Natural Gas Act (as opposed to the Federal Power Act)[9] at all. In a September 19, 2024, decision, FERC terminated an eight-year old proceeding against TotalEnergies Gas & Power involving an inquiry into whether it had manipulated the price of natural gas. The hearing FERC had ordered before an ALJ had previously been suspended in light of the Fifth Circuit's ruling in the *Jarkesy* case and, following the Supreme Court's ruling in June, FERC ruled that, since it lacked authority to impose penalties against Total following a proceeding before an ALJ, it would terminate the proceeding.[10] In that same case, it announced that it would issue a further order addressing "Jarkesy's impact on the Commission's existing enforcement procedures."[11] Stay tuned.

Corner Post is not likely to affect most of FERC's decisions. The NGA and FPA place strict time limits on petitions for review of FERC decisions. But the D. C. Circuit has held that FPA section 313(b) "limits review to orders issued in proceedings under the [Federal Power] Act — and [PURPA] § 210 is not part of th[at]

2. Loper-Bright Enters. v. Raimondo, 144 S. Ct. 1244 (2024).

3. Corner Post Inc. v. Bd. of Governors of Fed. Rsrv. Sys., 144 S. Ct. 2440 (2024).

4. SEC v. Jarkesy, 144 S.Ct. 2117 (2024).

5. Permian Basin Area Rate Cases, 390 U.S. 747 (1968).

6. FPC v. Fla. Power & Light Co., 404 U.S. 453 (1972).

7. FPC v Hope Nat. Gas Co., 315 U.S. 575 (1942).

8. *Loper-Bright*, 144 S. Ct. at 2263.

9. Parties facing FERC-ordered investigations under the Federal Power Act have the right to have charges against them adjudicated in federal district court. There is no such option under the Natural Gas Act.

10. *Total Gas & Power North America, Inc. et al.*, 188 FERC ¶61,197 at P 4-5 (2024).

11. *Id*. at P 6.

Act,"[12] adding the limited caveat that "FERC orders purporting to resolve a PURPA dispute 'might' be directly reviewable if they were 'in fact . . . mandatory, in the sense that' they 'fix[ed] the rights' of the parties and that 'failure to "comply" could expose [the losing party] to penalties as high as $1,000,000 a day under' the Federal Power Act's civil-penalty provisions."[13] Might that leave seemingly settled FERC PURPA regulations open to challenge by newly-formed entities?

These administrative law decisions were not the last of the Court's end-of-term blockbuster holdings. For good measure, the Supreme Court, in a sharply divided decision that Princeton history professor Sean Wilentz called "the Dred Scott of our time,"[14] declared that presidents enjoyed absolute immunity for otherwise criminal acts so long as their conduct could be construed as within a president's "conclusive and preclusive constitutional authority."[15] The Court further declared that, "at a minimum," a president enjoys "presumptive immunity" for "all his official [as opposed to private] acts."[16] The latter holding was apparently too much for Justice Barrett, who otherwise sided with the majority on the central question in the case. The majority opinion, Barrett noted, "holds that the Constitution limits the introduction of protected conduct as evidence in a criminal prosecution of a President."[17] Thus, she noted, if the President accepted a bribe for conducting an official act, the president could be charged with bribery but could block introduction of evidence of the official act taken in return for the bribe![18] Dissenting Justices Sotomayor, Kagan, and Jackson minced no words in declaring their dismay with the entirety of majority's decision:

> Let the President violate the law, let him exploit the trappings of his office for personal gain, let him use his official power for evil ends. Because if he knew that he may one day face liability for breaking the law, he might not be as bold and fearless as we would like him to be. That is the majority's message today . . . . In every use of official power, the President is now a king above the law.[19]

On June 27, millions witnessed a presidential debate in which President Biden performed so poorly that Donald Trump's answer to a question about his plans to tackle the climate crisis — "we had H_20"[20] — somehow drew no comment, much less ridicule from TV's late night talk show hosts. Two weeks later, Trump survived a July 13 assassination attempt at a rally in Butler, Pennsylvania (a second assassination attempt was thwarted in September). And only two days after that, he appeared at the Republican National Convention. The very same day, Trump learned that Judge Aileen Cannon, his appointee to a federal district court post, had dismissed as unconstitutional the felony charges against him for mishandling classified information, thereby assuring that he would not face trial on those charges before the election. Almost immediately following his selection of J.D. Vance to be his running mate at the convention, Vance faced withering criticism and tanking poll numbers over resurfaced remarks that childless persons

12. Portland Gen. Elec. Co. v. FERC, 854 F.3d 692, 701 (D.C. Cir. 2017).

13. *Id*. (quoting Midland Power Coop. v. FERC. 774 F.3d 1, 6-7 (D.C. Cir. 2014).

14. Sean Wilentz, *The 'Dred Scott' of Our Time*, N.Y REV. (Aug. 15, 2024), https://www.nybooks.com/articles/2024/08/15/the-dred-scott-of-our-time/.

15. Trump v. United States, 144 S. Ct. 2312, 2318 (2024).

16. *Id*. at 2347.

17. *Id*. at 2354 (Barrett, J., concurring and dissenting in part).

18. *Id*. at 2355 (Barrett, J., concurring and dissenting in part).

19. *Trump*, 144 S. Ct. at 2371 (Sotomayor, J., dissenting)

20. *READ: Biden-Trump debate transcript*, CNN (June 28, 2024), https://www.cnn.com/2024/06/27/politics/read-biden-trump-debate-rush-transcript/index.html [hereinafter Biden-Trump Debate].

have no stake in the future of this country and should not have the same vote as those with children.

Four days after the Republican National Convention ended, so did President Biden's candidacy, when he announced that he would not seek a second term. Little less than an hour after that bombshell announcement, President Biden endorsed his Vice President, Kamala Harris, for the presidency. In a matter of days, she had amassed enough delegate commitments to secure the Democratic nomination for that office.

There was also supposed to be a presidential election in Venezuela on July 28, 2024. People did, in fact, vote that day. And, by all accounts, they voted by a two to one margin to oust Venezuela's president and de facto dictator, Nicolás Maduro. But Maduro has falsely claimed victory[21] and started the round up and imprisonment of his political opponents, with the apparent winner of the election, Edmundo González, forced to flee to Spain.[22]

How many of us — be honest — still remember that, during this same thirty-day period, the Caribbean was hit with Hurricane Beryl? "On Sunday, June 30, 2024," NBC News reported, "Beryl became the first Category 4 storm ever to form in the Atlantic Ocean in the month of June. No storm," it added, "has reached Category 4 intensity so early in the hurricane season, which runs from June 1 to Nov. 30."[23]

Major FERC Developments

The FERC has three new commissioners. Commissioners Rosner, See, and Chang were sworn in, respectively, on June 17, June 28, and July 15, 2024. All five of the Commissioners will have remaining terms when President-Elect Trump takes office on January 20, 2025 (only Commissioner Christie has a term expiring in 2025). But the President has the authority to designate any of the sitting commissioners as the agency's chairman, a power that Trump exercised multiple times during his first term in office. It will be no surprise if he exercises that authority again upon taking office.

Petitions for review of Order No. 1920 have been consolidated in the Fourth Circuit Court of Appeals.[24]

The massive expected expansion of utility load related to the development of energy-hungry data centers will be a focus of state and federal regulators in the coming years. FERC's November 1, 2024 technical conference on co-location of data centers and generation in Docket No. RM21-11 and its rejection that same day of a co-location interconnection agreement between PJM, Susquehanna Nuclear, LLC, and PPL Electric Utilities Corporation[25] underscore the emerging importance of this issue.

21. Samantha Schmidt et al., *Maduro lost election, tallies collected by Venezuela's opposition show*, WASH. POST (Aug. 24, 2024), https://www.washingtonpost.com/world/2024/08/04/maduro-gonzalez-election-actas-analysis/.

22. María Luisa Paúl et al., *Edmundo González, likely winner of Venezuela election, flees to Spain*, WASH. POST (Sept. 8, 2024), https://www.washingtonpost.com/world/2024/09/08/edmundo-gonzlez-flees-venezuela-spain/.

23. Denise Chow, *Hurricane Beryl broke a startling record before making landfall in the Caribbean*, NBC NEWS (July 1, 2024), https://www.nbcnews.com/science/science-news/hurricane-beryl-records-category-4-storm-caribbean-rcna159723.

24. Appalachian Voices v. FERC, No. 24-1650, 2024 U.S. App. LEXIS 21569 (4th Cir. Aug. 26, 2024).

25. *PJM Interconnection, L.L.C*, 189 FERC ¶ 61,078 (2024).

Antitrust

Google Monopolization Verdict

On August 5, 2025, following a lengthy trial, federal district court judge Amit Mehta ruled that Google had acted unlawfully to maintain its monopoly over general internet search services in violation of Section 2 of the Sherman Act.[26] Google, the court found, had unlawfully maintained its monopoly by extracting exclusive default search engine agreements from Apple as well as Samsung and other Android systems. The case had originally been brought by the Justice Department during the Trump Administration and was continued under the Biden Administration. A little over a week later, a federal district court judge in California held a hearing to consider remedies proposed by Epic Games in the aftermath of *its* successful antitrust suit against Google for restraining trade in the market for Android app distribution and billing services.[27]

FTC's Non-Compete Rule Blocked

My May 2024 Editor-in-Chief Page mentioned the FTC's issuance, last January, of a general rule banning non-compete clauses as unfair methods of competition. Since then, a tax consulting firm, joined by the Chamber of Commerce and the Business Roundtable, filed suit in federal district court in (where else) Texas posing a sweeping array of challenges to the rule. The rule, they argued in a motion for summary judgment, exceeds the FTC's statutory authority and even if not, nonetheless violates the non-delegation doctrine, is unlawfully retroactive, is arbitrary and capricious, and, for good measure, is void because "the Commission is unconstitutionally insulated from presidential control."[28] The court did not reach the plaintiffs' constitutional challenges, which if successful would call into question the very existence of independent regulatory commissions like FERC, the FTC, SEC, FCC and NLRB. But, contrary to the D. C. Circuit's 1973 decision in *National Petroleum Refiners Ass'n v. FTC*,[29] it did accept the plaintiffs' statutory claim, concluding that while "the FTC has some authority to promulgate rules to preclude unfair methods of competition," it "lacks the authority to create substantive rules through this method"[30] and set aside the non-compete rule nationwide. That decision, which is in conflict with a federal district court ruling in Pennsylvania, will almost certainly be the subject of further appeals.

Summer Olympics

Led by superstar Olympians Simone Biles (gymnastics) and Katie Ledecky (swimming) and men's and women's basketball teams loaded with NBA and WNBA talent, the United States tied China with 40 gold medals and led all nations with more than 120 medals overall at the Paris Olympic games.[31] By beating

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26. United States v. Google LLC, No. 1:20-cv-3010, 2024 U.S. Dist. LEXIS 138798 (D.D.C. Aug. 5, 2024).

27. Bonnie Eslinger, *Google-Epic Antitrust Judge Vows To 'Tear The Barriers Down'*, LAW360 (Aug. 14, 2024), https://www.law360.com/articles/1869874/google-epic-antitrust-judge-vows-to-tear-the-barriers-down-#:~:text=Google%2DEpic%20Antitrust%20Judge%20Vows%20To%20%27Tear%20The%20Barriers%20Down%27.

28. Ryan LLC v. FTC, No. 3:24-CV-00986-E, slip op. at 13 (N.D. Tex. Aug. 20, 2024).

29. Nat'l Petroleum Refiners Ass'n v. FTC, 482 F.2d 672, 678 (D.C. Cir. 1973).

30. *Ryan LLC,* slip op. at 17.

31. Jerome Pugmire, *U.S. again beats China in Olympic medals table after they tie for gold; France exceeds expectations*, AP (Aug. 12, 2024), https://apnews.com/article/2024-olympics-medals-united-states-china-e9f013a206e0de69c41686ee122f425a.

France in the finals, Stephen Curry won his first and Kevin Durant his fourth gold medal in basketball.[32] Meanwhile, Gabby Thomas may have become the first Harvard graduate in neurobiology to win a gold medal (You could say that this is an educated guess). She won three — the women's 200-meter race, the 4x100 meter relay, and the 4x400 meter relay.[33] I cannot say for certain, but I do not believe there were any EBA members among the U.S. Olympians.

Hurricanes, Heat Waves, and Utility Infrastructure

Last spring, I and my co-authors, Dr. Janice Beecher and Dan Watkiss, wrote an article in the Journal about the imperative for utility regulators to mandate utility resilience planning in the face of increasing climate risks.[34] These risks, we wrote, were reflected in the marketplace in the form of rising insurance costs and lower credit ratings.

Nothing in the last six months has eased the concerns we discussed.

May 2024 was the hottest May on record in Miami.[35] In fact, it was the hottest May on record, period.[36] In early June, the World Meteorological Organization warned in a report that over the next five years there is "a nearly 90 percent chance Earth will set yet another record for its warmest year."[37] Later that month, on Sunday, June 30, 2024, "Beryl became the first Category 4 storm ever to form in the Atlantic Ocean in the month of June." The next day it became a Category 5 hurricane.[38]

"[A] record 10 million people who have fallen ill with dengue so far this year — an unprecedented surge that scientists say is fueled in part by climate change," wrote Washington Post reporters Lena H. Sun and Sarah Kaplan.[39] "Soaring global temperatures," they added, "have accelerated the life cycles and expanded the ranges of the mosquitoes that carry dengue, helping spread the virus to roughly 1 in every 800 people on the planet in the past six months alone."[40]

Although September's Hurricane Helene made landfall in northern Florida two hundred miles from the Tampa area, some of the hurricane's largest devastating effects in Florida were felt in Tampa and surrounding communities, mostly

32. David K. Li, *Steph Curry leads Team USA to fifth straight gold medal in men's basketball*, NBC NEWS (Aug. 10, 2024), https://www.nbcnews.com/news/sports/steph-curry-leads-team-usa-fifth-straight-gold-medal-mens-basketball-rcna166110.

33. A. Pawlowski, *Sprinter Gabby Thomas Says She'll Train For Los Angeles Olympics — After Taking Six Weeks Off*, TODAY (Aug. 6, 2024), https://www.today.com/health/womens-health/gabby-thomas-health-routine-rcna165329.

34. Janice A. Beecher et al., *Regulatory Imperative to Ensure Utility Climate Resilience Planning*, 45 ENERGY L.J. 83 (2024).

35. Patricia Mazzei, *'Insane' Heat Has Been Scorching Miami. It's Not Even June*, N.Y. TIMES (May 21, 2024), https://www.nytimes.com/2024/05/21/us/miami-heat-summer-weather.html?searchResultPosition=.

36. Raymond Zhong, *'Hanging by a Thread': U.N. Chief Warns of Missing a Key Climate Target*, N.Y. TIMES (June 5, 2024), https://www.nytimes.com/2024/06/05/climate/global-warming-outlook.html?searchResultPosition=1.

37. *Id.*

38. Denise Chow, *Hurricane Beryl is breaking records as it wreaks havoc in the Caribbean*, NBC NEWS (July 1, 2024), https://www.nbcnews.com/science/science-news/hurricane-beryl-records-category-4-storm-caribbean-rcna159723.

39. Lena H. Sun & Sarah Kaplan, *Dengue fever is surging worldwide. A hotter planet will make it worse*, WASH. POST (June 30, 2024), https://www.washingtonpost.com/health/2024/06/30/dengue-puerto-rico-mosquito-climate-change/.

40. *Id.*

from flooding — the worst storm to hit the area in a century.[41] As of this writing, nearly 150 persons in the U.S. had been killed by the hurricane, thousands more were injured and displaced, and millions lost electric power.[42] Some of the hurricane's worst damage occurred in Ashville, North Carolina, a community located in the mountains *five hundred* miles from where Hurricane Helene landed.[43] In all, the hurricane affected millions in Florida, Georgia, North Carolina, South Carolina, Tennessee, and Virginia.[44] Recovery from Hurricane Helene had barely begun when Florida was hit squarely with powerful Category 3 Hurricane Milton only weeks later, killing at least twenty-four persons and leaving three million Florida customers without power.[45]

It wasn't only the U.S. that was hit with massive storm damages. Floods from torrential rains in Spain killed two hundred persons, with scores of other persons still missing.[46]

Deaths of the Famous

James Earl Jones

"Luke, I am your father." "This is CNN." We've all heard the familiar baritone voice of James Earl Jones a hundred times over. A stage and screen star for decades, Jones overcame a childhood stutter to become the winner of Tony awards for *The Great White Hope* and *Fences* and the voice of Darth Vader in the Star Wars series, passed away on September 9, 2024. He was 93.[47]

Quincy Jones

Composer, arranger, record producer for more than half a century, Quincy Jones passed away on November 5, 2024, at the age of 91. The winner of twenty-eight Grammy awards (he was nominated eighty times), Mr. Jones produced Michael Jackson's "Thriller," "the best-selling album of all time," composed the soundtracks to *The Pawnbroker* (1964), *In Cold Blood* (1967), *The Color Purple* (1985), and *In the Heat of the Night*, among others. In 1985, he "produced, arranged and conducted a supergroup of more than 40 singers — including Diana Ross, Michael Jackson, Bruce Springsteen and Stevie Wonder — under the banner name USA for Africa, in "We Are the World," a fund-raising single for famine relief."[48]

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41. Langston Taylor et al., *For Tampa Bay, Helene was the worst storm in a century*, MIAMI HERALD (Oct. 2, 2024), https://www.miamiherald.com/news/weather/hurricane/article293362924.html.

42. Erik Verduzco et al., *Southerners stay in touch the old-fashioned way after Helene cuts roads, power, phones*, AP (Oct. 2, 2024), https://apnews.com/article/helene-asheville-north-carolina-3f812f70c4d2649e2198362e9ae42b06.

43. Lauren Sommer, *Hurricanes are dangerous far from the coast. Communities are struggling to prepare*, NPR (Oct. 2, 2024), https://www.npr.org/2024/10/01/nx-s1-5133530/hurricane-helene-rain-flooding-climate-change.

44. Mary Gilbert et al., *The latest on the aftermath of Hurricane Helene*, CNN (Oct. 1, 2024), https://www.cnn.com/weather/live-news/hurricane-helene-florida-north-carolina-georgia-09-30-24/index.html.

45. Alex Sundby et al., *Hurricane Milton leaves path of destruction across Florida, at least 24 dead*, CBS NEWS (Oct. 14, 2024), https://www.cbsnews.com/live-updates/hurricane-milton-2024/.

46. David Latona & Charlie Devereux, *At least 89 people missing from floods in eastern Spain*, REUTERS (Nov. 5, 2024), https://www.reuters.com/world/europe/spain-deploys-14898-police-officers-troops-areas-hit-by-flash-floods-2024-11-05/.

47. David Morgan, *James Earl Jones, Tony-winning actor and voice of Darth Vader, dies at age 93*, CBS NEWS (Sept. 11, 2024), https://www.cbsnews.com/news/james-earl-jones-dies-age-93-actor-darth-vader/.

48. Ben Ratliff, *Quincy Jones, Giant of American Music, Dies at 91*, N.Y. TIMES (Nov. 6, 2024), https://www.nytimes.com/2024/11/04/arts/music/quincy-jones-dead.html.

Ethel Kennedy

Ethel Kennedy, the widow of former Senator Robert F. Kennedy and a well-known human rights activist in her own right, died on October 10, 2024. Following her husband's assassination in 1968, she founded the Robert F. Kennedy Human Rights organization. In 2014, she was awarded the Presidential Medal of Freedom by President Barack Obama. And as late as 2018 — well into her eighties — she "joined a hunger strike to protest the then-Trump administration's separation of families at the US-Mexico border."[49]

Sheila Jackson Lee

Long-serving Texas congresswoman Sheila Jackson Lee lost her battle with pancreatic cancer, passing away at the age of 74 on July 19, 2024. Congresswoman Lee, who represented her Houston congressional district for thirty years, was among the earliest opponents of the war in Iraq War, had a long track record of advocacy for gay rights, and was an author of the Violence Against Women Act. She also authored and was the lead sponsor of legislation that established Juneteenth — "the first new federal holiday in 38 years."[50]

Willie Mays — the "Say Hey Kid"

Willie Mays, by consensus one of the greatest baseball players of all time, passed away on June 18, 2024, at the age of 93.[51] I grew up in Detroit, an American League city in the days before interleague play, so there were few opportunities for me to see him play except on television. But I did get to see him play in person twice. Two friends and I drove from Detroit to Cincinnati hoping (without success) to see him hit his 600th homerun (he had 598 going into the game). And in early October 1974, while in law school, I saw Mays get his last National League hit —a single up the middle in the New York Mets' pennant-clinching playoff game against the Reds.

Bob Newhart

Bob Newhart, the accountant-turned-comedian, died in Los Angeles, California on July 18, 2024, at the age of 94. In a comedy career that spanned nearly sixty years, he first gained fame with a 1960 comedy album, *The Button Down Mind of Bob Newhart* — "the first comedy album to hit No. 1 on Billboard's albums chart." But he gained his biggest success, which he attributed to his signature stammer, with two television hits — *The Bob Newhart Show*, where he played "a psychologist surrounded by eccentric, oddball patients" and *Newhart*, where he played the owner of a small Vermont hotel. He last "played a former kids TV show host bewildered by the fan worship of genius scientist Sheldon Cooper" on *The Big Bang Theory*."[52]

Janice Paige

Some of our readers are old enough to remember singer Steve Lawrence, whose passing at age 88 I wrote about in the spring edition of the Journal. But I'll bet that even fewer of our readers will remember Janice Paige, another singer/actor quite famous in her time, who died in June, 2024, at the age of 101. She was a

49. Piper Hudspeth Blackburn, *Ethel Kennedy, human rights activist and widow of Robert F. Kennedy, dies at 96*, CNN (Oct. 10, 2024), https://www.cnn.com/2024/10/10/politics/ethel-kennedy-dies/index.html.

50. Matthew Choi & Sejal Govindarao, *U.S. Rep. Sheila Jackson Lee is dead at 74*, TEX. TRIB. (July 19, 2024), https://www.texastribune.org/2024/07/19/sheila-jackson-lee-dies/.

51. Hillel Italie, *Willie Mays, the Giants' electrifying 'Say Hey Kid,' dies at 93*, AP (June 19, 2024), https://apnews.com/article/willie-mays-dies-at-93-baseball-33b31cc2d6382676ed54517d20ea36a3.

52. Eric Deggans, *'I've lived in an incredible time': Comic Bob Newhart dies at 94*, NPR (July 18, 2024), https://www.npr.org/2024/07/18/791345695/bob-newhart-dead.

dancer, singer, and actress most famous for starring as the "feisty, romance-resistant union leader" in the Broadway production of *The Pajama Game* and later as the star of *Mame*.[53]

Pete Rose

Pete Rose, the best baseball player not in the sport's Hall of Fame, passed away on September 30, 2024, at the age of 83. Rose, known as "Charlie Hustle" for headfirst slides and for running out walks at full speed, holds the all-time records for hits, singles, games won *and lost*, and games played. He was a player and a player-coach, a perennial all-star, and the winner of several World Series. But as a manager, he bet on baseball games (though not against his own team), resulting in his banishment from professional baseball and from the Hall of Fame.[54]

Bill Walton

Bill Walton, NBA Hall of Fame member and NBA MVP, winner of three consecutive College Player of the Year awards, two NCAA titles with UCLA, and two NBA titles with the Portland Trail Blazers and Boston Celtics, passed away on May 27, 2024, after a long battle with colon cancer at the age of 71. Following his playing days, he enjoyed a long and colorful[55] broadcasting career with NBC, ABC, CBS, Fox, Turner Sports, and ESPN that also won him an Emmy.[56]

Ruth Westheimer

A Holocaust survivor whose parents sent her from her home in Frankfurt to Switzerland at the age of 10 to escape the Nazis, Ruth Westheimer, or "Dr. Ruth" as she came to be known to millions of television viewers in the 1980s, passed away in July, 2024 at the age of 96. As NPR recounted, she was an "[i]nternationally acclaimed sex therapist . . . who tore down taboos with her open, nonjudgmental and good-humored public conversations about human intimacy." Beside her widely-watched television show, she wrote dozens of books and taught at Yale, Princeton, Columbia, and Hunter College.[57]

Jerry West

Selected not once, but three times for admission to the Naismith Basketball Hall of Fame — once as an NBA player, a second time as a member of the 1960 Olympic gold medal team, and a third time as a lifetime contributor to the sport — Jerry West passed away on June 12, 2024, at the age of 86. "The NBA has never confirmed the worst-kept secret in basketball," wrote AP sports reporter Tim Reynolds, "that Jerry West is the player whose silhouette is depicted in the league's logo."[58] A consensus pick as one of basketball's all-time greats — an all-star in each of his fourteen NBA seasons, an NBA champion, and an NBA MVP — West starred for West Virginia University and later the Los Angeles Lakers and

53. Anita Gates, *Janis Paige, Star of Broadway's 'The Pajama Game,' Is Dead at 101*, N.Y. TIMES (June 3, 2024), https://www.nytimes.com/2024/06/03/theater/janis-paige-dead.html.

54. Michelle Watson, *Pete Rose, Major League Baseball's all-time hit king, has died at 83*, CNN (Sept. 30, 2024), https://www.cnn.com/2024/09/30/sport/pete-rose-death-mlb-spt/index.html.

55. "Come on, that was no foul," the NBC obituary recounts Walton stating during a broadcast. "It may be a violation of all the basic rules of human decency, but it's not a foul." Corky Siemaszko, *Two-time NBA champion Bill Walton dead at 71*, NBC NEWS (May 27, 2024), https://www.nbcnews.com/news/obituaries/bill-walton-nba-hall-of-famer-basketball-dies-71-rcna154191.

56. *Id.*

57. Chloe Veltman, *Pioneering sex expert Dr. Ruth Westheimer dies at 96,* NPR (July 13, 2024), https://www.npr.org/2024/07/13/nx-s1-5038571/dr-ruth-westheimer-who-encouraged-america-to-talk-about-sex-dies-at-96.

58. Tim Reynolds, *Jerry West, a 3-time Hall of Fame selection and the inspiration for the NBA logo, dies at 86*, AP (June 14, 2024), https://apnews.com/article/jerry-west-dead-nba-033c08e78eb9749f4cc275c54ff31d97.

had a long and successful career as an executive with the Lakers, the Memphis Grizzlies, the Golden State Warriors, and the Los Angeles Clippers.[59]

. . . . and the Infamous

Hezbollah Terrorist-in-Chief Hassan Nasrallah

"Hassan Nasrallah is rotting in hell where he belongs." So remarked New York Congressman Ritchie Torres on the death of the head of Hezbollah, Lebanon's terrorist state within-a-state responsible for the deaths of hundreds of Israelis and Americans.[60] As head of Iran's chief proxy group, Nasrallah had overseen the killing of hundreds of Israelis and Americans "over a four-decade reign of terror," [61] sent thousands of fighters into Syria to bolster the repressive regime of Syrian dictator Bashar al-Assad, and trained the Houthis in Yemen to bomb shipping lanes.[62] His death following Israel's bombing of Hezbollah headquarters in a Beirut suburb drew cheers from both Iranian dissidents[63] and from Syrian victims of Assad's civil war.[64]

Hezbollah terrorist Fuad Shukr

Days after the Hezbollah terrorists who control much of southern Lebanon launched missiles at a soccer field in Israel's Golan Heights that killed twelve Arab Druse children and badly injured many others, Israel retaliated with a precision missile strike on an apartment building outside Beirut that killed Fuad Shukr.[65] Shukr, a senior commander in the Hezbollah terrorist hierarchy and close advisor to Hezbollah leader Hassan Nasrallah, has also been wanted by the U S. government for his role in the 1983 bombing of American military barracks in Beirut that killed 300 U.S. and French soldiers.[66]

Hamas Terrorist Ismail Haniyeh

On July 30, 2024, a bomb planted weeks or months earlier was detonated in an apartment in Tehran, killing its occupants — Hamas terrorist Ismail Haniyeh and his body guard. Haniyeh had been the leader of what the terrorist group called its "political bureau," and, while no party has claimed responsibility for the bombing, Israel is suspected of the killing. Haniyeh's chief role was to manage the terrorist group's considerable finances, which the U.S. estimates to be as much as $1 billion, "with assets in countries such as Sudan, Turkey, Saudi Arabia, Algeria

59. *Id.*

60. *See* Ritchie Torres (@RitchieTorres), X (Sept. 28, 2024, 1:13 PM), https://x.com/RitchieTorres/status/1840092451505332423 (September 2024).

61. *Statement from President Joe Biden on the Death of Hassan Nasrallah*, WHITE HOUSE (Sept. 28, 2024), https://www.whitehouse.gov/briefing-room/statements-releases/2024/09/28/statement-from-president-joe-biden-on-the-death-of-hassan-nasrallah/.

62. Benjamin Barthe, *In the Arab world, split reactions to Nasrallah killing reflect Hezbollah's divisiveness*, LEMONDE (Sept. 30, 2024), https://www.lemonde.fr/en/middle-east-crisis/article/2024/09/30/in-the-arab-world-split-reactions-reflect-hezbollah-s-twofold-dimension_6727768_368.html#.

63. Faramarz Davar, *Why Iranians Turned Against Hassan Nasrallah*, IRANWIRE (Sept. 30, 2024), https://iranwire.com/en/politics/134492-why-iranians-turned-against-hassan-nasrallah/.

64. Daniel Estrin et al., *Hezbollah leader's killing sparks joy and rage across the Middle East*, NPR (Sept. 29, 2024), https://www.npr.org/2024/09/29/nx-s1-5132098/hezbollah-nasrallah-world-reaction-israel-us-lebanon.

65. Ronen Bergman et al., *Israel Says It Killed Hezbollah Commander in Airstrike Near Beirut*, N.Y. TIMES (July 30, 2024), *https://www.nytimes.com/2024/07/30/world/middleeast/israel-hezbollah-lebanon.html?unlocked_article_code=1._U0.Ssxg.aJ3Qk_IAufCZ.*

66. Aaron Boxerman, Ronen Bergman and Euan Ward, *Who Is Fuad Shukr, Target of the Israeli Strike on Beirut?,* N.Y. TIMES (July 30, 2024), https://www.nytimes.com/2024/07/30/world/middleeast/fuad-shukr-hezbollah-israel-strike.html?smid=url-share.

and the United Arab Emirates. It also has other international funding sources, including Iran." Haniyeh had been on the State Department's Specially Designated Global Terrorists list since 2018 and was facing an arrest warrant from the International Criminal Court for "war crimes and crimes against humanity including murder, rape, torture and taking hostages, during and since the Oct. 7 attack on Israel."[67]

Hamas Terrorist-in Chief, Butcher of Khan Younis, Yayah Sinwar

Yaya Sinwar, the mastermind behind Hamas's October terrorist attacks that brutalized and killed 1200 Israelis — including women, infants, and the elderly — and captured another 250 Israelis to be used a hostages, was killed by Israeli soldiers on Thursday, October 17, his death confirmed hours later.[68] Sinwar, 61, was both the "political" and military leader of Hamas, an organization whose political and military objectives — the destruction of Israel and its Jewish inhabitants — were identical.

Ebrahim Raisi, President of Iran, Butcher of Tehran

Ebrahim Raisi, Iran's president, was killed in a May 20, 2024, helicopter crash along with Iran's foreign minister, Hossein Amirabdollahian. Raisi, who oversaw Iran's supply of bomb-carrying drones to Russia,[69] gained infamy as the Butcher of Tehran when he became that city's deputy prosecutor at age 25, sitting on a "prosecution committee" in the 1980s "that is believed to have ordered the executions of thousands of political prisoners."[70]

Big Elections Around the Globe

Elections in South Africa — ANC Loses Power It Held for 30 Years

South Africa's African National Congress (ANC) lost its longstanding grip on parliamentary control in elections held on June 1, 2024. The ANC, which had controlled the government since the end of apartheid thirty years ago, won only 40% of the vote, punished by voters for high unemployment and "shortages of clean water, electricity, housing and other services"[71]

Elections in India, a Setback for Modi's Party

Only days after the ANC's historic election loss in South Africa, Indian Prime Minister Narendra Modi won a rare third term. But his Hindu nationalist Bharatiya Janata Party lost its parliamentary majority, upsetting predictions that his party would win a supermajority. During the campaign, Modi and other party leaders

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67. Francis Vinall, *What to know about Ismail Haniyeh, the Hamas leader killed in Iran*, WASH. POST (July 31, 2024), https://wapo.st/4d1i2ve.

68. *Hamas leader Yahya Sinwar killed in Gaza: Israel*, DW (Oct. 17, 2024), https://www.dw.com/en/hamas-leader-yahya-sinwar-confirmed-dead-in-israeli-strike/a-70524393.

69. Jon Gambrell, *Iran's president and foreign minister die in helicopter crash at moment of high tensions in Mideast,* AP (May 20, 2024), https://apnews.com/article/iran-president-ebrahim-raisi-426c6f4ae2dd1f0801c73875bb696f48.

70. Lucia Stein & Rebecca Armitage, *For Ebrahim Raisi, the 'Butcher of Tehran', life was one brutal rise. Then he came in for a 'hard landing'*, AUSTL. BROAD. CO. NEWS (May 20, 2024), https://www.abc.net.au/news/2024-05-21/ebrahim-raisi-the-butcher-of-tehran-rise-and-fall/103870706.

71. Gerald Imray & Mogomotsi Magome, *The ANC party that freed South Africa from apartheid loses its 30-year majority in landmark election*, AP (June 1, 2024), https://apnews.com/article/south-africa-election-vote-anc-d9da7582ca98a4e00fec2da6a5fe1e91.

had been "accused of using hate speech and other inflammatory rhetoric, especially against Muslims."[72]

Violence-Marred Mexican Elections, Mexico Elects First Woman, First Jewish President.

In early June, Claudia Sheinbaum was elected as the next president of Mexico. She became the first woman and first Jewish president in that nation's history. A climate scientist by training, the former mayor of Mexico City began her six-year term on October 1, 2024.[73]

Venezuelan Dictator Maduro Uses Force to Overturn Election

Late last year, the United States had agreed to ease sanctions on Venezuela if its current president/dictator, Nicolás Maduro, agreed to hold free and fair elections for that country's presidency in 2024. When Maduro then blocked his main rival, Maria Corina Machado, from even registering to run, sanctions were reimposed even before the election with the promise of relief if there was a fair election.[74] That didn't happen. Elections were held on July 28, 2024. And publicly available election tabulations from 80% of the country's precincts showed that Maduro trailed his challenger, Edmundo González, by a two-to-one margin. But without producing the election results and only hours after the polls had closed, Venezuela's National Electoral Council declared Maduro the winner with "just after half of the vote."[75] While "governments around the world have expressed skepticism, and even outright disbelief, over President Nicolás Maduro's claim to victory," the Electoral Council has continued to withhold the machine-by machine results. The only member of the Electoral Council not a member of Maduro's party had decried the results, stating in August, "that he had no proof that Venezuela's authoritarian president won last month's election."[76] Following Maduro's announcement that opposition leaders would be arrested and criminally prosecuted, González, the apparent winner, fled to Spain.[77]

Hezbollah Chutzpah

On October 8, 2023, a day after Hamas terrorists slaughtered over 1,200 Israelis (raping many of the women they then killed) and took another 250 persons — including infants — hostage, Hezbollah, its fellow Iran-backed terrorist organization in Lebanon, began unprovoked shelling along Israel's norther border weeks before Israel entered Gaza. Described by Hezbollah leaders as an act of "solidarity" with Hamas, its constant bombing — an unambiguous act of war —

72. Mithil Aggarwal, *How Modi lost his magic — and his majority — in India election surprise*, NBC News (June 5, 2024), https://www.nbcnews.com/news/world/india-election-modi-bjp-lost-majority-election-surprise-rcna155557.

73. María Verza & Mark Stevenson, *Mexico elects Claudia Sheinbaum as its first female president*, AP (June 3, 2024), https://apnews.com/article/mexico-elections-president-governorships-lopez-obrador-d7fef5c7ac964072401ba6d9809dd7d4.

74. Clare Ribando Seelke, CONG. RSCH. SERV., IF10715, VENEZUELA: OVERVIEW OF U.S. SANCTIONS POLICY, CONGRESSIONAL RESEARCH SERVICE (2024); Joshua Goodman & Regina Garcia Cano, *U.S. reimposes oil sanctions on Venezuela as hopes for a fair presidential election fades*, PBS NEWS (April 17, 2024), https://www.pbs.org/newshour/world/u-s-reimposes-oil-sanctions-on-venezuela-as-hopes-for-a-fair-presidential-election-fades.

75. Julie Turkewitz, *No Evidence That Maduro Won, a Top Venezuelan Election Official Says*, N.Y. TIMES (Aug. 26, 2024), https://www.nytimes.com/2024/08/26/world/americas/maduro-venezuela-election-results.html?unlocked_article_code=1.F04.UvxX.1CZFKbvrSkBD.

76. *Id.*

77. *See* María Luisa Paúl et al., *supra* note 22.

has displaced over 60,000 Israeli civilians from their homes for more than a year[78] and killed twelve Israeli Arab Druze children playing soccer. Yet, when thousands of pagers and walkie-talkies held by Hezbollah terrorists were triggered to explode on successive days in late September 2024, Hasan Nasrallah (Hezbollah's former terrorist in chief) had the chutzpah[79] to label this response to Hezbollah's unrelenting terrorist attacks an "act of war" warranting "a severe reckoning."[80]

Santos Guilty Plea and Menendez Bribery Conviction

Former Senator Robert Menendez, who had escaped an earlier corruption prosecution with a hung jury, did not fare as well the second time around. On July 16, 2024, he was convicted on a number of corruption charges.[81] A month later, former Congressman and serial fibber George Santos plead guilty to charges of wire fraud and aggravated identity theft.[82] He had earlier been expelled from Congress after serving less than a full term.

Ignominy for New York City's Past and Present Mayors

On September 26, 2024, Rudolph Giuliani, the disgraced former mayor of New York City, was disbarred from legal practice in the District of Columbia, only a few months after having been disbarred from the practice of law in his home state of New York.[83] The same day, Eric Adams became the first sitting mayor of New York to be criminally indicted while in office. He has been charged with numerous counts of bribery and accepting unlawful foreign campaign contributions.[84]

Shrinking Squad
Primary Defeat of Jamal Bowman

Jamal Bowman, a two-term Congressman and member of "The Squad," was soundly defeated in the June New York Democratic primary.[85] Bowman's retraction of his false claim that documented cases of Hamas rape and torture of Israeli

78. Maayan Lubell & Dan Williams, *How Hezbollah attacks displace 60,000 Israelis, six months on*, REUTERS (April 4, 2024), https://www.reuters.com/world/middle-east/six-months-hezbollah-fire-keeps-uprooted-israelis-limbo-2024-04-04/.

79. "Chutzpah is a young man, convicted of murdering his parents, who argues for mercy on the ground that he is an orphan." Harbor Ins. Co. v. Schnabel Found. Co., 946 F.2d 930, 937 & n.5 (D.C. Cir. 1991).

80. Claire Parker et al., *Hezbollah chief calls pager, radio attacks an 'act of war' by Israel*, WASH. POST (Sept. 19, 2024), https://www.washingtonpost.com/world/2024/09/19/israel-lebanon-attack-explosions-hezbollah/.

81. Press Release, U.S. Att'y's Off., S.D.N.Y., Statement Of U.S. Attorney Damian Williams On The Convictions Of U.S. Senator Robert Menendez And Two New Jersey Businessmen (July 16, 2024), https://www.justice.gov/usao-sdny/pr/statement-us-attorney-damian-williams-convictions-us-senator-robert-menendez-and-two

82. Press Release, U.S. Att'y's Off., E.D.N.Y., Former Congressman George Santos Pleads Guilty to Wire Fraud and Aggravated Identity Theft (Aug. 19, 2024), https://www.justice.gov/usao-edny/pr/former-congressman-george-santos-pleads-guilty-wire-fraud-and-aggravated-identity.

83. Melissa Quinn, *Rudy Giuliani disbarred in D.C., months after disbarment in New York*, CBS NEWS (Sept. 26, 2024), https://www.cbsnews.com/news/rudy-giuliani-disbarred-washington-dc/.

84. Press Release, U.S. Att'y's Off., S.D.N.Y., New York City Mayor Eric Adams Charged With Bribery And Campaign Finance Offenses (Sept. 26, 2024), https://www.justice.gov/usao-sdny/pr/new-york-city-mayor-eric-adams-charged-bribery-and-campaign-finance-offenses.

85. Scott Wong & Bridget Bowman, *Rep. Jamaal Bowman, a vocal Israel critic and 'squad' member, loses primary*, NBC NEWS (June 25, 2024), https://www.nbcnews.com/politics/2024-election/jamaal-bowman-george-latimer-ny-house-primary-results-rcna158487.

women were a “lie” used for “propaganda”[86] was too little and too late, and his fire alarm antics that drew Congressional censure were apparently too much for his constituents, many of whom were Jewish.

Primary Defeat of Corey Bush

Not exactly a gracious loser, Corey Bush, another member of the Squad, vowed revenge against the American Israel Public Affairs Committee following her defeat by fellow progressive and St. Louis County prosecuting attorney Wesley Bell in Missouri’s August Democratic Party primary. Bush had refused to call Hamas what it is, a terrorist organization.[87] And her accusation that Israel, twenty percent of whose population is Arab, was engaged in “ethnic cleansing” in Gaza was “wrong and offensive” said Bell.[88] She also lost support for voting against President Biden’s infrastructure bill and perhaps because she was also “under ethics investigation related to paying her romantic partner to perform security work.”[89]

Loose Cannon?

On July 15, 2024, coincidentally the first day of the Republican National Convention, Florida federal district court judge Aileen Cannon issued an opinion dismissing as unconstitutional the entire felony indictment of Donald Trump and his co-defendants for the mishandling of classified documents. The grounds for Judge Cannon’s decision? Jack Smith, the special prosecutor who had brought the case, was independent of the Justice Department. To be legitimate, Cannon ruled, his appointment would have required him to be nominated by the President and confirmed by the Senate.[90] There is no small irony in the dismissal. For months, the former President and his supporters in Congress had argued that the criminal cases against him were evidence of the “weaponization” of the Justice Department.[91] But Judge Cannon’s decision rested on the *opposite* conclusion — that Smith had *too much* independence from the Attorney General. Her decision, the Department declared shortly thereafter, “deviates from the uniform conclusion of all previous courts to have considered the issue that the Attorney General is statutorily authorized to appoint a Special Counsel,”[92] and on August 27, 2024, the agency appealed the decision to the Eleventh Circuit Court of Appeals. An amicus brief filed by ethics professors and a former federal judge went beyond the government’s appeal, urging the appellate court not only to reverse Cannon’s ruling

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86. Daniel Lippman, *Bowman reverses after calling reports of Oct. 7 sexual assaults in Israel ‘propaganda’*, POLITICO (Mar. 26, 2024), https://www.politico.com/live-updates/2024/03/26/congress/bowman-house-israel-october-7-sexual-assault-hamas-00148426.

87. Luke Broadwater, *AIPAC Demonstrates Its Clout With Defeat of a Second ‘Squad’ Member*, N.Y. TIMES (Aug. 7, 2024), https://www.nytimes.com/2024/08/07/us/politics/bush-bell-aipac-missouri-primary.html.

88. *Wesley Bell, backed by AIPAC, defeats ‘Squad’ member Cori Bush in St. Louis district primary*, PBS NEWS (Aug. 7, 2024), https://www.pbs.org/newshour/politics/wesley-bell-backed-by-aipac-defeats-squad-member-cori-bush-in-st-louis-distrct-primary.

89. Broadwater, *supra* note 81.

90. U.S. v. Trump, Case No. 23-80101-CR, 2024 U.S. Distr. LEXIS 123552 (S.D. Fla. July 15, 2024).

91. *See, e.g.*, *Hearing on the Weaponization of the Federal Government Before the Select Subcomm. on the Weaponization of the Fed. Gov’t of the H. Comm. on the Judiciary*, 118th Cong. (2024); *See also* Scott Wong, *Trump allies say Biden is ‘weaponizing’ DOJ against his chief 2024 rival following indictment*, NBC News (June 8, 2023), https://www.nbcnews.com/politics/donald-trump/trump-indictment-republicans-say-biden-weaponizing-doj-rcna87962.

92. Devlin Barrett & Perry Stein, *Trump’s classified documents case dismissed by Judge Aileen Cannon*, WASH. POST (July 15, 2024), https://www.washingtonpost.com/national-security/2024/07/15/trump-classified-trial-dismisssed-cannon/.

but to remove her from the case. "Judge Cannon's conduct," they argued, "— including her solicitation of legally baseless jury instructions — has repeatedly appeared to cross the line from mere legal error to active judicial intervention and advocacy on behalf of the former president."[93] In light of Trump's subsequent reelection and his promise to kill all pending criminal charges against him once he takes office, however, all of this is certain to become moot.

They Said That?

"We do not wish to be the causes of instability in the region."

Masoud Pezeshkian, President of Iran, the state sponsor of the terrorist organizations Hezbollah, Hamas, and the Houthis, speaking with no sense of irony at the annual United Nations General Assembly[94] — only days before Iran launched nearly two hundred missiles at Israel.

My wife did it. I had nothing to do with it.

Paraphrase of the explanations of (1) subsequently convicted Senator Menendez explaining the presence of gold bars in his home and (2) Supreme Court Justice Alito explaining the display of an upside down flag — a symbol of "stop the steal" — in front of his home days after the January 6 mobs attacked the Capitol.[95]

"Milwaukee is a horrible city"

Republican presidential nominee Donald Trump commenting on the site of the Republican National Convention.[96]

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93. Tierney Sneed, *Retired federal judge and ethics experts want Judge Cannon taken off Trump documents case*, CNN (Sept. 4, 2024), https://www.cnn.com/2024/09/03/politics/retired-judge-wants-cannon-removed-trump-documents/index.html.

94. John Hudson & Michael Birnbaum, *Iran says Hamas leader's killing in Tehran will not go 'unanswered'*, WASH. POST (Sept. 23, 2024), https://www.washingtonpost.com/national-security/2024/09/23/iran-pezeshkian-united-nations-israel-hezbollah-gaza/.

95. *See* Lindsay Whitehurst & Gary Fields, *Upside-down flag at Justice Alito's home another blow for Supreme Court under fire*, AP (May 17, 2024), https://apnews.com/article/justice-samuel-alito-upsidedown-flag-trump-jan6-f5809b9fd3be19b2359907f7b16651e5; Caitlin Yilek, *Who is Nadine Menendez? Sen. Bob Menendez's wife is at center of bribery trial*, CBS NEWS (JULY 16, 2024), https://www.cbsnews.com/news/nadine-menendez-bob-menendez-wife-corruption-trial-allegations/.

96. Scott Bauer, *Trump refers to Milwaukee as 'horrible' just before the city hosts the Republican convention*, AP (June 13, 2024), https://apnews.com/article/trump-milwaukee-horrible-city-gop-convention-niomination-604fe33acb5606e9db1cbf3f966507e3.

BASH: 38 seconds left, President Trump. Will you take any action as President to slow the climate crisis?

TRUMP: So, I want absolutely immaculate clean water and I want absolutely clean air, and we had it. ***We had H_2O****. We had the best numbers ever . . .*

Republican Presidential Nominee (and now President-Elect), Donald Trump, responding to question on his plans to tackle climate change during June debate with President Biden.[97]

"*They're going to lay the groundwork and detail plans for exactly what our movement will do*."

Former President Trump's April 2022 speech to Heritage Foundation referring to Project 2025.[98]

"*I know nothing about Project 2025. I have no idea who is behind it. I disagree with some of the things they're saying and some of the things they're saying are absolutely ridiculous and abysmal. Anything they do, I wish them luck, but I have nothing to do with them.*"

Former President Trump, posting on Truth Social in July 2024.[99]

"In Springfield, they're eating the dogs. The people that came in. They're eating the cats. They're eating — they're eating the pets of the people that live there."

Former President Trump, during debate with Vice President Harris.[100]

"There's a lot of garbage on the internet and this is a piece of garbage that was simply not true, there's no evidence of this at all. These are positive influences on our community in Springfield and any comment about that otherwise I think is hurtful and is not helpful to the city of Springfield and the people of Springfield."

Ohio Governor Mike DeWine, denouncing rumors spread by President-Elect Trump and his running mate about lawful Haitian immigrants who have settled in Springfield, Ohio.[101]

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97. Biden-Trump Debate, *supra* note 20 (emphasis added).

98. Isaac Arnsdorf et al., *Trump took a private flight with Project 2025 leader in 2022*, WASH. POST (Aug. 7, 2024), https://www.washingtonpost.com/elections/2024/08/07/trump-heritage-project-2025-roberts/.

99. Franco Ordoñez, *It seems like Project 2025 is everywhere. But what is it?*, NPR (July 11 2025), https://www.npr.org/2024/07/11/nx-s1-5035272/project-2025-trump-biden-heritage-foundation-conservative

100. Riley Hoffman, *READ: Harris-Trump presidential debate transcript*, ABC NEWS (Sept. 10, 2024), https://abcnews.go.com/Politics/harris-trump-presidential-debate-transcript/story?id=113560542 [hereinafter Debate Transcript].

101. Maya Marchel Hoff, *Ohio Gov. Mike DeWine says claim about migrants eating pets is a false 'piece of garbage'*, USA TODAY (Sept. 15, 2024), https://www.usatoday.com/story/news/politics/elections/2024/09/15/ohio-gov-mike-dewine-migrants-eating-pets-false/75236689007/.

"If I have to create stories so that the American media actually pays attention to the suffering of the American people, then that's what I'm going to do."

JD Vance, in interview with Dana Bash, explaining why he and his presidential running mate were spreading the baseless rumors condemned by Ohio governor Mike DeWine.[102]

"Who's going to tell him that the job he's currently seeking might just be one of those 'Black jobs?'"

Michelle Obama's not-so-subtle reference to presidential candidate Trump's claim that immigrants were taking away "black jobs."[103]

"[My memory loss] was caused by a worm that got into my brain and ate a portion of it and then died."

"Donald Trump was a terrible president"

"Despite rhetoric to the contrary, President Trump has a weakness for swamp creatures, especially corporate monopolies, their lobbyists, and their money."

Various 2024 quotes from Robert F. Kennedy, Jr., former Democratic, then Independent candidate for the presidency and later named part of Trump transition team.[104]

Muddled Math

"Virtually 100% of the net job creation in the last year has gotten to migrants," said Trump, "You know that? Most of the job creation has gone to migrants. In fact, ***I've heard that substantially more than — uh, beyond, actually beyond the number of 100%,*** *it's a much higher number than that . . ."*

Presidential candidate Trump at an August 15, 2024, news conference.[105]

102. Kit Maher & Chris Boyette, *JD Vance defends baseless rumor about Haitian immigrants eating pets*, CNN (Sept. 15, 2024), https://www.cnn.com/2024/09/15/politics/vance-immigrants-pets-springfield-ohio-cnntv/index.html.

103. Stephanie Kelly, *Michelle Obama tells Trump the presidency just may be a 'Black job'*, REUTERS (Aug. 21, 2024), https://www.reuters.com/world/us/michelle-obama-tells-trump-presidency-just-may-be-black-job-2024-08-21/.

104. *See* Tim Balk, *'A Terrible President': 12 Times Robert F. Kennedy Jr. Criticized Trump*, New York Times (Aug. 28, 2024), https://www.nytimes.com/2024/08/28/us/politics/rfk-trump-criticisms.html; Laura Mannweiler, *A Look Back at the Most Bizarre Moments of the RFK Jr. Campaign*, U.S. NEWS (Aug. 23, 2024), https://www.usnews.com/news/national-news/articles/2024-08-23/rfk-jr-suspends-his-campaign-a-look-back-at-the-most-bizarre-moments.

105. Sarah Rumpf, *'INSANELY DELUSIONAL': Trump Brutally Mocked for Claiming 'Substantially More' Than 100% of Job Creation Went to Migrants*, MEDIAITE (Aug. 15, 2024), https://www.mediaite.com/trump/insanely-delusional-trump-brutally-mocked-for-claiming-substantially-more-than-100-of-job-creation-went-to-migrants/.

Too Extreme for Marjorie Taylor-Greene?

"This is appalling and extremely racist. It does not represent who we are as Republicans or MAGA. This does not represent President Trump. This type of behavior should not be tolerated ever."

Georgia Congressional Rep. Marjorie Taylor Greene (who had previously claimed that "a prominent Jewish banking family had used a space laser to start fires in California") responding to a racist comment about Vice President Harris from Trump advisor and right-wing extremist Laura Loomer.[106] Only weeks later, Greene suggested in the aftermath of Hurricane Helene that the government "can control the weather. It's ridiculous for anyone to lie and say it can't be done."[107]

More Muddled Math

"We had the greatest economy. We got hit with a pandemic. And the pandemic was, not since 1917 where 100 million people died has there been anything like it."

Presidential candidate Trump at the September 10, 2024, debate with Vice President Harris.[108] The entire population of the United States was 105 million in 2017 and 103 million in 2018. "Worldwide the death toll [from the 1918 influenza epidemic] is generally put at 20 million."[109]

Fascist Threat?

"He is the most dangerous person ever. I had suspicions when I talked to you about his mental decline and so forth, but now I realize he's a total fascist. He is now the most dangerous person to this country."

Mark Milley, retired Army General and former chair of the Joint Chiefs of Staff under Trump, speaking about the now President-Elect.[110]

"Certainly the former president is in the far-right area, he's certainly an authoritarian, admires people who are dictators — he has said that. So he certainly falls into the general definition of fascist, for sure."

John Kelly, a former four-star Marine general describing President-Elect Trump whom Kelly served as chief of staff during Trump's first term.[111]

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106. Josh Marcus, *Marjorie Taylor Greene slams Trump pal Laura Loomer for 'extremely racist' post about Kamala Harris*, INDEPENDENT (Sept. 12, 2024), https://www.independent.co.uk/news/world/americas/us-politics/marjorie-taylor-greene-laura-loomer-harris-india-b2611353.html.

107. Marina Dunbar, *Marjorie Taylor Greene condemned over Helene weather conspiracy theory*, THE GUARDIAN (Oct. 7, 2024), https://www.theguardian.com/us-news/2024/oct/07/marjorie-taylor-greene-hurricane-helene.

108. Debate Transcript, *supra* note 100.

109. Andrew Noymer & Michel Garenne, *The 1918 Influenza Epidemic's Effects on Sex Differentials in Mortality in the United States*, 26 POPULATION & DEV. REV. 565 (2000).

110. Tal Axelrod, *John Kelly comes out swinging against Trump, says he fits 'fascist' definition*, ABC NEWS (Oct. 23, 2024), https://abcnews.go.com/Politics/john-kelly-swinging-trump/story?id=115061457.

111. Michael Schmidt, *As Election Nears, Kelly Warns Trump Would Rule Like a Dictator*, N.Y. TIMES (Oct. 22, 2024), https://www.nytimes.com/2024/10/22/us/politics/john-kelly-trump-fitness-character.html.

"But he certainly has those [fascist] inclinations. And I think it's something we should be wary about."

Mark Esper, Secretary of Defense for President-Elect Trump during his first term, speaking about the former and now future President.[112]

Here is hoping, against all the evidence, that these officials who knew him best are wrong.

With Thanksgiving soon approaching, I want to give my thanks, as always, to my fellow editors and to the authors who make this Journal possible. And I am beyond grateful to the students at Tulsa's School of law who help produce the Journal. It has been a joy to coordinate with the Journal's student Editor-in-Chief, Devyn Saylor. Devyn has managed to juggle a full course load with coordinating the publication of this edition's five articles, multiple committee reports, student notes, and more. Happy reading.

Harvey Reiter
November 2024
Washington, D.C.

112. Greta Reich, *Mark Esper: Trump 'has those inclinations' toward fascism*, Politico (Oct. 23, 2024), https://www.politico.com/live-updates/2024/10/23/2024-elections-live-coverage-updates-analysis/esper-backs-kelly-00185125.

IN MEMORIAM: JUDGE ISAAC DAVID BENKIN

"Stand behind the yellow line"

On July 13, 2024, Judge Isaac David Benkin passed away from heart failure following a brief illness. He had just turned 89.

He was a brilliant judge and lawyer and an even better individual. But these words only begin to describe who he was.

David Benkin was a titan of the energy bar. He served as an Administrative Law Judge at FERC for about two decades, joining the agency when it was still operating as the Federal Power Commission. He was highly regarded by his colleagues. Lawyers who appeared before him could expect that he would know the law better than they did and that he would conduct his hearings efficiently, fairly, and with humor. Strongly committed to advancing federal energy regulatory practice, he worked tirelessly as an editor and contributor to the *Energy Law Journal* and on behalf of the Charitable Foundation of the Energy Bar Association. For those fortunate enough to be his law clerk, such as myself, he provided a mentorship experience that was invaluable and the opportunity to form a lifelong friendship.

To me he was always "Judge Benkin," even though I knew him for the full forty-plus years of my legal career, beginning with the very first day that I started working as his law clerk at FERC. Nobody could have asked for a better teacher. Eventually, we became colleagues in three different firms. Throughout, he served as an invaluable sounding board for me, always willing to puzzle through a difficult issue and providing solid counseling on topics that went well beyond matters of law.

He had a frighteningly good memory. Sometimes, just for the sport of it, lawyers upon realizing his extraordinary intellect might ask Judge Benkin if he knew of a case on a particular legal issue. Typically, he would immediately recall a decision on point by name – with a page reference and quote thrown in for extra flourish.

He was a terrific writer. His decisions as an ALJ are a joy to read. They are clearly written, well-reasoned, always insightful, and sprinkled with unforgettable turns of phrases and literary references to liven-up the reading experience. Likewise, the articles Judge Benkin contributed to the *Energy Law Journal* remain as fresh as the day they were written. Take a moment and skim something—anything—he crafted, and I am certain you will agree. You might wish to sample these: Initial Decision, *Long Island Lighting Co.*, Docket No. FA85-63-002, 42 FERC ¶ 63,005 (Jan. 15, 1988) and *The Inconsistent Lady: Discovery in Administrative Adjudications and the Evidentiary Use of Its Fruits,* 4 ENERGY L.J. 201 (1983).

His humor was sharp and memorable. Once, I asked Judge Benkin what he considered to be the best thing he had ever authored. Without hesitation, he responded that one of his *most effective and widely read* written pieces was "For your safety, please stand behind the yellow line while the bus is in motion." This warning was posted on public buses during the 1980s and was something that he had drafted earlier in his career while serving as an attorney for the Federal Highway Administration. Another time, I asked him who the smartest person in his law school class was, wondering whether he might mention himself. Judge Benkin had gone to Harvard College at the age of sixteen and then directly on to Harvard Law School, graduating in the class of 1959. He said he would not be able to answer that because the smartest person in his class had left after the first year. Taking the bait, I pressed him. “Well, who was that?” “Ruth Bader Ginsberg,” he responded with a smile.

Judge Benkin tried to teach me about baseball, a lifelong passion of his. Few knew more about America’s pastime than he did. We would occasionally go to games together, and Judge Benkin would patiently explain the intricacies of the sport to me even though I would frequently drift off, baseball’s charm eluding me. Fortunately, when my kids were young, he was happy to have me bring them along, and he would regale them with baseball lore during some of the lulls. I was never able to gain his love of the game, but my kids did.

Isaac David Benkin was born July 5, 1935, in Brooklyn, New York. After graduating law school, he served as a Judge Advocate in the Air Force. When his tour was over, he came to Washington to be the law clerk for Judge Samuel E. Whitaker of the U.S. Court of Claims. He then joined the trial staff of the Court of Claims Section of the Department of Justice and from there joined the legal staff of the Federal Highway Administration, where he was appointed Chief Counsel in 1970.

He became an ALJ with the Federal Power Commission in 1975, and in 1980, he was appointed Deputy Chief Judge of the agency after it became the Federal Energy Regulatory Commission. Upon retiring from FERC, Judge Benkin practiced as a lawyer before the agency in several law firms. He proudly served in the Air Force Reserve throughout most of his professional years, retiring as a Colonel and recognized with a Distinguished Service Award and an Air Force Legion of Merit. He leaves two children, Josh and Jeremy, a grandchild, and a devoted partner who was with him during his last years, Becky Adler.

A number of months ago, another former FERC law clerk, Miriam Swydan Erickson, and I approached Judge Benkin to write about his time serving as a FERC ALJ. Like myself, Miriam had remained close to Judge Benkin throughout her career, and the three of us would occasionally meet for lunch during his retirement years. He delighted in seeing and talking with us about our latest work activities and families. He was less interested in recalling his past; but after much nagging, he delivered the following short, reflective narrative that captures his spirit and style:

A RETIRED ALJ RECALLS LIFE IN THE OLD FPC

I joined the Administrative Law Judges Office of the Federal Power Commission in 1975. The Chief of the FPC's Office of Administrative Law Judges was Joe Zwerdling. After interviewing me, Judge Zwerdling introduced me to the Chairman of the Commission, John Nassikas. Mr. Nassikas was an old pol from New Hampshire. He thought it was very funny when I told him that he had gone very far for a graduate of Dartmouth.

At that time, the Office had only 18 ALJ's on board of the 21 or so that it was authorized to employ. So I was the first replacement for the judges who had recently retired. At first, I was asked to, and did, "clean up" after now-retired judges who had conducted hearings but did not prepare initial decisions.

Thereafter, I had my own docket.

My overwhelming impression of the job was amazement at the brilliance of my contemporaries and the attorneys who appeared before us. It was a steep learning curve for a brand-new ALJ who, until his appointment, had never seen an energy case before signing on with the Federal Power Commission.

At that time, the Commission's ALJ corps was mainly concerned with the so-called “curtailment” cases. The supply of natural gas available to the interstate market seemed to be drying up, threatening severe dislocations to America's economy. I drew the curtailment case involving Northern Natural Gas Company, which provided gas to the central part of the U.S. from Arkansas through Northern Minnesota. (At a later date Northern became a part of the Enron empire, but that's another story.) The hearing consumed many months and the resources of a large number of parties. One day, at the conclusion of our hearing on March 16, John O'Brian, Northern's general counsel, asked me to cancel the next day's session in honor of St. Patrick's Day. I declined to do so (we had witnesses schedule for that day's hearing) but ruled that in honor of the occasion, all persons in the hearing room would wear a green tie tomorrow. When I opened the hearing on March 17, I noted for the record that everyone in the hearing room except O'Brien was wearing green. Mr. O'Brien got to his feet and said, “Judge, if you've got it, you don't have to flaunt it.” We all broke up laughing at that.

The hearings were usually models of good will. Perhaps that was because the parties were, for the most part, large corporations and wealthy state and municipal entities who could afford to pay their legal counsels and expert witnesses. One of the rewards of sitting on the bench as an ALJ is that everyone laughs at your attempts at humor. The Commission's inability or unwillingness to decide most of the curtailment cases eventually led to its demise.

In time, Congress mooted the issue of curtailment policy by enacting its own set of priorities in the Natural Gas Policy Act of 1978.

There were instances in which I was required to determine the reasonable cost of equity capital for a jurisdictional pipeline or electric utility, not now but at some future date. I must confess that the process eluded me in several instances.

In general, however, the cases were fascinating. I am proud of the fact that my initial decision in favor of licensing the country's largest pumped storage facility (in Bath County, Virginia) was not appealed to the full Commission and so became the license under which that project was built and operated. Also, I have vivid memories of our visit to Alaska in connection with a case involving the expenditures to construct the Trans Alaska Pipeline System. (The case was settled, thank goodness). In addition, there were many cases in which I was required to determine the reasonable cost of equity capital for pipelines and jurisdictional electric utilities. How to do this accurately remains a mystery for me.

In time, Chief Judge Zwerdling retired, replaced by Curtis Wagner, and the Federal Power Commission morphed into the FERC that we still know today. Soon afterward, I was gone from the agency. I remain proud of much of the work we did, in spite of all the help we enjoyed from the Commissioners' suite.

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Judge Benkin's wisdom, dedication, wit, and kindness will be missed. Perhaps, then, it is best simply to end with another one of his most highly read regulatory issuances through which his legacy lives on. It is a concise teaching that perfectly reflects the judge's character, and you will do well to always remember it: "Do not talk to the driver while the bus is in motion."

May his memory be for a blessing.

IN MEMORIAM: DEREK ANTHONY DYSON

Derek Anthony Dyson, President and CEO of Today's Power, Inc., passed away unexpectedly on October 2, 2024, at his home in Little Rock, Arkansas. Derek is survived by his two children, Derek Robert (Robbie) Anthony Dyson and Cecelia Olivia Elizabeth Dyson, as well as siblings Carolyn Dyson Jackson, Thomasine Dyson Williams, Debra Dyson Taylor, Phyllis Dyson, Carl Dyson, Jr., Carlos Dyson, Denise Dyson Martin, and Veda Dyson. Derek was preceded in death by his parents, Olivia M. Dyson and Carl Dyson, Sr., and his sister Carla Dyson.

Derek received a bachelor's degree in economics from Virginia Polytechnic Institute and State University (VA Tech), an MBA from Florida Institute of Technology, and a Juris Doctor from American University, Washington College of Law (WCL).

Derek's professional life began as a Contracting Officer for the Department of the Navy, where he was in the Office of Special Projects. During his term with the Department of the Navy, he served as Acting Chief of Acquisition and Resource Management for the White House Situation Support Staff within the National Security Council. While studying for his J.D. at American University, mostly at night, Derek did "dual duty" as a Law Clerk with the Office of Administrative Law Judges at the Federal Energy Regulatory Commission (FERC), primarily working for (now retired) ALJ Lawrence Brenner. Upon graduation from WCL and passage of the Virginia Bar, Derek spent a short time with Hunton & Williams in Richmond, Virginia before deciding he wanted to come back to Washington, DC. Derek joined Duncan, Weinberg, Genzer & Pembroke, P.C. (DWGP) in January of 2002, where he spent twenty years — starting as a young associate and becoming a Shareholder with the Firm in 2006. While at DWGP, Derek served clients across the country and beyond, ranging from identifying a multi-million-dollar fraudulent bid for a power plant for a New York client, to exploring cutting edge ocean thermal energy in the Caribbean, to working closely with the Navajo Tribal Utility Authority and its General Manager (and friend) Walter Haase to bring electric service, running water, and access to wireless communications and broadband to unserved Native American communities. Fulfilling his lifelong ambition of running a company, in January of 2022, Derek left DWGP to join Today's Power, Inc. as its President and CEO, where he and his team worked to develop utility-scale solar photovoltaic and energy storage systems and electric vehicle charging stations for members of the Arkansas Electric Cooperatives, Inc. and across the United States.

In addition to his professional work, Derek also contributed significantly to his community. Along with filling many, many other roles within the Energy Bar Association (EBA) over the years, Derek was elected to serve as the President of the Charitable Foundation of the Energy Bar Association (CFEBA) from 2005-2006 and President of the Energy Bar Association from 2011-2012. He also served as President of the DC Chapter of the American Association of Blacks in Energy (AABE) from 2009-2011, served as General Counsel for the national AABE organization, and, when he moved to Little Rock, immediately became involved in the Arkansas Chapter of AABE. And if that wasn't enough, Derek also served on the Board of Directors for H Street Main Street since its founding in 2010, where he worked tirelessly toward its mission of promoting economic development on H Street, NE in Washington, DC, through among other things, an annual festival that highlights local businesses and the community, testifying before the DC City Council, and working for grant funding to support H Street business improvements.

But enough about Derek's many, many accomplishments. Derek was, and will be, unforgettable. He was a large man with an even larger personality. Derek had a commanding presence in any situation and in any room. He never shied away from a leadership position. If he found an issue or a cause important, it was important enough to step in, tell others what to do, and get it done. Derek's booming laugh — and he laughed a lot — was both unmistakable and infectious. He loved his kids, his family, his community, and helping others. He was a great friend and a great person. And he will be greatly missed.

IN MEMORIAM: GORDON EDWARD KAISER

Gordon Edward Kaiser passed away peacefully on May 16, 2024, surrounded by his family following a brief illness. Gordon was a highly recognized and revered expert in the field of Canadian energy regulation. He made significant contributions to energy policy, the law, and the public interest, with a work ethic and unique style that garnered him the respect of his colleagues.

Born in Victoria, Canada, on March 9, 1944, Gordon spent his early years growing up in numerous cities across Canada before entering St Michael's College at the University of Toronto in 1963, where he completed his undergraduate degree in economics, and Queen's University in 1966, where he obtained his law degree and a Master of Economics. To pay for school he worked as a porter for CN Rail and prided himself on being able to survive an entire shift on a single Oh Henry! candy bar.

Specializing in competition and energy regulatory law for over forty years, he appeared in all levels of Canadian courts, including the Supreme Court of Canada, and as counsel in regulatory hearings in six Canadian provinces and four Federal Tribunals. Gordon also was a bold entrepreneur, pushing innovation in the early days of the telecommunications industry. In the early 1990s, he bought a fledgling subsidiary of telecom giant Nokia and built a California-based paging company, CUE, which represented the largest American FM subcarrier network at the peak of the paging industry.

Combining his education as a lawyer and economist, Mr. Kaiser held many important and influential positions as a lawyer, adjudicator, arbitrator, and market monitor. He acted for many important public institutions including the Attorney General of Canada, the Commissioner of Competition, the Alberta Utilities Commission, and the Ontario Independent Electricity System Operator. Mr. Kaiser was adjunct professor at both Queen's University and the University of Toronto; authored three books: Competition Law in Canada, Energy Law and Policy, and the Guide to Energy Arbitration; and served as Vice-Chair of the Ontario Energy Board from 2004- 2010.

Through his work as Vice-Chair of the Ontario Energy Board, Mr. Kaiser distinguished himself and gained the respect of his peers and the public through his leadership in advancing the public interest. Two decisions authored by Mr. Kaiser are noteworthy.

The first is a decision from the Ontario Court of Appeal in the Toronto Hydro dividend case. The Court upheld Mr. Kaiser's reasons and ordered that future dividend payments from the utility to the municipality of Toronto be approved by a majority of Toronto Hydro's independent directors. This decision raised a number of interesting issues, the most significant being the role of the regulatory compact and how it informs directors' duties. The Court agreed with Mr. Kaiser that when there is a potential clash between a utility's obligations to its shareholders and its obligations to ratepayers, the decision should be approved by a majority of independent directors. The principle, championed by Mr. Kaiser, is that constraints may be imposed on utilities and their directors because they have an obligation not only to the shareholder but also to the public at large.

The second decision involved the Ontario Energy Board's ability to set special rates for low-income consumers, sometimes called "lifeline rates." In a split decision, the Ontario Energy Board ruled that the Board lacked jurisdiction. Mr. Kaiser authored the dissenting opinion later upheld by the Court of Appeal in ruling that the Board did have jurisdiction to set low-income rates. Mr. Kaiser's interpretation of the law created a lasting legacy of affordable gas and electricity rates for poorer consumers in Ontario.

After stepping down from the Ontario Energy Board, Mr. Kaiser founded Energy Arbitration Chambers, a firm of independent arbitrators based in Ottawa, Calgary, and Toronto specializing in energy and infrastructure disputes. Mr. Kaiser served as Alberta's Market Surveillance Administrator from 2018-2020.

Mr. Kaiser's leadership in advancing energy law extended beyond his significant contributions to the regulatory framework. During the last two decades, Bob Heggie (currently Chief Executive at the Alberta Utilities Commission) had the privilege of co-chairing two initiatives with Mr. Kaiser to advance the understanding of energy law and policy in Canada.

First was his pioneering work to establish the CAMPUT Energy Regulation Course. CAMPUT is Canada's analogue to NARUC in the United States. Held annually at his alma mater Queen's University, the weeklong course has educated over 1,400 regulators since its inception. At his heart, Mr. Kaiser was a teacher and a perfect role model for the generation of students who had the honor of being taught by him.

Mr. Kaiser also spearheaded the Canadian Energy Law Forum, held annually across the country. Founded in 2007, under his stewardship, the Forum brought energy regulatory lawyers from Canada and the U.S. (including Joe Kelliher, Bob Fleishman, and Scott Hempling) together to discuss key cases, issues, and developments in the Canadian energy regulatory framework.

The forum inspired Mr. Kaiser to work with others to establish (and later serve as a co-editor of) the Energy Regulation Quarterly (ERQ): Canada's leading energy law journal.

Gordon facilitated for many years robust conversations among regulators, the legal community, utility executives, and policymakers. There was much agreement in Canada that too often energy regulatory decisions came down and no one reflected on their implications, much less their merits. He was instrumental in building support for the idea of an ERQ from the beginning. Drawing on his incredible network of friends and acquaintances, Gordon was key to soliciting content, bending arms as few others could to get pieces written from experts across the country and abroad. He also made a point of personally contributing on a regular basis. The EBA's Energy Law Journal in 2019, 2021, and 2022 published Mr. Kaiser's annual review of Canadian energy law developments.

Mr. Kaiser served on the EBA's Northeast Chapter Board from 2013-2014, the first Canadian so named. He also served on the EBA Board from 2014-2017, the first Canadian so named.

Always the trailblazer, Mr. Kaiser was the driving force behind EBA's decision in 2019 to establish a Canadian Chapter. He was the first Chapter President; when he passed, Mr. Kaiser was the Chapter's Vice President.

The EBA presents the State/Provincial Regulatory Practitioner Award to those who represent clients before U.S., or Canadian provincial, regulatory agencies and whose advocacy has produced significant results or recognition. Originally known as the "state" practitioner award, a few years ago, the EBA renamed the award to include its Canadian members (by referencing "Provincial"). Since 2010, the EBA has presented it only to lawyers from the U.S. The EBA presented the award to Mr. Kaiser posthumously in October 2024 – the first Canadian so honored.

Gordon is survived by his loving spouse of eighteen years, Charlene Bain, who stood by him through triumphs and challenges, sharing in his joys and supporting him through his endeavors. Gordon's remarkable spirit, intellect, and generosity opened her world and provided their lives together with endless opportunities and unforgettable experiences. Gordon is also mourned by his five children: Christine (Chris Bentley), Kelly (Kevin Bean), Gordon Jr., their mother Terry, Jennifer (Alen Sadeh), Colleen, and their mother Sandra. Gordon took extraordinary pride in the achievements of his children and provided them with unwavering support.

Gordon was a force of nature; it showed in how he got things done. Working with Gordon often involved the unexpected, and he relished meeting over a good meal and fine red wine. He will be missed, deeply.

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DESIGNING DURABLE NON-RTO ORGANIZED MARKETS

*CeCe Coffey**

Synopsis: Utilities face mounting pressures to reduce costs, integrate an increasing amount of new generation onto the grid, and—in many states—achieve decarbonization targets. These pressures have led both utilities and their state regulators to explore forming multilateral electricity markets, even in regions of the country that have historically declined to create Regional Transmission Organizations (RTO). This article provides a history of organized market development and evaluates the structure of five non-RTO[1] organized market frameworks that the Federal Energy Regulatory Commission (FERC or Commission) has approved over the past decade. This article also identifies similarities and differences among the markets regarding (i) market structure, (ii) participation requirements, (iii) governance frameworks, (iv) pricing, and (v) transmission service. Lastly, this article highlights guidelines that designers of imbalance markets, enhanced bilateral markets, and extended day-ahead markets may follow to demonstrate how their market proposals would comply with FERC Order Nos. 888 and 2000.

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* CeCe Coffey is currently a law clerk at the Federal Energy Regulatory Commission. The views expressed herein do not represent those of the Commission, individual Commissioners, or Commission staff, nor do they express any opinion on any specific matter currently pending before the Commission or that may come before the Commission in the future. Many thanks to Shelley Welton, Ken Kulak, Ed Comer, Joshua Macey, Regine Baus, and Matthew Christiansen for their guidance. Thank you as well to the student editors of the *Energy Law Journal* for their feedback and editorial assistance. Any errors are the author's own.

1. Reference to "non-RTO markets" in this article refers to market structures that do not require full participation in an RTO or Independent System Operator (ISO), even though several of these markets are organized or administered by a traditional RTO/ISO. This article sometimes uses "RTOs" to include both RTOs and ISOs.

I. INTRODUCTION

New pressures to address mounting grid reliability challenges, reduce energy production costs, and meet decarbonization goals are encouraging states that previously rebuffed organized electricity markets to reconsider forming regional alliances. For example, Colorado's legislature passed a law in 2021 that requires the state's transmission-owning utilities to join an RTO or Independent System Operator (ISO) by 2030.[2] The Colorado bill text states that a qualifying wholesale market will be one that improves service reliability, achieves emissions reductions,

2. Emma Penrod, *Colo. legislators direct all transmission utilities to join an organized wholesale market by 2030*, UTIL. DIVE (June 8, 2021), https://www.utilitydive.com/news/colorado-legislators-direct-all-transmission-utilities-to-join-an-organized/601423/.

and delivers savings to customers, among other features.[3] And Colorado is not alone; several states—including Nevada, New Mexico, and Washington—have set 100% carbon-free electricity goals.[4] According to Berkshire Hathaway Energy's Jonathan Weisgall, "every state west of the Rockies except Wyoming now has a 100% renewables or zero emissions mandate or a utility with an agreement moving it in that direction."[5] Other stakeholders across the West have also called for a western RTO to provide reliability and guide long-term transmission planning, especially to "handle 'surprise events' such as heat waves and wildfires."[6] Drawing on a diverse portfolio of generation resources across a larger footprint may serve all these goals.

Despite the benefits that regional markets may offer to electricity customers, regulators in certain regions of the country have preferred to maintain a system of state-regulated, vertically integrated utilities, which grants states more direct control over the portfolio of generation resources and transmission assets developed within their states. These included the Southeast, Southwest, and Rocky Mountain regions. For more than twenty years, utilities in these regions retained this system for overseeing the development of new power plants and the delivery of electricity to customers. The vertically integrated model has enabled certain utilities to offer their customers comparatively lower electricity rates.[7] Perhaps as a result, state regulators list several reasons for their reticence to join multi-state RTOs, including giving up "a certain amount of control," as Kent Chandler, then Chairman of the Kentucky Public Service Commission, remarked.[8] Regulators in these states also cite greater utility accountability as a benefit of state regulation.[9] As a result,

3. *Public Utilities Commission Modernize Electric Transmission Infrastructure*, S.B. NO. 21-072 (Colo. 2021) (codified as amended in scattered sections of Colorado Revised Statutes), https://leg.colorado.gov/sites/default/files/2021a_072_signed.pdf.

4. Warren Leon & Anna Ziai, *Table of 100% Clean Energy States*, CLEAN ENERGY STATES ALL., https://www.cesa.org/projects/100-clean-energy-collaborative/guide/table-of-100-clean-energy-states/ (last visited May 28, 2024).

5. Herman Trabish, *The 3 key challenges to expanding the West's real-time energy market to day-ahead trading*, UTIL. DIVE (June 3, 2020), https://www.utilitydive.com/news/the-3-key-challenges-to-expanding-the-wests-real-time-energy-market-to-day/578390/#:~:text=The%20voluntary%20Energy%20Imbalance%20Market,time%20dispatch%2C%20according%20to%20CAISO.

6. Garrett Hering, *Western U.S. Regional grid, reliability efforts reach crossroads in 2023*, S&P GLOB. (Jan. 11, 2023), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/western-us-regional-grid-reliability-efforts-reach-crossroads-in-2023-73650835; *see also* Martha Castañeda, *Powering the West Through a Reliable Energy Grid*, CSG WEST (Dec. 7, 2023), https://csgwest.org/2023/12/07/powering-the-west-through-a-reliable-energy-grid/.

7. *See, e.g.*, *Snohomish, WA Electricity Statistics*, ELEC. LOCAL, https://www.electricitylocal.com/states/washington/snohomish/ (last visited Jan. 14, 2024). Largely due to Washington's abundance of hydropower resources, the average residential electricity rate for customers of Snohomish Public Utility District is 8.44 ¢/kWh, compared to an average of 12.9 ¢/kWh in Philadelphia and 11.5 ¢/kWh in Minneapolis, to give two examples of cities that sit squarely within their RTO's footprint.

8. Robert Zullo, *In the Southeast, Where Big Utilities Rule, Calls for a Real Power Market Persist*, GA. RECORDER (May 7, 2023), https://georgiarecorder.com/2023/05/07/in-the-southeast-where-big-utilities-rule-calls-for-a-real-power-market-persist/.

9. *See, e.g.*, Tim Echols, *PSC Member: Georgia regulators working to fix 'tears' in power grid to prevent Texas-like failure*, SAVANNAH NOW, https://www.savannahnow.com/story/opinion/2021/02/24/georgia-psc-

efforts to form regional electricity markets have not proceeded uniformly across the country, although each of these three regions now hosts an active non-RTO market, as discussed later in this article.

Prior to the 1990s, electric utility companies across the United States were regulated almost exclusively by state public utility commissions. These utilities largely controlled vertically integrated portfolios of generation, transmission, and distribution infrastructure. The costs of building, operating, and maintaining this infrastructure were passed down to the utilities' customers through retail rates, which the state commissions also regulated.[10] Because the generation and distribution of electricity is capital-intensive and benefits from economies of scale, state regulators initially determined that granting local monopolies to individual companies and then closely regulating those monopolies could achieve the state's goal of making reliable electric service available to customers at affordable rates.[11]

As the energy generation mix began to change, however—including due to environmental regulations affecting coal-fired power plants, the U.S. fracking boom, and the development of more efficient renewable generation technologies—federal and some state regulators began to support the development of competitive, wholesale energy markets.[12] These markets were designed to allow merchant-owned electric generating facilities to compete with the utility-owned generators.

Furthermore, several regions of the country—including the Northeast, Mid-Atlantic, Midwest and Northwest—already operated "power pools" that allowed utilities to capture the expanded reliability benefits and cost savings of sharing generating facilities among utilities.[13] New legislation from Congress and regulations issued by FERC, as discussed in the following section, encouraged the transition in these regions from limited power pools to integrated wholesale energy markets.

Over the past decade, both the mounting costs of building and maintaining an increasingly flexible grid and the substantial potential savings from generating energy from near-zero marginal cost resources like wind and solar have encouraged even states that traditionally supported vertically integrated utilities to look for ways to dispatch resources across their region more efficiently. One potential solution is to develop a power pool, in which utilities remain vertically integrated

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power-grid-ensure-ready-severe-weather-texas-failure/4539437001/ (updated Feb. 24, 2021) ("Another stitch we have made is resisting the temptation to deregulate the power system in Georgia. We are still a 'regulated' state meaning that from the power plant to the meter behind your house, the power company, with PSC oversight, is responsible and has complete control of ensuring reliability.").

10. *See* FERC v. Elec. Power Supply Ass'n, 136 S. Ct. 760, 767 (2016) (noting that "in the early 20th century, state and local agencies oversaw nearly all generation, transmission, and distribution of electricity").

11. For a brief history of the roots of this regulatory compact in English common law, *see* Heather Payne, *Private (Utility) Regulators*, 50 ENV'T L. 999, 1009 (2020).

12. *See* ENERGY INFO. ADMIN., *The Changing Structure of the Electric Power Industry 2000: An Update* 61 (Oct. 2000), https://grist.org/wp-content/uploads/2010/02/update2000.pdf.

13. *See* Hagler Bailly, *Report on Power Pool Options*, U.S. AGENCY FOR INT'L DEV., BUREAU FOR EUR. & NIS OFFICE OF ENV'T: ENERGY AND URB. DEV. ENERGY AND INFRASTRUCTURE DIV. (Sept. 1997), https://pdf.usaid.gov/pdf_docs/PNACE418.pdf.

but schedule and dispatch their shared power plants to serve the entire system. Another solution is to establish an "energy imbalance market," in which third-party generators are invited to sell energy in real time alongside the energy produced by utility generators. Either of these options stops short of a fully competitive, deregulated wholesale electricity market, and thus potentially allows state regulators[14] to maintain tighter control over the system. But closely held agreements also require greater legal scrutiny; exclusionary participation requirements and restrictive governance provisions in non-RTO organized markets may raise antitrust and market manipulation concerns.

Legal scholars have written extensively about the formation, development, and operation of these wholesale electricity markets.[15] Several have outlined the roles of FERC and the state public utility commissions in regulating the participation of generation and load in these markets, despite disagreeing about the relative effectiveness of the Federal Power Act in guiding such regulation.[16] Others have focused on evaluating the effectiveness of the requirements of FERC Order No. 888 and the market and governance structures of existing RTOs.[17] Some even have proposed alternative market designs that seek to retain consumer and economic benefits while de-emphasizing centralized energy markets.[18] Lastly, both legal and non-legal scholars have studied the monetary benefits of regionalization, concluding that huge amounts of consumer savings may be left on the table in states that do not capture the benefits of competitive markets.[19]

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14. Most utilities that join these markets are subject to general oversight by state commissions, but several are not, such as certain municipal electric utilities and electric cooperatives, which are formally self-regulated but may have their tariffs reviewed by state regulators. *See e.g.*, NRECA INT'L LTD., *Guides for Electric Cooperative Development and Rural Electrification* 8 (Nov. 2016), https://www.nrecainternational.coop/wp-content/uploads/2016/11/GuidesforDevelopment.pdf.

15. *See, e.g.,* Joshua C. Macey & Robert Ward, *MOPR Madness*, 42 ENERGY L.J. 67, 74 (2021); Joshua C. Macey et. al., *Grid Reliability in the Electric Era*, 41 YALE J. ON REG. 164 (2024); Avi Zevin, *Regulating the Energy Transition: FERC & Cost-Benefit Analysis*, 45 COLUM. J. ENV'T L. 419, 455 (2020).

16. *See, e.g.*, Matthew R. Christiansen & Joshua C. Macey, *Long Live the Federal Power Act's Bright Line*, 134 HARV. L. REV. 1360, 1361 (2021); Robert R. Nordhaus, *The Hazy "Bright Line": Defining Federal & State Regulation of Today's Electricity. Grid*, 41 ENERGY L.J. 323 (2020); Joel B. Eisen, *FERC's Expansive Authority to Transform the Electricity Grid*, 49 U.C. DAVIS L. REV. 1783 (2016). *See also* Jody Freeman & David B. Spence, *Old Statutes, New Problems*, 163 U. PA. L. REV. 1, 43 (2014); David B. Spence, *Can Law Manage Competitive Energy Markets?*, 93 CORNELL L. REV. 765, 766 (2008).

17. *See* Shelley Welton, *Rethinking Grid Governance for the Climate Change Era*, 109 CALIF. L. REV. 209 (2021); Michael H. Dworkin & Rachel Aslin Goldwasser, *Ensuring Consideration of the Public Interest in the Governance & Accountability of Regional Transmission Organizations*, 28 ENERGY L.J. 543, 551-52 (2007); Richard A. Drom, *New Metrics for Measuring the Success of A Non-Profit RTO*, 28 ENERGY L.J. 603 (2007).

18. *See* Susan Kelly & Elise Caplan, *Time for A Day 1.5 Market: A Proposal to Reform RTO-Run Centralized Wholesale Eletricity Markets,* 29 ENERGY L.J. 491 (2008).

19. *See, e.g.*, M. Milligan et al., *Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection*, NAT'L RENEWABLE ENERGY LAB. (Mar. 2023), https://www.nrel.gov/docs/fy13osti/57115.pdf; John Tsoukalis et al., *Western Energy Imbalance Service and SPP Western RTO Participation Benefits*, BRATTLE (Dec. 2, 2020), https://spp.org/documents/63517/weis%20and%20spp%20west%20rto%20benefits%20study.pdf; Joshua C. Macey, *Zombie Energy Laws*, 73 VAND. L. REV. 1077 (2020).

No one to date, however, has reviewed how FERC has evaluated non-RTO market proposals or outlined the legal landscape against which FERC and the courts may judge new non-RTO market designs, beyond the standards that Order No. 888 applies to all public utility transmission providers.

Limited action in the appellate courts may partially explain the lack of scholarship. Although FERC has approved several non-RTO market structures during the last decade, the three earliest proposals—two energy imbalance markets and a multi-utility trading arrangement in Colorado—received relatively little pushback from stakeholders. FERC's 2021 approval of the Southeast Energy Exchange Market (SEEM), however, prompted an appeal of the Commission's decision to the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit). Petitioners raised several concerns about SEEM's proposed design, including arguing that the framework did not comply with Order No. 888.[20] The D.C. Circuit noted these concerns in an order that remanded FERC's suite of SEEM orders to the Commission for further consideration.[21]

Since 2021, protestors have alleged that components of two further proposals—the California Independent System Operator's (CAISO) Extended Day Ahead Market (EDAM) and the Southwest Power Pool's (SPP) Markets+ proposal[22]—do not comply with FERC precedent.[23] Taken together, these three market footprints blanket portions of nearly 30 states. Future determinations by FERC and reviewing courts about the compliance of non-RTO markets with the Commission's requirements of open access and non-discriminatory service will impact state regulators, policymakers, and market participants across the country.

This article builds on the existing literature by providing a history of organized market development in the U.S. and evaluating five non-RTO market structures to distill the standards that these markets must meet to receive FERC approval and be upheld by reviewing courts. First, section II reviews how wholesale electricity markets emerged and evolved over the 20th century. Next, section III summarizes key components of five non-RTO market structures that FERC approved between 2015 and 2023. The article evaluates the five markets—plus one market proposal—in pairs: first, two energy imbalance markets: the Western Energy Imbalance Market (EIM) and SPP's Western Energy Imbalance Service Market (WEIS Market); second, two enhanced bilateral markets: the Public Service Company of Colorado (PSCo) Joint Dispatch Agreement (PSCo JDA) and SEEM;

20. Advanced Energy Econ. v. FERC, No. 22-1018, 2022 WL 4593131, at *48 (D.C. Cir. 2022).

21. Advanced Energy United, Inc. v. FERC, 82 F.4th 1095, 1111–12 (D.C. Cir. 2023).

22. At the time of publication, FERC has not yet issued a final order on SPP's Markets+ proposal. On July 31, 2024, FERC staff issued a deficiency letter seeking additional information about SPP's Markets+ proposal before it issues an order approving or rejecting SPP's proposed market design. Accordingly, this paper includes a short overview of what SPP has proposed for Markets+, but does not include Markets+ in the summary tables or conclusion because it has not been approved by FERC and, therefore, does not yet form part of the legal landscape for non-RTO organized markets. *See* Letter informing Southwest Power Pool, Inc. that the 03/29/2024, as amended 04/05/2024, filing is deficient and requesting additional information to be filed within 60 days, Docket No. ER24-1658-000 (July 31, 2024) [hereinafter Markets+ Deficiency Letter].

23. *See, e.g.*, *Cal. Indep. Sys. Operator Corp.*, Motion to Intervene and Limited Protest of Western Power Trading Forum, FERC Docket No. ER23-2686-000 at 6-7 (Sept. 21, 2023); *Southwest Power Pool,* Protest of Public Interest Organizations, FERC Docket No. ER24-1658-000 at 16 (Apr. 29. 2024).

and third, two extended day-ahead markets: CAISO's EDAM and SPP's Markets+ proposal.

Following that summary, section IV defines the legal landscape for non-RTO markets broadly. Section V reviews what the Commission has indicated passes legal muster under the Federal Power Act when evaluating different non-RTO market designs. Section V also includes an expanded comparison table, but a condensed version is included here:

Market	Structure & Operational Control	Participation	Governance	Pricing	Transmission (TX) Use
EIM	• 5-minute energy transfers, financial settlement only	•Voluntary; BAA by BAA	• Three- part governance structure: (1) EIM Governing Body, (2) Body of State Regulators, (3) public Regional Issues Forum; CAISO monitors market	• LMP unless mitigated	• As-available TX, lowest priority; standard TX charges
PSCo JDA	• Real-time joint dispatch using SCED, but utilities maintain resource planning & commitment role	• Only LSEs within the PSCo BAA; participants must secure reciprocal TX service	• No formal governance structure	• Service-dependent, ranging from LMP plus $0.50/MWh for Joint Dispatch Energy to LMP plus $10/MWh for Deficit Energy	• As-available TX, lowest priority; $0/MWh
WEIS	• Real-time dispatch using SCED; participants retain operational control	• Participation open to BAAs in the Western Interconnect; all BAAs must secure reciprocal TX; all resources in a participating BAA must register or opt out	• Western Market Executive Committee (WMEC) includes participants; all market rule proposals must be approved by both load-weighted & popular supermajority votes	• LMP, adjusted for marginal losses	• As-available TX, lowest priority; $0/MWh
SEEM	• SEEM matched bilateral energy exchanges in 15-minute increments; participants retain operational control; parties settle transactions bilaterally	• Participants must own or control a source or sink in the SEEM footprint, secure TX service, enter into enabling agreements with 3+ potential counterparties	• Membership Board composes of member representatives; Operating committee oversees market; third party auditor reviews market integrity	• "Split-the-savings" (i.e. midpoint) pricing includes shared financial losses, may be mitigated to MBR price cap	• As-available TX, lowest priority; $0/MWh
EDAM	• Centralized, day-ahead energy auction with must-offer requirement clears bids to produce day-ahead schedules; CAISO settles the market & bill participants	• Voluntary; BAA by BAA, so every resource in a participating BAA must submit bids or self-schedule	• Three- part governance structure: (1) EIM Governing Body, (2) Body of State Regulators, (3) public Regional Issues Forum; CAISO monitors market	• BAA-specific day-ahead LMP; prices mitigated by CAISO DMM as needed	• Participants must either reserve unused TX to receive $0/MWh service or pay a standard TX charge for the use of unreserved TX

Section VI provides a brief update on both past and planned non-RTO market consolidation. Lastly, section VII explains what developers of future markets may wish to consider when designing a new market structure that can attract states seeking to achieve their reliability, cost, and decarbonization goals.

Reviewing new non-RTO market proposals presents FERC with a balancing act: the agency must respect the jurisdictional authority of state regulators to guide energy generation and retail rate-setting decisions within their states' boundaries while at the same time fulfilling its own statutory obligations to ensure just and reasonable wholesale rates, prevent undue discrimination in energy markets, and police anti-competitive behavior.

Getting these balances right is critical to designing—and operating—wholesale markets that deliver the reliability, economic, and environmental benefits demanded by states and their consumers. Effective markets should encourage broad participation, prevent market manipulation, and integrate new resources to secure benefits for consumers. Determining which market structures, governance frameworks, participation models, and even transmission arrangements can produce just and reasonable rates, therefore, is a crucial task for FERC. As much of the country learned from Enron's manipulation of the California energy markets in the early 2000s, market manipulation can greatly reduce the economic savings passed through to consumers.[24] Furthermore, overly restrictive participation requirements or discriminatory governance structures can support exclusive dealing arrangements and other forms of manipulation. Market designs, as a result, must strike a balance between respecting the voluntary and flexible nature of non-RTO markets, which may appeal to some state regulators, and ensuring that any market design can ultimately pass legal muster at FERC and in the courts.

II. How Wholesale Electricity Markets Emerged and Evolved

Electric utilities began to experiment nearly a century ago with ways to pool their assets to reduce the average production cost of electricity and to support regional electric system reliability.[25] In 1927, for example, three utilities that served customers in Pennsylvania and New Jersey formed the country's first continuing power pool.[26] The arrangement allowed the utilities to share generating resources. With the addition of two Maryland utilities in 1956, the power pool rebranded as the Pennsylvania–New Jersey–Maryland Interconnection, or PJM.[27] In the Southwest, World War II catalyzed demand for aluminum and other defense production. To meet the demand for power these industries required, eleven regional utilities formed the Southwest Power Pool in December 1941, just eight days after Congress declared war on Japan.[28]

Utilities in the Northeast took similar steps, albeit for different reasons. The great Northeast blackout of 1965 resulted in cascading power outages that affected a territory from Ontario to Massachusetts and prompted serious conversations about improving regional reliability.[29] New York utility companies in 1966 established the New York Power Pool (NYPP),[30] which in 1977 agreed to interconnect its electric system with that of Ontario Hydro.[31] The stated goal of the Ontario–

24. *Staff Report: Price Manipulation in Western Markets*, FERC Docket No. PA02-2-000 (Mar. 26, 2003).

25. *About NEPOOL*, New Eng. Power Pool, https://nepool.com/about-nepool (last visited Jan. 14, 2024) [hereinafter NEPOOL].

26. *PJM History,* PJM Interconnection, L.L.C., https://www.pjm.com/about-pjm (last visited Jan. 14, 2024).

27. *Electric Power Markets*, FERC, https://www.ferc.gov/industries-data/electric/electric-power-markets/pjm#:~:text=PJM%20was%20founded%20in%201927,%2DMaryland%20Interconnection%2C%20or%20PJM (last visited Jan. 14, 2024).

28. Nathania Sawyer & Les Dillahunty, *The Power of Relationships: 75 Years of Southwest Power Pool*, Sw. Power Pool 20 (May 2016), https://www.spp.org/documents/46282/spp-75th-anniversary-online.pdf.

29. U.S. Can. Power Sys. Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* 104 (Apr. 2004), https://www3.epa.gov/region1/npdes/merrimackstation/pdfs/ar/AR-1165.pdf.

30. Gina Elizabeth Craan, *Introduction to NYISO: New York Market Orientation Course Webinar*, NYSIO 3 (Sept. 17-19, 2024), https://www.nyiso.com/documents/20142/3037451/Introduction-to-NYISO.pdf/f7ad7e5c-65e9-635a-0aee-62709c33c412.

31. NYISO, Interconnection Agreement Between Independent Electricity Market Operator and The New York Independent System Operator, Inc. 2 (May 1, 2022), https://www.nyiso.com/documents/20142/1397306/imonyiso.pdf/73afa0b0-3f20-15e2-1e61-33abf1c919d5.

NYPP expansion was "to achieve, as a result of coordinated interconnection operation, benefits to their respective power systems and thereby to the public."[32] Similarly, in 1971, electric utilities in New England formed the New England Power Pool "to coordinate transmission planning and to achieve economic and reliability benefits through coordinated regional dispatch of power."[33]

Antitrust concerns also boiled up during the late 1960s and early 1970s, prompting both energy regulators and the federal courts to address the potential for electric utilities to behave anticompetitively in these developing markets.[34] In *Otter Tail Power Co. v. U.S.*, for example, the Justice Department brought suit against a transmission-owning utility for refusing either to sell energy at wholesale to municipal customers or to wheel power to the municipalities from third-party suppliers of wholesale energy.[35] The Supreme Court in *Otter Tail* rejected the utility's claims that it should be immune from antitrust regulation for these "refusals to deal" because section 202(b) of the Federal Power Act enabled the Federal Power Commission to remedy anticompetitive behavior by ordering an uncooperative utility to interconnect its system with that of any requesting customer.[36] The Court answered instead that "activities which come under the jurisdiction of a regulatory agency nevertheless may be subject to scrutiny under the antitrust laws," affirming that the Federal Power Commission (now FERC) retained authority to direct Otter Tail to interconnect with its competitors and transmit power to them.[37] The Court clarified that the Federal Power Act should be interpreted as setting out "an overriding policy of maintaining competition to the maximum extent possible consistent with the public interest."[38]

In this and other landmark decisions, the Court affirmed that FERC's approval of utility proposals pursuant to the Federal Power Act must consider those proposals' effects on competition. In *Gulf States Utilities Co. v. Federal Power Commission*, for example, the Court clarified that when a public utility applies pursuant to Federal Power Act section 204 for authority to issue a security, the

32. *Id.*

33. *See* NEPOOL, *supra* note 25, at 1.

34. For example, Congress in 1970 amended the Atomic Energy Act of 1954 to require the Nuclear Regulatory Commission to conduct antitrust reviews of nuclear license applications and, where necessary, to include limited wheeling conditions and other obligations in nuclear licenses to address antitrust concerns. *See* S. Hom & C. Pittiglio, *Standard Review Plan on Transfer and Amendment of Antitrust License Conditions and Antitrust Enforcement*, U.S. NUCLEAR REGUL. COMM'N: OFF. OF NUCLEAR REACTOR REGUL., NUREG-1574, Rev. 2, at iii (Dec. 2007), https://www.nrc.gov/docs/ML0722/ML072260035.pdf. The report notes, however, that Congress in 2005 passed the Energy Policy Act of 2005, which removed the Nuclear Regulatory Commission's antitrust review authority regarding license applications, such that the agency no longer conducts antitrust reviews or imposes new antitrust license conditions.

35. Otter Tail Power Co. v. U. S., 410 U.S. 366, 371 (1973).

36. *Id.* at 373.

37. *Id.* at 372–74.

38. Harvey L. Reiter, *Competition and Access to the Bottleneck: The Scope of Contract Carrier Regulation under the Federal Power and Natural Gas Acts*, 18 LAND & WATER L. REV. 1 (1983), *citing Otter Tail Power Co.*, 410 U.S. 366, 374 [hereinafter Competition and Access to the Bottleneck].

Commission must consider any anticompetitive effects of the issuance in determining whether it is "compatible with the public interest."[39] And in *Federal Power Commission v. Conway Corp.*, the Court determined that the Commission must consider allegations that a proposed rate is discriminatory and anticompetitive in effect when evaluating whether that rate is "just and reasonable" under Federal Power Act section 205."[40] The Commission, in 1978, applied these standards in striking down a proposed settlement term that would restrict the ability of wholesale customers of Gulf States Utility Company to resell power delivered by Gulf States. Finding that the Federal Power Act does not allow public utilities to use tariff provisions to foreclose wholesale competition, FERC established what is sometimes called the "least anti-competitive alternatives" test in its conditional approval of the Gulf States settlement.[41] Under the test, the Commission would consider whether resale prohibitions or other measures that curtail competition "serve some significant regulatory purpose which cannot be achieved by a less anticompetitive method."[42] FERC applied a similar theory in conditioning its approvals of several mergers and market-based rate applications on the establishment of open access tariffs or wheeling conditions.[43]

National legislation during the same period expanded competition in both the generation and transmission industries. In 1978, the Public Utilities Regulatory Policies Act initiated deregulation of energy production by providing a pathway for certain qualifying facilities—mostly renewable generators—to sell their energy to utilities for resale to end-use customers.[44]

Other policy changes, including the passage of the National Energy Policy Act in 1992, expanded competition among incumbent utilities.[45] By the mid-1990s, several regions of the United States began to explore how competition among wholesale generators could both support a non-discriminatory transmission system and provide consumers with a choice of energy suppliers. PJM, for example, began its transition to becoming a fully independent system operator in 1993, more than thirty years after it started scheduling and dispatching a combined system.[46] In 1997, after receiving approval from FERC, PJM opened its first bid-based energy market.[47]

39. Gulf States Utils. Co. v. FPC, 411 U.S. 747, 749 (1973).

40. FPC v. Conway Corp., 426 U.S. 271, 279 (1976).

41. Competition and Access to the Bottleneck, *supra* note 38, at n.12.

42. *Gulf States Utils. Co*., 5 FERC ¶ 61,066 at *3 (1978).

43. *See, e.g.*, Ne. Utilities Serv. Co. v. FERC, 993 F.2d 937, 954 (1st Cir. 1993) (upholding FERC's decision to condition its approval of the merger of Northeast Utilities and the Public Service Company of New Hampshire on Northeast Utilities' offering any spare transmission capacity for wheeling use); *Pub. Serv. Co. of Indiana, Inc.*, 51 F.E.R.C. ¶ 61,367, 62,189–90 (1990) (accepting Public Service Company of Indiana's application to sell power at market based rates on the condition that the utility file an open access transmission tariff).

44. *IRC History*, ISO/RTO COUNCIL, https://isorto.org/ (last visited Jan. 14, 2024).

45. *Id*.

46. PJM INTERCONNECTION, L.L.C., *supra* note 26, at 1.

47. *Id.*

III. FOUNDATIONAL FERC ORDERS

The Commission's issuance of several landmark orders laid the foundation for the legal and regulatory regime that transmission owners in both RTO and non-RTO regions still face today. Concurrently with the development of centralized energy markets in the 1990s, FERC began to support the development of regional transmission systems both by issuing policy guidance and through formal rule-making proceedings. FERC issued a policy statement in 1993 that both encouraged the development of "regional transmission groups" (RTG)[48] and provided guidance regarding the composition of regional transmission group agreements (RTG Policy Statement).[49] The RTG Policy Statement noted that several transmission groups were developing in parallel across the country and that "there is a need for flexibility in forming these voluntary associations and the agreements that govern them, in order to reflect specific geographic, operational, historical, or other circumstances of the parties."[50] The RTG Policy Statement, therefore, allowed parties to propose "any RTG agreement that they believe satisfies their contractual needs and complies with the substantive standards of the FPA," but established a policy that RTG agreements should, at a minimum, reflect certain foundational characteristics.[51] FERC approved the Western Regional Transmission Association in 1995 as the first regional transmission group to comply with the RTG Policy Statement.[52]

In 1996, FERC issued Order No. 888, which required all public utilities to provide "open access" to their transmission systems—that is, to provide transmission service to third parties on substantially the same terms as the utility would provide transmission to itself.[53] Complying with Order No. 888 required utilities to file Open Access Transmission Tariffs (OATT), which set out standard and non-discriminatory terms for taking transmission service.[54] For many utilities, this requirement necessitated the development of a new, standardized menu of transmission services. For others, including many utilities that had filed OATTs to satisfy FERC's earlier, conditional approvals of their mergers, Order No. 888 required more moderate revisions to tariffs that were already on file with the Commission.

48. The Commission defines an RTG as a voluntary organization of transmission owners, transmission users, and other entities interested in coordinating transmission planning (and expansion), operation and use on a regional (and interregional) basis. *See Policy Statement Regarding Regional Transmission Groups*, 58 Fed. Reg. 41,626, at 41,626-27 (1993) (to be codified at 18 C.F.R. pt. 2).

49. *Id.* at 41,629.

50. *Id.*

51. *Id.* at 41,629–30. The foundational characteristics included seven basic components: (1) broad membership, (2) coordination with states, (3) an obligation to provide transmission services to members, (4) coordinated transmission planning, (5) non-discriminatory governance procedures, (6) voluntary dispute resolution procedures, and (7) an exit provision for members.

52. Lori A. Burkhart, *WRTA First to Get FERC Final Approval*, PUB. UTIL. FORT. (July 1, 1995), https://www.fortnightly.com/fortnightly/1995/07/wrta-first-get-ferc-final-approval.

53. *History of OATT Reform*, FERC, https://www.ferc.2gov/industries-data/electric/industry-activities/open-access-transmission-tariff-oatt-reform/history-oatt-reform (last updated Jan. 18, 2023).

54. *Id.*

Nearly ten years after its issuance of Order No. 888, FERC, in 2005, issued a Notice of Inquiry to seek input on whether the Commission's *pro forma* OATT needed further reform, in light of changes to the structure and electric utility industry.[55] Following FERC's issuance of a Notice of Proposed Rulemaking (NOPR) on this question and the collection of comments on both documents, the Commission issued order No. 890, which adopted certain reforms proposed in the NOPR to "strengthen the *pro forma* [OATT]," reduce opportunities for undue discrimination, and increase transparency around transmission system planning processes.[56] Among other reforms, Order No. 890 required transmission providers to include transmission customers in their transmission planning processes and increased the transparency requirements for OATTs so that both customers and FERC's Office of Enforcement could better "detect undue discrimination."[57]

Although Order Nos. 888 and 890 reduced opportunities for transmission owners to discriminate in their provision of transmission service, utilities largely planned and operated their systems independently of each other. FERC identified several "deficiencies" in transmission providers' existing transmission planning and cost allocation procedures, and, in 2011, issued Order No. 1000 to require transmission providers to implement reforms.[58] More specifically, Order No. 1000 required that each public utility transmission provider: (i) participate in a regional transmission planning process that produces a regional transmission plan and has a regional cost allocation method for new transmission facilities selected in the regional transmission plan for purposes of cost allocation, (ii) revise its OATT to include guidelines for selecting competitive transmission projects, (iii) eliminate a federal right of first refusal from its OATT for constructing certain new transmission facilities, and (iv) engage in interregional transmission planning coordination and cost allocation.[59]

In addition to the above-noted reforms to require non-discriminatory access to transmission, FERC "encouraged the voluntary formation of [RTOs] to administer the transmission grid on a regional basis throughout North America."[60] The

55. *Id.*

56. Order No. 890, *Preventing Undue Discrimination and Preference in Transmission Service*, FERC STATS. & REGS. ¶ 31,241 (2007), 72 Fed. Reg. 12,266 (Mar. 15, 2007) [hereinafter Order No. 890]; *order on reh'g*, Order No. 890-A, 73 Fed. Reg. 2,984 (Jan. 16, 2008), FERC STATS. & REGS. ¶ 31,261 (2007) [hereinafter Order No. 890-A].

57. Order No. 890, *supra* note 56, at P 6. *But see Cal. Pub. Utils. Comm'n v. Pac. Gas & Elec. Co.*, 164 FERC ¶ 61,161 at P 66 (2018) (finding "that the Order No. 890 transmission planning reforms were intended to address concerns regarding undue discrimination in grid expansion [and] to the extent that PG&E asset management projects and activities do not expand the grid, they do not fall within the scope of Order No. 890 [reforms]").

58. Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, FERC STATS. & REGS. ¶ 31,323 (2011), 76 Fed. Reg. 49,842, at P 4 (Aug. 11, 2011) (to be codified at C.F.R. pt. 35) [hereinafter Order No. 1000].

59. *Id.* at PP 8, 146, 284, 325.

60. *RTOs and ISOs*, FERC, https://www.ferc.gov/power-sales-and-markets/rtos-and-isos#:~:text=Subsequently%2C%20in%20Order%20No.,North%20America%20(including%20Canada) (last visited Jan. 17, 2024).

Commission envisioned that RTOs would "operate transmission systems and develop innovative procedures equitably."[61] In the rulemaking process for Order No. 2000, the Commission weighed whether to mandate RTO participation or to continue to pursue a voluntary approach.[62] The Commission determined in Order No. 2000 that although "it is clear that RTOs are needed to resolve impediments to fully competitive markets," the agency "should pursue a voluntary approach to participation in RTOs."[63] Thus, Order No. 2000 required transmission-owning public utilities to evaluate potential RTO participation but stopped short of requiring utilities to join RTOs.[64]

To aid in what the Commission still called the "voluntary development of RTOs," Order No. 2000 also established certain minimum characteristics and functions that each market must satisfy before it can be approved by FERC to serve as an RTO.[65] The minimum characteristics of an RTO applied to four categories: (i) independence, (ii) scope and regional configuration, (iii) operational authority, and (iv) short-term reliability.[66] The minimum functional requirements of an RTO were organized into eight categories: (i) tariff administration and design; (ii) congestion management; (iii) parallel path flow; (iv) ancillary services; (v) public posting of open access system information, total transmission capability, and available transmission capability; (vi) market monitoring; (vii) planning and expansion; and (viii) interregional coordination.[67] The Commission described its RTO requirements as creating an "open architecture" policy for RTO development, as opposed to a more top-down, "cookie cutter" organizational format.[68]

Although FERC did not mandate RTO formation, many former power pools in the years leading up to Order No. 2000's issuance had already begun to function more like the Commission's conception of RTOs. These included CAISO, ISO New England, and the New York Independent System Operator.[69] After 2000, PJM Interconnection (PJM), the Midcontinent Independent System Operator (MISO), and SPP formalized as RTOs, which extended the ability to participate in regional markets to more than twenty-five additional states.[70]

Utilities in other regions of the country, however, either declined to join RTOs or proposed regional transmission conglomerates that were rejected by state or federal regulators. One of these failed RTOs, SeTrans, was proposed by nine

61. *Electric Power Markets*, FERC, https://www.ferc.gov/electric-power-markets (last visited Jan. 14, 2024).

62. Order No. 2000, *Regional Transmission Organizations*, FERC STATS. & REGS. ¶ 31,089 (2000), 65 Fed. Reg. 809 (2000) [hereinafter Order No. 2000].

63. *Id.* at 834.

64. *Id.* at 812.

65. *Id.* at 811-12.

66. Order No. 2000, *supra* note 62, at 811.

67. *Id.*

68. *Id.*

69. Richard Doying, *Order 2000 Revisited: FERC Market Expansion and RTO Policy—Where Are We Now?*, HARV. ELEC. POL'Y GRP. 5 (Apr. 20, 2021), https://hepg.hks.harvard.edu/sites/hwpi.harvard.edu/files/hepg/files/doying-hepg-beyong_rto_1000_for_posting.pdf?m=1626199870.

70. *Id.*

transmission-owning utilities in the Southeast, a region that had repeatedly resisted developing a multi-state wholesale market.[71] FERC issued an order in 2002 finding that the proposed business model and governance structure of SeTrans complied with Order No. 2000.[72] By the following year, however, the utilities that had proposed SeTrans had abandoned the initiative, announcing that it was "highly unlikely" that the group could agree on final market design parameters that would satisfy both Southeast state regulators and FERC.[73]

For more than fifteen years after SeTrans' dissolution, the Southeast retained its existing system of state public utility regulation of mainly vertically integrated utilities. Over the same period, utilities in the West and Rocky Mountain regions of the country maintained a similar regulatory framework. However, increasing pressures to interconnect massive amounts of new generation resources, and—in some states—make progress toward achieving state-level decarbonization goals recently have revived conversations in these three regions about developing regional electricity markets. The following section discusses market development initiatives in each.

IV. THE CREATION OF MODERN NON-RTO MARKETS

Over the last decade, regions across the country have explored how to unlock the economic and reliability benefits of generating and selling energy across a wider market footprint without sacrificing robust state-level oversight. Several of these regions have proposed non-RTO organized markets to facilitate the trading of energy, first in the real-time energy markets and most recently in CAISO's day-ahead energy market. This article evaluates five non-RTO market structures that have been approved by FERC since 2014. Although the five markets vary in their characteristics, this article consider them in categories: first, two energy imbalance markets; second, two enhanced bilateral markets; and lastly, CAISO's extended day-ahead market. The section on enhanced bilateral markets also provides a brief overview of a sixth proposed market, SPP's Markets+ proposal. This organization approximately tracks the development pathway for non-RTO organized markets, which began with CAISO's creation of the EIM, progressed through two versions of bilateral market enhancements, and continues today with the development both of CAISO's EDAM and SPP's proposed day-ahead offering, Markets+.[74]

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71. Mary O'Driscoll, *SeTrans Breakup Adds to Mandatory RTO Debate*, E&E NEWS (Dec. 2003), https://subscriber.politicopro.com/article/eenews/2003/12/05/setrans-breakup-adds-to-mandatory-rto-debate-242110.

72. FERC in its order, however, did not address other details of an RTO for SeTrans. *See Cleco Power LLC,* 101 FERC ¶ 61,008 at PP 18-19 (2002) ("The purpose of SeTrans Sponsors' instant Petition is to seek approval and preliminary guidance only on certain issues related to the proposed formation of the SeTrans RTO. . . . Accordingly, this order makes a finding only on SeTrans Sponsors' proposed business model and ISA selection process, and generally the governance structure, and provides preliminary guidance on certain limited issues that have been raised in SeTrans Sponsors' Petition.").

73. O'Driscoll, *supra* note 71.

74. Although PSCo's Joint Dispatch Agreement predated SPP's launch of its Western Energy Imbalance Service Market, SPP WEIS is evaluated together with CAISO's EIM because both real-time imbalance markets share several common characteristics.

Specifically, this section examines: (1) the overall market structure and allocation of operational control for each paradigm, (2) participation requirements for the market, (3) the system of market governance, (4) how energy transactions are priced, and (5) how transmission service to facilitate transactions is procured and paid for. The following section highlights commonalities and differences among these market designs to define the threshold for what may pass legal muster with FERC—and potentially reviewing courts—when filing parties propose a new market design.

A. Imbalance Markets

The first type of organized market framework to be offered to non-RTO market participants was that of an energy imbalance market. Two such markets are described below.

1. Western Energy Imbalance Market

CAISO in February 2014 filed with FERC its proposal to offer participation in the imbalance portion of its real-time energy market—the EIM—to non-CAISO Balancing Authority Areas (BAA) in the Western states.[75] According to CAISO, the extension of its EIM structure to external BAAs did not represent the creation of a new market,[76] but would provide "other [BAAs] the opportunity to participate in the real-time market for imbalance energy that CAISO operates in its own [BAA]."[77] The proposal was designed to allow the voluntary participation of other balancing authorities without disrupting the existing market structure.[78] By leveraging a "wider and more diverse pool of supply resources" and by using an automated market process, CAISO asserted other Western BAAs could both reduce their energy costs and better facilitate the integration of renewable resources onto their systems.[79]

Certain stakeholders expressed concern over discrete aspects of CAISO's proposal, but many agreed that "expansion of CAISO's energy imbalance market beyond its BAA [would] provide customers with a range of benefits, including reduced costs, more efficient dispatch, improved integration of renewable resources, and enhanced reliability."[80]

In accepting the proposal, FERC found that CAISO's proposal complied with FPA section 205 but noted that the EIM filing differed "from [RTO] or [ISO] filings of a consolidated tariff for an overall footprint."[81]

75. *California Independent System Operator Corp.*, 147 FERC ¶ 61,231 (June 19, 2014) [hereinafter EIM Order].

76. *Id.* at P 74; *see Cal. Indep. Sys. Operator Corp.*, ISO Tariff Amendments to Implement an Energy Imbalance Market, FERC Docket No. ER14-1386-000 at 2 (Feb. 28, 2014) [hereinafter CAISO EIM Proposal].

77. *Cal. Indep. Sys. Operator Corp.*, Filing of CAISO Rate Schedule, FERC Docket No. ER21-1003-000 at 1 (Jan. 29, 2021).

78. EIM Order, *supra* note 75, at PP 6–7.

79. *Id.* at P 3.

80. *Id.* at P 76 & n.93.

81. *Id.* at P 76.

a. Market Structure & Operational Control

Under CAISO's proposal, participating BAAs would be able to purchase and sell real-time energy in CAISO's existing energy imbalance market on a five-minute basis.[82] CAISO would financially settle the EIM using locational marginal prices (LMP) that reflect "the clearing price of energy, the marginal cost of congestion, and the marginal cost of losses at the delivery location."[83] The EIM would build upon CAISO's 2014 introduction of a 15-minute energy market in response to FERC Order No. 764, which directed ISOs to offer intra-hour transmission scheduling in order to reduce barriers to the participation of variable energy resources in its markets.[84]

Under CAISO's EIM market structure, participating BAAs retain operational control over their transmission systems, but certain provisions would separate EIM transfers from normal energy sales.[85] For example, EIM transfers—transfers of imbalance energy from one EIM Entity BAA to another through the EIM—would not require individual resource e-Tags and would instead be modeled as dynamic schedules between CAISO and each relevant EIM entity.[86] Stakeholders generally approved of the market structure that CAISO proposed for the EIM, although several protested discrete market design choices, such as the application and allocation of uplift, resource sufficiency requirements, transmission charge and use issues, and settlements.[87]

In approving the overall EIM market design, the Commission agreed with CAISO that its proposal did not represent a new market, but instead would extend CAISO's existing real-time market to more participants.[88] The Commission explained, however, that "the proposal encompasses—within one real-time balancing market—entities within an ISO market and entities outside an RTO/ISO market operating BAAs pursuant to OATTs" and noted that this major structural difference requires treatment by FERC that differs from the regulation of a traditional ISO.[89] Overall, the Commission noted the voluntary nature of the EIM and the wide range of benefits that CAISO's proposed market structure might deliver to Western customers.[90]

b. Participation

Participation in the EIM would be voluntary both for BAAs and for individual resource owners within a participating BAA.[91] In order to participate, each

82. EIM Order, *supra* note 75, at P 2.

83. CAISO EIM Proposal, *supra* note 76, at 5.

84. Order No. 764, *Integration of Variable Energy Resources*, 139 FERC ¶ 61,246 (2012) (to be codified at 18 C.F.R. pt. 35).

85. EIM Order, *supra* note 75, at P 10.

86. *Id.* at P 27.

87. *See, e.g., Id.* at PP 132, 142.

88. *Id.* at P 76.

89. EIM Order, *supra* note 75, at P 76.

90. *Id.*

91. *Id.* at P 8.

interested BAA would enter into an implementation agreement with CAISO that sets out certain milestones and fees to accommodate CAISO's evaluation—and, ultimately, facilitation—of that BAA's participation in the EIM.[92] Participation in the EIM would not require any participating BAA to "join" CAISO.[93] CAISO would run its market software to economically dispatch the energy systems of EIM Entities and would financially settle the EIM, but that EIM Entities would be responsible for allocating the costs and revenues for imbalance sales according to their own respective OATTs.[94]

CAISO introduced four new types of participants in its real-time market, including EIM Entities and EIM Participating Resources, the resources within those BAAs that would offer imbalance energy into CAISO's real-time market.[95] Although CAISO proposed that EIM participation rules would be unique to the new market, it pledged that these rules would ensure comparable treatment between EIM participants and other CAISO market participants.[96]

In approving the EIM proposal FERC declined to spill ink specifically on CAISO's participation requirements. FERC determined when addressing seams issues, however, that CAISO had "taken sufficient steps to ensure that EIM transfers between EIM Entity BAAs and CAISO will not adversely impact non-participant systems."[97]

c. Governance

The EIM governance framework includes a Governing Body, participation by the Body of State Regulators (BOSR), and the convening of a Regional Issues Forum.[98]

Established by charter agreement in December of 2015, the five-member EIM Governing Body shares its authority with the CAISO Board of Governors—CAISO's board of directors—over rules specific to participation in the EIM.[99] New appointees to the Governing Body are selected by a nominating committee composed of stakeholder representatives and confirmed by the existing Governing

92. *Id.* at P 10. CAISO also explained that as part of the EIM's voluntary participation framework, a BAA's termination of its participation in the EIM would not be subject to an exit fee because each BAA will have paid its associated startup costs before joining and will remain responsible for any charges incurred during its participation in the EIM. CAISO proposed to retain the authority to suspend the participation of any EIM Entity within the first 60 days of its participation in the EIM if operational issues on its system adversely affect the overall market's operation. *See* EIM Order, *supra* note 75, at PP 13, 16.

93. EIM Order, *supra* note 75, at P 8.

94. *Id.* at P 8-9.

95. *Id.* at P 18.

96. *Id*.

97. EIM Order, *supra* note 75, at P 250.

98. CAL. INDEP. SYS. OPERATOR, CHARTER FOR ENERGY IMBALANCE MARKET GOVERNANCE 2 (Dec. 18, 2015), https://www.caiso.com/documents/decision-policies-implement-eim-governance-attach-b-charter-july-2021.pdf [hereinafter EIM Charter].

99. *Id.*

Body members.[100] Five stakeholder constituencies each contribute one voting representative to the nominating committee: (1) the EIM Entities, (2) participating transmission owners, (3) suppliers and marketers of generation, (4) publicly-owned utilities, and (5) state regulators.[101] Three additional constituencies each contribute one non-voting representative: (1) the current EIM Governing Body, (2) the CAISO Board of Governors, and (3) public interest groups and consumer advocates.[102] In total, the eight-member nominating committee is composed of these five voting and three non-voting representatives.

The BOSR meets periodically and exists primarily to serve as a forum for state regulators to track EIM and other CAISO developments that may impact their jurisdictional responsibilities.[103] The BOSR is independent from the CAISO Board of Governors, and participation on the BOSR does not preclude any state commission or commissioner from taking individual positions before FERC or in other fora. The Regional Issues Forum, convened approximately quarterly, is organized by a group of eleven sector liaisons.[104] Meetings of the Regional Issues Forum are open to the public and are designed to allow stakeholders to discuss issues related to the EIM or other related CAISO initiatives.

CAISO proposed that its Department of Market Monitoring (CAISO DMM) would provide market-monitoring services for the EIM participants in CAISO's real-time market.[105] Furthermore, CAISO would apply real-time local market power mitigation—which mitigates bids that might create non-competitive prices at transmission constraints—to the transfers of EIM market participants, as needed.[106]

Although a handful of commenters expressed support for CAISO's proposed governance and market monitoring regime, several others argued that "extending the authority of an RTO or state entity to a hybrid or multi-state market is unprecedented and does not comport with the Commission's independence criteria."[107] In support of this argument, one protester cited prior Commission orders regarding PJM and MISO to argue that the Commission had previously discouraged one state's ability to impact an RTO's operations disproportionately.[108]

CAISO noted in response that FERC had already found the CAISO DMM to be sufficiently independent of the ISO in compliance with Order No. 719. CAISO also argued that FERC had already accepted its governance structure as compliant

100. Jennifer Gardner, *Decision on EIM Governing Body Nomination*, W. ENERGY IMBALANCE MKT. (Aug. 28, 2019), https://www.westerneim.com/Documents/DecisiononEIMGoverningBodyNomination-Presentation-Jan2020.pdf.

101. *Id.* at 4.

102. *Id.*

103. *Body of State Regulators*, W. ENERGY IMBALANCE MKT., https://www.westerneim.com/Pages/Governance/EIMBodyofStateRegulators.aspx (last visited Jan. 14, 2024).

104. *Regional Issues Forum*, W. ENERGY IMBALANCE MKT., https://www.westerneim.com/Pages/Governance/RegionalIssuesForum.aspx (last visited Jan. 14, 2024).

105. EIM Order, *supra* note 75, at P 60.

106. *Id.* at PP 15, 61.

107. *Id.* at PP 105-06, n.34.

108. *Id.* at P 106, n.135.

with the independence requirements of Order Nos. 888, 2000, and 719, and that FERC had not established different independence requirements for multi-state ISOs.[109] Furthermore, FERC had not required changes to CAISO's governance structure when a Nevada-based electric utility joined CAISO.[110] Nor did FERC require MISO to revise its governance structure when it began providing reliability coordination service to non-MISO entities.[111]

In approving the EIM proposal, FERC found that the proposed governance and market monitoring structures were just and reasonable. FERC agreed with CAISO that the CAISO Board of Governors satisfies the Commission's independence requirements.[112] FERC also agreed with CAISO that the earlier integration of a Nevada cooperative had not necessitated changes to CAISO's governance. Noting the voluntary nature of the market and the availability of market participants to seek recourse with the Commission, FERC also concluded that the CAISO DMM would provide sufficiently independent and competent monitoring services for the EIM, and that CAISO had proposed a sufficient market oversight framework.[113]

d. Pricing

CAISO proposed to financially settle the EIM using LMPs that reflect the clearing price of energy, "the marginal cost of congestion, and the marginal cost of losses at the delivery location."[114] CAISO would allocate costs for energy transfers to each participating BAA, but that BAAs would settle these costs with market participants within their footprints.[115] Where necessary, CAISO would mitigate the bids or offers of EIM market participants, as required by their market-based rate authorizations.[116]

In approving the EIM proposal FERC declined to comment specifically on CAISO's proposed use of LMPs for EIM transfers. The Commission's top-line determinations in accepting CAISO's proposal, however, noted that the expansion

109. EIM Order, *supra* note 75, at P 108 (citing *Cal. Indep. Sys. Operator Corp.*, 112 FERC ¶ 61,010 at PP 18-36 (2005); *Cal. Indep. Sys. Operator Corp.*, 133 FERC ¶ 61,067 at PP 46-57 (2010)).

110. *Id.*

111. *Id.*

112. *Id.* at P 109 (citing *Cal. Indep. Sys. Operator Corp.*, 129 FERC ¶ 61,157 (2009), *order on compliance*, 134 FERC ¶ 61,050 (2011) (accepting CAISO's Order No. 719 compliance filing with language regarding independence and oversight of the Department of Market Monitoring); 112 FERC ¶ 61,010, at PP 18-36 (finding that CAISO's proposed Board selection process was "consistent with the principles of independence that the Commission has previously enumerated and acceptable for purposes of the Order Nos. 888 and 2000 independence requirements" and that the current Board was independent pursuant to Order No. 888); *Cal. Indep. Sys. Operator Corp.*, 133 FERC ¶ 61,067 at PP 46-57 (2010) (finding that CAISO's governance structure meets the requirements of Order No. 719: inclusiveness, fairness in balancing diverse interest, representation of minority position, ongoing responsiveness, and public posting of mission statement or organizational charter)).

113. EIM Order, *supra* note 75, at P 109.

114. CAISO EIM Proposal, *supra* note 76, at 5.

115. *Id.* at 3.

116. *Id.* at 40.

of CAISO's energy imbalance market—including, presumably, the pricing of energy imbalance transfers—was just and reasonable.[117]

e. Transmission Service

Transmission access to the EIM would be provided to participating resources under the applicable transmission providers' tariffs.[118] Energy transfers would be scheduled and dispatched between BAAs participating in the EIM only over transmission rights specifically made available for that purpose.[119] CAISO explained that imbalance energy transfers would not compromise the transmission rights of non-participants.[120]

CAISO did not propose to assess an incremental transmission charge for the use of unreserved transmission to support EIM transfers between participating BAAs.[121] Instead, to avoid rate pancaking, EIM transfers would be exempt from wheeling charges that might otherwise be imposed by the exporting BAA. Transfer recipients would only pay their local transmission charge.[122] CAISO argued that because EIM transfers represent a new transmission service under its tariff, its proposed treatment of EIM transfers would not amount to a discounted transmission service.[123] CAISO characterized this approach as consistent with Commission precedent that directs the removal of pancaked transmission rates "within and between ISOs and RTOs."[124]

Several commenters protested CAISO's proposal to exempt EIM transfers from wheeling charges, arguing that exempting EIM transfers from wheeling charges is unduly discriminatory because otherwise-identical transactions would be charged differently for transmission "depending on whether the transaction is EIM or non-EIM, which will give a price advantage to resources participating in the EIM."[125] Some argued that CAISO's proposal set forth an unduly preferential transmission rate for EIM transactions and constitutes preferential treatment for EIM resources.[126] Other utilities supported the proposal, arguing that exempting EIM transfers from transmission charges is critical to the efficient operation of the market.[127] Another argued that, although avoiding rate pancaking is beneficial, CAISO's proposal functionally establishes a "free transmission zone" that applies exclusively to EIM transactions.[128] Commenters cited to Order No. 2000 and several prior Commission orders in arguing that pancaked rates should be removed

117. EIM Order, *supra* note 75, at P 76.
118. *Id.* at P 11.
119. *Id.*
120. *Id.*
121. EIM Order, *supra* note 75, at P 12.
122. *Id.* at P 53.
123. *Id.* at P 127.
124. *Id.* at P 126.
125. EIM Order, *supra* note 75, at P 129.
126. *Id.* at PP 129–30.
127. *Id.* at P 129.
128. *Id.* at P 132.

for all market participants and not a subgroup of market participants.[129] One suggested that implementing a single OATT transmission rate across all market timeframes would be a more appropriate means of eliminating rate pancaking.[130]

CAISO explained in reply that transactions within the CAISO markets are not charged pancaked rates and, thus, that it was reasonable to apply the same policy to EIM transfers.[131] Although the proposed EIM would be the first energy imbalance market to extend beyond an existing RTO footprint, CAISO argued that the removal of pancaked rates for the entire EIM would not be unduly discriminatory because the EIM would provide a distinctly different service than CAISO's then-existing day-ahead and fifteen-minute energy markets.[132]

FERC approved CAISO's proposal to exempt EIM transfers from wheeling access charges, explaining that EIM transfers would not be similarly situated to other CAISO energy exports. FERC concluded instead that "the EIM represents a sufficiently different market structure to justify different rate treatment of EIM transfers and other CAISO exports."[133] Even if an EIM transfer uses the same transmission lines as other energy exports, FERC determined the transmission service used to deliver imbalance energy to be distinct from the service used for scheduled transactions.[134]

Noting that the elimination of the seam between CAISO and the EIM Entity BAAs would promote more efficient and competitive energy markets and would allow customers to draw on a wider pool of generation resources, FERC determined that eliminating pancaked transmission rates within the EIM was just and reasonable.[135] The Commission explained that although it had required the elimination of intra-RTO pancaking and had not previously required the elimination of inter-RTO pancaking,[136] the facts underlying the EIM— "an energy imbalance market utilizing an existing ISO's market software beyond the borders of that ISO"—did not fit cleanly into either category.[137] The Commission reasoned that CAISO's proposal to eliminate rate pancaking within the EIM footprint was designed to address goals similar to those underlying organized markets, such as enhanced efficiency and reliability.

The Commission supported its finding by citing to *Illinois Power Company*, in which FERC had allowed transmission rates to remain pancaked for entities outside of two participating RTOs but had allowed for non-pancaked rates between the RTOs. In *Illinois Power Company*, FERC had reasoned that non-pancaked rates "create a benefit for customers" within the RTO and "may provide to

129. EIM Order, *supra* note 75, at P 134
130. *Id.* at P 132.
131. *Id.* at P 144.
132. *Id.* at P 145.
133. EIM Order, *supra* note 75, at P 153.
134. *Id.* at P 154.
135. *Id.* at P 156.
136. *Id.* at P 155.
137. EIM Order, *supra* note 75, at P 155.

[RTO] customers additional supply alternatives that might otherwise be uneconomic."[138] The Commission analogized this circumstance to the EIM in accepting CAISO's proposed use of available transmission, finding that the proposed non-pancaked rates for the EIM would not only provide a benefit to EIM participants, but also could provide "an incentive for EIM participation that need not be offered to non-EIM entities."[139]

2. SPP WEIS Market

SPP, in October of 2020, filed a proposal to create the WEIS Market and to offer energy imbalance service through the WEIS Market to non-SPP RTO members. SPP's proposal consisted of: (1) tariff revisions to implement the WEIS Market, (2) Western Joint Dispatch Agreements (WJDA) executed by prospective WEIS Market participants, and (3) a charter for the Western Market Executive Committee (WMEC), which SPP proposed would serve as the governing body for the WEIS Market.[140] SPP's revised proposal built on an earlier proposal, which FERC had rejected in July of 2020 with guidance.[141]

SPP's WEIS Market Tariff, as revised, provided for the implementation of a market, to be operated by SPP, for five-minute energy imbalance service.[142] SPP would administer the WEIS Market separately from the existing wholesale energy market that it operates for RTO members.[143] At the time of filing, eight utilities had indicated interest in joining the WEIS Market and had taken steps to become WEIS Market participants.[144]

FERC accepted SPP's WEIS Market proposal, effective February 2021, finding that the WEIS Market was designed to yield economic and reliability benefits to market participants in the West.[145] The Commission explained that the WEIS Market not only would make a broader pool of resources available to provide energy imbalance service than did SPP's existing RTO footprint, but also that it could both improve reliability and facilitate the integration of an increasing number of variable energy resources.[146] The Commission noted that it had previously recognized the benefits that energy imbalance markets could yield and determined that it expected the WEIS Market to deliver similar benefits.[147]

138. *Id.* at P 157 (citing *Ill. Power Co.*, 95 FERC ¶ 61,644, *reh'g denied*, 96 FERC ¶ 61,026 (2001)).

139. *Id.*

140. *Southwest Power Pool, Inc.*, 173 FERC ¶ 61,267 at P 1 (2020) [hereinafter WEIS Market Order].

141. *Id.* at P 4 (citing *Southwest Power Pool, Inc.*, 172 FERC ¶ 61,115 (2020) at PP 18-19).

142. *Id.* at P 5.

143. *Id.*

144. WEIS Market Order, *supra* note 140, at P 6.

145. *Id.* at P 20.

146. *Id.*

147. *Id.* (citing 147 FERC ¶ 61,231, at P 75 (describing benefits of CAISO's energy imbalance market in the Western Interconnection); *Southwest Power Pool, Inc.*, 114 FERC ¶ 61,289 at P 2 (describing benefits of SPP's energy imbalance market that operated in the Eastern Interconnection from 2007-2014)).

a. Market Structure & Operational Control

The WEIS Market was designed to implement security constrained economic dispatch (SCED) to optimize the centralized dispatch of "all available participating resources across the WEIS Market footprint to help balance load and generation."[148] SPP would settle all imbalance energy within participating BAAs in the WEIS Market and thus would require all resources—load and generation—located within the WEIS Market footprint to register with the market.[149] If entities within a participating BAA opted not to execute the WJDA, SPP would settle any imbalance energy associated with their resources with their host BAA on their behalf.[150]

The WEIS Market structure would not require participants to transfer functional control of their generation or transmission assets to SPP.[151] Furthermore, the market would not determine unit commitments or clear any non-energy products, such as operating reserves. SPP would neither consolidate nor administer market participants' OATTs but would serve only as the market operator.[152]

FERC approved SPP's overall market design, which was not protested, explaining that SPP had addressed the Commission's concerns with its previous filing and had demonstrated that its revised filing "presents a just and reasonable regional solution."[153]

b. Participation

Prospective WEIS Market participants would be required to execute a Western Joint Dispatch Agreement (WJDA), which establishes a contractual relationship between SPP and a prospective market participant and allocates to the participant its share of total administrative costs.[154] At SPP's time of filing, all eight utilities seeking to participate in the WEIS Market at its inception had executed WJDAs.[155] FERC accepted SPP's proposed participation requirements, which were not protested, and declined to spill more ink on how those participation requirements comported with Commission precedent.

c. Governance

SPP set forth its proposed governance structure for the WEIS Market in the WMEC Charter, which SPP filed as part of the WEIS Market Tariff. All major governance decisions would be made through the WMEC, which would have the authority to approve or reject proposed amendments to the tariff or market rules, to recommend amendments to the WJDA, and to advise SPP on other market rule

148. WEIS Market Order, *supra* note 140, at P 8.
149. *Id*. at P 9.
150. *Id*.
151. *Id*. at P 11.
152. WEIS Market Order, *supra* note 140, at P 11.
153. *Id*. at PP 20–21.
154. *Id*. at P 7.
155. *Id*.

changes.[156] Each WEIS Market participant would have one representative on the WMEC. The WMEC would use a "house and senate" approach to voting; for a resolution to be approved it would typically need to receive both "(1) an affirmative vote of at least 75% with the WMEC representative votes weighted by the total net energy for load of WEIS Participants; and (2) an affirmative vote of at least 75% of WMEC representatives."[157] The WMEC would meet biannually, at minimum, and all meetings would be noticed and open to the public unless a specific vote required confidentiality.[158]

SPP also designed a governance system that would allow a broad collection of non-utility stakeholders to participate. For example, any state with a resource or load participating in the WEIS Market would be empowered to designate a state liaison to attend the WMEC in an advisory role.[159] SPP claimed that its "WEIS Revision Request" process would allow "any interested party to meaningfully participate" in WEIS Market governance.[160]

The SPP independent market monitor (SPP MMU) would monitor the WEIS Market.[161] Furthermore, the results of a Market Power Study that the SPP MMU had completed before the WEIS Market proposal was finalized informed mitigation provisions that were incorporated into the WEIS Market Tariff.[162]

Some commenters expressed support for the proposed governance structure, arguing that it would be broadly inclusive and align with existing governance frameworks for public power utilities.[163] Other stakeholders disagreed. One utility, for example, argued that the voting structure was unduly discriminatory because it provided disproportionate representation to a federal power administration over public utilities with several affiliates.[164] A coalition of public interest organizations argued that the WMEC Charter unreasonably limited voting to WEIS Market participants and unreasonably excluded "entities that have no direct financial interest in the operation of the WEIS Market."[165] In response, SPP explained that the WMEC—modeled on SPP's Market and Operations Policy Committee—provided sufficient transparency to all stakeholders.[166]

156. WEIS Market Order, *supra* note 140, at P 52.

157. *Id*. at P 53.

158. *Id*. at n.90.

159. *Id*. at P 54.

160. WEIS Market Order, *supra* note 140, at P 54 ("Entities that may submit a Revision Request are: (1) any WJDA signatory; (2) any staff member of a governmental authority having jurisdiction over the WEIS Market or any WEIS Participant; (3) SPP staff; (4) any rostered individual of an official WMEC organizational group; (5) any entity designated by a qualified entity to submit a Revision Request "on their behalf"; (6) a WEIS Participant; (7) SPP Western Transmission Customers or other entities that are parties to transactions under the WEIS Tariff; and (8) the SPP MMU. SPP notes that this will allow any interested party to meaningfully participate in the governance of the WEIS Market.").

161. *Id*. at P 10.

162. *Id*.

163. *Id*. at P 55.

164. WEIS Market Order, *supra* note 140, at P 56.

165. *Id*. at P 57.

166. *Id*. at P 60.

FERC approved the proposed WEIS Market governance framework, determining that limiting voting rights to WJDA signatories was reasonable "because only WJDA signatories have made a financial commitment to the WEIS Market."[167] The Commission noted, however, that any party could receive voting rights on the WMEC by executing a WJDA.[168] The Commission also found that SPP's WMEC Charter would provide adequate opportunity for stakeholders who do not execute WJDAs to participate in WMEC open meetings, engage in the Revision Request process, and appeal to SPP's Board of Directors any WEIS Market matter of concern.[169]

Regarding market power mitigation, one utility argued that SPP's proposed Market Power Study would not be adequate to address anticipated market concentration and potential pivotal suppliers in the WEIS Market.[170] FERC disagreed, determining that SPP's proposed monitoring scheme would address the major market power issues that SPP's MMU identified and allow SPP to mitigate "resources with local and structural system-wide market power" as necessary.[171] FERC also noted that although the market monitoring scheme for the WEIS Market resembled SPP's existing monitoring regime, it appropriately applied more stringent mitigation thresholds because the "smaller, more concentrated" WEIS Market might offer greater opportunities to exercise market power.[172]

d. Pricing

SPP proposed that it would calculate each WEIS Market participant's imbalance energy within the market footprint every five minutes and would settle the market by calculating LMPs for each area.[173] SPP adopted an earlier suggestion by the Commission that it add a marginal loss component to its calculated LMPs and incorporate marginal losses into its market software.[174] One utility protested SPP's pricing proposal, arguing that SPP had not proved that transactions on its system would reflect marginal losses accurately.[175] FERC determined in accepting SPP's pricing proposal that its framework—including accounting for marginal losses through its pricing and dispatch algorithms—was just, reasonable, and responsive to the Commission's earlier guidance. More specifically, the Commission found that the use of marginal losses would ensure least-cost dispatch, "minimize imbalance costs, provide prices that accurately reflect marginal costs, and preserve resources' incentives to follow dispatch."[176]

167. *Id*. at P 66.
168. WEIS Market Order, *supra* note 140, at P 66.
169. *Id*. at P 67.
170. *Id*. at P 71.
171. *Id*. at P 69.
172. WEIS Market Order, *supra* note 140, at P 80.
173. *Id*. at P 8.
174. *Id*. at P 85.
175. *Id*. at P 86.
176. WEIS Market Order, *supra* note 140, at P 89.

e. Transmission Service

SPP proposed to constrain dispatch of the WEIS Market to the amount of transmission capacity that market participants made available to be used for Joint Dispatch Transmission Service (JDTS).[177] In its initial filing, which FERC had rejected, SPP had not clearly explained how it would ensure that JDTS was not provided over the transmission capacity of non-participating entities in violation of the requirements of Order Nos. 890 and 890-A.[178] In its revised proposal, SPP clarified that it would not only restrict its dispatch of resources to transmission paths made available by market participants, but also that SPP would create and maintain constraints in its models to reflect this limited transmission capacity.[179] To facilitate this modeling, SPP proposed that JDTS providers would be required to communicate to SPP the transmission capacity that they would make available to the WEIS Market and that the WEIS Market's dispatch would not use non-participants' transmission rights.[180] SPP's revised proposal noted that JDTS would be provided at a rate of $0/MWh.[181]

Some commenters argued that SPP's proposal, even as revised, would not protect non-participants sufficiently from uncompensated use of their transmission rights.[182] One utility requested that FERC direct SPP to report on WEIS Market transactions and demonstrate that JDTS transactions did not displace other transmission service.[183] Another argued that the WEIS Market could create loop flow—a situation where increases in generation could create flows of electrons on unscheduled paths.[184]

FERC noted in approving the WEIS Market that SPP's solution would constrain transmission flows explicitly to the capacity that market participants designated as available and would respect the transmission rights of non-participants.[185] The Commission also disagreed that potential loop flows warranted rejection or modification of SPP's proposal.[186] Citing to its own precedent, FERC explained that "changes to market operations may indeed result in changes to flows on the integrated transmission system[;] [t]his, however, is not reason to prevent im-

177. *Id*. at P 8.

178. *Id*. at P 101.

179. *Id*. at P 102.

180. WEIS Market Order, *supra* note 140, at P 102.

181. *Southwest Power Pool*, Submission of Western Energy Imbalance Service Market Tariff, Western Joint Dispatch Agreements, and the Western Markets Executive Committee Charter, FERC Docket No. ER21-3-000 at 29 (Oct. 1, 2020).

182. WEIS Market Order, *supra* note 140, at P 106.

183. *Id*. at P 108.

184. *Id*. at P 112.

185. *Id*. at P 124.

186. WEIS Market Order, *supra* note 140, at P 106.

provements to market operations that will result in increased efficiencies and benefits to customers."[187] The Commission also declined to impose new reporting requirements.[188]

B. Enhanced Bilateral Energy Markets

Concurrently with the creation of imbalance markets in the West and Southwest, utilities in the Rocky Mountain and Southeast regions of the country began to develop frameworks that could enhance bilateral trading of short-term energy within their regions.

1. PSCo Joint Dispatch Agreement

PSCo, in late 2014, filed a proposal to implement joint dispatch service to facilitate the centralized, intra-hour dispatch of resources within its BAA and across the transmission systems of three utilities: PSCo; Black Hills/Colorado Electric Utility Company, LP; and Platte River Power Authority (Platte River).[189] FERC rejected PSCo's initial proposal in June of 2015, finding that it could have resulted in excessive costs and that it included insufficient protections against both the exercise of market power and possible violations of the Commission's Standards of Conduct.[190]

PSCo filed a revised proposal in October of 2015, in which it explained that the three parties had renegotiated the JDA to address the Commission's concerns.[191] PSCo's revised proposal explained that the JDA was representative of a long-standing interest in development and participation in a broader energy market, and that, for some time, the utility had sought the efficiency benefits of integrated regional market operations.[192] The proposal clarified that the JDA was not a commitment agreement, but that it would implement a more efficient mechanism for providing imbalance energy among the parties.[193]

Prospective JDA participant Platte River expressed support for the proposal, but another PSCo transmission customer raised concerns, arguing that the JDA and PSCo's JDTS together comprised a loose power pool and that PSCo had not proposed the types of transmission rate measures that Order No. 888 requires for

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187. *Id*. (citing 147 FERC ¶ 61,231, at P 268).

188. *Id.* at P 130.

189. *Public Service Company of Colorado & Black Hills/Colorado Electric Utility Company, LP*, 151 FERC ¶ 61,248 at P 2 (2015).

190. *Id.* at P 1.

191. *Public Service Company of Colorado & Black Hills/Colorado Electric Utility Company, LP*, 154 FERC ¶ 61,107 at P 5 (2016) [hereinafter Order Accepting PSCo JDA].

192. *Id.* at P 6.

193. *Id.* at P 7.

a power pool, such as a joint OATT.[194] The customer called on FERC to distinguish the JDA from other energy imbalance markets, such as CAISO's EIM.[195]

FERC disagreed with this protest, finding that PSCo's proposal did not establish a loose power pool and that the requirements of Order No. 888, accordingly, did not apply.[196] The Commission accepted PSCo's revised JDA and the associated tariff revisions to implement JDTS, explaining that the structure would enable participants to realize "substantial cost savings" by dispatching their collective resources more efficiently and on a least-cost basis.[197] FERC explained that PSCo had addressed its prior concerns adequately and that the passing through of cost savings to the utilities' customers would not affect third parties adversely.[198]

a. Market Structure & Operational Control

The proposed JDA contemplated that each party would continue to commit certain generation resources and operating reserves—either its own or by contract—to meet its native load requirements.[199] JDA parties would "determine how much or how little of their resources to make available for dispatch under the JDA" and no control would be conferred over a party's non-dispatchable units.[200] Under the JDA, the transacting parties would pay each other directly for energy transactions, but PSCo would operate the settlement process and issue invoices to each party.[201] JDA transactions generally would not be tagged like other energy transactions because the Western Electricity Coordinating Council already monitored transmission on the western grid. Where the Joint Dispatch Energy sales could create loop flows, however, PSCo would tag transactions.[202]

FERC approved the market structure, explaining that although the JDA would allow for the real-time dispatch of resources on a least-cost basis and could therefore replace some energy imbalance transfers, the JDA did not replace energy imbalance service altogether because it did not include scheduled transmission service.[203]

194. *Id.* at PP 38, 41; *see Id.* at P 38 n.58 (noting that the protester cited in support of its arguments to Order No. 888. Order No. 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, FERC STATS. & REGS. ¶ 31,036, at 31,728 (1996) [hereinafter Order No. 888], *order on reh'g*, Order No. 888-A, FERC STATS. & REGS. ¶ 31,048 [hereinafter Order No. 888-A], *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom.* Transmission Access Pol'y Study Grp. v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom.* N.Y. v. FERC, 535 U.S. 1 (2002)).

195. Order Accepting PSCo JDA, *supra* note 191, at P 40.

196. *Id.* at P 85.

197. *Id.* at PP 81, 87.

198. *Id.*

199. Order Accepting PSCo JDA, *supra* note 191, at P 7.

200. *Id.* at PP 8–9.

201. *Id.* at P 16.

202. *Id.* at P 17.

203. Order Accepting PSCo JDA, *supra* note 191, at PP 41, 87.

b. Participation

To participate in the JDA, an entity needed to: "(1) be a load serving entity within the PSCo BAA; (2) execute the Joint Dispatch Agreement with each participating transmission provider; (3) offer generating resources that meet dispatch criteria into the Joint Dispatch Agreement pool; and (4) secure an agreement with its host transmission provider to provide corresponding non-firm zero-rate transmission service for use by other Parties to the Joint Dispatch Agreement."[204] If a load-serving entity operating in the PSCo BAA does not serve as its own transmission provider, it may still participate in the JDA by committing to contribute its generating resources to the JDA pool and making arrangements with its host transmission provider to provide reciprocal JDTS.[205]

One utility criticized PSCo's proposed participation requirements, arguing that it is unreasonable to require a utility to pay for transmission facilities used to provide JDTS when it cannot unilaterally elect to take JDTS itself as an existing PSCo transmission customer.[206]

In accepting PSCO's proposal, FERC noted that the JDA "allows any entity to join, provided … it makes arrangements with its transmission provider to have access to unused Available Transfer Capability [] at a zero dollar rate."[207] The Commission found this condition not to be "unduly burdensome, as it would not bar participation by any entity that seeks to receive the cost savings benefits" of the JDA.[208] Instead, the Commission noted that any prospective participant that is an existing customer of the JDA parties could participate by executing the JDA and electing to receive the JDTS that these parties had already agreed to provide.[209]

c. Governance

PSCo's proposal did not establish a formal system of governance for the JDA or the provision of JDTS, but instead established a set of audit rights and transparency provisions that PSCo claimed would enable JDA parties to access unit cost information.[210] In a supplemental filing, PSCo clarified that each JDA party would contribute two employees to an Audit Committee that would periodically review the JDA and audit JDA operations.[211] The JDA also would empower any party to audit the records of any other party "to the extent reasonably necessary to verify the accuracy of any statement, charge, or computation."[212]

204. *Id.* at P 22.
205. *Id.* at P 18.
206. *Id.* at P 39.
207. Order Accepting PSCo JDA, *supra* note 191, at P 85.
208. *Id.*
209. *Id.*
210. *Id*. at P 69
211. Order Accepting PSCo JDA, *supra* note 191, at P 69.
212. *Id.* at P 19.

PSCo clarified that the Parties would create a web-based portal through which each JDA participant would submit production cost information for its resources.[213] The portal would be designed to ensure that each party's dispatch date remained confidential and that PSCo personnel involved in marketing PSCo's own energy would not have access to other parties' cost information.[214] One utility argued that PSCo marketing function employees might still be able to access the non-public cost information of its competitors, despite the portal structure, and use that information to obtain an unfair advantage in the bilateral energy market.[215]

FERC did not make a determination specifically on the governance of the JDA, nor did it address the Audit Committee in its findings, but FERC agreed with PSCo that the use of a web-based portal would prevent PSCo employees from accessing non-public information.[216] The Commission also noted that PSCo had committed to implement additional physical and cyber safeguards to protect non-public information.

d. Pricing

Energy prices under the JDA would be determined after transactions are completed and energy is delivered within the PSCo BAA.[217] The JDA outlined three energy products: (1) Joint Dispatch Energy, (2) Deficit Energy, and (3) Surplus Energy.[218] Each would be priced differently. JDA participants would also pay a \$0.50/MWh management fee to PSCo for providing each service.[219]

First, PSCo contemplated that most energy transactions under the JDA would be for Joint Dispatch Energy, a service that would be priced on a per-MWh basis at the system-wide marginal price and calculated hourly.[220] Joint Dispatch Energy pricing, like traditional energy pricing, would be based on the marginal unit's incremental fuel cost plus any non-fuel variable operations and maintenance costs.[221] Because PSCo at the time of filing the JDA did not have market-based rate (MBR) authority in the PSCo BAA, the JDA also proposed to apply a cost-based price cap to any payments that JDA participants would make to PSCo for Joint Dispatch

213. *Id.* at P 20.

214. *Id.*

215. Order Accepting PSCo JDA, *supra* note 191, at PP 75, 77.

216. *Id.* at P 83.

217. *Id.* at P 10.

218. *Id.*

219. Order Accepting PSCo JDA, *supra* note 191, at PP 14-15; *see id.* at P 15 nn.23-24 ((citing *Commonwealth Edison Co.*, 35 FERC ¶ 61,352 (1986)) (for the proposition that the Commission has historically allowed the use of adders for the recovery of transmission costs related to purchase and resale service) and (citing *Terra Comfort Corp.*, 52 FERC ¶ 61,241, at p. 61,840 (1990); *Indiana & Michigan Electric Co.*, 12 FERC ¶ 61,167 (1980); *Niagara Mohawk Power Corp.*, 86 FERC ¶ 61,009, at p. 61,028 (1999)) (for the proposition that the Commission has allowed percentage adders for generating entities to recover incremental energy costs)).

220. *Id.*

221. *Id.* at P 10.

Energy.[222] PSCo clarified that the price for Joint Dispatch Energy would never be negative.[223]

Second, if a JDA party's internal resources were insufficient to meet its hourly energy requirements, it could purchase Deficit Energy from PSCo at a rate of the marginal variable cost of supplying that energy plus an adder, which would be the greater of $10/MWh or 10 percent of PSCo's costs for providing the Deficit Energy.[224] This higher price was designed to incentivize participants not to plan to outsource its resource adequacy responsibilities to other JDA participants.

Third, the JDA would allow any party to sell Surplus Energy to PSCo when its generation produces energy in excess of its hourly energy requirements. The rate for Surplus Energy would be set at the system marginal price minus $1/MWh to discourage excessive over-production of energy.[225]

One utility criticized PSCo's pricing proposal, arguing that charging JDA participants a negotiated, "non-cost justified penalty" for requiring Deficit Energy or selling Surplus Energy in lieu of assessing the standard energy imbalance charges for those transfers under the existing PSCo OATT is not just and reasonable.[226] The utility argued that PSCo's proposed cost-based cap for its energy sales did not mitigate market power concerns sufficiently.[227]

FERC accepted PSCo's proposed pricing framework, finding specifically that PSCo's proposal to cap payments for its energy sales at the utility's existing cost-based price cap reasonably addressed the Commission's earlier concerns about PSCo's potential to exercise market power.[228] The Commission also rejected concerns that the rate for deficit energy represented a "non-cost justified penalty," finding that the price for deficit energy was based on the actual cost of providing such service.[229]

e. Transmission Service

PSCo proposed that JDTS would be a non-firm, intra-hour transmission service provided only on an "as-available" basis.[230] The service would use unreserved transmission and would have a lower priority than any other transmission

222. *Id*. at P 11 (citing *Xcel Energy Services, Inc*., 117 FERC ¶ 61,180 at P 38 (2006)).

223. Order Accepting PSCo JDA, *supra* note 191, at P 10.

224. *Id.* at P 12.

225. *Id.* at P 13 (citing *Carolina Power & Light Co.*, 95 FERC ¶ 61,429, at p. 62,597 (2001); *Algonquin Gas Transmission, LLC*, 115 FERC ¶ 61,067 (2006)) (for the proposition that penalties are not cost-based and therefore cost-based support is not required).

226. *Id.* at P 45.

227. Order Accepting PSCo JDA, *supra* note 191, at P 47.

228. *Id.* at P 82.

229. *Id.* at P 87.

230. *Id.* at P 21.

service, meaning that service could be interrupted.[231] PSCo explained that its proposed JDTS rate of $0/ MWh would represent the true opportunity cost of using transmission that would otherwise go unused—that is, zero.[232]

PSCo also cited to earlier Commission decisions on the CAISO EIM to support its zonal, *i.e.,* "license-plate," transmission service for imbalance energy.[233] Although the service would have no nominal cost, PSCo noted that JDA parties must provide reciprocal transmission service as a condition of joining the JDA, an arrangement that PSCo also claimed FERC had approved previously as a form of in-kind compensation.[234]

Critics commented that PSCo's pricing of JDTS at $0/MWh would erode other non-firm transmission service and would deprive PSCo's other transmission customers of revenue credits by serving as an improper subsidy for JDA participants.[235] One utility argued that PSCo's proposal to offer zero-dollar transmission service did not align with the Commission's policy of allowing for discounted transmission service only when a discount is required to increase throughput or when it is necessary to avoid rate pancaking and the distortion of competitive bids.[236]

FERC disagreed, determining that a zero-dollar rate for JDTS was just and reasonable when the transmission service is used as part of the JDA.[237] The Commission explained that JDTS makes available only transmission capacity that was not committed through either the firm or non-firm reservation processes. Because the transmission would otherwise go unused, FERC agreed that JDTS presents no opportunity cost and thus a zero-dollar rate is justified.[238] FERC also explained that because the use of JDTS is limited to energy imbalance transfers that result

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231. Order Accepting PSCo JDA, *supra* note 191, at P 21.

232. *Id.* at P 23.

233. *Id.* at P 35 (citing *PacifiCorp*, 147 FERC ¶ 61,227 at P 146 (2014)).

234. *Id.* (citing Ctr. Iowa Power Coop., Inc. v. FERC, 606 F.2d 1156, 1172 (D.C. Cir. 1979)). FERC determined in *Ctr. Iowa Power* that "reciprocal transmission" could be required of power pool members and that each participant could provide such reciprocal transmission either "in kind," i.e., by donation of transmission capacity for use by the pool, or "in money," by paying for the value of the transmission service required. *Ctr. Iowa Power Coop., Inc.*, 606 F.2d 1156, 1170 at n. 46. In *Ctr. Iowa Power*, the D.C. Circuit evaluated whether FERC erred in finding that the membership requirements of a 31-member Mid-Continent Area Power Pool (MAPP) were discriminatory and accepting the MAPP membership agreement only with modified membership conditions. In finding that the Commission had not erred, the court upheld the modified conditions as based on substantial evidence. One such modified condition rejected a MAPP proposal to relegate small utility systems to "associate participant" status on the basis of those systems' being too small to "to reciprocate in kind for the short-term transmission services" that would be used to facilitate MAPP. FERC determined in its order accepting the MAPP membership agreement that as long as these smaller utilities "can provide compensation for the true value of this transmission service, whether in kind or money," their obligation to provide reciprocal transmission service should be considered satisfied. *Id.*

235. Order Accepting PSCo JDA, *supra* note 191, at P 84.

236. *Id.* at PP 38, 40.

237. *Id.* at P 84.

238. *Id.*

from least-cost dispatch under the JDA, it does not serve as a substitute for typical non-firm transmission service for bilateral transactions.[239]

FERC found protesters' reliance on SPP precedent to be "misplaced."[240] The Commission explained that its acceptance of a prior SPP proposal "did not preclude zero-cost transmission in these circumstances, and further, transmission service at zero cost was not at issue in SPP."[241]

2. Southeast Energy Exchange Market

Fourteen Southeast utilities, in February 2021, filed a proposal to establish SEEM, which the filing parties described as a "new voluntary electronic trading platform designed to enhance the existing bilateral market in the Southeast" by using surplus transmission capacity.[242] SEEM was designed to match bidders and offerors on a 15-minute basis; matched pairs would transact with each other under existing bilateral agreements.[243] SEEM transactions would take place over available transmission capacity using a new lowest-priority, zero-dollar transmission service called Non-Firm Energy Exchange Transmission Service (NFEETS), a service that SEEM participants would be required either to provide over their own transmission systems or to arrange to take from their local transmission provider.[244] These parameters were outlined in a contractual document—the "SEEM Agreement."[245]

Commenters raised a series of concerns with the SEEM proposal, arguing that the market's structure, participation requirements, governance framework, and proposed transmission service were unjust and unreasonable.

After FERC staff issued two deficiency letters to seek more information from the SEEM filing parties, the Commission elected not to issue an order by the statutory deadline. Instead, the Commission Secretary released a notice on October 13, 2021, that the proposal had gone into effect by operation of law (BOL Notice).[246] The BOL Notice was accompanied by statements from Chairman Richard Glick and each of the other then-sitting FERC Commissioners.[247] In November 2021, the Commission issued a substantive order that solely accepted the tariff

239. Order Accepting PSCo JDA, *supra* note 191, at P 84.

240. *Id*. at P 86.

241. *Id.*

242. *Alabama Power Co.*, Southeast Energy Exchange Market Agreement, FERC Docket No. ER21-1111 at 1–2 (Feb. 12, 2021) [hereinafter SEEM Proposal].

243. *Id*. at 2, 4.

244. *Id*.

245. *See generally id.*

246. *Alabama Power Co.*, Notice of Filing Taking Effect by Operation of Law, FERC Docket Nos. ER21-1111 et al. (Oct. 13, 2021) [hereinafter BOL Notice].

247. *See* 16 U.S.C. § 824(d)(g) (Congress in 2018 added section 205(g) to the Federal Power Act. Section 205(g) provides that inaction by the Commission that allows a rate change to take effect shall be considered an order for purposes of rehearing and judicial review. Section 205(g)(1)(B) requires each Commissioner to submit a statement whenever a rate takes effect by operation of law that explains the views of the Commissioner with respect to the change).

revisions necessary to implement NFEETS (NFEETS Order).[248] FERC issued several further orders denying rehearing of these Commission decisions, including an order in December 2021 that rejected requests for rehearing on the BOL Notice as untimely[249] and two orders issued concurrently in March 2022: one that denied rehearing of the December 2021 rejection order[250] and another that modified the Commission's rationale for denying rehearing of the NFEETS Order.[251]

Several protesters appealed the Commission's decision to the D.C. Circuit. The D.C. Circuit determined that FERC had failed to respond adequately to protests of the SEEM proposal.[252] The court vacated and remanded the NFEETS Order and remanded several related SEEM decisions without vacatur so that FERC could address protesters' concerns more thoroughly.[253]

As of May 2024, FERC had again declined to issue an order addressing protests of the SEEM Proposal and several protesters had again petitioned the D.C. Circuit for review of that decision.[254] In June 2024, however, FERC issued an order seeking further briefing to assist the Commission in addressing the D.C. Circuit's remand directives.[255] FERC established a schedule whereby initial briefs would be due on August 13, 2024, and reply briefs would be due on September 12, 2024. As of the date of this article's publication, the SEEM proceeding remained pending before the Commission, following the submission of an initial brief by the SEEM filing parties and three reply briefs, among other pleadings.

Although several SEEM-related orders remain vacated until the D.C. Circuit issues another opinion, SEEM reflects another flavor of non-RTO organized market that provides a useful comparison to its Western and Southwestern counterparts. Accordingly, a summary of the SEEM proposal and the reception it received from stakeholders, FERC, and the D.C. Circuit are included below.

a. Market Structure & Operational Control

SEEM was proposed to be a "region-wide, intra-hour market platform to facilitate bilateral trading between voluntary market participants that will utilize unused transmission capacity to achieve cost savings throughout the region."[256] SEEM would use an algorithm to "match" participant bids and offers for each

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248. *Duke Energy Progress, LLC*, 177 FERC ¶ 61,080 at P 1 (2021) [hereinafter NFEETS Order]; *Duke Energy Progress, LLC,* 178 FERC ¶ 61,195 at P 1 (2022).

249. *Alabama Power Co.*, 177 FERC ¶ 61,178 at P 1 (2021).

250. *Alabama Power Co.*, *Order Addressing Arguments Raised on Rehearing*, 178 FERC ¶ 61,196 at P 2 (2022).

251. *Duke Energy Progress, LLC*, 178 FERC ¶ 61,195 at P 2 (2022).

252. Advanced Energy United, Inc. v. FERC, 82 F.4th 1095, 1117 (D.C. Cir. 2023) [hereinafter D.C. Circuit Remand Order].

253. *Id*.

254. *See* Adv. Energy United et. al. v. FERC, Joint Petition for Review, D.C. Circuit Case No. 23-1341 (Dec. 18, 2023) [hereinafter Joint Petition for Review].

255. *Alabama Power Co*., 187 FERC ¶ 61,174 at P 53 (2024) ("We find that supplementing the record would allow the Commission to appropriately address the D.C. Circuit's remand directives, including the directive to address the rehearing requests of the Deadlock Order.").

256. SEEM Proposal, *supra* note 242, at 4.

fifteen-minute trading period into paired transactions that would be priced at the midpoint between the bid and the offer, adjusted for losses.[257] "Energy Exchanges," the fifteen-minute transfers of imbalance energy from seller to buyer, would be delivered over the zero-cost NFEETS that SEEM participating transmission providers make available.[258]

The filing parties explained that many prospective SEEM participants already transacted with each other bilaterally and that FERC had found the existing bilateral market—i.e., sales made pursuant to entities' MBR authority—to be just and reasonable.[259] Transactions through the preexisting bilateral market in the Southeast were typically made on an hourly basis, however, whereas SEEM would allow for shorter, intra-hour transactions and more efficient price discovery.[260]

Commenters criticized the SEEM proposal on several grounds, including arguing that the overall market structure constituted a loose power pool that did not comply with FERC's requirements for power pools,[261] that the structure would allow participants to act anti-competitively,[262] and that SEEM would fall short in several areas of the Commission's standards for RTO/ ISOs and other organized markets.[263]

As noted above, FERC failed to issue an order either accepting or rejecting the SEEM proposal by the statutory deadline. The tariff provisions that would establish SEEM therefore became effective by operation of law as of October 12, 2021.[264]

The D.C. Circuit, in its opinion addressing the NFEETS Order as well as FERC's non-decisions on the overall SEEM proposal, found that the Commission had properly concluded that the record in the SEEM proceeding "demonstrated that SEEM's structure disincentivizes" anticompetitive behavior."[265] The Court remanded several components of SEEM, however, for further consideration by FERC.

b. Participation

The filing parties proposed several distinct roles for participants in SEEM, including "Members" and "Participants."[266] "Members" would be those founding entities of SEEM who had both signed onto the market proposal and agreed to fund, collectively, the market's upfront and ongoing costs.[267] Membership would

257. *Id*.

258. *Id*.

259. *Id*. at 5.

260. SEEM Proposal, *supra* note 242, at 9.

261. *See, e.g.*, *Motion to Intervene & Limited Protest & Comment of Public Interest Organizations.*, FERC Docket Nos. ER21-1111 et al. at 8-10 (Mar. 15, 2021) [hereinafter PIOs Initial Protest].

262. *Id*. at 74.

263. *Id*. at 18.

264. *See generally* BOL Notice, *supra* note 246.

265. D.C. Circuit Remand Order, *supra* note 252, at 1111.

266. SEEM Proposal, *supra* note 242, at 15.

267. *Id*.

be open, on a going-forward basis, to any entity that was: "(i) a Load Serving Entity located in the [SEEM] Territory; (ii) an Association, Cooperative or Governmental Entity that is a Load Serving Entity located in the Territory; or (iii) an Association, Cooperative or Governmental Utility created for the purpose of providing Energy to a Cooperative or Governmental Load Serving Entities (or the Load Serving Entities being served by an Association, Cooperative or Governmental Entity) located in the Territory."[268] Any future Member also must agree to the membership conditions outlined in the SEEM Agreement.[269]

"Participants" would be those entities that submit bids and offers to be matched through SEEM into energy *exchanges*.[270] Any entity may become a Participant by: (i) owning—or otherwise controlling—a source or sink within the SEEM footprint; (ii) executing a Participation Agreement, included as an attachment to the SEEM Agreement; (iii) arranging to take NFEETS from each participating transmission provider; and (iv) entering into contractual "enabling agreements"—contracts to facilitate bilateral trading—with at least three other SEEM Participants.[271] Regardless of an entity's membership status, Members and Participants would participate in SEEM "on exactly the same terms."[272] SEEM would not require minimum participation terms for Members or Participants and each could withdraw from the market after giving written notice.[273]

Some commenters criticized SEEM's proposed participation requirements, arguing that they unreasonably barred participation by certain types of generators—including independent power producers—and that limited participation could hinder the deployment of renewable energy resources in the Southeast.[274]

FERC's failure to act to reject the SEEM proposal by the statutory deadline resulted in acceptance of the SEEM participation requirements by operation of law.

The D.C. Circuit agreed, at least in part, with commenters who raised similar arguments in their petition for review of FERC's acceptance of SEEM, characterizing petitioners' arguments as "not without some merit" and noting that petitioners' "expert affidavit explained numerous ways SEEM's participation requirements could be manipulated by a Member acting in its own monopoly interests."[275] The court ultimately determined, nevertheless, that the petitioners had failed to demonstrate that FERC had acted arbitrarily and capriciously or had "'altered the

268. *Id*.
269. *Id*.
270. SEEM Proposal, *supra* note 242, at 16.
271. *Id*.
272. *Id*.
273. *Id*. at 20.
274. *See, e.g.*, PIOs Initial Protest, *supra* note 261, at 50. "The SEEM Market Rules require that a Participant '[o]wn or otherwise control a Source within the Territory and/or be contractually obligated to serve a Sink within the Territory.' It is not clear that independent power producers could meet this criteria [sic]."
275. D.C. Circuit Remand Order, *supra* note 252, at 1111.

burden of proof' in determining that SEEM's participation requirements were not unduly discriminatory."[276]

c. Governance

The filing parties claimed that SEEM's governance structure would "respect[t] and recogniz[e] the diverse Member interests" and would provide sufficient transparency into SEEM transactions to both participating and non-participating stakeholders.[277] As proposed, the SEEM governance framework consisted of a Membership Board, which would be responsible for all significant issues, and an Operating Committee, which would oversee the day-to-day functioning of the SEEM system.[278] The filing parties also proposed to retain a third-party Auditor to "ensur[e] that the [SEEM] system functions properly"[279] and noted that Members would hold annual meetings that would be open to all interested parties.[280]

The Membership Board would be composed of Member representatives and each representative would have two votes: a popular vote and a weighted vote based on net energy load.[281] Approval of proposals by the board would require a combined majority of the popular vote and either a majority or a super-majority of the weighted vote, depending on whether the proposal was considered a "general matter" or a "significant matter," respectively.[282]

The Operating Committee would be composed of four committee members, with each holding a single, equal vote and each representing one of four sectors: two voting members representing investor-owned utilities, one representing cooperatives, and one representing governmental utilities.[283] A proposal before the Operating Committee would need to receive unanimous support from the committee members to be approved.[284] Furthermore, all Members would "have a right to attend, observe, and participate in Operating Committee meetings," although only committee members would vote on proposals.[285]

Several parties criticized the SEEM governance framework. One coalition argued both that the governance structure "create[d] opportunities for specific applicants to control and manipulate the market" and that the framework unreasonably excluded non-Participant stakeholders from meaningfully engaging in decision-making around market rules.[286] Another coalition called for the Commission to "address membership and governance shortcomings" of the SEEM proposal,

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276. *Id*.
277. SEEM Proposal, *supra* note 242, at 21.
278. *Id*.
279. *Id*. at 18.
280. *Id*. at 23.
281. SEEM Proposal, *supra* note 242, at 21.
282. *Id*. at 21-22.
283. *Id*. at 22.
284. *Id*.
285. SEEM Proposal, *supra* note 242, at 22.
286. PIOs Initial Protest, *supra* note 261, at 28.

arguing that the proposed governance framework "excludes whole classes of interested parties from any participation in governance" and "allows for control entirely by vertically integrated utilities."[287]

In response to these protests and FERC staff's first deficiency letter, the filing parties proposed certain modifications to the SEEM governance framework. Although they did not modify the core structure of the Membership Board and Operating Committee, the filing parties indicated that they would submit confidential data to FERC on a weekly basis and would increase transparency regarding the role of the Market Auditor, including by requiring the Market Auditor to disclose its reports to market participants.[288]

FERC in declining to act on the SEEM Agreement also declined to comment substantively on the proposed governance framework for SEEM.

Although the D.C. Circuit opinion notes that the SEEM Agreement outlines governance procedures for SEEM, the court also declined to make any specific findings on the legality of SEEM's proposed governance framework in its order remanding the SEEM proceeding to FERC for further consideration.[289] The court may, however, make substantive determinations surrounding SEEM's governance structure if it takes up petitioners' second petition for review, which is currently pending before the court.[290]

d. Pricing

Transactions matched through SEEM would be priced on a "split-the-savings" basis, meaning that "the transaction price [would] reflect the midpoint between the seller's offer price and the buyer's bid price, with an adjustment for losses."[291] Losses, which would be reflected financially, would be allocated evenly between the two transacting parties.[292] The settlement of transactions would occur bilaterally.[293] Furthermore, prices for Energy Exchanges would be cost-capped, where applicable, so that market participants would not collect revenues in excess of their existing MBR authorizations.[294]

Commenters largely expressed ambivalence about SEEM's proposed pricing structure. One party, for example, noted that "the split-savings pricing proposal

287. *Advanced Energy Econ. et al.,* Comments of Advanced Energy Economy, Advanced Energy Buyers Group., Renewable Energy Buyers Alliance, and the Solar Energy Industry Association, FERC Docket Nos. ER21-1111 et al. at 19 (Mar. 15, 2021) [hereinafter Clean Energy Coalition Comments].

288. *Alabama Power Co.,* Response to Deficiency Letter, FERC Docket Nos. ER21-1111 et al. at 3 (June 7, 2021).

289. *See* D.C. Circuit Remand Order, *supra* note 252, at 1103.

290. *See generally* Joint Petition for Review, *supra* note 254; *but see* Renewed Motion of Respondent Federal Energy Regulatory Commission to Hold Appeal in Abeyance and Suspend Filing of the Certified Index to the Record, D.C. Cir. No. 23-1341 (filed June 15, 2024) (requesting that the D.C. Circuit again hold its proceeding in abeyance pending FERC action pursuant to its request for further briefing on several issues action pursuant to its request for further briefing on several issues related to SEEM's Compliance with Order No. 888).

291. SEEM Proposal, *supra* note 242, at 4.

292. *Id*. at 28.

293. *Id*. at 10.

294. *Id*.

[is] largely a reflection of current price formation" for bilateral transactions in the Southeast.[295] The same party argued that although "the proposed split-savings model is [not] unjust or unreasonable per se, it is generally thought to be inefficient when compared to other pricing models."[296] FERC in declining to act on the SEEM Agreement also declined to comment substantively on SEEM's proposed pricing methodology.

The D.C. Circuit also declined to opine on SEEM's proposed midpoint pricing. The court may have implicitly blessed the practice, however, when it noted that although two-thirds of the U.S. population is served by RTO/ISOs, which use auctions to set a single clearing price for energy at each location, "traditional markets still exist," within which primarily vertically integrated utilities "sometimes use short-term transactions to purchase energy from another utility" when it is economic.[297] Furthermore, Judge Rao, in a partially-concurring opinion, noted that the SEEM "algorithm matches eligible buyers and sellers at 15-minute increments, pricing transactions at the midpoint between the offer price and the bid price," but that the algorithm serves only a matching function; the participants consummate each transaction under separate contractual agreements to enable bilateral trading.[298]

e. Transmission service

Concurrently with their filing of the SEEM Agreement at FERC, each prospective SEEM Member that serves as a transmission provider and maintains an OATT filed an amendment to that OATT to reflect its intent to offer NFEETS.[299]

Describing NFEETS as a new "non-firm product, provided on an as-available basis for the sole purpose of facilitating Energy Exchanges," the filing parties explained that it would have the lowest priority of all transmission services.[300] More specifically, NFEETS would be available only on an "as-available basis," meaning that it would only be offered into SEEM if no transmission customer had reserved that capacity for another firm or non-firm transaction. NFEETS would also have the "lowest curtailment priority," meaning that capacity used to provide the service would be the first to be overridden by a competing transmission need.[301] NFEETS would be priced at $0/MWh, based on the lack of opportunity costs associated with otherwise-unused transmission capacity, and any anticipated transmission losses would be reflected in the Energy Exchange prices as financial losses, so that they could be shared between buyer and seller.[302] Lastly, NFEETS would only be obtainable "using the reservation, scheduling and tagging functions" of the SEEM system, such that no transaction would be able to use NFEETS unless it was a

295. PIOs Initial Protest, *supra* note 261, at 22.
296. *Id*. at 22 n.74.
297. D.C. Circuit Remand Order, *supra* note 252, at 1103.
298. *Id*. at 1118.
299. SEEM Proposal, *supra* note 242, at 3.
300. *Id*. at 24.
301. *Id*.
302. *Id*.

transaction guaranteed to generate some amount of cost savings for utility customers.[303]

A few parties filed comments in support of the NFEETS proposal, arguing that the $0/MWh price would help facilitate transactions that might otherwise be economic and would, as a result, deliver benefits to market participants and their customers across the Southeast.[304] One coalition, however, argued that the NFEETS provisions had not been shown to be just and reasonable or compliant with FERC Order No. 888 requirements.[305] The group argued that scheduling NFEETS through SEEM instead of through the usual platform for reserving transmission capacity would be inappropriate,[306] that the SEEM proposal lacked detail on which party to a bilateral transaction would bear any penalties for energy imbalances,[307] and that SEEM participants' use of NFEETS could adversely impact existing, firm transmission customers.[308]

After requesting more information about the provision of NFEETS and its potential impacts on existing transmission customers—and receiving filing parties' response—FERC issued an order in which a majority of commissioners voted to accept the OATT revisions that filing parties submitted to incorporate NFEETS as a new transmission service.[309] Unlike the rest of the SEEM proposal, which FERC declined to issue an order addressing, this standalone Commission order found the OATT revisions that implement NFEETS to be just, reasonable, and not unduly discriminatory or preferential.[310] The Commission explained that NFEETS "will utilize otherwise unused transmission capacity [and] will promote more efficient operation of Participating Transmission Providers' systems, while at the same time reducing the transactional friction normally associated with bilateral transactions."[311] Having determined that the SEEM filing parties had "sufficiently addressed" protesters' concerns about how NFEETS would be reserved and how any penalty charges would be assessed to NFEETS users, the Commission explained that NFEETS' impact on existing, firm transmission customers should be "minimal."[312]

FERC also addressed protesters' arguments that (i) NFEETS represented a discounted transmission rate, (ii) provision of this discounted transmission to one group of parties amounted to the creation of a loose power pool, and (iii) the SEEM proposal, by offering NFEETS pursuant to individual transmission providers

303. SEEM Proposal, *supra* note 242, at 24-25.

304. *See, e.g.*, *Tenn. Valley Pub. Power Ass'n,* Motion to Intervene of Tennessee Valley Public Power Association, Inc., Docket Nos. ER21-1111 et al. at 5 (Mar. 15, 2021); *Associated Elec. Coop., Inc.*, Motion to Intervene and Comments in Support of the Southeast Energy Exchange Market, Docket Nos. ER21-1111 et al. at 3 (Mar. 15, 2021).

305. Clean Energy Coalition Comments, *supra* note 287, at 8.

306. *Id*. at 35.

307. *Id*. at 36-39.

308. *Id*. at 39-40.

309. *See generally* NFEETS Order, *supra* note 248.

310. *Id.* at P 40.

311. *Id*.

312. NFEETS Order, *supra* note 248 at PP 41-43.

OATTs and not pursuant to a joint, market-wide OATT, violated the requirements of Order No. 888 and the Commission's regulations.[313] The Commission rejected these concerns, not only disagreeing with protesters that SEEM constituted a loose power pool, but also waiving the Commission's typical joint OATT requirement and concluding that restricting access to NFEETS to SEEM participants was not unduly discriminatory.[314] In support of these findings, the Commission cited to Order No. 888-A, which defines a loose power pool.[315] The Commission also cited to its precedent in accepting the PSCo JDA, explaining that a zero-dollar rate for NFEETS is just and reasonable because "[j]ust like in *PSCo*, the Southeast EEM Agreement allows for zero-dollar, non-firm service for unused transmission capacity, and thus entails no opportunity costs."[316]

Because FERC accepted the OATT revisions to implement NFEETS via a Commission order supported by a majority of commissioners, the D.C. Circuit reviewed that order separately from its consideration of the rest of the SEEM proposal, which went into effect by operation of law. Applying the Administrative Procedure Act's arbitrary and capricious standard,[317] the court dispensed with many of petitioners' challenges to the NFEETS Order but indicated it found merit in two of the petitioners' arguments.[318]

First, the court expressed that the Commission had failed to explain sufficiently how SEEM's participation requirements would square with the requirements of Order No. 888. The court directed FERC, on remand, to "provide a more fulsome explanation for why the 'market design decisions made by the filing parties'—couched as operational requirements and limits associated with 'technical feasibility'—are actually superior to the status quo in light of Order No. 888's open access principles."[319]

Second, the court took issue with FERC's determination that NFEETS is not a discounted transmission rate, noting that Order No. 888 itself provides that "non-pancaked" transmission, such as NFEETS, is one example of a discounted transmission rate.[320] On the basis of these two findings, the D.C. Circuit held that the Commission had failed to respond adequately to commenters' objections, vacated the NFEETS Order, and remanded the proceeding to FERC for further consideration.[321]

As noted earlier in this section, FERC issued an order, in June 2024, seeking further briefing to assist the Commission in addressing the D.C. Circuit's remand

313. *Id*. at P 62.

314. *Id*.

315. *Id.* at P 63 (citing Order No. 888-A, *supra* note 122, at 31,235).

316. NFEETS Order, *supra* note 248, at P 64. FERC also explained that "Protesters' attempts to distinguish *PSCo* are unavailing" and that "there is no basis in the record to conclude that the Southeast EEM will result in more of a reduction in non-firm transmission revenues than the agreement at issue in *PSCo*."

317. D.C. Circuit Remand Order, *supra* note 252, at 1110 (citing Emera Me. v. FERC, 854 F.3d 9, 21 (D.C. Cir. 2017)).

318. *Id*. at 1111-13.

319. *Id*. at 1113.

320. *Id*. at 1115 (citing Order No. 888, *supra* note 194, at 21,594).

321. D.C. Circuit Remand Order, *supra* note 252, at 1117.

directives.[322] In August 2024, the SEEM filing parties submitted their responses to the Commission's questions.[323] As of the date of this article's publication, several parties had submitted reply briefs or further pleadings, but the Commission had not yet taken further action.[324]

C. *Extended Day-Ahead Energy Markets*

Following these launches of imbalance energy markets and bilateral trading enhancements, market operators in the West and Southwest have begun pioneering more expansive day ahead markets, which extend a range of RTO services to non-RTO market participants.

1. CAISO Extended Day Ahead Market

CAISO in August 2023 filed a proposal to offer participation in the CAISO-operated day-ahead energy market to external BAAs in the Western states through an extended day-ahead market (EDAM). CAISO's EDAM framework would allow western BAAs to offer the output of the generation resources under their operational control into a market with a larger footprint. Because net load imbalances in CAISO's existing footprint have grown in recent years "following rapid growth in variable energy resource capacity, extreme weather-related uncertainty, and extreme weather events,"[325] CAISO concluded that extending participation in its day-ahead market to resources in neighboring BAAs would support the commitment of the lowest-cost power plants needed to serve load, would optimize the use of available regional transmission capacity, and would provide "broad economic, reliability, and environmental benefits" to the region.[326] Thus, CAISO designed its EDAM framework to optimize the transmission and resources offered into the CAISO day-ahead market to identify the most efficient portfolio of resource commitments and energy transfers to meet forecasted demand across the footprint.[327]

CAISO supported its proposal by citing to FERC's 2014 acceptance of CAISO's EIM, which allows other BAAs in the Western Interconnection to participate in the imbalance portion of CAISO's real-time energy market.[328] CAISO also cited to specific sections of its Commission-approved EIM Tariff as support for its argument that extend certain EIM provisions to its day-ahead market would be just and reasonable under the Federal Power Act.[329] CAISO did not explicitly

322. *Alabama Power Co.*, 187 FERC ¶ 61,174 at P 53 (2024).

323. *See Ala. Power Co.,* Joint Affidavit of Christopher McGeeney and Corey Sellers in response to FERC's 06/14/2024 Briefing Order, FERC Docket Nos. ER21-1111-006 et al.

324. *See, e.g., Adv. Energy United, Inc..,* Reply Brief, pursuant to the Commission's 06/14/2024 Order under ER21-1111 et al., FERC Docket Nos. ER21-1111-006 et al.

325. *Cal. Indep. Sys. Operator Corp.*, 185 FERC ¶ 61,210 at P 7 (2023) [hereinafter Order Accepting EDAM] (citing *Cal. Indep. Sys. Operator Corp.*, Day-Ahead Market Enhancements and Extended Day-Ahead Market, FERC Docket No. ER23-2686-000 at 2-3 (Aug. 23, 2024) [hereinafter CAISO EDAM Proposal]).

326. *Id*. at P 8 (citing CAISO EDAM Proposal, *supra* note 325, at 12-13).

327. *Id*. at P 10 (citing CAISO EDAM Proposal, *supra* note 325, at 13).

328. *Id*. at P 3 (citing EIM Order, *supra* note 75).

329. *See, e.g.*, Order Accepting EDAM, *supra* note 325, at n.32.

tie its proposal to other legal authority, including any citation to Order No. 888 regarding its transmission or CAISO's role as an ISO under Order No. 2000. In defending its proposal, however, CAISO alluded to precedent established by the D.C. Circuit, set out most notably in *Cities of Bethany*, that FERC need not consider alternative proposals if it finds a filing party's proposal to be just and reasonable under the Federal Power Act.[330]

FERC approved most of CAISO's proposal in December 2023.[331] The Commission found that the overall design of EDAM and CAISO's associated day-ahead market enhancements together represented a reasonable and nondiscriminatory framework for accommodating the participation of additional resources in the CAISO energy markets.[332] Overall, the Commission recognized that extending participation in CAISO's day-ahead energy market to resources located in other western BAAs could yield sufficient economic and reliability benefits to participants across the West.[333] FERC also explained that it expected EDAM would help CAISO and other market participants manage the impacts of increasing variable energy generation and extreme weather events in the region by leveraging a larger and more diverse set of resources.[334]

As part of its approval, FERC made several findings on discrete components of CAISO's EDAM proposal that parallel the case studies of other market designs discussed previously.

a. Market Structure & Operational Control

Regarding market structure, FERC noted that CAISO's EDAM filing differed from standard RTO or ISO filings, which typically "propose a consolidated OATT for one market footprint."[335] The EDAM filing, FERC explained, proposed something novel: the development of a day-ahead energy market that would include entities operating both within an ISO-controlled grid—CAISO market participants—and entities operating in external BAAs. Under the EDAM framework, each EDAM participant would offer its energy into a centralized day-ahead energy market while nevertheless operating pursuant to its respective BAA's OATT.[336]

EDAM's market structure also reflects a unique allocation of responsibilities among generating resources, CAISO, and participating BAAs. As proposed, each resource would be responsible for either submitting an economic bid or self-sched-

330. *Id.* at P 10 (citing Cities of Bethany v. FERC, 727 F.2d 1131, 1136 (D.C. Cir. 1984) (Cities of Bethany)).

331. *Id.* at PP 460–65. FERC initially rejected without prejudice CAISO's proposed EDAM access charge, which CAISO had indicated was severable from the rest of its proposal. In a subsequent order issued in June 2024, FERC accepted CAISO's proposed tariff revisions to implement a transmission access charge for EDAM. *See California Independent System Operator Corporation*, 187 FERC ¶ 61,154 (2024).

332. *Id.* at P 41.

333. Order Accepting EDAM, *supra* note 325, at P 42.

334. *Id.*

335. *Id.* at P 43.

336. *Id.*

uling in CAISO's day-ahead market based on its availability and operating parameters.[337] Each resource would also be responsible for satisfying CAISO's communication, telemetry, and control requirements.[338]

CAISO would oversee all four stages of resource participation in the day ahead market: (1) bid submission, (2) market power mitigation, (3) the financial clearing of bid-in supply against bid-in load and ancillary service requirements, and (4) the creation of day-ahead schedules through the residual unit commitment process.[339] In Step 4, EDAM would produce resource commitments and energy transfers that CAISO—as the market operator—would settle and allocate to the appropriate scheduling coordinator for each participating BAA.[340]

Each BAA would be responsible for distributing charges and revenues to the appropriate entities, as the EDAM provisions do not prescribe a methodology for intra-BAA cost allocation.[341] Each BAA must also demonstrate that it has sufficient supply to meet CAISO's resource adequacy, balancing, and flexibility requirements and for complying with CAISO's creditworthiness requirements.[342] In real-time, each BAA would remain responsible for coordinating the scheduling of resources within its operational control and dispatching resources in accordance with their real-time energy schedules.[343]

As FERC explained in approving EDAM's structure, "accommodating multiple market structures requires certain adaptations," such as transmission adaptations and EDAM's resource sufficiency demonstrations.[344] Although these adaptations represent deviations from traditional ISO/RTO market design, FERC noted that the overall EDAM proposal received support from a broad collection of prospective market participants and other stakeholders.[345] FERC's approval of this hybrid market structure—centralized energy offers but decentralized transmission tariffs—represents a concrete step in the evolution of Commission precedent to accommodate greater flexibility both in market design and in the provision of transmission service.

b. Participation

Participation in EDAM would be voluntary and determined on a system-wide basis by each BAA.[346] The primary prerequisite for a balancing authority to join EDAM is its current membership in—or a concurrent application to join—the EIM. Unlike in the EIM, however, all resources located within a BAA that elects to join EDAM must participate in both the day-ahead and real-time energy markets

337. Order Accepting EDAM, *supra* note 325, at P 14.
338. *Id*. at P 26.
339. *Id*. at PP 4-6.
340. *Id*. at P 18.
341. Order Accepting EDAM, *supra* note 325, at P 205.
342. *Id*. at P 13.
343. CAISO EDAM Proposal, *supra* note 76, at 104.
344. Order Accepting EDAM, *supra* note 325, at P 43.
345. *Id*. at n.55.
346. *Id*. at P 20.

either by submitting economic bids or by self-scheduling their participation as price takers.[347] Although every resource in a participating BAA is required to bid into EDAM, each BAA will have the flexibility to determine how much of each resource's capacity it offers into the day-ahead market.[348]

The Tariff provisions that govern EDAM participation set out four categories of participants: (1) EDAM Entities, i.e., the participating BAAs; (2) EDAM Resources; (3) EDAM Transmission Service Providers; and (4) EDAM LSEs. The Tariff defines the roles and responsibilities of each category and provides *pro forma* participation agreements for each.[349] To participate in EDAM, each party must execute the relevant participation agreement with CAISO and engage in a period of parallel operation with CAISO.[350]

Although CAISO explained that the EDAM framework and these standard forms were designed with the goal of accommodating a diverse group of western BAAs, each BAA and participating transmission provider would need to develop individualized OATT changes to facilitate its participation in EDAM.[351] Each BAA would further need to develop a methodology to allocate EDAM revenues and costs within its territory, ideally through a stakeholder process.[352] And each transmission provider would need to harmonize its existing menu of transmission services with those used to facilitate EDAM participation.[353]

No stakeholder expressed a view that the EDAM participation requirements would represent unreasonable or anticompetitive barriers to entry. This lack of protests on CAISO's proposed participation requirements stands in stark contrast to the reception that SEEM's participation requirements received, as discussed above. A few EDAM commenters instead noted limited and often situation-specific concerns. One utility, for example, expressed concern that transmission providers might be forced to participate in EDAM if they own assets or transmission rights within a certain BAA.[354] The same utility also argued that resources operating within the territory of a participating BAA should be able to opt out of participation.[355] In response, CAISO explained that third-party asset- or rights-owners would have the ability to carve themselves out of the BAA's participation.[356]

347. *Id*.
348. Order Accepting EDAM, *supra* note 325, at P 220.
349. *Id.* at P 21.
350. *Id.* at PP 207–08.
351. *Id.* at P 205.
352. Order Accepting EDAM, *supra* note 325, at P 206.
353. *Id.* at P 205.
354. *Id.* at P 213.
355. *Id.* at P 220.
356. Order Accepting EDAM, *supra* note 325, at P 217.

c. Governance

CAISO proposed a governance framework for EDAM that would extend the jurisdiction of the existing "WEIM Governing Body"—the committee of five independent members that oversees the EIM—to oversee EDAM as well.[357] The EDAM governance framework, like the existing EIM governance structure, would divide authority between the WEIM Governing Body and the CAISO Board of Governors.[358] CAISO committed to briefing its Board of Governors and the WEIM Governing Body on "all aspects" of EDAM, including the market's implementation, any market simulations, the role of market parameters, and—once operable—market performance.[359] Any revisions to CAISO's business practice manuals that address EDAM participation, including changes to EDAM market parameters, would only be made as part of the stakeholder process, which itself allows for appeals.[360]

Several stakeholders expressed concern that CAISO's proposed governance framework for EDAM would not be sufficiently independent from the CAISO Board of Governors and, by extension, from California interests.[361] A federal utility argued that CAISO should develop a more independent and representative governance structure for EDAM, especially because it views EDAM as a potential stepping-stone to a broader Western RTO.[362] Another stakeholder questioned the dual roles that both CAISO and its Board of Governors would be expected to play regarding EDAM: in the case of CAISO, the roles of market operator and balancing authority; and in the case of the Board of Governors, the oversight of both these operator and balancing authority functions.[363]

Despite these concerns, FERC approved CAISO's EDAM governance proposal, noting that the structure was consistent with the existing EIM governance structure, which the Commission approved as just and reasonable in 2014.[364] The Commission did not provide further detail when it explained that it was not persuaded by protesters' concerns about the WEIM/ EDAM Governing Body's independence, aside from noting that EDAM is a voluntary market and that participants may file complaints at FERC.[365]

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357. *Id.* at P 476; *see* CAL. INDEP. SYS. OPERATOR, CHARTER FOR ENERGY IMBALANCE MARKET GOVERNANCE, https://www.westerneim.com/Documents/CharterforEnergyImbalanceMarketGovernance.pdf (last visited Jan. 14, 2024).

358. *Id.*; *see Governance and committees*, CAL. INDEP. SYS. OPERATOR, https://www.caiso.com/informed/Pages/BoardCommittees/Default.aspx (last visited Jan. 14, 2024).

359. *Id.* at P 142.

360. Order Accepting EDAM, *supra* note 325, at P 142.

361. *Id.* at PP 477–79.

362. *Id.* at P 478.

363. *Id.* at PP 480–81.

364. Order Accepting EDAM, *supra* note 325, at P 484 (citing EIM Order, *supra* note 75, at P 109).

365. *Id.*

d. Pricing

CAISO proposed to calculate a marginal energy cost for each participating BAA by adding the BAA-specific redispatch costs arising from transmission congestion to the system-wide marginal energy price.[366] In plain language, this means that CAISO would calculate a baseline day-ahead energy price for each EDAM Entity based on the total cost of delivering one megawatt-hour of energy to a customer in that EDAM Entity's territory. CAISO noted that each EDAM Entity would be able to use its BAA-wide marginal energy cost as a starting point to calculate LMPs within its footprint.[367]

CAISO currently uses a similar process to calculate the real-time marginal energy cost for the EIM.[368] In the EIM, however, potential energy transfers are reflected as part of a BAA's marginal energy cost, whereas energy transfers in EDAM may be scheduled and settled separately from other energy settlements.[369] CAISO concluded that pricing in EDAM would need to be calculated for each BAA instead of for the entire system because of this difference.[370] The designated market monitor would evaluate imbalance reserves and day-ahead energy prices separately and would mitigate each to competitive levels as necessary.[371]

CAISO's proposed pricing methodology received wide-ranging feedback. One stakeholder argued that calculating a BAA-specific marginal energy cost instead of a system-wide cost would obscure a price signal that market participants rely on.[372] Another, conversely, called for even more granular pricing and argued that CAISO's EDAM proposal departed from Commission policy on price formation.[373]

FERC accepted CAISO's proposed pricing framework, determining that "it is no longer necessary or appropriate to reference a system marginal energy cost" in the formation of LMPs and that CAISO's proposal to calculate BAA-specific marginal energy costs is reasonable.[374] Because BAAs in EDAM can receive revenues for energy transfers, calculating a single system marginal cost would not

366. *Id.* at P 394.

367. *Id.*

368. Order Accepting EDAM, *supra* note 325, at P 396. *See also id*. PP 4-6. Because CAISO's EDAM proposal represents an extension of CAISO's existing day-ahead markets to participants in other BAAs, the system-wide market price for energy in EDAM will be those that result from CAISO's Integrated Forward Market (IFM). CAISO's IFM is a financial market that clears bid-in supply against bid-in load and ancillary service requirements. After the IFM yields its set of market clearing prices for each location—LMPs—CAISO procures any additional capacity needed to fill the gaps between the financial market solution and the physical supply needed to meet forecasted demand.

369. *Id.* at P 395.

370. *Id.*

371. Order Accepting EDAM, *supra* note 325, at PP 152, 173.

372. *Id.* at P 397.

373. *Id.* at P 398 ("Powerex asserts that price formation is a critical topic in the context of EDAM and notes that EDAM will not incorporate fast-start or "robust" scarcity pricing, diverging from other organized markets and Commission policy on price formation").

374. *Id.* at P 401.

reflect the true costs for energy in each BAA.[375] FERC instead concluded that CAISO's calculation of a separate marginal energy cost for each BAA would provide sufficiently transparent price signals to market participants.[376]

e. Transmission Service

At a high level, CAISO's EDAM transmission framework requires each transmission provider operating in each participating BAA to amend its OATT to make its transmission system available to EDAM.[377] Unlike the EIM, which uses as-available transmission to support real-time energy transfers, transmission capability made available to EDAM to support day-ahead schedules must also be reserved for real-time use so that market transfers arranged through EDAM can be effectuated in real time.[378] In other words, parties must carry forward day-ahead transmission reservations into real time. Consequently, resources participating in EDAM either must reserve transmission in advance under their transmission provider's OATT or must pay a transmission charge for the real-time use of previously-unreserved transmission capacity.[379]

More specifically, the EDAM transmission framework can be broken into three steps.[380] First, EDAM BAAs would provide transmission system information for the transmission capacity they make available to EDAM.[381] Second, CAISO would assign legacy transmission contracts priority over EDAM scheduling.[382] Third, CAISO would enable each EDAM Entity's transmission customers to reflect their existing transmission rights in the market.[383] Steps two and three are designed to respect existing transmission obligations and to ensure that EDAM BAAs can continue to serve their local load reliably.[384] As a further failsafe, each EDAM BAA would retain ultimate control over its own transmission system and CAISO would defer to the local BAA in managing infeasibilities.[385]

CAISO's EDAM transmission framework was designed to maximize the amount of transmission capacity that is available to the market.[386] The framework was also designed to strike an appropriate balance between respecting existing contract rights for transmission and making sufficient transmission available to EDAM to allow the market to produce regional benefits.[387]

375. Order Accepting EDAM, *supra* note 325, at P 401.
376. *Id.*
377. *Id.*
378. *Id.* at P 242.
379. Order Accepting EDAM, *supra* note 325, at P 246.
380. *Id.* at PP 243-45.
381. *Id.* at P 243.
382. *Id.* at P 244.
383. Order Accepting EDAM, *supra* note 325, at P 245.
384. *Id.*
385. *Id.* at P 247.
386. *Id.* at P 241.
387. Order Accepting EDAM, *supra* note 325, at P 282.

Many commenters expressed support for the EDAM transmission framework.[388] Some argued that CAISO's treatment of OATT rights would be at least as robust as what FERC's *pro forma* OATT requires.[389] A few expressed strong support for CAISO's framework, arguing that it not only preserves the firm nature of OATT service in line with the requirements of the Commission's *pro forma* OATT, but also that it appropriately addresses the needs of the existing Western Resource Adequacy Program.[390] Others referred to the proposed transmission framework as a reasonable starting point from which a more sophisticated transmission model should be developed in the future.[391] Not all feedback was positive, however. Several commenters highlighted what they perceive as shortcomings in the framework, seeking assurances that the EDAM design would not erode existing transmission rights,[392] produce infeasible solutions,[393] or enable market manipulation through transmission withholding.[394]

In approving the proposal, FERC agreed that CAISO's EDAM transmission framework would preserve legacy transmission rights by allowing EDAM Entities to use their existing transmission rights to participate in EDAM while making any remaining transmission capacity available to EDAM on an as-available basis.[395] FERC also found the overall framework to be consistent with or superior to the *pro forma* OATT.[396] The Commission noted, however, that its acceptance of the proposed transmission framework for EDAM did not pre-determine action on any prospective EDAM Entity or EDAM transmission service provider's individual filing.[397] The Commission committed to reviewing all future filings on a case-by-case basis to determine whether each entity's proposed OATT revisions to facilitate its participation in EDAM continued to comply with the *pro forma* OATT.[398]

2. SPP Markets+

As noted earlier in this article, SPP, in March 2024, submitted a proposal to implement a centralized day-ahead and real-time unit commitment and dispatch market (Markets+) in the Western interconnection.[399] Markets+ would enable SPP to offer a suite of RTO-like services to non-member BAAs, including facilitating the participation of external BAAs in SPP's day-ahead market. Under the proposed Markets+ tariff, transmission providers and BAA operators would continue to fulfill their existing roles and obligations, except that SPP would administer and

388. *Id.* at PP 250–81.

389. *Id.* at PP 256–57, 261.

390. *Id.* at PP 261, 270.

391. Order Accepting EDAM, *supra* note 325, at PP 250, 254, 258.

392. *Id.* at P 255.

393. *Id.* at P 263.

394. *Id.* at P 252.

395. Order Accepting EDAM, *supra* note 325, at P 307.

396. *Id.*

397. *Id.* at P 308.

398. *Id.*

399. *See Southwest Power Pool,* Submission of Tariff to Establish Markets+, FERC Docket No. ER24-1658-000 (Mar. 29, 2024) [hereinafter Submission of Tariff to Establish Markets+]

operate a centrally committed and dispatched day-ahead market and real-time balancing market for the resources and loads within the Markets+ footprint.[400]

At the time of this article's publication, FERC had not yet issued a final order on SPP's Markets+ proposal,[401] and thus Markets+ does not yet form part of the legal landscape for non-RTO organized markets. Nevertheless, SPP's proposal mirrors that of CAISO's EDAM framework in several key ways. For example, Markets+—like EDAM—proposes to use existing generation and transmission more efficiently by committing and dispatching resources across several BAAs and transmission owners' systems.[402] Markets+ also would limit commitment and dispatch to available transmission, similarly to EDAM, and would provide market access to all resources and loads in participating BAAs.[403] If SPP's proposal were approved, it would establish a potential rival to CAISO's EDAM by offering BAAs in the Western interconnection a choice of day-ahead market constructs. SPP's proposal therefore provides useful additional context for what SPP and other market operators may see as the future of non-RTO organized markets.

Despite these similarities between SPP's Markets+ proposal and CAISO's Commission-approved EDAM framework, however, FERC staff posed questions to SPP that highlight certain topics grid operators may need to better flesh out in developing future organized market proposals. Transmission, for example, remains a major challenge—including both the designation of transmission that will be made available to a non-RTO market and how the priority of non-RTO transmission reservations will stack up against existing transmission uses.[404] Greenhouse gas accounting, a necessary component of many western states' decarbonization plans, also creates challenges for would-be market designs, as evidenced by FERC staff's questions on SPP's proposed methodology for incorporating greenhouse gas accounting mechanisms into its proposed market design.[405]

V. SUMMARY OF COMMON CHARACTERISTICS AMONG NON-RTO MARKETS

Evaluating the preceding market designs can help define what passes legal muster with FERC—and potentially reviewing courts—when filing parties propose a new market structure. The next two pages includes a summary table comparing the characteristics of the five non-RTO markets discussed above, i.e., excluding Markets+. Following the summary table, summary sections explain how FERC's determinations on each market design component contributes to the creation of an overarching framework for just, reasonable, and not unduly discriminatory non-RTO organized markets.

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400. *Id*. at 5.

401. *See* Markets+ Deficiency Letter, *supra* note 22, at 1 (explaining that FERC staff in late July 2024 issued a deficiency letter seeking additional information about SPP's Markets+ proposal).

402. *See* Submission of Tariff to Establish Markets+, *supra* note 399, at 4.

403. *Id*. at 5.

404. *See, e.g.*, Markets+ Deficiency Letter, *supra* note 22, at 1-4.

405. *See id.* at 6–8.

Market	Structure & Operational Control	Participation	Governance	Pricing	Transmission Use
EIM	• 5-minute energy transfers • Extension of existing CAISO imbalance energy market • Financial settlement only • BAAs maintain operational control within their own footprints	• Voluntary participation by each BAA and resources within participating BAAs • Participants must execute a participation agreement and complete certain pre-integration tests	• Three- part governance structure: (1) EIM Governing Body, (2) oversight by the Body of State Regulators, (3) convening of a quarterly Regional Issues Forum that is open to the public • CAISO Department of Market Monitoring provides monitoring and market power mitigation services	• LMP • Costs for energy transfers allocated by CAISO to transacting BAAs • EIM transfer prices may be mitigated if a transacting party has market power	• As-available transmission, lowest priority • No wheeling charge for use of reciprocal transmission systems • Standard transmission charge for transfer recipients
PSCo JDA	• Real-time joint dispatch of all shared, "dispatchable" generation resources using SCED • Participating utilities maintain authority over resource planning, commitment, and operations • PSCo settles the market and bills participants, who pay each other directly	• Participation limited to load-serving entities within the PSCo BAA • Participants must execute a joint dispatch agreement and either secure--or provide themselves-- JDTS	• No formal governance structure	• Joint Dispatch Energy: LMP plus $0.50/MWh admin. fee • Surplus Energy: LMP minus $1/MWh plus admin. fee • Deficit Energy: LMP plus $10/MWh adder plus admin. fee	• As-available transmission, lowest priority • $0/MWh • Participants (LSEs) must provide reciprocal transmission system use
WEIS	• 5-minute energy imbalance market open to participating resources across the market footprint • All resources in a participating BAA must register with SPP and either execute a WJDA or opt out • Participants retain operational control • SPP dispatches the market using SCED and settles all imbalance energy	• Participation limited to BAAs in the Western Interconnect that do not already belong to SPP • Participants must execute a joint dispatch agreement and secure--or provide-- JDTS	• Western Market Executive Committee (WMEC) is the governing body for WEIS • Each WEIS market participant contributes a representative to WMEC • Proposals must be approved by supermajorities of both popular and load-weighted votes • Any party may request a market rule revision	• LMP, adjusted for marginal losses	• As-available transmission, lowest priority • SPP will model only available transmission • $0/MWh • Participants must provide reciprocal transmission system use
SEEM	• SEEM matches participant bids and offers into bilateral energy exchanges • Energy exchanges are arranged in 15-minute increments • No centralized market clearing or dispatch • Participants retain operational control • Parties settle transactions bilaterally	• Own or control a source or sink in the SEEM footprint • execute a participation agreement • arrange to take NFEETS from all necessary transmission providers • enter into enabling agreements with 3+ potential counterparties	• Members contribute voting representatives to a Membership Board • Sector representatives sit on an Operating Committee, which oversees SEEM operations • Third party auditor reviews market integrity	• "Split-the-savings" price at the midpoint between each bid–offer pair • Financial losses shared equally between buyer and seller • Transaction prices cost-capped for participants with mitigated MBR authority	• As-available transmission, lowest priority • $0/MWh, with any losses split as financial losses between buyer and seller • Offered under individual OATTs of SEEM Participating Transmission Providers

EDAM	• CAISO conducts a centralized, day-ahead energy auction • All resources in a participating BAA must either bid or self-schedule • Resource bids are reviewed for market power and cleared using SCED to create day-ahead schedules • CAISO settles the market and bills participants	• Participation determined BAA by BAA • execute a participation agreement • engage in pre-integration testing • voluntary participation: every resource in a participating BAA must submit economic bids or self-schedule	• Like EIM, three- part governance structure: (1) EIM Governing Body, (2) oversight by the Body of State Regulators, (3) convening of quarterly Regional Issues Forum • CAISO Department of Market Monitoring provides monitoring and market power mitigation services	• BAA-specific day-ahead LMP • day-ahead priced mitigated by CAISO DMM, as needed	• Participants (BAAs) must make unused transmission available to EDAM • Individual participants must either reserve unused transmission to receive $0/MWh transmission or must pay a standard transmission charge for the use of unreserved transmission

A. Overall Market Structure

Of the five approved non-RTO markets, only the PSCo JDA proposed centralized dispatch of participating resources, perhaps because PSCo offered participation only to utilities for which it already served as the balancing authority. The other four market proposals explained that existing balancing authorities would maintain operational control within their own footprints. The EIM, WEIS Market, and EDAM, for example, all noted that although the RTO would conduct centralized energy auctions, settle the market, and issue bills to participants, resources participating in those markets would continue to conduct their own resource planning and commitment processes.

SEEM's structure differed from the other four markets because although SEEM also left operational control of participating resources to resource owners, the market design did not include any centralized clearing mechanism or dispatch signal. Instead, SEEM proposed only that its algorithm would identify potential counterparties for energy bids and offers associated with fifteen-minute delivery periods; the matched pair counterparties would be responsible for executing energy exchanges and settling those transactions bilaterally.

FERC's acceptance of both types of market structures suggests that both centralized clearing and decentralized matching of market participants may be considered reasonable under the Federal Power Act. Furthermore, FERC reiterated both in approving the PSCo JDA and in approving SEEM that voluntarily organized markets need not be held to the same standards as either fully-fledged RTOs or power pools.[406]

FERC only invoked Order No. 2000 in one of the five orders—its order accepting CAISO's EIM proposal.[407] The Commission explained in that order that it had required the elimination of intra-RTO transmission rate pancaking, as a matter of policy, but clarified that Order No. 2000 did not prohibit rate pancaking between RTOs or in other regions of the country.

In sum, the orders accepting all five non-RTO organized market structures suggest that non-RTO markets may be centrally cleared or settled bilaterally, that operational control may be ceded to market operators or retained by resource owners, and that market participants may continue to conduct their own planning,

406. *See* NFEETS Order, *supra* note 248, at P 22; Order Accepting PSCo JDA, *supra* note 191, at P 85.

407. EIM Order, *supra* note 75, at P 155.

scheduling, and resource commitment processes, all while remaining compliant with the Federal Power Act and FERC precedent.

B. Participation

Participation requirements varied only slightly among the five markets. The EIM proposed arguably the most flexible set of participation requirements, with provisions that allowed EIM participation both by BAAs and by individual resources who would meet the criteria for participating in CAISO's energy market.[408] Furthermore, the EIM rules required only that prospective participants execute a participation agreement and complete certain pre-integration tests to participate. The EIM did not require that participants furnish or secure their own transmission, but—as a result—the EIM also did not exempt participants from transmission charges in their home BAA; it only exempted participants from wheeling charges for the use of transmission systems within the broader EIM footprint.[409]

Both the PSCo JDA and WEIS implemented more restrictive participation requirements, establishing that only LSEs located within the PSCo BAA or only BAAs in the western interconnect, respectively, would be able to elect to participate.[410] EDAM also required that participation would be determined at the BAA level and that every resource within a participating BAA must be accounted for in the market, either by bidding or by self-scheduling.[411]

The participation requirements for SEEM strike a balance between facilitating broad participation and ensuring that all resources are deliverable to the market. SEEM's requirement that prospective participants must own only a source or sink within the SEEM footprint is less restrictive than the PSCo JDA, which limited participation to LSEs, or WEIS and EDAM, which limited participation to BAAs. An individual resource owner, therefore, could elect to participate in SEEM where it could not in other markets. Similarly, because all participating transmission owners have agreed to provide zero-cost NFEETS to energy exchanges throughout the SEEM footprint, individual resources do not need either to secure reciprocal transmission system use, like they would in PSCo or WEIS, or to pay for transmission, like they would in the EIM.[412] Yet SEEM's requirement that participants execute bilateral contracts with at least three potential counterparties represents a potential barrier to entry that the other markets lack because—at least in theory—all existing participants could collude to prevent a new participant from joining.[413]

Of all the markets, SEEM received the most criticism of its proposed participation requirements, despite the relatively moderate nature of those requirements. FERC alluded somewhat to this discrepancy when it explained in the NFEETS

408. *Id.* at P 21.

409. *Id.* at P 53.

410. Order Accepting PSCo JDA, *supra* note 191, at P 22; WEIS Market Order, *supra* note 140, at P 9.

411. Order Accepting EDAM, *supra* note 325, at P 320.

412. *See*, e.g., Order Accepting PSCo JDA, *supra* note 191, at P 22.

413. SEEM Proposal, *supra* note 242, at 16.

Order that "it is not uncommon to require execution of an agreement like the Participant Agreement for voluntary structures like the Southeast EEM" and the provision of a standard form protects against undue discrimination.[414]

Stakeholders' concerns about participation requirements, therefore, may not be grounded solely in the letter of those requirements, but also in the perceived fairness of market governance and oversight. Both WEIS and EDAM, the two other markets approved since 2020, are operated by RTOs and are monitored by those RTOs' market monitors. This distinction may have preempted some stakeholder concerns about the potential anti-competitive impacts of participation requirements as applied to individual participants.

As of November 2024, the legal landscape for non-RTO market participation requirements remains broad and generally permissive. Furthermore, although the D.C. Circuit may scrutinize the SEEM framework more closely in the future, the court preliminarily validated FERC's determination that SEEM's participation requirements were just and reasonable, noting that "the Commission properly concluded that the record demonstrated that SEEM's structure disincentivizes" anti-competitive behavior, such as refusing to trade with potential counterparties.[415]

C. Governance

The five markets vary widely in their governance structures. The PSCo JDA, for example, did not establish any formal governance framework. Furthermore, that lack of formal governance procedures was not protested before FERC, which seems surprising in light of the extensive criticism that SEEM's governance framework received and, to a lesser extent, protests of WEIS Market governance.

In lieu of a standalone board of directors or operating committee, PSCo had explained that the JDA would rely on audit rights and transparency measures to enable participants to verify "the accuracy of any statement, charge, or computation" on an *ad hoc* basis.[416] When FERC questioned this initial lack of procedure, PSCo proposed that an Audit Committee composed of JDA participant representatives would also conduct routine oversight of JDA operations.[417] Although FERC accepted the PSCo JDA proposal, it declined to address the Audit Committee or specific transparency measures in its order.

The two other markets established prior to 2020—the EIM and SPP's WEIS Market—proposed governance structures that resembled pared-back versions of their existing RTO governance processes. CAISO proposed, for example, that the EIM would be overseen by three entities: its own Governing Body, a pre-existing Body of State Regulators, and a pre-existing Regional Issues Forum.[418] The EIM

414. NFEETS Order, *supra* note 248, at P 69 (citing Order Accepting PSCo JDA, *supra* note 191, at P 85 (noting that prospective participants "only need[] to sign the Joint Dispatch Agreement" to participate in the JDA); EIM Order, *supra* note 75, at P 6 (noting that CAISO proposed a *pro forma* agreement for use by participants in the EIM)).

415. D.C. Circuit Remand Order, *supra* note 252, at 1111.

416. Order Accepting PSCo JDA, *supra* note 191, at P 19.

417. *Id*. at P 69.

418. EIM Charter, *supra* note 98, at 2.

proposal did not specify vote thresholds, but SPP proposed that modifications to its WEIS Market would need to be approved by a supermajority of participants, measured both by popular and load-weighted votes.[419]

SEEM's governance framework borrowed from the frameworks of its three predecessors: members would contribute voting representatives to a Membership Board and Operating Committee; SEEM would hire a third-party auditor to oversee its matching system; and the market would host public annual meetings, akin to CAISO's Regional Issues Forum.

But whereas criticism of the PSCo JDA proposal was limited to the scope of audit rights and critics of the EIM governance framework argued only that CAISO would have too much oversight authority,[420] several stakeholders took issue with the governance frameworks proposed for the WEIS Market and for SEEM. At least one protester argued that each market unreasonably limited voting rights to market participants.[421] Others accused each market's governance system of affording a disproportionate amount of decision-making power to a few large utilities.[422]

Due to these variations and the odd procedural posture of SEEM's having gone into effect by operation of law, little Commission guidance exists on what components a non-RTO organized market must include in its governance framework to pass legal muster. In accepting the WEIS Market, FERC explained that limiting voting rights to market participants was reasonable, both because participants "have made a financial commitment to the WEIS Market" and because any party could receive voting rights by executing a participation agreement.[423] FERC also determined that SPP's WMEC Charter afforded adequate opportunity for non-participants to participate in the WEIS Market stakeholder process.[424] In addressing the SEEM proposal, furthermore, both FERC and the D.C. Circuit declined to make specific determinations about the legality of SEEM's governance framework.[425]

Perhaps because of the lack of consistent guidance, commenters have argued more strenuously in protests of the more recent market designs that governance frameworks need to provide greater access to non-participant stakeholders.[426] As non-RTO regions continue not only to develop more sophisticated markets but also to expand the services they offer from sub-hourly energy or imbalance energy service to day-ahead energy markets and coordinated regional planning, FERC

419. WEIS Market Order, *supra* note 140, at P 53. Notably, EDAM's governance proposal copied the EIM governance framework almost exactly. Perhaps as a result, only one party protested the framework, arguing that it afforded California interests too much control. *See* Order Accepting EDAM, *supra* note 325, at P 477.

420. EIM Order, *supra* note 75, at PP 105-06 n.34

421. *See* WEIS Market Order, *supra* note 140, at P 57; PIOs Initial Protest, *supra* note 261, at 28.

422. *See* WEIS Market Order, *supra* note 140, at P 56; Clean Energy Coalition Comments, *supra* note 287, at 19.

423. WEIS Market Order, *supra* note 140, at P 66.

424. *Id.* at P 67.

425. *See* D.C. Circuit Remand Order, *supra* note 252, at 1103.

426. *See, e.g.*, Clean Energy Coalition Comments, *supra* note 287, 19; PIOs Initial Protest, *supra* note 261, at 28 (in response to SEEM); Order Accepting EDAM, *supra* note 325, at P 478.

may need to speak more clearly on what level of governance it will require for non-RTO markets. As long as these market structures remain voluntary, FERC may decline to impose the governance requirements on non-RTO markets that Order No. 2000 maintains for RTOs. But the Commission may wish to develop a more formalized roadmap—or even issue a policy statement—that outlines what it considers "just and reasonable" when it comes to market governance.

D. Pricing

Four of the five markets use some form of LMP determined through a centralized market clearing process. The EIM prices imbalance energy at LMP, mitigated as needed to comply with transacting parties' MBR authorizations.[427] The PSCo JDA also prices its three products—Joint Dispatch Energy, Surplus Energy, and Deficit Energy—at LMP plus an administrative fee, with the latter two services' prices further adjusted to provide a financial incentive for resources to follow PSCo's dispatch signals.[428] The WEIS Market proposed perhaps the purest pricing, setting the price for imbalance energy at LMP, adjusted for marginal losses.[429] And although EDAM differs from the other markets in that it establishes day-ahead—and not real-time—energy prices, CAISO also proposed to use LMP to develop schedules for resources within the EDAM footprint.[430]

SEEM is the only market that does not use LMP, but SEEM's "split-the-savings" pricing was designed to reflect the bilateral nature of Energy Exchange transactions and to comply with the market's requirement that transacting parties settle with each other directly.[431] Because SEEM transactions represent matched, bilateral transactions between an offeror and a bidder, the midpoint pricing formula guarantees that each party receives half of the cost savings generated by the transaction. Although FERC did not opine on SEEM's "split-the-savings" pricing because SEEM went into effect by operation of law, the D.C. Circuit noted that "traditional wholesale markets still exist" and that vertically integrated utilities have long traded energy bilaterally, albeit without the assistance of a matching algorithm.[432]

Overall, FERC's acceptance of both LMP and midpoint pricing for short-term energy sales indicates that either is a viable alternative for non-RTO organized markets.

E. Transmission

Most of the non-RTO markets proposed transmission schemes that share several common characteristics. All five indicate that their transactions will be delivered—or scheduled and delivered, in the case of EDAM—across "as-available transmission," i.e., transmission that has not been reserved for any other firm or non-firm transmission service and would otherwise go unused. Transactions in all

427. EIM Order, *supra* note 75, at P 40.
428. Order Accepting PSCo JDA, *supra* note 191, at PP 14-15.
429. WEIS Market Order, *supra* note 140, at PP 8, 85.
430. Order Accepting EDAM, *supra* note 325, at P 394.
431. *See* SEEM Proposal, *supra* note 242, at 4-5.
432. D.C. Circuit Remand Order, *supra* note 252, at 1103

five markets also would be assigned the lowest priority, meaning that they would be curtailed before other, scheduled transmission service.

Four of the five markets—all but the EIM—establish that their baseline transmission charge for using this surplus transmission capacity will be $0/MWh. Several market designs attached additional conditions to the use of this zero-dollar transmission, however. The PSCo JDA and WEIS Market require that participants must provide reciprocal use of their own transmission facilities to take advantage of zero-dollar transmission service across others' transmission facilities.[433] EDAM allows participants to reserve unused transmission capacity to receive the zero-dollar rate, but also allows for participants to be charged standard transmission rates if they use transmission without a reservation.[434]

The EIM and EDAM require that participating BAAs make their unused transmission available to the markets, although the EIM assesses standard transmission charges to imbalance energy transactions whereas EDAM enables participants to use zero-dollar transmission service. The PSCo JDA, similarly, required that participating LSEs make an "in-kind" commitment of reciprocal transmission capacity.[435]

SEEM also required market participants who own transmission to modify their OATTs to establish NFEETS as a service and agree to provide NFEETS to SEEM participants.[436] FERC affirmatively blessed SEEM's transmission framework in its NFEETS Order, finding not only that the zero-dollar rate for NFEETS was just and reasonable based on the service's lack of opportunity costs, but also that it was reasonable for SEEM participating transmission providers to offer NFEETS pursuant to their individual OATTs.[437] The Commission used the NFEETS Order to explain more of its rationale for why the requirements of Order No. 888 did not necessitate that SEEM's filing parties develop a Joint OATT. FERC explained that requiring a Joint OATT "would place form over substance" because NFEETS would be provided by FERC-jurisdictional transmission providers in accordance with OATTs that remain on file with the Commission and subject to the Federal Power Act.[438] FERC further agreed with the SEEM filing parties that requiring a joint, system-wide OATT could jeopardize the expected benefits of the Southeast EEM by precluding the membership of the Tennessee Valley Authority without providing any clear "increase in functionality or benefits" to SEEM participants.[439]

The D.C. Circuit signaled its potential agreement with FERC's findings on NFEETS. Nevertheless, Judge Wilkins, writing for the majority, expressed skepticism about the Commission's explanation for why NFEETS should not be considered discounted transmission and why, therefore, SEEM should not be required

433. Order Accepting PSCo JDA, *supra* note 191, at P 35; WEIS Market Order, *supra* note 140, at P 8.
434. Order Accepting EDAM, *supra* note 325, at P 246.
435. Order Accepting PSCo JDA, *supra* note 191, at P 35.
436. NFEETS Order, *supra* note 248, at P 40.
437. *Id.* at P 62 (citing Order No. 888-A, *supra* note 122, at 31,235).
438. *Id.* at P 73.
439. *Id.*

to file a Joint OATT with the Commission to comply with Order No. 888.[440] The court directed the Commission, on remand, to "provide a more fulsome explanation for why the market design decisions made by the filing parties" are "superior to the status quo in light of Order No. 888's open access principles."[441]

The Commission's June 2024 order directing further briefing, however, likely postpones any further D.C. Circuit decision regarding what counts as discounted transmission service and whether identical OATTs may be substituted for a Joint OATT until after the Commission has reviewed the briefs it requested and issued a further order on the merits of the SEEM market construct. Although any future decision by the D.C. Circuit would affect SEEM alone, zero-dollar transmission underpins all five extant market structures, so a finding by the court that zero-dollar transmission will be considered discounted transmission service for the purpose of evaluating compliance with Order No. 888 would represent a substantial shift in the legal landscape for non-RTO market design.

VI. PAST AND PLANNED NON-RTO MARKET CONSOLIDATION

Only four of the five market structures remain operational as of this article's publication. PSCo—doing business as Xcel Energy-Colorado—and the other JDA parties announced in January 2022 that they would join the WEIS Market, which SPP operates.[442] In late March 2023, FERC accepted revisions to PSCo's tariff to reflect its authorization to participate in the WEIS Market, effective April 1, 2023.[443]

SPP also recently announced its plan to phase out the WEIS Market after the RTO launches two new markets: (i) Markets+; (ii) and an expanded, fully integrated western RTO.[444] As of 2024, however, the WEIS Market remains operational and represents the state of market development available to non-SPP BAAs in the western interconnect.

Regardless of these past and planned reorganizations, FERC's approvals of all five market structures together form the existing legal landscape for non-RTO organized markets. Stakeholders working to develop new markets, therefore, should be able to model future market proposals after the components that FERC and reviewing courts have found to be just, reasonable, and compliant with existing laws and regulations.

VII. CONCLUSION

The Commission's relatively recent approvals of these five market structures could not exist without the foundation laid by FERC's earlier landmark orders, however. As introduced before the market summaries, Order No. 888 required all

440. D.C. Circuit Remand Order, *supra* note 252, at 1115, 1117.

441. *Id.* at 1113.

442. *Colorado Utilities Plan to Join the Western Energy Imbalance Service Market*, SW. POWER POOL (Jan. 25, 2022), https://www.spp.org/news-list/colorado-utilities-plan-to-join-the-western-energy-imbalance-service-market/.

443. *Public Service Company of Colorado*, 182 FERC ¶ 61,223 (2023).

444. *SPP to Phase Out WEIS as New Market Offerings Expand*, RTO INSIDER (Apr. 14, 2022), https://www.rtoinsider.com/29946-spp-phase-out-weis-new-market-offerings-expand/.

FERC-jurisdictional transmission providers to maintain OATTs that set out non-discriminatory terms for their provision of transmission service. FERC in Order No. 2000 then established a comprehensive list of requirements for RTOs that were designed to ensure just and reasonable rates for electricity, facilitate regional coordination, and promote transparency in regional markets. Because the Commission stopped short of mandating RTO membership, however, FERC-jurisdictional utilities located in non-RTO regions of the country were required to comply with Order No. 888—including Order No. 888's requirements for power pools—but were not required to pursue the type of coordinated market development envisioned by Order No. 2000.[445] As a result, when these regions—including the West, Southeast and Southwest—began to form the non-RTO organized markets described in the prior section, FERC operated largely without a roadmap in reviewing whether proposed market designs would satisfy the requirements of the Federal Power Act.

A review of all five markets suggests that states still have wide latitude in designing markets that reflect their regional preferences, so long as the resulting markets comply with the requirements of Order Nos. 888 and 2000. Compliance will look slightly different for each type of market, but future market proponents may be more likely to receive approval from FERC and reviewing courts if they use prior market approvals as a guide.

For each of the existing energy imbalance markets, compliance with the market requirements set out in Order Nos. 888 and 2000 may have been simplified by the fact that despite being non-RTO markets, both the EIM and SPP's WEIS Market benefit from the underlying RTO governance and market monitoring frameworks of CAISO and SPP. For example, although participation can be decided on a BAA-by-BAA basis and participants in each energy imbalance market retain operational control of their resources, both market proposals established representative governing bodies and relatively open stakeholder processes.

For enhanced bilateral energy markets, Order No. 888 provides more guidance than Order No. 2000. Both the PSCo JDA and SEEM, as proposed, retain the bilateral nature of short-term energy transactions. Although the PSCo JDA established a menu of set prices that differed depending on whether participating utilities were net long, net short, or neutral for their short-term energy supplies and SEEM uses midpoint pricing for all energy exchanges, participants in both markets pay each other directly for energy, rather than the market operator settling and billing transactions. Enhanced bilateral frameworks therefore depend on energy being delivered in accordance with each participant's OATT. Governance structures, however, may not need to be as formalized as for those markets operated or administered by RTOs. When the PSCo JDA was established, for example, participation was limited to LSEs only and any prospective LSE needed either to provide or to secure reciprocal transmission to participate. SEEM, in contrast, allowed a wider group of resources to access its platform, requiring only that participants control either a source or a sink within the market footprint and execute trading agreements with prospective counterparties. Unlike for the PSCo

445. D.C. Circuit Remand Order, *supra* note 252, at 1113.

JDA, SEEM participants were not required to furnish their own transmission service.

For day-ahead energy markets, the model is still evolving, with only CAISO's EDAM having been approved to date and SPP's Markets+ pending before the Commission, but the importance of must-offer requirements to operating competitive and efficient day-ahead markets may remain a focus going forward. In EDAM, for example, all resources in a participating BAA must either bid or self-schedule their output for the following day and must either reserve unused transmission or pay a standard transmission charge for the delivery of that energy. Especially as the resource mix continues to transition to a higher penetration of duration-limited resources and system net load peaks get steeper, customers and regulators may pay even more attention to safeguards against the exertion of market power and other market-based tools to ensure rates are just and reasonable.

Despite the lessons learned from prior market approvals, several open questions remain about exactly what the Federal Power Act's "just and reasonable" standard requires of new markets, especially regarding participation requirements and governance. If the D.C. Circuit determines that transmission offered at a $0/MWh rate must be considered a discounted transmission rate under Order No. 888, for example, that decision could require SEEM to restructure substantially. Market monitoring, furthermore, has never been required formally of non-RTO markets, but providing monitoring and implementing other transparency measures may help new market proponents garner support from potential participants and other regional stakeholders.

Nevertheless, the pressures mentioned in this article's introduction—to save customers money, to integrate an increasing amount of new generation onto the grid, and to pursue decarbonization goals—likely will continue to encourage states across the country to explore regional markets. Even states in regions that historically have declined to join RTOs may continue to pursue non-RTO organized markets to capture the lower costs, greater resilience, and potential environmental benefits that operating resources across a wider geographical footprint offers.

Prospective market operators have already convened extensive stakeholder processes to discuss the formation of several new markets, including an expansion of SPP's integrated marketplace to utility service territories in the western interconnect, currently named "RTO West,"[446] and the West-Wide Governance Pathways Initiative.[447] These and other future markets may benefit from addressing potential concerns of FERC and reviewing courts in advance by using existing market designs in each of the three categories as a template and including detailed justifications for why any decisions to deviate from previously-accepted market designs comply with the Federal Power Act and Commission precedent.

446. *RTO West*, SW. POWER POOL, https://spp.org/western-services/rto-west/ (last visited Jan. 15, 2024).

447. *West-Wide Governance Pathways Initiative*, W. INTERSTATE ENERGY BD., https://www.westernenergyboard.org/wwgpi/ (last visited July 7, 2024).

THE LAW AND ECONOMICS OF TRANSMISSION PLANNING AND COST ALLOCATION

Joshua Macey & Jacob Mays[*]

Synopsis: This Article considers how to allocate the costs of transmission when states, utilities, or other classes of customers adopt different clean energy policies. It explains that the beneficiary pays approach to cost allocation does not result in some customers being forced to pay for their neighbors' benefits and is therefore consistent with the Federal Power Act's (FPA) prohibition on undue discrimination. In fact, beneficiary pays is likely the *only* approach to cost allocation that does not result in some customers free riding off their neighbors' transmission investments. For that reason, every federal court that has reviewed methods for allocating the costs of regionally planned transmission lines has required FERC and transmission planners to use the beneficiary pays approach. The Article also summarizes the last hundred years of federal interventions in transmission and natural gas markets to demonstrate that this view is consistent with decades of judicial, congressional, and regulatory policy, and it explains how beneficiary pays can be implemented when different states and classes of customers adopt different energy policies.

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I. INTRODUCTION

In May 2024, the Federal Energy Regulatory Commission (FERC) issued an Order—Order No. 1920—that aims to improve the processes for planning and allocating the costs of transmission investments.[1] Order No. 1920 imposes two important new requirements on transmission planners. First, it requires forward-looking, long-term regional planning that considers at least seven types of benefits of proposed lines.[2] Second, it instructs transmission planning entities to allocate the costs of new lines and upgrades such that customers pay their share of the benefits.[3] This approach to cost allocation, known as beneficiary pays, stipulates that customers cannot be charged for benefits they do not receive, and they cannot free ride off their neighbors by benefitting from new lines without having paid their share.

In a sharp dissent, Commissioner Mark Christie argued that the Order forces states to pay for neighboring states' clean energy programs.[4] The Federal Power Act (FPA) gives states authority over their generation facilities, and it prohibits electricity rates that are "unduly discriminatory or preferential."[5] The dissent appears to think that, if a new line helps some states meet their clean energy goals, then spreading the costs of the line across multiple states amounts to ordering all states to pay for their neighbors' clean energy policies. On this view, states should not have to pay for any part of a new line if any of the line's benefits are tied to another state's clean energy policies.

As an alternative to the approach adopted by Order No. 1920, the dissent proposes that transmission planners respond to individual needs—reliability or congestion or emissions reductions—and then allocate all the costs of new lines to the customers on the basis of only those benefits.[6] This is essentially a form of

1. Order No. 1920, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, 187 FERC ¶ 61,068, 89 Fed. Reg. 49,280 (2024) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order No. 1920].

2. *Id*. at P 3 ("This final rule also requires transmission providers to measure and use at least the seven specified benefits to evaluate Long-Term Regional Transmission Facilities as part of Long-Term Regional Transmission Planning.").

3. *Id*. at P 1305 ("[A]ny cost allocation method applied to a Long-Term Regional Transmission Facility must ensure that costs are allocated in a manner that is at least roughly commensurate with the estimated benefits of the facility, consistent with cost causation and court precedent.").

4. *See* Order No. 1920, at P 67 (Christie, Comm'r, dissenting).

5. 16 U.S.C. § 824e(a) (2005).

6. *See* Order No. 1920, at P 67 (Christie, Comm'r, dissenting) ("For each identified reliability problem, there is an optimal solution that solves the reliability problem at the least cost to consumers. For an economic project, consumers should receive the maximum reduction in congestion costs relative to the cost of the project,

single-value planning. If a line is categorized as a reliability upgrade, then the customers who benefit from reliability improvements pay the entire cost of the line—even if the line also reduces the price of electricity or makes it easier for a state to meet its decarbonization targets.[7]

The debates surrounding Order No. 1920 thus raise important questions about how to allocate the costs of transmission, especially when states do not all share the same clean energy priorities. In our view, the most pressing questions have to do with what the FPA requires in terms of transmission planning and cost allocation, and how the beneficiary pays approach works when multiple states benefit from a new line but only a subset of states have adopted binding clean energy plans.[8] As we explain,

1. The FPA requires multi-benefit planning in which FERC and transmission planning entities consider the many factors that influence what transmission lines get built.
2. The FPA prohibits any approach to cost allocation that would require states to pay for benefits they do not receive, and it also prohibits cost allocation that allows states to free ride by benefitting from lines they do not pay for.
3. The beneficiary pays approach to cost allocation is the *only* approach that meets this standard.
4. The FPA therefore requires the beneficiary pays approach to cost allocation, which, though not a precise science, requires that the costs of new lines and upgrades be allocated in a way that is at least "roughly commensurate" with their benefits.[9]
5. The beneficiary pays approach to cost allocation does not involve states paying for energy policies they do not share (if it did, it would not be permissible under the FPA).
6. An alternative cost allocation approach that responds to individual needs such as reliability, congestion, or state decarbonization policies would increase costs and force some states to cross-subsidize their neighbors.
7. The Commission's approach to transmission planning and cost allocation is consistent with over sixty years of regulatory and judicial precedent.

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or put in another way, for a given reduction of congestion costs, consumers should pay the least costs for the project").

7. *See* Request for Rehearing, *supra* note 5, at 12. It also urges courts to find that the Commission has strayed beyond its jurisdiction or, in the alternative, strike the Order down under the Major Questions Doctrine *see also id.* at 14. Because Order No. 1920 fits comfortably within the historic cost allocation framework within which FERC and its predecessor have long operated with judicial blessing, we do not believe the MDQ is implicated by that order. The broader impact of the MQD is beyond the scope of this article.

8. For prior work on how to implement beneficiary pays approach, *see* Han Shu & Jacob Mays, TRANSMISSION BENEFITS AND COST ALLOCATION UNDER AMBIGUITY (2024); *see also* William Hogan, *A Primer on Transmission Benefit and Cost Allocation*, 7 ECON OF ENERGY & ENV. POL'Y 25, 25-46 (2018).

9. Courts accept that this is not a perfect science. The costs of new lines must only be "roughly commensurate" with the benefits. Ill. Commerce Comm'n v. FERC, 576 F.3d 470, 477 (7th Cir. 2009) (ICC I).

> 8. The Commission has relied on the same cost allocation principles—nondiscrimination and opposition to free ridership—since the FPA was passed. In fact, FERC used the same principle to restructure the natural gas industry. Overturning Order No. 1920's approach to cost allocation would thus open the door to relitigating gas restructuring.

In short, Order No. 1920 does not turn FERC into a national grid planner; it does not require that any particular transmission line or type of generation be built; and it does not force any state to pay a share of other states' clean energy policies. To the contrary, the beneficiary pays approach is the only way for the Commission to avoid cross-subsidization when allocating the costs of lines across states, regions, or utility services territories that do not share energy goals.

The specific reason Order No. 1920 avoids cross-subsidization is that costs are assigned to the customers who benefit from the line. If a line provides economic benefits to Ohio while facilitating emissions reductions in New Jersey, then Ohio pays for economic benefits in Ohio but only New Jersey pays for the environmental benefits in New Jersey. By contrast, under the dissent's proposed approach, if a line is built to address a one-off need—say to improve reliability in Ohio—then Ohio is saddled with all the costs of a line that also provides economic or clean energy benefits to New Jersey. Similarly, if New Jersey builds a line to support offshore wind that happens to improve reliability in Ohio, New Jersey pays the full costs of the line even though the line improves reliability in Ohio, since the costs are assigned based on the ostensible purpose the line serves. In other words, New Jersey would be forced to pay for—or cross-subsidize—Ohio's reliability benefits.

The converse is also true. Under the dissent's approach, if Ohio builds a line to support coal-fired generation in Ohio, and the line reduces congestion in New Jersey, Ohio would pay the full costs of a line that also benefits customers in New Jersey. In other words, the single-value approach results in cross-subsidization, since states are assigned costs based entirely on the individual benefits—economic, reliability, or decarbonization—that justify the line. States that benefit for other reasons therefore free ride off the states that pay for the line. As we discuss in Part IV, concerns surrounding precisely this type of free ridership have prompted courts to consistently require the use of the beneficiary pays approach when allocating the costs of transmission lines.

Finally, although we do not directly address how much deference courts should afford FERC, or the possibility that Order No. 1920 implicates the *Loper Bright* or the Major Questions Doctrine, our analysis is nevertheless relevant to potential *Loper Bright* and Major Questions challenges. As Part IV explains, Order No. 1920 fits comfortably within the historic cost allocation framework within which FERC and its predecessor have operated. In fact, much of the judicial precedent cited in Part IV predates the Supreme Court's *Chevron* decision or is based on *courts'* preferred reading of the FPA. When FERC or grid operators have tried to deviate from the beneficiary pays framework, courts, not FERC, have insisted that beneficiaries pay for gas and electricity infrastructure that benefits them.[10] For that reason, Order No. 1920 appears to be consistent with decades of judicial, congressional, and administrative practice.[11]

This Article proceeds in three parts. Part II provides a history of FERC interventions in transmission planning and cost allocation. Part III summarizes Order No. 1920 and the dissent. It also explains how to implement beneficiary pays cost allocation when states disagree about climate policy. Part IV describes the law of transmission planning and cost allocation and argues that Order No. 1920's approach to planning and cost allocation applies sixty years of judicial precedent to markets in which states have adopted different clean energy policies.

II. HISTORY OF FERC REGULATION OF TRANSMISSION PLANNING AND COST ALLOCATION

For decades, FERC has tried to address three persistent issues that have contributed to ballooning electricity rates and undermined system reliability. First, transmission planners often build lines in response to one-off issues such as reliability, congestion, or expected future load growth.[12] Doing so causes them to overbuild (and overpay) for small lines when larger lines could have addressed multiple needs simultaneously. Second, some utilities have used their influence over planning to push for lines that favor their own generating facilities and allow them

10. Even under *Loper Bright*, when Congress has given a regulatory agency authority to determine what is "reasonable" or "appropriate," it can thereby indicate a direct Congressional intent to give the agency considerable discretion in interpreting such terms. See others empower an agency to prescribe rules to "fill up the details" of a statutory scheme, Wayman v. Southard, 23 U.S. 1, 43 (1825), or to regulate subject to the limits imposed by a term or phrase that "leaves agencies with flexibility," Michigan v. EPA, 576 U.S. 743, 752 (2015), such as "appropriate" or "reasonable." *See* Loper Bright Enters. v. Raimondo, 144 S. Ct. 2244, 2263 (2024). The Court continued, "In a case involving an agency, of course, the statute's meaning may well be that the agency is authorized to exercise a degree of discretion. Congress has often enacted such statutes. For example, some statutes "expressly delegate[]" to an agency the authority to give meaning to a particular statutory term. Batterton v. Francis, 432 U. S. 416, 425 (1977) (emphasis deleted). When the best reading of a statute is that it delegates discretionary authority to an agency, the role of the reviewing court under the APA is, as always, to independently interpret the statute and effectuate the will of Congress subject to constitutional limits. The court fulfills that role by recognizing constitutional delegations, "fix[ing] the boundaries of [the] delegated authority," Henry Monaghan, *Marbury and the Administrative State*, 83 COLUM. L. REV. 1, 27 (1983), and ensuring the agency has engaged in "'reasoned decisionmaking'" within those boundaries, Michigan, 576 U. S., at 750 (quoting Allentown Mack Sales & Serv., Inc. v. NLRB, 522 U. S. 359, 374 (1998)); *see generally* Motor Vehicle Mfrs. Assn. of U.S., Inc. v. State Farm Mut. Auto. Ins. Co., 463 U. S. 29 (1983). By doing so, a court upholds the traditional conception of the judicial function that the APA adopts.

11. Moreover, *Loper Bright* clarified that courts would not revisit prior decisions that were based on *Chevron*. *See* Loper Bright Enters., 144 S. Ct. at 2247 (2024) ("By overruling *Chevron*, though, the Court does not call into question prior cases that relied on the *Chevron* framework. The holdings of those cases that specific agency actions are lawful—including the Clean Air Act holding of Chevron itself—are still subject to statutory stare decisis despite the Court's change in interpretive methodology"). Since FERC in Order No. 1920 is adopting the same approach to cost allocation it has adopted in the past, then it can at the very least rely on past decisions and stare decisis to support the approach adopted in Order No. 1920.

12. *See* Alexandra Klass et al., *Grid Reliability Through Clean Energy*, 74 STAN. L. REV. 969, 1028-31 (2022); see also Ari Peskoe, *Is the Utility Transmission Syndicate Forever?*, 42 ENERGY L.J. 1, 50-58 (2021).

to avoid competing with other developers.[13] This, too, results in excessive investment in local projects. Third, when the costs of new lines are not allocated to the beneficiaries of the line, regions can free ride off their neighbors, leading to underinvestment in the transmission system that would reduce congestion and improve system reliability.[14] Nearly every major FERC Order in the last thirty years has sought to address one or more of these issues.

A. Transmission Planning and Cost Allocation Before Order No. 1920

Federal authority to regulate transmission planning and cost allocation dates to the early years of the twentieth century. In fact, an influential 1921 federal report that urged Congress to pass national energy legislation—known as the Keller Report—pointed to the need to integrate transmission infrastructure as one of the primary justifications for federal regulation of the electrical grid, explaining that the "lack of flexible and capacious interconnections between adjacent power systems" had made it "virtually impossible to reduce [a coal] shortage by taking advantage of the diversity factor and by releasing for active use part of the installed reserves which interconnection would have rendered safely available."[15]

To that end, Congress instructed FERC's predecessor, the Federal Power Commission (FPC), to make sure that transmission rates are "just and reasonable" and not "unduly discriminatory."[16] Section 202 dealt specifically with the need to expand the transmission system, authorizing the FPC to order interconnection when doing so was "necessary or appropriate in the public interest."[17] At the time, policymakers assumed that regulated monopolists would build generation and

13. *See* Joshua C. Macey, *Outsourcing Electricity Market Design*, 91 U. CHI. L. REV. 1243 (2024).

14. *See* Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051 (2011) [hereinafter Order No. 1000] ([T]he risk of the free rider problems associated with new transmission investment is particularly high for projects that affect multiple utilities' transmission systems and therefore may have multiple beneficiaries. With respect to such projects, any individual beneficiary has an incentive to defer investment in the hopes that other beneficiaries will value the project enough to fund its development."); El Paso Elec. Co. v. FERC, 832 F.3d 495, 502 (5th Cir. 2016) (explaining that if certain transmission owners did not have to pay for benefits their customers receive, they "would become the subsidized free riders that Order No. 1000 sought to reduce or eliminate").

15. CHARLES KELLER, THE POWER SITUATION DURING THE WAR at 18 (1921). We are grateful to Benjamin Rolsma for drawing our attention to the relevance of this report. For a description of the Keller Report and the larger role concerns about reliability played in the passage of the FPA, *see* Benjamin Rolsma, *The New Reliability Override*, 57 CONN. L. REV. (forthcoming 2025) (manuscript at 12-16).

16. Public Utility Act of 1935, ch. 687, § 205(a), 49 Stat. 803, 851 (codified as amended at 16 U.S.C. § 824d(a)).

17. *Id*. § 202(b) (codified as amended at 16 U.S.C. §824a(b); *see id.* at §824a(a) ("[T]he Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy, and it may at any time thereafter, upon its own motion or upon application, make such modifications thereof as in its judgment will promote the public interest. Each such district shall embrace an area which, in the judgment of the Commission, can economically be served by such interconnection and coordinated electric facilities. It shall be the duty of the Commission to promote and encourage such interconnection and coordination within each such district and between such districts.").

transmission, subject to regulatory oversight, to meet their service territories' electricity needs. From the start, federal regulation in the electricity industry recognized the need for forward-looking planning.[18]

A few decades after the FPA was enacted, the technological and economic underpinnings of rate regulation had come under attack,[19] most notably from free market economists who published several influential and damning critiques of rate regulation.[20] In 1978, perhaps in response to these developments, Congress added section 211 to the FPA to give FERC the authority to order electric utilities to provide transmission service to independent power producers.[21] Fourteen years later, Congress further expanded FERC's authority over transmission by passing the Energy Policy Act of 1992.[22] Congress recognized that, because regulated monopolists could use their control over transmission to discriminate against their

18. *See* Horace M. Gray, *The Integration of the Electric Power Industry*, 41 AM. ECON. REV. 538, 538 (1951) ("By 1935, fifteen years of intensive criticism, beginning with the Keller report and terminating with the National Power Survey, had exposed the defective organization of the electric power industry and delineated the essential features of an integrated power system" (footnotes omitted)); 1 FED. POWER COMM'N, NATIONAL POWER SURVEY INTERIM REPORT 54 (1935) (concluding that "studies . . . have gone far enough to show that interconnection as it exists today in the United States is not the result of any definitely planned program. Its growth has been relatively haphazard, handicapped by intercompany rivalry and prejudices and by artificial barriers"). As one Senate Report explained, "'In recent years the growth of giant holding companies has been paralleled by the rapid development of the electric industry along lines that transcend State boundaries. To a great extent through the agency of the holding company, local operating units have been tied together into vast interstate systems. As a result the proportion of electric energy that crosses State lines has steadily increased. While in 1928, 10.7 percent of the power generated in the United States was transmitted across State lines, the percentage had increased by 1933 to 17.8. The amount of energy which flowed in interstate commerce in 1933 exceeded the entire amount generated in the country in 1913 . . . The necessity for Federal leadership in securing planned coordination of the facilities of the industry which alone can produce an abundance of electricity at the lowest possible cost has been clearly revealed in the recent reports of the Federal Power Commission, the Mississippi Valley Committee, and the National Resources Board. . . . The new part 2 of the Federal Water Power Act seeks to bring about the regional coordination of the operating facilities of the interstate utilities . . . '" Jersey Cent. Power & Light Co. v. Fed. Power Comm'n, 319 U.S. 61, 68, at n. 7 (1943) (quoting S.Rep. No. 621, 74th Cong., 1st Sess., at PP 17).

19. *See* GILBERT M. MASTERS, RENEWABLE AND EFFICIENT ELECTRIC POWER SYSTEMS 6-7 (2d ed. 2013) (describing how technological and regulatory changes made it possible "small, on-site generators" cost-competitive); Severin Borenstein & James Bushnell, *The US Electricity Industry After 20 Years of Restructuring*, 7 ANN. REV. ECON. 437, 438 (2015).

20. Harvey Averch & Leland L. Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 AM. ECON. REV. 1052 (1962). For work building on their theory, see *also* William J. Baumol & Alvin K. Klevorick, *Input Choices and Rate-of-Return Regulation: An Overview of the Discussion*, 3 BELL J. ECON & MGMT SCI. 162 (1970); Alvin K. Klevorick, *The Behavior of the Firm Subject to Stochastic Regul. Rev.*, 4 BELL J. ECON & MGMT SCI. 57 (1974).

21. Public Utility Regulation Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117 (codified as amended at Pub. L. 113-23).

22. *See* Energy Policy Act of 1992, Pub. L. No. 102-486, § 711, 106 Stat. 2776, 2905-88 (1992) (repealed 2005) (authorizing exempt wholesale generators to sell electricity to utilities). *Id*. at §721 ("Any electric utility, Federal power marketing agency, or any other person generating electric energy for sale for resale, may apply to the Commission for an order under this subsection requiring a transmitting utility to provide transmission services (including any enlargement of transmission capacity necessary to provide such services) to the applicant.") (to be codified at 16 U.S.C. 824(j)); *see also* 18 C.F.R. § 366.1 (2019) (defining "exempt wholesale generator").

competitors, federal oversight was necessary to prevent transmission owners from having sole discretion to determine which transmission lines get built.[23]

In the period between 1978 and 1992, FERC relied on case-by-case adjudication to make sure that independent power producers enjoyed non-discriminatory access to the bulk power system.[24] By the mid-1990s, however, the Commission recognized that this case-by-case approach had not resolved the systemic problems with transmission planning. As part of its larger effort to restructure the wholesale power markets, FERC enacted a series of reforms designed to improve the processes for planning and allocating the costs of transmission investments.

FERC's first major intervention came in 1993, one year after Congress passed the Energy Policy Act of 1992, when the Commission issued a Policy Statement urging utilities to join Regional Transmission Groups (RTGs) that would coordinate to plan transmission investments. As FERC explained:

> Since RTGs bring together both transmitting utilities and their customers (and potential customers) in a region, they can provide a means for companies to coordinate their transmission planning more effectively, avoid costly duplication of facilities, and, in conjunction with their respective state commissions, find more efficient solutions to region-wide problems.[25]

The Commission felt that coordinated transmission planning would lead to more efficient transmission investment.[26]

FERC's next reforms focused on reducing barriers to competition in wholesale markets. In the late 1990s, FERC issued two landmark Orders—Orders No. 888 and 2000—to prevent transmission owners from discriminating against independent power producers.[27] While these Orders primarily concerned barriers to

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23. Congress again recognized the importance of opening up the transmission system in 2005, when it gave FERC authority to require "on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential." Energy Policy Act of 2005, Pub. L. No. 109–58, § 211A, 119 Stat. 955 (2005).

24. *See* Policy Statement, *Policy Statement Regarding Regional Transmission Groups*, 58 Fed. Reg. 41626, 41627-31 (1993) (to be codified at 18 C.F.R. pt. 2). FERC started down the same road a decade earlier in the gas industry. *See* Order No. 436, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, 50 Fed. Reg. 42,408 (1985) [hereinafter Order No. 436]; Order No. 636, *Pipeline Service Obligations and Revisions to Regulation Governing Self Implementing Transportation Under Part 284 of the Commission's Regulations*, 59 FERC ¶ 61,030 (to be codified at 18 C.F.R. pt. 284) (1992); Final Rulemaking, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, 57 Fed. Reg. 13,267, at 13,268 (1992) (to be codified at 18 C.F.R. pt. 284).

25. 58 Fed. Reg. 41626 at 41628. *See* 18 C.F.R. 2.21 (1993) ("An RTG agreement should require, at a minimum, the development of a coordinated transmission plan on a regional basis and the sharing of transmission planning information, with the goal of efficient use, expansion, and coordination of the interconnected electric system on a grid-wide basis"); *see also* 58 Fed. Reg. 41626, at 41628 ("Properly functioning RTGs will enable[e] the market for electric power to operate in a more competitive, and thus more efficient manner, and provid[e] coordinated regional planning of the transmission system to assure that system capabilities are adequate to meet system demands").

26. *See generally* 58 Fed. Reg. 41626, at 41627-31.

27. Order No. 888, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 75 FERC ¶ 61,080 (1996) [hereinafter Order No. 888] (FERC ordered utilities to functionally unbundle—to sep-

competition among electric power producers, both Order No. 888 and 2000 recognized that open, independent, and forward-looking planning were important features of a healthy electricity industry. For example, in Order No. 888-A, the Commission encouraged utilities to coordinate with other utilities and their customers and consider the needs of all affected parties when conducting transmission planning.[28] In Order No. 2000, FERC announced that, when deciding whether to certify RTOs, it would consider whether the region had developed a transmission planning process that would keep costs down while preserving system reliability. The Commission explained that "a single entity must coordinate these [transmission planning] actions to ensure a least cost outcome that maintains or improves existing reliability levels. In the absence of a single entity performing these functions, there is a danger that separate transmission investments will work at cross-purposes and possibly even hurt reliability."[29] FERC also recognized that proper planning would require RTOs to "address[] many specific design questions, including who decides which projects should be built and how the costs and benefits of the project should be allocated."[30] Both Order No. 888 and 2000 were thus justified by FERC's concern that utilities would use their control over the transmission system to favor their own resources.[31]

At the time, FERC repeatedly emphasized that regional planning could not simply aggregate or roll up plans submitted by individual transmission owners. For example, in the Order approving PJM's request for RTO status, FERC "emphasize[d] that RTO regional transmission expansion plans must be more than a collection of traditional expansion plans developed by individual TOs and assembled by the RTO after confirming that they serve reliability needs."[32] FERC ob-

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arate the transmission and generation functions into separate subsidiaries—and to provide nondiscriminatory service to independent power producers). Order No. 2000, *Regional Transmission Organizations,* 89 FERC ¶ 61,285 (1999) [hereinafter Order No. 2000] (encouraged utilities to join Regional Transmission Organizations (RTOs) that would control regional power systems).

28. *See* Order No. 888-A at 30,311.

29. Order No. 2000, *supra* note 27, at P 486. *Id*. at P 255 ("[T]ransmission expansion would be more efficient if planned and coordinated over a larger region."). *Id*. at P 485 ("the RTO must have ultimate responsibility for both transmission planning and expansion within its region that will enable it to provide efficient, reliable and non-discriminatory service and coordinate such efforts with the appropriate state authorities"). *Id*. at P 63 ("The traditional use of regional coordination through study groups and planning committees is no longer effective because these entities are usually not vested with the broad decision making authority needed to address larger issues that affect an entire region.").

30. Order No. 2000, *supra* note 27, at P 486.

31. *See* New York v. FERC, 535 U.S. 1, 8 (2002) ("The utilities' control of transmission facilities gives them the power either to refuse to deliver energy produced by competitors or to deliver competitors' power on terms and conditions less favorable than those they apply to their own transmissions"); Transmission Access Pol'y Study Group v. FERC, 225 F.3d 667, 684 (D.C. Cir. 2000) ("[T]ransmission-owning utilities thus can be expected to act in their own interest to maintain their monopoly and to use that position to retain or expand the market share for their own generated electricity, even if they do so at the expense of lower-cost generation companies and consumers"); Order No. 888, *supra* note 27, at 21,546 ("The most likely route to market power in today's electric utility industry lies through ownership or control of transmission facilities. Usually, the source of market power is dominant or exclusive ownership of the facilities.").

32. *Order Provisionally Granting RTO Status*, 96 FERC ¶ 61,061, at p. 30 (2001).

jected that PJM's proposed approach to transmission planning "details a significant role for TOs in the planning process as members of the Planning Committee, which appears to conduct all the required analyses" while "provid[ing] little opportunity for comparable involvement of other parties."[33] Once again, FERC expressed concern that piecemeal planning would allow existing transmission owners to control which projects the PJM Board would review: "Although the Board has final approval of the plan, it appears that the Board has an opportunity to review only those projects that survive a study process significantly influenced by TOs."[34] To mitigate incumbents' influence over transmission planning, FERC required that transmission planning "include meaningful participation by third parties, and provide all interested parties an opportunity to participate."[35] FERC imposed the same requirements in other regions.[36]

But it quickly became apparent that FERC's open access orders had not removed all the barriers to competition in electric power markets. Over the next decade, FERC sought to further limit the ability of transmission owners to use their control over transmission planning to favor their own generation facilities.[37] To that end, in 2007 the Commission issued Order No. 890 to increase transparency in transmission planning. Order No. 890 required "each public utility transmission provider . . . to submit . . . a proposal for a coordinated and regional planning process."[38] Once again, FERC worried about incumbent self-preferencing. As the Commission explained:

> We cannot rely on the self-interest of transmission providers to expand the grid in a nondiscriminatory manner. Although many transmission providers have an incentive to expand the grid to meet their state-imposed obligations to serve, they can have a disincentive to remedy transmission congestion when doing so reduces the value of their generation or otherwise stimulates new entry or greater competition in their area. For example, a transmission provider does not have an incentive to relieve local congestion that restricts the output of a competing merchant generator if doing so will make the transmission provider's own generation less competitive. A transmission provider also does not have an incentive to increase the import or export capacity of its transmission system if doing so would allow cheaper power to displace its higher cost generation or otherwise make new entry more profitable by facilitating exports.[39]

33. *Id*.

34. *Id*.

35. *Id*.

36. *Southwest Power Pool*, 106 FERC ¶ 61,110 at P 188 (2004); *New York ISO et al.*, 96 FERC ¶ 61,059, at p. 61,203 (2001); *Carolina Power & Light Co*., 94 FERC 61,273, at p. 62,009 (2001); *Alliance Cos.*, 96 FERC ¶ 61,052, at p. 61,144 (2001); PJM Interconnection, *supra* note 32, at p. 61,240-41; *Translink Transmission Co.*, 101 FERC 61,140 at P 58 (2002); *ISO-NE*, 106 FERC ¶ 61,280 at P 213 (2004). For a discussion of these requirements, *See* Ari Peskoe, *Is the Transmission Syndicate Forever?*, *supra* note 12, at 38-40.

37. *See*, *e.g.,* Order No. 2003, *Standardization of Generator Interconnection Agreements and Procedures*, 104 FERC ¶ 61,103 at P 12 (2003) (to be codified at 18 C.F.R. pt. 35).

38. Order No. 890, *Preventing Undue Discrimination and Preference in Transmission Service*, 118 FERC ¶ 61,119 at P 437 (2007) (to be codified at 18 C.F.R. pts. 35, 37) [hereinafter Order No. 890].

39. *Id.* at P 422; *see also id*. at P 39 ("[I]t is in the economic self-interest of transmission monopolists, particularly those with high-cost generation assets, to deny transmission or to offer transmission on a basis that is inferior to that which they provide to themselves."); see also *id.* at P 57 ("[V]ertically-integrated utilities do not

One of Order No. 890's primary concerns was that existing transmission planning processes created collective action problems. As FERC explained "there are free rider problems associated with new transmission investment, such that customers who do not agree to support a particular project may nonetheless receive substantial benefits from it."[40] While FERC did not insist on a particular approach to cost allocation, it explained that "cost allocation proposal[s]" should "fairly assign[] costs among participants, including those who cause them to be incurred and those who otherwise benefit from them," and "provide[] adequate incentives to construct new transmission."[41]

A few years later, FERC issued Order No. 1000, which required utilities to develop regional planning processes that allowed non-incumbent developers to compete with incumbents on a non-discriminatory basis. Once again, FERC worried that transmission owners were favoring their generation assets, and that piecemeal planning processes were causing regions to make inefficient transmission investments.

To address these issues, Order No. 1000 set out six cost allocation principles for regional planning, two of which instructed transmission planners to use the beneficiary pays approach.[42] The first principle required that "[t]he cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits."[43] The second clarified that "[t]hose that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities."[44]

In other words, FERC has consistently justified the need for holistic transmission planning and beneficiary pays cost allocation by pointing out that transmission owners have incentives to exercise market power and protect their generation facilities.[45] Note that the Commission has used the phrases "cost causation"

have an incentive to expand the grid to accommodate new entries or to facilitate the dispatch of more efficient competitors.").

40. Order No. 890, *supra* note 38, at P 561 (FERC also expressed concern that incumbent control over transmission planning would impede economic growth.); *see id.* at P 58 ("Our concern over this flaw is heightened by the critical need for new transmission infrastructure in this Nation. . . . [T]ransmission capacity is being constructed at a much slower rate than the rate of increase in customer demand.").

41. *Id.* at P 559.

42. Order No. 1000, *supra* note 14, at P 586.

43. *Id.*

44. *Id*.

45. New York v FERC, 535 U.S. 1, 8 (2002) ("The utilities' control of transmission facilities gives them the power either to refuse to deliver energy produced by competitors or to deliver competitors' power on terms and conditions less favorable than those they apply to their own transmissions."); Transmission Access Pol'y Study Group, 225 F.3d at 684 ("[T]ransmission-owning utilities thus can be expected to act in their own interest to maintain their monopoly and to use that position to retain or expand the market share for their own generated electricity, even if they do so at the expense of lower-cost generation companies and consumers"); Order No. 888, *supra* note 27, at 21,546 ("The most likely route to market power in today's electric utility industry lies through ownership or control of transmission facilities. Usually, the source of market power is dominant or exclusive ownership of the facilities."); Order No. 890, *supra* note 38, at P 422 ("We cannot rely on the self-interest of transmission providers to expand the grid in a nondiscriminatory manner."); Order No. 1000, *supra* note 14, at P

and "beneficiary pays" interchangeably, and it apparently did so because it understood cost causation to mean beneficiary pays. Citing to D.C. Circuit case law, FERC explained that "the cost causation principle requires that the costs allocated to a beneficiary be at least roughly commensurate with the benefits that are expected to accrue to it."[46] Despite the Commission's somewhat confusing terminology, beneficiary pays was now required for regional planning across the country, and it was justified because the Commission recognized that "a departure from cost causation principles can result in inappropriate cross-subsidization. This is why cost causation is the foundation of an acceptable cost allocation method."[47] As we explain in Part IV, this approach to cost allocation followed decades of judicial precedent in electricity and gas markets that pushed FERC to use this approach.

B. Problems with Transmission Planning and Cost Allocation

Unfortunately, Order No. 1000 appears to have inadvertently created incentives for some transmission owners to overinvest in small projects at the expense of regional solutions. It is worth clarifying that regional projects are those in which a regional planning entity allocates the costs, typically to more than one utility.[48] Local projects, by contrast, are those that are paid for by a single utility.[49] Since Order No. 1000 went into effect, transmission spending has more than doubled.[50] Yet during this period, the United States has significantly slowed the building of high-voltage transmission lines,[51] and most transmission investment that has occurred has been made outside of the regional process, with spending on local reliability upgrades increasing dramatically in the past decade such that they now account for a majority of spending in many regions.[52] Consumers are therefore spending a great deal of money on transmission projects for which there is no

256 ("It is not in the economic self-interest of incumbent transmission providers to permit new entrants to develop transmission facilities").

46. Order No. 1000, *supra* note 14 at P 504; *see also id.* at P 505 ("The Commission explained that, while costs generally have been allocated through voluntary agreements, the cost causation principle is not limited to such arrangements. If it were, the Commission could not address free rider problems associated with new transmission investment and could not ensure that transmission rates are just and reasonable and not unduly discriminatory").

47. *Id.* at P 626.

48. *Id.* at PP 63-64.

49. *Id*. at PP 62-64.

50. Johannes Pfeifenberger & John Tsoukalis, *Transmission Inv. Needs and Challenges* 2, BRATTLE (June 1, 2021), https://www.brattle.com/wp-content/uploads/2021/10/Transmission-Investment-Needs-and-Challenges.pdf.

51. *See* Jay Caspary et al., *Fewer New Miles: The U.S. Transmission Grid in the 2010s*, GRID STRATEGIES LLC 1, https://gridstrategiesllc.com/wp-content/uploads/grid-strategies_fewer-new-miles.pdf ("[T]he U.S. dropped from installing an average of 1,700 miles of new high-voltage transmission miles per year in the first half of the 2010s, to averaging only 645 miles per year in the second half of the 2010s").

52. *See* Claire Wayner, *Increased Spending on Transmission in PJM - Is It the Right Type of Line?*, RMI (2023), https://rmi.org/increased-spending-on-transmission-in-pjm-is-it-the-right-type-of-line/; Ohio Consumers Initial Comments at 5 ("Since 2017, in Ohio, less than 25% of the new investment in transmission has been associated with large regional transmission projects needed for reliability or economic efficiency").

regulatory or market check to ensure that new investments cost-effectively address economic and reliability needs. The basic problem, which has been the subject of considerable commentary, is that incumbent utilities have both the incentive and ability to arbitrage around regional planning.

1. Rate Basing Local Projects

Economists have long understood that rate regulated utilities have misaligned incentives. Because utilities earn a return on capital investments, their profits increase when they spend more. They care that regulators authorize a return on the investments they make but do not necessarily have strong incentives to ensure their investments promote the public good.[53] This is known as gold-plating or the Averch-Johnson effect.

While Order No. 1000 required that regionally planned lines be open to competition, it authorized exemptions for certain projects planned outside the regional process. One example of this is Baseline Reliability Projects, which are projects that "are not cost shared and are generally developed by Transmission Owner(s), via their role as the NERC Transmission Planner (TP), to address localized Transmission Issues and reliability-related Transmission Issues."[54] Even within the regional planning process, some lines, such as those that respond to immediate reliability needs, are not required to undergo competitive solicitations.[55] These types of projects receive little, if any, scrutiny from regulators.[56] Still, not only are incumbent utilities legally entitled to build these types of projects in their service territories; they also typically establish the criteria for determining whether to build these projects. There may be good policy reasons for this. After all, certain reliability upgrades may be time sensitive or involve upgrades to assets the utility

53. *See* Harvey Averch & Leland L. Johnson, *supra* note 20, at; *see also* Stanislaw H. Wellisz, *Regulation of Natural Gas Pipeline Cos.: An Economic Analysis*, 71 J. POL. ECON 30, 31 (1963) ("The pipeline companies are restricted to a "fair return" on the investment ascribed to jurisdictional sales. It is therefore in their interest to apportion to the regulated sales as much investment as possible.); *see also* Robert M. Spann, *Rate of Return Regulation and Efficiency in Prod.: An Empirical Test of the Averch-Johnson Thesis*, 5 BELL J OF ECON & MGMT. SCI. 38, 39 (1974) (describing the Averch-Johnson effect as "The overcapitalization in regulated firms hypothesized by Averch and Johnson is a direct result of a model which starts with the premise that the regulated firm maximizes profits subject to an effective rate-of-return constraint" and confirming the effect by studying data from electric utilities). For a discussion of the governance implications, see Aneil Kovvali & Joshua Macey, *The Corp. Governance of Pub. Utils.*, 40 YALE J. REG. 569, 582-97 (2023).

54. MIDCONTINENT IND. SYS. OP., TRANSMISSION PROJECT CATEGORIES & TYPES § 2.3, at § 2.3.1.1, https://cdn.misoenergy.org/DRAFT%20BPM-020%20Section%202.3%20Edits%20for%20INRP561844.pdf.

55. *See id*. at 2.3.2.3 ("Facilities comprising Market Efficiency Projects approved by MISO's Board after December 1, 2015 are subject to MISO's Competitive Developer Section Process unless such facilities: (1) are subject to a law granting a right of first refusal to the incumbent Transmission Owner; (2) qualify as upgrades to existing transmission facilities; or (3) qualify as an Immediate Need Reliability Project as described under Appendix I of this BPM. . . . Facilities that are exempt from the Competitive Transmission Process are assigned to the applicable Transmission Owner(s) in accordance with Appendix B of the Owners Agreement.").

56. *See Asset Condition Projects and Process Improvements*, NEW ENGLAND STATES COMM. ON ELEC. *2-3* (2023) https://www.iso-ne.com/static-assets/documents/2023/02/2023_02_08_nescoe_asset_conditions_letter.pdf (observing that spending on Asset Condition projects do not undergo competitive solicitations, grew from $58 million in 2016 to nearly $800 million in 2023, and pointing out that these projects "are subjected to materially less regional review and scrutiny").

already owns.[57] Nonetheless, these and similar exemptions to Order No. 1000's competitive process have allowed utilities to invest in transmission upgrades without being forced to compete with other developers. As Ari Peskoe has shown, utilities appear to have turned to non-regional processes to avoid being forced to compete with other transmission developers.[58] FERC appears to agree, observing that "incumbent transmission providers, as a result of those [Order No. 1000] reforms, may be presented with perverse investment incentives that do not adequately encourage those incumbent transmission providers to develop and advocate for transmission facilities that benefit more than just their own local retail distribution service territory or footprint."[59] In other words, the shift to non-regional planning in response to Order No. 1000 is likely due in part to the fact that utilities prefer to gold plate local projects rather than compete with other developers.

2. Protecting Generators' Market Power and Justifying Investment in New Generation

Another reason utilities prefer to invest in local projects is that, when utility holding companies own both generation and transmission assets, they can protect their generators' market power and justify the need to invest in new power plants by focusing on small projects that do not increase transfer capacity between regions or utility service territories. FERC never forced transmission owners to divest themselves of their generation assets.[60] The Commission's open access orders required functional unbundling, which means that their generating units must receive transmission service on the same terms as everyone else, but FERC continues to allow holding companies to own both generation and transmission assets.[61]

57. *See* Order No. 1000, *supra* note 14, at P 263 ("Given that incumbent transmission providers may rely on transmission facilities selected in a regional transmission plan for purposes of cost allocation to comply with their reliability and service obligations, delays in the development of such transmission facilities could adversely affect the ability of the incumbent transmission provider to meet its reliability needs or service obligations. To avoid this result, in section III.B.3 below, we require each public utility transmission provider to amend its OATT to describe the circumstances and procedures under which public utility transmission providers in the regional transmission planning process will reevaluate the regional transmission plan to determine if delays in the development of a transmission facility selected in a regional transmission plan for purposes of cost allocation require evaluation of alternative solutions, including those the incumbent transmission provider proposes, to ensure the incumbent can meet its reliability needs or service obligations.").

58. *See* Peskoe, *supra* note 12, at 50-58; FERC Docket No. ER20-2054-000 (Jan. 31, 2024) ("Maine's concern is that at least some New England utilities may be taking advantage of this lax review process to the benefit of their shareholders. Are they building replacement projects prematurely? If so, such practices can contribute to significant and unnecessary rate increases. Could the projects be more targeted and smaller? Are there less expensive alternatives to large transmission replacement projects? Do the NETOs adequately keep track of the condition of their current transmission assets? Do they have processes for maximizing the timing of replacements or the evaluation of non-transmission or hybrid alternatives?").

59. Order No. 1920, *supra* note 1, at P 1548.

60. Order No. 888, *supra* note 27, at P 59 ("In the absence of evidence that functional unbundling will not work, we are not prepared to adopt a more intrusive and potentially more costly mechanism—corporate unbundling—at this time").

61. Order No. 2000, *supra* note 27, at P 47; Order No. 1000, *supra* note 14, at P 818.

To be clear, FERC has developed standards of conduct and affiliate purchase rules that do not ignore the affiliate favoritism issue altogether,[62] but the Commission's unwillingness to fully quarantine rate regulated affiliates nevertheless left in place incentives for transmission owners to avoid investing in regional and interregional lines that reduce congestion.[63] Increasing regional and interregional transfer capacity allows load serving entities to import power from generators located outside the utility's service territories. A utility that invests in these lines may therefore expose its existing generation facilities to competition from low-cost power producers that are located outside the utility's service territory.[64]

There are two reasons that overinvesting in local projects can be seen as an exercise of vertical market power. The first is that it increases the price of energy by preventing low-cost suppliers in neighboring regions from competing with the utilities' generation. The second is that utilities can cite transmission constraints to convince regulators to authorize cost-recovery for new generation investments. As one of us has described in previous work, utilities in the Midcontinent Independent System Operator (MISO) have used the lack of regional transmission lines to justify spending hundreds of millions on new generation facilities.[65] The financial stakes are often significant. According to a recent study by Catherine Hausman, transmission constraints in MISO and the Southwest Power Pool (SPP) caused $2 billion in allocative inefficiencies in 2022.[66] Hausman estimates that reducing transmission congestion in MISO would have caused Entergy Arkansas and Entergy Louisiana to lose $930 million in revenue in that year.[67]

3. Avoiding Regulatory Oversight

A final problem is that local projects receive little scrutiny from state and federal regulators.[68] RTOs and other regional planners typically provide only a cursory review of transmission investments made outside the regional process. In some regions, transmission planners make sure non-regionally planned lines do not cause the region to fall out of compliance with reliability standards but do not

62. *See* Order No. 717*, Standards of Conduct for Transmission Providers,* 125 FERC ¶ 61,064 (2008).

63. *See* Kovvali & Macey, *supra* note 53, at 2164-67.

64. *See id*.

65. *See id*.

66. *See* Catherine Hausman, *Power Flows: Transmission Lines, Allocative Efficiency, and Corp. Profits* 2 (Nat'l Bureau of Econ. Rsch., Working Paper No. 32091, 2024), https://www.nber.org/system/files/working_papers/w32091/w32091.pdf.

67. *See id*. at 25.

68. *Id.; see* FERC Docket No. ER20-2054-000 (Mar. 4, 2024) ("[T]he TOs do not actually specify any significant state level scrutiny [for asset condition projects]. And while they dispute Maine's concern that there is 'limited review of asset management projects,' their own internal documents say something else entirely. In rejecting consideration in two separate instances of building a parallel line to address the reliability concerns about an existing line, Eversource was concerned that that 'constructing a new line parallel could potentially trigger a more formal and lengthy regulatory review process.' The Identified TOs cannot truly believe to be "false" Maine's characterization of asset condition project cost review as, at best, limited. On the contrary, they have touted their cooperation with NESCOE in increasing the transparency of their processes. Their claim that they have agreed to 'increased notice and opportunities for stakeholders to submit written feedback' is an implicit recognition that the current review process is indeed limited.'" (citations omitted)).

consider whether alternative investments would provide greater aggregate benefits.[69]

Nor have state regulators filled this regulatory gap. State utility commissioners may lack jurisdiction to assess the benefits of multi-state lines,[70] and many states do not require a certificate of public convenience and necessity for lines that either fall below a certain kV threshold or are constructed on existing rights of way.[71] As a result, many transmission lines receive automatic rate recovery and undergo virtually no scrutiny from state or federal regulators.

All else equal, utilities prefer to avoid regulatory red tape. And because customers in rate regulated markets have limited ability to protect themselves—after all, there are no competitors to turn to if the incumbent provides costly or subpar service—their only recourse is diligent and effective regulatory oversight. Unfortunately, the lines that receive the least regulatory scrutiny are also the ones whose costs are not checked through competition or third-party planning.[72]

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Thus, in the past ten years, transmission investment has shifted away from regional-scale projects subject to competitive procurements and toward smaller local projects over which incumbents exercise greater control.[73] By avoiding the regional process, utilities ensure that they—not their competitors—build the line. And when utilities remain vertically integrated—when utility holding companies own both generation and transmission assets—they prefer to build small projects to obviate the need for regional and interregional lines that would expose their generation to additional competition.[74] Finally, local projects often receive little, if any, review from state and federal regulators. The result is a piecemeal process in which lines are built in response to one-off needs and in which incumbents steer investment towards projects that protect their financial interests but do not provide the most cost-effective approach to meeting the country's transmission needs.

Unfortunately, a piecemeal planning process in which a region's transmission needs are met through small, local projects reduces the need for regional and interregional solutions. That would not be a problem if local projects were cost-

69. For an explanation of these review processes, *see* Macey, *supra* note 13, at 1265.

70. *See* Matthew R. Christiansen & Joshua C. Macey, *Long Live the Fed. Power Act's Bright Line,* 134 HARV. L. REV. 1360, 1381-1407 (2021); Jim Rossi*, The Brave New Path of Energy Federalism,* 95 TEX. L. REV. 399, 443-61 (2016) (even if state regulators had jurisdiction to do so, it is unclear why a regulator in one state would be motivated to consider out-of-state benefits).

71. *See*, *e.g.*, Gen. Order No. 131-D, Pub. Util. Comm'n of the State of Cal.§ III.A, at 2 (Sept. 10, 1995), https://docs.cpuc.ca.gov/PUBLISHED/Graphics/589.PDF (requiring a finding of "public convenience and necessity" for "major electric transmission line facilities which are designed for immediate or eventual operation at 200kV or more," but authorizing exemptions for replacements, relocations, or conversions or upgrades of existing lines); Testimony of Simon Hurd, Program & Project Supervisor, FERC Docket No AD22-9-00 (Oct. 6, 2022) (stating that 63% of transmission capacity in California built between 2019 and 2021 was self-approved and did not undergo regulatory review by a California energy agency).

72. *See, e.g., Maine Power Link*, 179 FERC ¶ 61,215 (2022) (describing the lack of regulatory supervision over projects in New England).

73. *See* Peskoe*, supra* note 12; Hausman*, supra* note 66.

74. *See* Hausman, *supra* note 66; Macey, *supra* note 13, at 1294-95.

effectively meeting the country's transmission needs. But because utilities and regulators do not consider whether these lines are more cost-effective compared to regional or interregional solutions, we are skeptical that utilities have stumbled on the most cost-effective investments.[75]

III. ORDER NO. 1920

While the underlying regulatory challenges remain the same as they were fifteen years ago, the stakes have grown considerably as a result of a changing resource mix and increasingly ambitious state clean energy policies. Wind in particular relies on transmission to connect the best resources with load centers and smooth variability across different sources. Along these lines, academic and national lab studies consistently observe that expanding regional and inter-regional transfer capacity would lead to significant economic benefits. The gains from improved coordination are even more significant when one accounts for state and federal decarbonization policies.[76] Heightening the tension, states participating in the same regional planning process often have significantly different decarbonization policies. Order No. 1920 reflects both FERC's most recent attempt to address market power issues that have long beleaguered U.S. electricity markets, and to do so in a manner that fairly and cost-effectively allocates costs of a changing grid.

A. Planning and Cost Allocation in Order No. 1920

At a high level, Order No. 1920 requires a transparent process for evaluating and selecting projects and the creation of an *ex ante* cost allocation method that meets the beneficiaries pay standard.[77] The Order requires the use of transparent processes for developing inputs into planning models, evaluating their outputs, and allocating the cost of any projects selected as a result. As such, the Order is consistent with the traditional regulatory goals of (1) selecting projects that maximize economic surplus while ensuring reliability and (2) allocating the cost of shared projects commensurate with benefits.

A significant portion of the text of the Order sets out minimum requirements that should be included in the transmission planning process.[78] In a regional process, transmission planners consider a set of potential projects and examine the possible consequences that could arise once the projects are built. These consequences include altered generator investment and retirement decisions, effects on

75. In fact, a large amount of research has documented the economic and reliability benefits of regional and interregional transmission investments.

76. *See* Alexander E. MacDonald et al., *Future Cost-Competitive Electricity Systems and Their Impact on US CO_2 Emissions*, 6 NATURE CLIMATE CHANGE, 526, 526-31 (2016); *See also* Patrick R. Brown & Audun Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, 5 JOULE 115, 115-34 (2021).

77. The order also discusses issues connected to construction work in progress incentives, rights of first refusal, and local transmission planning inputs that have cost and modeling implications but are less salient to the present discussion.

78. Since including all relevant benefits is straightforwardly a best practice, most comments related to this item had to do with whether it makes sense to include relevant but difficult-to-model benefits beyond the required seven (e.g., increased liquidity and reduction of market power).

local transmission processes, and changes to operational decisions such as which generators would be dispatched. Planners also encode constraints that prevent the model from recommending a system configuration that would lead to an unacceptably low level of reliability, be inconsistent with physical constraints governing power system operations, or result in the region falling out of compliance with environmental laws. In this context, Order No. 1920 requires that:

1. Planners must construct at least three scenarios in developing a regional transmission plan.[79]
2. Planners must develop at least one "sensitivity," akin to a "stress test," for each scenario to study the benefits of the proposed plan during extreme weather events in which there are "multiple concurrent and sustained generation and/or transmission outages."[80]
3. The model should cover at least twenty years past the in-service date of potential projects.[81]
4. The model should reflect the impact of seven listed *benefits* related to cost and reliability.[82]
5. Planners should use the best available data when constructing the scenarios, in particular incorporating seven required categories of *factors*.[83]
6. Transmission planners should consider certain projects identified in generator interconnection processes.[84]
7. Transmission planners should consider grid-enhancing technologies.[85]

These requirements can be straightforwardly interpreted in the context of the models used in transmission expansion planning. In a standard optimization framework, planners attempt to maximize the present value of expected surplus subject to reliability constraints and applicable laws.[86] The first requirement is aimed at ensuring some representation of uncertainty in the system. The second ensures that model results will be tested against a broader range of potential futures

79. Order No. 1920, *supra* note 1, at P 559 ("We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to develop at least three distinct Long-Term Scenarios as part of Long-Term Regional Transmission Planning. In implementing this requirement, transmission providers must develop, at least once during the five-year Long-Term Regional Transmission Planning cycle, at least three distinct Long-Term Scenarios that, at a minimum, incorporate the seven categories of factors listed in the Categories of Factors section above.").

80. *Id.* at PP 494, 593-95.

81. *Id.* at P 3.

82. *Id.* at PP 1505-08.

83. Order No. 1920, *supra* note 1, at P 231.

84. *Id.* at PP 7, 472.

85. *Id.* at P 1198 ("We . . . require transmission providers . . . to consider, in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes, dynamic line ratings and advanced power flow control devices for each identified transmission need.").

86. For a more comprehensive discussion of optimization modeling for transmission expansion planning, *see generally* Shu & Mays, *supra* note 8.

than those used directly in development of the plan. Given the outsized role that extreme weather can play in the value of transmission,[87] the specific inclusion of such events in the analysis is consistent with techniques of importance sampling used for variance reduction in optimization and simulation. The requirement to evaluate benefits over a twenty-year time horizon intends to strike a balance of ensuring proactive identification of regional solutions that cost-effectively resolve needs that today are being addressed outside the regional process, while also preventing overoptimism about benefits that may accrue beyond the first twenty years of the project's life. Requiring the consideration of seven different benefits ensures that planning does not underestimate benefits by examining only a subset of potential benefits; in optimization terms, these can be thought of as ensuring that certain parameters are included in the model. The seven categories of factors are meant to ensure that planners use the best possible information when developing estimated values of parameters used in the model.[88] The sixth requirement elaborates on a particularly important source of information: the interconnection queue process. Lastly, requiring the consideration of grid-enhancing technologies ensures that the set of feasible solutions is as large as possible.[89] In our view, all these principles follow from FERC's central mission of preventing undue discrimination.

By defining a minimum set of benefits, the planning requirements are necessarily connected to the Order's approach to cost allocation. Order No. 1920 encourages states to reach an agreement about how to allocate the costs of regionally planned transmission facilities, but, if the state agreement approach fails, transmission planners must use a backstop cost allocation method.[90] Though the Order leaves specific details regarding implementation to transmission planners, it does require a transparent process for evaluating and selecting projects and the creation of an *ex ante* cost allocation method that meets the beneficiaries pay standard. Thus, although FERC will consider whether a region has complied with the beneficiary pays approach by looking at the record before it in specific proceedings, Order No. 1920 makes clear that "any cost allocation method applied to a Long-Term Regional Transmission Facility must ensure that costs are allocated in a manner that is at least roughly commensurate with the estimated benefits of the facility, consistent with cost causation and court precedent."[91]

One proposed method of meeting the beneficiary pays standard is to use the outputs of the planning models themselves.[92] Planning models attempt to measure the cost of projects against the discounted benefits that are projected to accrue years in the future once the lines are built. The benefits estimated in these models

87. Dev Millstein et al., *Empirical Estimates of Transmission Value using Locational Marginal Prices*, ENERGY MKTS. & POL'Y: BERKELEY LAB 3 (2022) https://emp.lbl.gov/publications/empirical-estimates-transmission.

88. Order No. 1920, *supra* note 1, at PP 314-15.

89. *Id.* at PP 842-43.

90. *Id.* at P 228.

91. *Id.* at 1305.

92. *See, e.g.,* Hogan, *supra* note 8, at 25-46.

can be disaggregated into estimates for each of the market participants included in the model. Accordingly, a "direct benefits modeling" approach offers the potential to "allocate the costs of transmission facilities selected [in the regional plan] to meet those transmission needs in a manner that is at least roughly commensurate with [the facility's] benefits."[93] The benefits of regional lines include, among other things, improved reliability, reduced congestion, and reducing the costs states face in meeting their energy goals. It is worth noting that in an optimization modeling context, different benefits are all translated into a common unit, namely dollars, for purposes of computing tradeoffs. Certain physical laws and reliability standards may be expressed as hard constraints, violation of which will not be allowed in the transmission plan or in any valid counterfactual against which benefits might be calculated. Other constraints, e.g., a state renewable portfolio standard that includes an alternative compliance payment provision, may be coded as soft constraints that the model will violate if the cost becomes excessive. One consequence of this common unit is that a direct benefits modeling approach does not distinguish between separate categories of economic, reliability, and public policy benefits; to the extent such a distinction is needed for accounting purposes, it would require additional calculations.

A virtue of the direct benefits modeling approach is that no cost is allocated to a state on the basis of a different state's clean energy policies. Consider a region that consists of New Jersey and Ohio. Planners have identified a new line that costs \$40 and would create \$100 of benefits across the two states. Each state would receive \$20 in benefits for reliability improvements and \$20 in benefits for reduced congestion. That yields \$80 in total benefits—\$20 for Ohio reliability, \$20 for suggestion reduction, \$20 for New Jersey reliability, and \$20 for New Jersey congestion reduction. The remaining \$20 in benefits arise because the line reduces the costs of meeting New Jersey's clean energy goal. New Jersey thus receives \$60 in total benefits (\$20 for improved reliability, \$20 for reduced congestion, and \$20 in clean energy) whereas Ohio only receives \$40 in benefits (\$20 for improved reliability and \$20 for reduced congestion). Under the direct benefits modeling approach, New Jersey pays \$24 (sixty percent of \$40 is \$24) and Ohio pays \$16 (forty percent of \$40 is \$16). Table One Presents such a case:

Table 1: Direct Benefits Modeling Approach

	New Jersey	Ohio	Total
Reliability Improvement	\$20	\$20	\$40
Reduced Congestion	\$20	\$20	\$40
Clean Energy Goal Attainment	\$20	-	\$20
Total Benefits	\$60	\$40	\$100
Share of Benefits	\$60/100	\$40/100	
% of Costs Allocated	60%	40%	
Costs Allocated	\$24	\$16	\$40

93. *Id.* at 114.

Note that Ohio customers pay only for benefits they receive.[94] While the line makes it less expensive for New Jersey to meet its clean energy goals, Ohio is not responsible for paying for those benefits. When calculating the percentage of costs that are allocated to Ohio, planners only consider direct and measurable benefits to Ohio electricity consumers—here, improved reliability and reduced congestion.

Now imagine a situation in which regional planners did *not* consider region-wide benefits of some lines when allocating the costs of new transmission. In that case, a state with a clean energy policy—New Jersey, in our hypothetical—would need to make additional investments to meet its clean energy goals. To do so, New Jersey would likely either pay for additional carbon-free generation or additional transmission lines that are planned outside the regional process. Those assets would create benefits for Ohio customers. For example, the cost of energy in Ohio might go down or the line might allow Ohio utilities to import power during extreme weather events. Because New Jersey has paid the entire costs of these upgrades, New Jersey has provided a subsidy to Ohio customers. As we discuss in the next subpart, the dissent appears to endorse this siloed approach for *all* new transmission lines—not simply for resources that support state clean energy policies.[95]

The primary challenge in this regard is the uncertainty inherent in long-term transmission planning.[96] Suppose that in this example, transmission planners compute benefits by state in each scenario used in the planning model, with the results shown in Table 1. The hypothetical is constructed to maximize contrast between the scenarios. In Scenario 1, benefits accrue entirely to New Jersey, while in Scenario 2 they accrue entirely to Ohio. Scenario 3 exhibits the same 60/40 split in benefits as before, but the overall benefits are substantially lower ($25 instead of $100). The average across the three scenarios reflects the $60 and $40 of expected benefits in the original example. Further, it should be understood that the three scenarios chosen for study are a small subset of the potential futures that may arise.[97]

94. *See* Order No. 1920, *supra* note 1, at P 1510 (acknowledging New Jersey's concerns about free ridership and explaining that the beneficiary pays approach will address those concerns).

95. *See id.* at P 67 (Christie, Comm'r, dissenting) ("For each identified reliability problem, there is an optimal solution that solves the reliability problem at the least cost to consumers. For an economic project, consumers should receive the maximum reduction in congestion costs relative to the cost of the project, or put in another way, for a given reduction of congestion costs, consumers should pay the least costs for the project").

96. It is worth pointing out that the direct benefits modeling approach described here has not been implemented in any region, nor is it required by Order No. 1920.

97. For an example with more extensive out-of-sample tests, *see* Shu & Mays, *supra* note 8.

Table 2: Example with Different Benefits by State in Different Scenarios

	New Jersey	Ohio	Total
Scenario 1	$165	$0	$165
Scenario 2	$0	$110	$110
Scenario 3	$15	$10	$25
Average	$60	$40	$100

Order No. 1920 does not require that the project in this example is selected. Despite the expected benefits of $100, a region could decide that the presence of a scenario with only $25 of benefits implies too much risk for ratepayers. Similarly, it does not require that allocation be based on the expected value of benefits. Given the uncertainty in the calculation, states may decide that a different method of allocating costs would be preferable. Instead, Order No. 1920 requires a transparent process by which the transmission planner constructs scenarios and sensitivities, as well as a default method by which costs can be allocated. In the context of the direct benefits modeling approach, this transparency is a significant advantage. If cost is allocated in a way that diverges significantly from modeled benefits, it is reasonable to reevaluate whether the method leading to that allocation is consistent with the beneficiary pays standard. Such a reevaluation is only possible if the relevant model outputs are available.

It should also be noted that Order No. 1920's approach to cost allocation is resource agnostic. Ohio remains free to pass a "Coal Energy Law" that would keep its coal-fired power plants online. If Ohio passed such a law, multi-benefit regional planning would incorporate Ohio's preference for coal and allocate costs accordingly. In that scenario, if a new line reduced the costs of keeping an Ohio coal-fired power plant online, perhaps by increasing the market available to the coal-fired power plant, Ohio customers would benefit. New Jersey customers would pay for the economic and reliability benefits they receive but would not be responsible for the cost savings Ohio receives on account of the fact that the line reduces the costs of meeting its energy policy.

It is of course possible that *transmission* costs would be lower if planners did not consider state clean energy policies, but that would not result in lower *electricity* rates.[98] An alternative planning process might look at reliability benefits

98. Congress stressed the importance of this distinction in the Energy Policy Act of 2005, when it instructed FERC to "establish, by rule, incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion." Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594, 315, 1283; *see* Federal Power Act 219(a), 16 U.S. Code § 824s(a). In other words, Congress has required FERC to adopt rules that encourage utilities to invest in transmission that reduces congestion and the cost of delivered power. FERC promulgated incentive-based rates in 2006. *See also* Order No. 679, *Promoting Transmission Investment through Pricing Reform*, 116 FERC ¶ 61,057 at P 34 (2006) (to be codified at C.F.R. pt. 35) ("[A]ny investment made in, or costs incurred for, transmission infrastructure after August 8, 2005 that ensures reliability or lowers the cost of delivered power by reducing transmission congestion will be eligible for incentive-based rate treatments under this Rule.").

while ignoring state energy policies. But consider what happens if transmission planners blind themselves to state energy policies in this way. New Jersey would still need to make additional investments to meet its clean energy targets.[99] Because planners, by definition, only select projects if the projected benefits exceed the costs, a line will not be selected if the aggregate costs of meeting system needs would be lower with an alternative portfolio of investments.[100] In other words, transmission planning that ignores state policies can be expected both to cause total costs to increase and force states that have adopted clean energy policies to subsidize states that have not.[101]

When utilities join an RTO or transmission planning region, they (or state or federal regulators) decide that the scale benefits of participating in a regional market—improved reliability, lower energy prices, more efficient transmission investment—are worth giving up some amount of control over transmission planning. If a state or utility is unhappy about this trade-off, it should exercise the remedy negotiated for when it joined an RTO, which may include the ability to leave an RTO.[102] But it cannot enjoy the benefits of regional integration while insisting that its neighbors pay for the economic and reliability benefits it receives from participating in an integrated system.

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99. These investments would also, as discussed, provide direct economic benefits to Ohio customers.

100. Because there is considerable uncertainty in future investments and policy decisions, planners will not be able to do this perfectly.

101. Alternatively, if PJM or Ohio refused to build lines that support New Jersey's clean energy policies, they could thereby prevent New Jersey from meeting its own clean energy goals. But The FPA is very clear that states retain authority over their generation facilities. *See* 16 U.S.C. § 824(b) (2000). Ohio and PJM would, in effect, be making decisions about what generation New Jersey can build. Incorporating state policy decisions is therefore needed to preserve state authority over generation facilities.

102. Whether, and under what circumstances, a utility can leave an RTO has not been fully resolved. RTO tariffs and operating agreements outline the procedures under which utilities can leave RTOs, though FERC has authority to review exit decisions to make sure that they do not result in unjust, unreasonable, or unduly discriminatory rates. *See, e.g., American Transmission Systems, Inc.*, 129 FERC ¶ 61,249 (2009), order on reh'g; *see also Order Addressing Expedited Partial Requests for Clarification and Rehearing*, 130 FERC ¶ 61,171 (2010) (approving American Transmission System's request to leave MISO and join PJM). Moreover, the Energy Policy Act of 2005 gives FERC untested preemption authority where FERC finds that state law is inhibiting voluntary coordination efforts by the utilities they regulate. In addition, Section 205(a) of PURPA provides that "[t]he Commission may, on its own motion, and shall, on application of any person or governmental entity, after public notice and notice to the Governor of the affected States and after affording an opportunity for public hearing, exempt electric utilities, in whole or in part, from any provision of State law, or from any State rule or regulation, which prohibits or prevents the voluntary coordination of electric utilities, including any agreement for central dispatch, if the Commission determines that such voluntary coordination is designed to obtain economical utilization of facilities and resources in any area." 16 U.S.C. § 824a-l (2000). Section 205 contains two exceptions. However, the Commission may not grant an exemption if it finds that the relevant provision of state law, rule, or regulation is either: (1) required by Federal law; or (2) designed to protect public health, safety, or welfare, or the environment or conserve energy or is designed to mitigate the effects of emergencies resulting from fuel shortages. *See id.*; *See also The New PJM Companies,* 105 FERC ¶ 61,251 (2003) (considering the question whether FERC can enforce a merger condition obligating a utility to join an RTO where the utility also requires, but has not received, the approval of a state commission before it can turn control of its transmission assets over to an RTO).

B. The Order No. 1920 Dissent

The dissent's primary critique of Order No. 1920 is that the Order's approach to cost allocation forces some states to pay for other states' clean energy policies in what he calls a "dereliction of the Commission's duty under the [Federal Power Act] to protect consumers."[103] In arguing that the "final rule ignores the principle of the optimal solution in transmission planning," the dissent makes two arguments about how cost allocation should work.[104] First, under the dissent's preferred approach, transmission planners would consider needs individually and not look at the aggregate benefits of new lines.[105] If FERC adopted this approach, developers would build "reliability lines" in response to reliability needs, allocating the costs to regions that experience reliability benefits and ignoring the other benefits these lines provide. They would build "economic lines" to lower energy market prices, allocating the costs to regions in which the price of energy goes down and ignoring the other benefits of the line. And they would build "clean energy lines" in response to state decarbonization needs, allocating the costs to states that have adopted clean energy policies and ignoring reliability and economic benefits. Second, the dissent also urges planners to pursue a "cost minimization" approach that meets reliability needs at the lowest cost rather than maximizing the cumulative benefits of new lines.[106]

1. Multi-Value Projects

The dissent endorses an approach to cost allocation that considers benefits individually by identifying solutions to one-off needs. The dissent states that:

> [f]or each identified reliability problem, there is an optimal solution that solves the reliability problem at the least cost to consumers. For an economic project, consumers should receive the maximum reduction in congestion costs relative to the cost of the project, or put in another way, for a given reduction of congestion costs, consumers should pay the least costs for the project.[107]

In other words, Christie prefers an approach to transmission planning in which planners identify a single problem and determine the least-cost means of addressing that problem.

The problem with this approach is that it does not in fact identify the globally optimal solution. It instead endorses pursues solutions that are optimal only when assessed against individual benefits.[108] Suppose planners have identified a reliability violation and decide to consider two candidate solutions to the violation. Both potential solutions will resolve the issue. Option A costs $20 million, and option B costs $25 million but is projected to lead to economic (not climate) benefits of $10 million in present value terms. Option B is clearly globally optimal.

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103. Order No. 1920, *supra* note 1, at P 21 (Christie, Comm'r, dissenting).
104. *Id.* at P 101.
105. *Id.*
106. *Id.*
107. Order No. 1920, *supra* note 1, at P 101 (Christie, Comm'r, dissenting).
108. *Id.*

It costs $5 million more but produces an additional $10 million in economic benefits. However, the reliability-focused analysis the dissent endorses will select option A. It is the least-cost solution, and the dissent argues that planning should be based on individual needs—here, the reliability need that originally justified the line.

The dissent elsewhere acknowledges that "[a]s we know from basic transmission planning, any transmission built is going to bring some reliability and economic benefits," yet the approach it endorses would not allow transmission planners to include these benefits in cost allocation.[109] In a modeling context, even if the primary purpose of a project is to resolve a reliability issue, it will inevitably alter power flows and consequently have some impact on congestion, losses, and nodal prices. The Order requires an approach that considers those benefits in cost allocation, whereas the dissent seems to wish to preserve an artificial distinction between different project types. This amounts to "ignor[ing] the principle of the optimal solution" that it claims to be defending.[110]

In fact, FERC itself recognized that a siloed approach to transmission planning would increase system costs and allow certain states and classes of customers to free ride off their neighbors. As the Commission explained in Order No. 1920:

> [A]llocating costs based on . . . project types would result in transmission providers undertaking investments in relatively inefficient or less cost-effective transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. Allocating costs based on these project types could, for example, encourage the selection of transmission facilities based on either their economic or reliability benefits alone rather than based on an evaluation of the wider range of benefits that they may provide. This dynamic results in, among other things, transmission customers paying more than is necessary or appropriate to meet their transmission needs, customers forgoing benefits that outweigh their costs, or some combination thereof, which results in less efficient or cost-effective transmission investments. We further find that permitting the use of such project-type-limited cost allocation methods for Long-Term Transmission Facilities would not allocate costs in a manner that is at least roughly commensurate to estimated benefits.[111]

In addition to suggesting suboptimal solutions, the siloed approach to transmission planning has created significant disagreements regarding cost allocation—specifically about how to categorize transmission investment decisions under the single-value approach. Commissioner Christie drew attention to this challenge in a recent proceeding in which PJM selected several transmission projects that were needed to resolve reliability violations that arose after the deactivation of the Brandon Shores coal plant in Maryland.[112] Since the projects were classified as reliability projects, PJM applied the cost allocation method in place

109. *Id.* at P 64 n. 238.

110. *Id*. at P 67.

111. Order No. 1920, *supra* note 1, at P 1508.

112. *PJM Interconnection, L.L.C.*, 185 FERC ¶ 61,107 at P 3 (2023) ("PJM notes the urgent need to upgrade the PJM Transmission System to address the reliability violations caused by the deactivation of Brandon Shores.").

for reliability projects.[113] Commissioner Christie described the challenge with the resulting allocation as follows:

> [I]f the resulting transmission projects under protest in this [Regional Transmission Expansion Plan] filing are caused more by Maryland's policy choices than by organic load growth and economic resource retirements, then a salient question that may be asked is whether these transmission projects are more accurately categorized as *public policy* projects . . . . And if they are more accurately categorized as public policy projects, should such projects be regionally cost-allocated, potentially to consumers in Pennsylvania, West Virginia, Ohio, *et al.*?[114]

The problem Christie identified is that it can be unclear whether the benefits provided by a given portfolio of projects should be considered as belonging to reliability, economics, or public policy. Differentiating between the categories requires a model that includes all relevant reliability and economic benefits, as well as the public policy factors that enter the planning process. As described above, this is precisely the modeling approach set out in Order No. 1920. Without such a model, it is not clear how to answer the question raised by Commissioner Christie in the context of Brandon Shores.

2. Least-Cost vs. Highest Surplus

At other points, the dissent argues that system planners should pursue cost minimization over other priorities, asserting, for example, that "the fundamental principle historically embedded in utility regulation in the United States is to provide consumers with reliable power at the least cost under applicable law."[115] While this principle is framed as a cost minimization problem, the planning approach adopted in Order No. 1920 is posed as a maximization problem—it pursues transmission solutions that provide the highest possible value.

When customers all have the same preferences, the cost minimization formulation and surplus maximization formulation are synonymous. Customers want the cheapest solution that addresses their needs. The difference between these two objectives arises when customers in the system do not share the same preferences. For example, in the context of reliability, it has long been recognized that assuming a shared reliability target for all customers implies a cross subsidy from customers who might place a lower value on reliability to those that place a higher value on it. Presumably the more salient concern in the context of the Order is the different preferences that many states and corporate buyers have for low-carbon generation. At a high level, modelers have three options when incorporating the effect of these different preferences on relevant parameters: (1) incorporating customer- or state-specific values, (2) computing a market-wide average value, or (3) assuming no preference for low-carbon generation.

Only option 1 avoids cross-subsidization. Option 2 would lead to cross subsidies between different states or customers, and option 3 explicitly overrides the preferences of some states or customers, which, as discussed in the previous sub-

113. *See id*. at P 2.

114. *Id*. at P 7.

115. Order No. 1920, *supra* note 1, at P 2 (Christie, Comm'r, dissenting).

part, also results in cross-subsidization, since states would make additional investments that would benefit their neighbors. Option 3 may also be inconsistent with the FPA's mandate that states retain authority over their generation mixes. At the very least, it is in tension with the dissent's stated belief that FERC and transmission planners should in general defer to state priorities. Accordingly, the order's pursuit of option 1 is the most consistent with the "principle of the optimal solution."[116]

To understand this, it is worth returning to the Ohio-New Jersey example above, though using different numbers. Suppose for simplicity that the two states have equal electricity consumption. New Jersey has clean energy policies that could be included in the planning process, while Ohio does not. The regional planner is analyzing a transmission project with a cost of $5/MWh when amortized over the consumption of one of the states over the evaluation period. Suppose the planner conducts the analysis two times, once accounting for the policies and once without accounting for them, and calculates the following average cost per MWh in each state under the different scenarios, with no differences in reliability:

Table 3: Prices in Two States With and Without Transmission Expansion. "Base" refers to a price per MWh without including the cost allocated due to transmission expansion. Total transmission cost is allocated proportional to modeled benefits.

		New Jersey			Ohio		
		Base	Allocated	Total	Base	Allocated	Total
No policy	No expansion	$50	--	$50	$50	--	$50
	With expansion	$48	$2.50 (50%)	$50.50	$48	$2.50 (50%)	$50.50
With policy	No expansion	$60	--	$60	$50	--	$50
	With expansion	$54	$3.75 (75%)	$57.75	$48	$1.25 (25%)	$49.25

Without transmission expansion, the addition of policy-related constraints increases the expected cost of electricity in New Jersey from $50/MWh to $60/MWh. When evaluated without the effect of the state policy, the line would fail to be selected: total cost rises from $50/MWh to $50.50/MWh in both states with the expansion. When evaluated after accounting for the policy, however, the total benefit amounts to $8/MWh ($60/MWh-$54/MWh=$6/MWh for New Jersey and $50/MWh-$48/MWh=$2/MWh for Ohio). Since this benefit exceeds the cost of $5/MWh, the line is selected. The model suggests a cost allocation of 75% to New Jersey and 25% to Ohio, after which both states see a lower total cost than they would have without the line. As previously described, the planning study would not compute a separately specified "public policy" benefit within the

116. *Id.* at P 101.

model: the benefits are computed as "economic." By performing the planning analysis two times, it is possible to define such a public policy benefit as the difference ($8/MWh−$4/MWh = $4/MWh). However, this accounting change does not affect the recommended solution or the overall benefits calculation.

It is worth repeating one point for emphasis: Ohio sees its costs go down because the line has direct economic benefits for Ohio customers—it reduces congestion. Ohio customers only pay for those economic benefits. In this context, it is not clear how to interpret the dissent's allegation of "a mismatch between planning criteria and benefits."[117] One potential source of confusion has to do with the relationship between the "benefits" that must be included in the transmission planning process and the "factors" that planners must consider when constructing scenarios. In this example, the relevant benefit is production cost savings, while the relevant factor is New Jersey's policy-related constraints. In a modeling context, omitting these policy constraints would both lead to a suboptimal solution and make it impossible to correctly assess the split of benefits between Ohio and New Jersey.

The dissent argues that Ohio should not be included in the analysis and cost allocation at all, claiming that this approach "shoehorn[s] the broadest group of beneficiaries possible for projects that do not remotely relate to reliability and economic needs"[118] and that "[t]he result of this shell game is to ensure preferential policy and corporate-driven projects are selected with the widest group of beneficiaries possible, so as to socialize the costs across the widest group of consumers."[119] The implication is that the dissent would prefer to exclude some beneficiaries and allocate all of the project cost to New Jersey. Since New Jersey nevertheless would see net benefits from the transmission project, it may be willing to do so in this example. But that, of course, would result in New Jersey subsidizing Ohio's electricity consumption, violating the beneficiary pays principle and contradicting the dissent's stated goal of avoiding cross subsidies.

It is possible that some projects may "not remotely relate to reliability and economic needs."[120] Suppose that the transmission planner performs the same analysis as in Table 2 but on a different project. Suppose the outcome for New Jersey is an $8 reduction in cost when policy is included but $0 if it is not, and the outcome for Ohio is $0 in either case. The direct benefits modeling approach, supported by the multi-value planning approach required by Order No. 1920, would suggest an allocation of 100% of the project's cost to New Jersey. More generally, a multi-value model can be applied even if some benefits are not relevant for a given project. Single-purpose models, by contrast, will not necessarily contain the information required to compute the other, non-modeled benefits. Rather than shoehorning the broadest group of beneficiaries possible, a multi-value model is the only plausible way to assess the distribution of total benefits that might arise.

117. *Id.* at P 45.

118. *Id.* at P 98.

119. Order No. 1920, *supra* note 1, at P 98

120. *Id.* at P 98 (Christie, Comm'r, dissenting).

It is also worth noting that Order No. 1000 is technologically and politically neutral. If Ohio adopted a policy intended to facilitate access to coal-fired generation, transmission planners would have to consider whether transmission lines reduce the costs Ohio faces in meeting its coal-fired generation standard, and they would have to allocate the costs accordingly. Again, in such circumstances, only Ohio customers would be responsible for paying the costs associated with keeping coal-fired generation online, and New Jersey customers would be responsible for the economic and reliability benefits they receive.

It is therefore difficult to understand the dissent's allegation that "[t]he final rule's goal is to socialize the costs associated with preferential policy and corporate-driven projects across the multi-state regions, even when the states have never consented for their consumers to pay for such projects."[121] As we have explained, the most straightforward way to calculate public policy benefits, differentiate them from reliability and economic benefits, and assign them to particular states or customers is to explicitly include them in the planning model formulation. Without including the influence of public policy in the planning process, there is no straightforward way to identify the related benefits and beneficiaries. In other words, Order No. 1920 supports an approach wherein customers are allocated cost commensurate with the benefits they are projected to receive, whereas the dissent seems to make such an allocation impossible.

3. Practical considerations

Given the straightforward interpretation of Order No. 1920 as consistent with best practices in modeling and cost allocation, it is worth describing in more general terms how the planning processes it envisions might nevertheless lead to some states paying for other states' clean energy policies. To start, given the irreducible uncertainty involved in long-term planning, some mismatch between allocated costs and realized benefits is guaranteed to occur when regional projects are evaluated *ex post*, no matter what processes for planning and cost allocation are implemented. Returning to the example with the three scenarios described in Table 1 above, assume that an *ex ante* cost allocation method assigns 60% of the cost to New Jersey and 40% to Ohio based on the expected value of benefits across the three scenarios. If an *ex post* analysis were to find that the benefits accrued entirely to New Jersey, then it would turn out to be the case that Ohio subsidized New Jersey in this instance. With sound planning and cost allocation practices, however, this type of cross-subsidization would cancel out over the course of many projects and planning cycles.

Accordingly, we must instead look for the possibility that planning and/or cost allocation processes will be biased in such a way that the resulting allocations will lead to persistent cross subsidies. Suppose that the planner in this example used an allocation method that differed from the distribution of benefits projected in the planning model, e.g., assigning 50% of the project cost to each state. If the true expected distribution of benefits is indeed 60% to New Jersey and 40% to Ohio, and this imbalance holds for many projects, then over time the cost allocation method would embed a cross subsidy. Since Order No. 1920 does not specify

121. *Id.* at P 86.

a cost allocation method, it will only be possible to evaluate the potential for such a cross subsidy in the context of individual compliance filings. However, it does not seem to be a major concern for the dissent, which asks "in what reality will a transmission provider seeking to comply with today's final rule identify different beneficiaries from those identified in the planning process?"[122] As discussed above, the planning process laid out in Order No. 1920 identifies beneficiaries in a way that accounts for public policy and assigns their associated costs to the states or groups that have enacted them, enabling for their straightforward inclusion in an allocation consistent with the beneficiary pays standard.

The dissent raises two possible exceptions to this more general expectation that the beneficiaries will correspond to benefits. First, the dissent argues that including information from generator interconnection processes as a factor when modeling transmission needs will lead to cost shifts, with costs that would otherwise be borne by interconnecting generators instead of being paid by consumers.[123] Here, the dissent presumes that planners will suggest a cost allocation method that excludes generators from cost allocation, even if those generators have been identified as beneficiaries. Since Order No. 1920 allows for the possibility that generators will be included in cost allocation, it is not clear how to assess any potential cost shift in advance of compliance filings. The second, potentially more challenging case arises in the case of corporate demand for clean energy resources, also included in Order No. 1920 as one of the factors influencing transmission needs.[124] As explained above, it is appropriate in an optimization context to incorporate the different preferences of different customers when seeking a solution that maximizes overall surplus. However, inclusion of corporate demand as a factor in the parameterization of models will imply that the relevant corporations can be identified as beneficiaries by the models. As argued in the dissent, inclusion of such entities in cost allocation may present challenges in compliance and implementation. In this context, the dissent observes that "[n]othing in the final rule will prevent transmission providers from discounting these commitments one hundred percent."[125] To ensure compliance with the beneficiary pays standard, it is possible that planners will take this approach.

Rather than occurring in the step of mapping planning model benefits to beneficiaries, the most challenging source of potential cross subsidies arises in the construction of the scenarios and sensitivities used in the planning models themselves. In this context, the dissent argues that "[w]hile the final rule insists that it is not mandating *outcomes*, when you manipulate the *inputs* of transmission planning, you are effectively mandating outputs."[126] While "mandating" is too strong, both the Order and the dissent agree that it is possible to manipulate outcomes through the development of scenarios or sensitivities that will be more likely to lead to desired outputs. Indeed, a major motivation for the Order is the belief that

122. *Id*. at P 65.
123. *See* Order No. 1920, *supra* note 1, at P 71.
124. *Id*. at P 314.
125. *Id*. at P 73 (Christie, Comm'r, dissenting).
126. *Id*. at P 12 (Christie, Comm'r, dissenting).

current processes implicitly underestimate the expected benefits of regional projects. It is therefore possible that a different planning regime could instead lead to overestimates. While the dissent is right to be concerned about this possibility, there is no *a priori* reason to think that the potential for such manipulation will increase under Order No. 1920. In our view, the question should therefore be addressed in individual compliance filings, when it is possible to assess the specific scenarios and sensitivities transmission planners adopt. Similarly, it is not clear why such manipulation would necessarily favor states with clean energy goals as opposed to other parties.

IV. Legal Principles of Transmission Planning and Cost Allocation

Given their disagreement about how to allocate the costs of new transmission, it is somewhat surprising that both the Order and the dissent agree on the legal principles that should guide cost allocation. Notably, they agree that FERC cannot force some states to subsidize others, and that states retain authority over their generation mixes. Disagreement is primarily about how to meet this legal standard when states have adopted different clean energy policies. As we explained in the previous Part, the beneficiary pays approach prevents free ridership and does not force states to subsidize other states' energy policies. As we explain here, the beneficiary pays approach is also consistent with decades of judicial precedent.

A. Post-Order No. 1000 Cases

FERC's authority to regulate transmission planning and cost allocation is based on the text of the FPA, which gives FERC jurisdiction over "the transmission of electric energy in interstate commerce" and instructs FERC to make sure that transmission rates are "just and reasonable" and not "unduly discriminatory."[127] This is a clear grant of authority. In fact, courts have acknowledged that FERC's legal authority is strongest in the context of transmission[128] and, over the past sixty years, have emphasized that the FPA allows—and may even require—multi-factor planning in which the costs of transmission are allocated to the customers who benefit from the line.

Courts most clearly articulated this standard in the wake of Order No. 1000, when some utilities challenged the beneficiary pays approach to cost allocation. Order No. 1000, like Order No. 1920, "require[d] each planning process to have a method for allocating costs *ex ante* among the beneficiaries of new transmission facilities in the regional transmission plan."[129] The D.C. Circuit first considered challenges to this approach in *South Carolina Public Service Administration v.* FERC, where the Court held that FERC has "authority under Section 206 [of the

127. Federal Power Act, § 201, 16 U.S.C. § 824p(b); *Id.* § 205, 16 U.S.C. 824d; *Id.* § 206, 16 U.S.C. 824f; New York v. FERC, 535 U.S. 1, 1 (2002). FERC's authority to regulate transmission rates perfectly mirrors its authority to regulate pipeline rates.

128. S.C. Pub. Serv. Auth. v. FERC, 762 F.3d 41, 63 (D.C. Cir. 2014) ("[T]he Commission possesses greater authority over electricity transmission than it does over sales.").

129. *Id.* at 48.

Federal Power Act] to require the *ex ante* allocation of the costs of new transmission facilities under beneficiaries."[130] The Court pointed out that "the deficiencies in transmission planning and cost allocation practices were well-understood and not based on guesswork" and recognized that forward-looking planning based on beneficiary pays cost allocation were the proper remedy to the free rider problem that had led to ineffective transmission planning.[131]

In *South Carolina Public Service Administration*, the D.C. Circuit also described the evidentiary burden FERC faces when reforming transmission planning and cost allocation. FERC must identify "existing planning and cost allocation practices that could thwart the identification of more efficient and cost-effective transmission solutions."[132] Historically, FERC has met this burden through generic findings showing that existing processes can be expected to impede competition, reduce reliability, or allow transmission owners to favor their own affiliates and discriminate against competitors.[133] Courts have not required that the Commission precisely quantify the costs and benefits, especially when it is not feasible to do so.[134]

After *South Carolina Public Service Administration*, courts continued to emphasize that, at least in most circumstances, FERC *must* assign the costs of new transmission to the customers that benefit from new lines.[135] One of the first challenges to Order No. 1000's approach to cost allocation—*Illinois Commerce Commission v. FERC* (*ICC 2*)—concerned multi-value projects in MISO. Some utilities argued that they were being charged for benefits they would not receive, and utilities outside MISO argued that they should not be forced to pay for lines that are planned to address MISO's transmission challenges. Both state regulators and utilities therefore accepted that beneficiary pays cost allocation was now the legally required standard and argued that MISO and FERC applied this standard incorrectly. The question, in other words, was not whether the FPA authorized a beneficiary pays approach, but whether FERC and MISO had marshaled enough evidence to show that certain customers would in fact see benefits from these lines. In upholding MISO's approach to cost allocation, the Court made clear that costs must be assigned on the basis of benefits, explaining that since the lines "will benefit electricity users in PJM, those users should contribute to the costs."[136]

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130. *Id.* at 49.

131. *Id.* at 65; *see* FirstEnergy Serv. Co. v. FERC, 758 F.3d 346, 346 (2016) ([A] 'beneficiary pays' approach is a just and reasonable basis for allocating the costs of regional transmission projects, even if it leads to reallocating sunk costs."). .

132. S.C. Pub. Serv. Auth., 762 F.3d 41 at 66.

133. *See generally* Order No. 888, *supra* note 27; Order No. 2000, *supra* note 27; Order No. 890, *supra* note 38; Order No. 1000, *supra* note 14.

134. *See id.*

135. *See* Ill. Commerce Comm'n v. FERC, 721 F.3d 764, 779 (7th Cir. 2013) (ICC II); *see also id.* at 779; *see also* Old Dominion Elec. Coop. v. FERC, 898 F.3d 1254 (D.C. Cir. 2018); *see also* Entergy Arkansas, LLC v. FERC, 40 F.4th 689, 692 (D.C. Cir. 2022); El Paso Elec. Co. v. FERC, 76 F.4th 352, 366 (5th Cir. 2023).

136. Ill. Commerce Comm'n v. FERC, 721 F.3d 764, 779 (7th Cir. 2013).

The Seventh Circuit also weighed in on the evidence planners need to produce to support cost allocation decisions. The Court observed that MISO had produced "voluminous evidentiary materials, including MISO's elaborate quantifications of costs and benefits" and explained that FERC and transmission planners need not quantify costs and benefits perfectly when it is not feasible to do so:[137]

> As we explained in *Illinois Commerce Commission v. FERC*, if FERC 'cannot quantify the benefits [to particular utilities or a particular utility] . . . but it has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with those utilities' share of total electricity sales in [the] region, then fine; the Commission can approve [the pricing scheme proposed by the Regional Transmission Organization for that region] . . . on that basis. For that matter it can presume [as it did in this case] that new transmission lines benefit the entire network by reducing the likelihood or severity of outages.[138]

The Court was emphatic on this point: "[i]t's not enough for Illinois to point out that MISO's and FERC's attempt to match the costs and the benefits of the MVP program is crude; if crude is all that is possible, it will have to suffice."[139]

The Seventh Circuit confirmed this position a year later, when it reviewed a challenge to cost allocation in PJM. In that case, also called *Illinois Commerce Commission v. FERC (ICC 3)*, utilities argued that FERC acted arbitrarily and capriciously because it failed to respond to allegations that utilities in western PJM were being forced to pay for lines that would not provide benefits to their customers.[140] This time, the utilities won, and they did so because PJM failed to rebut the charge that utilities in western PJM were paying for benefits that went to utilities in eastern PJM. PJM allocated costs "in proportion to each utility's electricity sales, a pricing method analogous to a uniform sales tax."[141] The problem with this approach, according to the Seventh Circuit, was that utilities had introduced evidence showing that most of the economic and reliability benefits went to customers in eastern PJM. Rather than respond to this concern, "[t]he Commission defended its approach by appealing to the difficulty of measuring the benefits that the western utilities would derive from the new lines."[142] This, according to the Court, was "a feeble defense. . . . FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members."[143] The Court therefore struck down PJM's cost allocation methods because "charging costs greater than the benefits would overcharge the utilities, and charging costs less than the benefits would undercharge them."[144]

137. *Id.* at 775.

138. *Id.*

139. *Id.*

140. Ill. Commerce Comm'n v. FERC, 756 F.3d 556, 558 (7th Cir. 2014) ("The question presented by the petition for review is the extent to which the members of PJM in its western region (we'll call these the "western utilities") can be required to contribute to the costs of newly built or to-be-built 500–kV lines (we'll call these the "new transmission lines") even though the lines are primarily in the eastern part of PJM").

141. *Id.*

142. *Id.*

143. *Id.* (citing Ill. Commerce Comm'n v. FERC, 576 F.3d 470, 476 (7th Cir. 2009)).

144. Ill. Commerce Comm'n, 756 F.3d at 558.

The two *ICC* cases establish that customers should not be charged for lines that do not benefit them. Nor should they escape cost responsibility for lines that do benefit them. Both cases accept FERC's use of the beneficiary pays approach but insist that transmission planners show that costs are actually being allocated to beneficiaries. These cases are especially relevant to Order No. 1920, since they explicitly state that it is not sufficient to ensure that costs are only being assigned to beneficiaries. One most also ensure there are no significant beneficiaries escaping cost responsibility. The dissent's preferred single-value approach would meet the first criterion—as all those assigned costs would in fact be beneficiaries—but it fails the second criterion because it leads to other beneficiaries escaping cost responsibility, and thus assigns the costs of transmission infrastructure on an unduly small group.

As courts have continued to review transmission cost allocation, they have continued to require system planners to use beneficiary pays cost allocation. For example, in *El Paso Electric Company v. FERC*,[145] the Fifth Circuit struck down cost allocation in the WestConnect planning region that did not allocate costs to non-jurisdictional utilities. The Court was concerned that the transmission planner did not "apply that foundational principle of cost causation for about half of the utilities in the WestConnect region" and emphasized that the Commission failed to "provide a reasoned explanation for why the non-jurisdictional utilities have incentive or obligation to participate in binding cost allocation when they can get many of the same benefits at the jurisdictional utilities' expense."[146]

El Paso recognized that failure to use beneficiary pays cost allocation "creates a 'free rider' problem that Order No. 1000 sought to reduce or eliminate" and, as a result, "unlawfully violates the principle of cost causation."[147] Importantly, the Court expressly connected the beneficiary pays approach to the text of the FPA, concluding that FERC's "Compliance Orders fail to adequately explain how the mandates in those orders do not ensure unjust and unreasonable rates as between jurisdictional and non-jurisdictional utilities (and their customers) in the WestConnect region."[148]

The D.C. Circuit reinforced the need for planners to use beneficiary pays cost allocation in 2018, in *Old Dominion Electric Cooperative v. FERC*.[149] *Old Dominion* concerned FERC's decision to approve an amendment to the PJM tariff

145. *See generally* El Paso Elec. Co. v. FERC, 832 F.3d 495 (5th Cir. 2016).

146. *Id.* at 505.

147. *Id.* at 504. The facts of El Paso were complex, largely because the WestConnect region includes non-jurisdictional utilities that, under some circumstances, can opt out of the regional planning process and binding cost allocation. Under WestConnect's proposed approach, transmission plans could only proceed if the benefits to the utilities that paid for the lines exceeded their costs. FERC felt that this would reduce non-jurisdictional utilities' incentive to free ride. *See* Joint Brief of Intervenors in Support of Respondent at 14, El Paso Elec. Co. v. FERC, No. 18-60575 (5th Cir. 2022) ("[A]s FERC found on remand, if substantial numbers of non-public utilities choose not to accept cost allocation for a project that benefits them in the hopes they would get a free ride they would be taking a major risk that the project would not proceed at all") (citing Order on Remand, 161 FERC ¶ 61,188 at P 47).

148. *Id.* at 504.

149. *See id.*

that denied cost sharing for projects "undertaken only to satisfy an individual utility's planning criteria."[150] Because these projects result in significant regional benefits, they had historically been funded through cost sharing.[151] The Court held that the beneficiaries of new lines must pay their share and reversed FERC's decision on the ground that it forced customers to pay the entire costs of certain new lines even when those lines benefited customers in neighboring regions.

Old Dominion clarified two questions about the beneficiary pays approach. First, the Court explained that beneficiary pays was required even when lines do not go through the regional planning process, and second, that beneficiary pays was based on the FPA, not Order No. 1000. The Court emphasized that "compliance with Order No. 1000 does not necessarily ensure compliance with the cost causation principle."[152] To the contrary, the Court described cost causation as "a pre-existing, more general rule that, in order to ensure just and reasonable rates, FERC must make some reasonable effort to match costs to benefits."[153] Despite the fact that the lines at issue in *Old Dominion* did not go through Order No. 1000's regional planning process, the Court held that FERC exceeded its statutory authority by forcing a subset of customers to pay for lines that created region-wide benefits:

> [W]e fail to see how a categorical refusal to permit any regional cost sharing for an important category of projects conceded to produce significant regional benefits can be reconciled with the background principle [of beneficiary pays cost allocation]. To the contrary, the cost-causation principle prevents regionally beneficial projects from being arbitrarily excluded from cost sharing—a necessary corollary to ensuring that the costs of such projects are allocated commensurate with their benefits.[154]

Another point the *Old Dominion* court made, or at least implied, is that the benefits a project produces matter more for cost allocation purposes than the planning criteria the project was originally built to satisfy. As the Court explained, "the cost-causation principle focuses on project benefits, not on how particular planning criteria were developed."[155] This suggests that, if a project produces significant secondary benefits (e.g., reliability or economic benefits for a project built primarily to support a state's policy goal), then allocating the cost of a project solely based on the primary planning purpose for which it was built runs afoul of the FPA's just and reasonable requirement.

In the last few years, courts have continued to require beneficiary pays cost allocation. For example, in 2022, the D.C. Circuit said that "[i]n assessing whether a rate is 'just and reasonable,' FERC and the courts determine . . . whether the rate comports with the 'cost-causation principle' which requires that the rates charged

150. Old Dominion Elec. Coop. v. FERC, 898 F.3d 1254, 1255 (D.C. Cir. 2018).

151. *Id.*

152. *Id.* at 1263.

153. *Id.*

154. Old Dominion Elec. Coop., 898 F.3d 1254 at 1263.

155. *Id*. at 1262.

for electricity reflect the costs of providing it."[156] As the Court explained, "[w]e often frame this principle as one that ensures burden is matched with benefit, so that FERC generally may not single out a party for the full cost of a project, or even most of it, when the benefits of the project are diffuse."[157]

Since Order No. 1000, every court that has considered cost allocation has sanctioned FERC's use of the beneficiary pays approach, and every case striking down transmission cost allocation has done so either because the RTO allocated costs to customers who did not benefit from the line or failed allocate costs to customers who did benefit from the line. In short, judicial skepticism of cost allocation decisions has arisen when FERC and system planners allow cross-subsidies, force customers to pay for lines that do not benefit them, or allow customers to benefit from lines without paying. At the very least, planners cannot ignore evidence that costs are (a) being allocated to customers who do not benefit from new lines or (b) being allocated to customers who do benefit.

It is worth noting that some of these cases predate *Chevron* while others rest on the court's understanding of the text of the FPA—not an agency construction of vague or ambiguous statutory text. For example, *Loper Bright* does nothing to call into question cases like *Old Dominion*, where the court specifically overrode FERC's determination based on the court's own reading of the FPA. By definition, that means *Old Dominion*'s reasoning is in no way dependent on *Chevron* deference, as in overruling FERC, the court was clearly not showing deference to FERC. In our view, *Loper Bright* actually reinforces the beneficiary-pays principle as interpreted and set forth by the *Old Dominion*, *El Paso*, and other courts, as those cases suggest that the beneficiary pays approach is based on statutory text and thus reduce FERC's ability to re-interpret what statutorily rooted principle means. That supports an argument that FERC's approach to cost allocation in Order 1920 is the legally safest route it had, given courts' repeated determination that the FPA prohibits FERC from allowing significant free riding. Order No. 1920 thus appears to be adopting the standard courts have required for decades.

B. Early Cost Allocation Cases

But even before FERC promulgated Order No. 1000, courts required the use of the beneficiary pays approach.[158] This legal standard originated before the Supreme Court's *Chevron* decision, immediately after Congress passed the FPA and

156. Entergy Ark., LLC v. FERC, 40 F.4th 689, 692-93 (D.C. Cir. 2022).

157. *Id.* at 693.

158. *See, e.g.*, Western Mass. Elec. Co. v. FERC, 165 F.3d 922, 927-28 (D.C. Cir. 1999) ("The Commission's position with regard to assignment of costs is, so far as we can tell, part of a consistent policy to assign the costs of system-wide benefits to all customers on an integrated transmission grid. We have approved the underlying rationale of this policy. When a system is integrated, any system enhancements are presumed to benefit the entire system"); Pub. Serv. Comm'n of Wisconsin v. FERC, 545 F.3d 1058, 1067 (D.C. Cir. 2008) ("Our precedent requires only that 'all approved rates reflect to some degree the costs actually caused by the customer who must pay them.' . . . Moreover, [MISO's approach to cost allocation] is consistent with the "Cost Causation Rate Principles" FERC has embraced in previous decisions, notwithstanding the petitioners' claim to the contrary, *see* PSCW Br. pt. IV; ISO New England, Inc. v. New England Power Pool, 91 F.E.R.C. ¶ 61,311, at 62,076 (2000) ("Our general principle is to assign costs of various upgrades to those who benefit to the extent that they can be

Natural Gas Act (NGA), when FERC relied on parallel provisions of the NGA to allocate the costs of natural gas pipelines.[159] In fact, even before Congress passed the FPA and NGA, the Supreme Court used language in utility cases suggesting that utility principles of nondiscrimination required some version of beneficiary pays cost allocation.[160]

Before discussing these cases, it is important to clarify a semantic point. As we briefly explained in Part III, the language FERC and the courts use in these cost allocation cases is often confusing. Sometimes FERC has used the phrase "cost causation." At other times, it has used "beneficiary pays." The phrases have become synonymous. Regulators and courts use both interchangeably. This appears to be a result of the history of the gas and electricity industries. When utilities planned gas and electricity investments to serve local service territories, costs were allocated to the utility that planned the investment.[161] In that period, utilities

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identified"); Ill. Commerce Comm'n v. FERC, 576 F.3d 470, 476-77 (7th Cir. 2009) ("To the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed"); *id*. at 477 ("We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars. Midwest ISO Transmission Owners v. FERC, supra, 373 F.3d 1361, 1369 (D.C. Cir. 2004) ("'we have never required a ratemaking agency to allocate costs with exacting precision'"); *Id.* at 1368 (The court describes MISO Owners' primary contention as being that "FERC's order does not comport with the 'cost causation principle.' We have described this principle as 'requir[ing] that all approved rates reflect to some degree the costs actually caused by the customer who must pay them.' . . . Not surprisingly, we evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party").

159. Fed. Power Comm'n v. Nat. Gas Pipeline Co. of Am., 315 U.S. 575, 584 (1942) ("The second [step of utility ratemaking] is the adjustment of a rate schedule conforming to that level so as to eliminate discriminations and unfairness from its details"); Battle Creek Gas Co. v. FPC, 281 F.2d 42, 46 (D.C. Cir. 1960) (authorizing cost allocation that "rolled [costs] into the rate base of all pipeline customers on the ground that "all customers enjoy the benefits"); Laclede Gas Co. v. FERC, 722 F.2d 272, 276 (5th Cir. 1984) (upholding the use of rolled in pricing). After *Chevron*, many Supreme Court cases do not appear to have relied on *Chevron* when requiring that beneficiaries be assigned the costs of gas infrastructure. *See, e.g.*, Associated Gas Distrib. v. FERC, 824 F.2d 981 (D.C. Cir. 1987) ("The Commission has a mandate under sections 205 and 206 of the FPA to ensure that, with respect to any transmission in interstate commerce or any sale of electric energy for resale in interstate commerce by a public utility, no person is subject to any undue prejudice or disadvantage. We must determine whether any rule, regulation, practice or contract affecting rates for such transmission or sale for resale is unduly discriminatory or preferential, and must prevent those contracts and practices that do not meet this standard. . . . AGD demonstrates that our remedial power is very broad and includes the ability to order industry-wide non-discriminatory open access as a remedy for undue discrimination."); Pacific Gas & Elec. Co v. FERC, 373 F.3d 1315, 1317 (D.C. Cir. 2004) ("'It has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them'") (citing K N Energy v. FERC, 968 F.2d 1295, 1300 (D.C. Cir. 1992)).

160. *See e.g.,* U.S. v. Ill. Cent. R.R. Co., 263 U.S. 515, 524 (1924) ("[T]he difference in rates cannot be held illegal, unless it is shown that it is not justified by the cost of the respective services, by their values, or by other transportation conditions."); Interstate Commerce Comm'n v. U.S. ex rel. Campbell, 289 U.S. 385, 387–88 (1933) ("The Commission found that the failure of the carriers to establish joint or group rates over the short line connections had the effect of an undue preference to lumber companies doing business within the group territory. . . .").

161. Some of the old cost allocation cases understand cost causation to mean the rate regulated utility that plans investments. *See, e.g.*, Ala. Elec. Coop., Inc. v. FERC, 684 F.2d 20, 27 (D.C. Cir. 1982) ("[I]t has come to be well established that electrical rates should be based on the costs of providing service to the utility's customers, plus a just and fair return on equity").

made investments to serve customers in their franchise territory, and so it made sense to ask who the but-for cause of utility investments was.[162] As utilities expanded their systems and integrated with their neighbors, FERC recognized that the proximate cause of energy infrastructure should be understood, at least for cost allocation purposes, by looking at the beneficiaries. To that end, in 1992, the D.C. Circuit observed that:

> [T]he benefit principle may simply prove to be another prism through which to view the question of cost causation—one that admittedly extends the chain of causation further than FERC has done traditionally. That is, rather than focusing us on the most immediate and proximate cause of the cost incurred, the benefit principle may only ask us to look at a host of contributing causes for the cost incurred (as ascertained by a review of those who benefit from the incurrence of the cost) and assign them liability too. Simply, it may be a proxy for an extension of the chain of causation.[163]

It thus appears that, as system planners recognized the need for regional and interregional planning, they began to assert that cost causation requires the beneficiary pays approach. That is why FERC and courts have repeatedly accepted that "adoption of a beneficiary-based cost allocation method is a logical extension of the cost causation principle."[164] In our view, any terminological confusion results from the electricity industry's history of cost-of-service regulation.

Despite FERC's use of these different phrases, FERC and courts have consistently insisted that, when there is evidence that a class of customers benefits from the line, those beneficiaries should pay for the benefits they receive, and customers should not be able to free ride off their neighbors. In the years immediately following the passage of the Federal Power Act and Natural Gas Act, courts required energy regulators to assign costs based on who benefits. For example, in a series of orders in the 1940s and 1950s, the Federal Power Commission (the FPC, FERC's predecessor) consistently held that it would be discriminatory for a gas company to charge different rates to customers who received similar benefits and service.[165] Courts typically upheld these decisions, and, in rare cases where they

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162. *See id.*

163. K N Energy, Inc., 968 F.2d at 1302.

164. S.C. Pub. Serv. Auth. v. FERC, 762 F.3d 41, 85 (D.C. Cir. 2014). *See* Town of Norwood v. FERC, 962 F.2d 20, 25 (D.C. Cir. 1992) (allowing cost allocation "based upon that customer's proportionate use of existing capacity at the time of peak system demand" because this approach "ensures that the cost of new capacity is allocated to those who contribute to the need for adding it—an eminently sensible allocation, and one that we have endorsed before"); *see also* Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC, 475 F.3d 1277, 1285 (D.C. Cir. 2007) ("But FERC has long taken the view that customer 'but-for' causation isn't dispositive of this issue. '[E]ven if a customer can be said to have caused the addition of a grid facility, the addition represents a system expansion used by and benefitting all users due to the integrated nature of the grid'"). In gas markets, they use the phrase "rolled in "rates to describe the beneficiary pays approach. *See* Battle Creek Gas Co., 281 F.2d at 47–48 ("We find that the Commission's basic conclusion that this partial expansion would be part of the integrated gas system was proper, and therefore affirm the use of the rolled-in allocation method. This conclusion is confirmed by, although it is not dependent upon, the later applications of Trunkline, clearly indicating an intent to utilize for the benefit of all customers the 'cheap expansibility' and new reserves made available through the facilities involved in this application").

165. In re City of Cleveland v. Hope Nat. Gas Co., 3 F.P.C. 150, 190 (1942); In re La. Pub. Serv. Comm'n v. United Gas Pipe Line Co., 3 F.P.C. 402, 404-05 (1943); In re Trunkline Gas Supply Co., 8 F.P.C. 250, 258 (1949); In re Colo. Interstate Gas Co., 11 F.P.C. 324, 353-54 (1952); In re United Gas Pipe Line Co., 14 F.P.C.

pushed back against the FPC, it was typically because the Commission failed to distinguish among differently situated classes of customers and assign costs accordingly.[166] In fact, James Bonbright's seminal treatise on public utility regulation, which was published in 1961, notes that ratemaking involves a "fair-cost apportionment objective, which invokes the principle that the burden of meeting the total revenue requirements must be distributed fairly among the beneficiaries of the service."[167] Utility regulators continue to rely on the Bonbright principles to guide utility regulation to support the proposition that "[t]he fundamental objective is to ensure that the revenue burden is being equitably shared amongst each customer class."[168] Both before and after FERC restructured the natural gas industry, courts and the Commission accepted something called rolled-in pricing as the proper approach to pricing for gas pipelines. Under that approach, the costs of pipeline expansions are allocated across the system to reflect the fact that the pipeline creates system-wide benefits.[169]

Cases upholding rolled-in pricing have repeatedly cautioned that it would be discriminatory for FERC to approve a rate structure that forces customers to pay for benefits they do not receive.[170] In fact, when the Commission began to accept alternative cost allocation approaches for gas pipelines, it did so because there was evidence that some customers were *not* benefitting from the additional pipeline capacity. In 1981, for example, the Fifth Circuit upheld a FERC decision not to use rolled-in pricing for "emergency-gas costs."[171] The pipeline expansion was being built to ensure that high-priority customers received uninterrupted service. FERC found, and the Fifth Circuit agreed, that "the method of pricing United uses

353, 391-400 (1955); Cf. In re Colo. Interstate Gas Co., 19 F.P.C. 1012, 1021 (1958) (authorizing an exemption to rolled in rates when doing so would harm existing customers and raise prices).

166. Miss. River Fuel Corp. v. Fed. Power Comm'n, 252 F.2d 619, 626 (D.C. Cir. 1957) (remanding an FPC rate decision for charging different prices to similarly situated ratepayers); Order No. 436, *supra* note 24, at 42,415 ("The Commission has generally followed rolled-in treatment for new facilities except where the costs of the new facilities are more appropriately assigned to a particular customer or group of customers. Thus, new pipeline construction or looping of some portion of a mainline transmission system in order to provide increased services to some particular customer downstream has been granted rolled-in treatment on the grounds that the new looping will also benefit all system customers through greater reliability of service").

167. JAMES C. BONBRIGHT, PRINCIPLES OF UTILITY RATEMAKING 292 (1961).

168. ARTHUR ABAL ET AL., TARIFF TOOLKIT: PRIMER ON RATE DESIGN FOR COST-REFLECTIVE TARIFFS 12 (2021).

169. Battle Creek Gas Co., 281 F.2d at 47 (D.C. Cir. 1960) ("We find that the Commission's basic conclusion that this partial expansion would be part of the integrated gas system was proper, and therefore affirm the use of the rolled-in allocation method. This conclusion is confirmed by, although it is not dependent upon, the later applications of Trunkline, clearly indicating an intent to utilize for the benefit of all customers the 'cheap expansibility' and new reserves made available through the facilities involved in this application.").

170. Michigan Gas & Elec. Co. v. Fed. Power Comm'n, 290 F.2d 374, 376 (D.C. Cir. 1961) (upholding rolled in pricing and rejecting a utility proposal that "would unduly discriminate in its favor and would impose an undue burden upon the other customers of Michigan Wisconsin").

171. Laclede Gas Co. v. FERC, 722 F.2d 272, 274-75 (5th Cir. 1984) (stating that "[t]raditionally, the Commission has endorsed the practice of rolled-in pricing unless it would lead to an unfair result." But explaining that, "[d]uring the natural gas shortages of the 1970's, FERC allowed an exception to the rolled-in pricing practices for emergency gas purchases.").

(to recover the cost of emergency gas) is unjust, unreasonable, unduly discriminatory, and preferential, in violation of section 5 of the Natural Gas Act."[172] The Court explained that FERC can use rolled in pricing if "there is a direct benefit to all classes of customers."[173] But that is not the case when a pipeline expansion is built for the sole purpose of providing uninterrupted service to high-priority customers. In such circumstances, requiring non-priority customers to pay a share of those costs would force them to subsidize benefits that redound entirely to other customers.

Both FERC and courts continue to insist that cost allocation must prevent customers from free riding off their neighbors' investments. As in the electricity industry, courts have connected cost causation to the NGA's "just and reasonable" requirement. In *BNP Paribas*, for example, the D.C. Circuit stated that:

> The Natural Gas Act requires that rates be just and reasonable and not unduly discriminatory. 15 U.S.C. § 717c(a)-(b). The Commission has 'added flesh to these bare statutory bones' through adoption of the 'cost causation' principle, which requires that rates 'reflect to some degree the costs actually caused by the customer who must pay them.' *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992). This typically translates into a process of 'comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party.' *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004). The flip side of the principle is that the Commission generally may not single out a party for the full cost of a project, or even most of it, when the benefits of the project are diffuse.[174]

The court emphasized that "the cost causation principle itself manifests a kind of equity. This is most obvious when we frame the principle (as we and the Commission often do) as a matter of making sure that burden is matched with benefit)."[175]

Thus, in both the gas and electricity industry, courts have long allowed FERC to allocate costs to the customers who benefit from new infrastructure. This approach to cost allocation has been used in the natural gas industry since at least the 1960s. Alternative approaches allow some customers to free ride off their neighbors in violation of the FPA and NGA's prohibition on undue discrimination.

V. CONCLUSION

As the previous Part explained, the beneficiary pays approach to cost allocation is consistent with decades of judicial precedent. Order No. 1920 therefore adopts the approach to cost allocation that courts have required for decades. Courts have repeatedly suggested that alternative cost allocation approaches are not consistent with FERC's mandate to ensure rates are just and reasonable and not unduly discriminatory. At various points, the Order No. 1920 dissent appears to agree with this legal interpretation, arguing, for example, that the FPA prohibits cost allocation approaches that allow some classes of customers to free ride off

172. *Id.* at 276 (quoting United Gas Pipe Line Co. v. FERC, 649 F.2d 1110, 1113 (5th Cir. 1981)) (upholding use of rolled in pricing when FERC showed all customers benefited from pipeline expansion).

173. *Id.*

174. BNP Paribas Energy Trading GP v. FERC, 743 F.3d 264, 267-68 (D.C. Cir. 2014).

175. *Id.*

their neighbors. The dissent thus accepts, at least as a doctrinal matter, the beneficiary pays approach that FERC and courts have endorsed for decades.

But the specific proposal outlined in the dissent does not meet the standard it endorses. The dissent argues, for example, that "the cost causation principle cannot, and should not . . . require that the ratepayers of a non-consenting state pay costs of other states' public policies where there is mismatch between planning criteria and benefits."[176] The dissent appears to envision a separate category of "public policy" lines in which all costs should be allocated to states that have adopted clean energy policies. It is true that, when only a subset of states in a region adopt clean energy policies, states and customers without decarbonization goals will be forced to pay for projects that support the policy goals of other states and customers.

The reality of an interconnected transmission system is that essentially every line will produce some economic benefits, some reliability benefits, and some climate benefits. As we explained in Part II, if the Commission forced states that have adopted clean energy laws to pay all the costs of such lines, it would force those states to pay for economic and reliability benefits they do not enjoy. As a result, the siloed cost allocation approach the dissent proposes would result in precisely the type of cross-subsidization to which he objects. Of course, in Order No 1920's compliance filings, transmission planners could propose an approach to cost allocation that would force states to pay for energy policies they have not adopted. But that is not a reason to reject beneficiary pays cost allocation, since it would plainly violate the beneficiary pays standard and thus be vulnerable to legal challenge.

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176. Order No. 1920, *supra* note 1, at P 67 (Christie, Comm'r, dissenting).

POWER AND POLITICS IN THE TENNESSEE VALLEY

Rachel Neuburger[*]

Synopsis: When President Roosevelt signed the Tennessee Valley Authority Act of 1933 into law, he envisioned a public power institution that would electrify the Southeast and serve as a model for countering the "power trust" that dominated electric service across the country. In the mid-twentieth century, the Tennessee Valley Authority ("TVA") supplanted privately-owned utilities in the Tennessee Valley, brought affordable electricity to farms, and invested in infrastructure and industry in the region. But in doing so, and unguided by the private profit motive, TVA evolved into a monopoly utility whose scale and power relative to potential competitors and customers rivals any of its investor-owned peers. TVA's position of dominance has come into question as Congress and federal and state regulators opened the United States electric sector to competition and customers clamor for affordable, clean energy resources.

In 2019, TVA imposed uniquely onerous power supply contracts upon its distribution utility customers. The contracts' twenty-year terms, annual one-year term extensions, and twenty-year termination notice requirements distinguish them from previous all-requirements contracts in the Tennessee Valley and elsewhere in the country and gave rise to political contestation and legal challenges.

This article analyzes TVA's 2019 all-requirements contracts in context, making sense of them in light of TVA's history, modern electric sector conditions, and economic and political pressures. I argue that TVA's unique role and legal status, developed in the first half of the twentieth century, made it particularly vulnerable to the political and economic threats that emerged in the latter half of the twentieth century. I explain how this vulnerability led TVA to develop the 2019 all-requirements contracts and discuss two cases that arose to challenge them. Finally, I examine what this litigation has to say about TVA's past and future in a changing electric sector.

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I. INTRODUCTION

The power trust has done more to sap the vitality of the Nation than the hook-worm. And I would rather be the most humble worker for the T.V.A. and do all I could for humanity for a few short years and die than to be the whole power trust and wiggle in its hookworm slime for a million years.

Letter from Tennessee physician R. L. Montgomery to
TVA Director David E. Lilienthal, June 1936[1]

We have a hard time understanding why TVA can't operate more like a true public power provider.

Athens Utilities Board Assistant General Manager Wayne Scarbrough,
Athens, Tennessee, February 2023[2]

When President Roosevelt signed the Tennessee Valley Authority Act into law in 1933, he envisioned an endeavor that would "accomplish a great purpose for the people of many States and, indeed, for the whole Union." The new federal project in the Tennessee Valley would "set[] an example of planning, . . . tying in industry and agriculture and forestry and flood prevention, tying them all into a unified whole over a distance of a thousand miles so that we can afford better

1. THOMAS K. MCCRAW, TVA AND THE POWER FIGHT: 1933–1939, at 125 (1971) [hereinafter TVA AND THE POWER FIGHT].

2. Press Release, Athens Utils. Bd., As "Winter" Continues, TVA Raises AUB's Power Rate (Jan. 2023), https://perma.cc/Y5UJ-VT4T [hereinafter Press Release, Athens Utils. Bd.].

opportunities and better places for living for millions of yet unborn in the days to come."[3] The Tennessee Valley Authority went on to take on the powerful, interstate monopolies that dominated electric service in the Tennessee Valley, bring affordable electricity to farms, and introduce infrastructure, industry, and sounder agricultural practices to the Tennessee River watershed. But notwithstanding its broad statutory mandate to promote economic development and environmental stewardship in the Tennessee Valley region, TVA today is primarily an electric utility. It owns the bulk power infrastructure[4] that 153 locally-owned distribution utilities rely on.[5] These utilities together cover a territory of 80,000 square miles, including virtually all of Tennessee and parts of Alabama, Georgia, Kentucky, Mississippi, North Carolina, and Virginia.[6] In 2023, TVA generated or purchased 9% of its electricity from hydroelectric plants, 15% from coal, 30% from gas and oil, 42% from nuclear, and 4% from wind and solar.[7]

Moreover, over the course of the twentieth century and into the twenty-first, TVA evolved into a monopoly utility itself—one whose scale, power relative to customers and competitors, and resistance to competition rivals its privately owned peers.

In the face of TVA's growing monopoly and monopsony power, customers and potential competitors have called for reform, with proposals ranging from increasing transparency to introducing open transmission access to TVA territory to outright privatization. In August 2019, TVA sought to secure its future by asking its customers—municipal and cooperatively-owned electric utilities that distribute electricity supplied and transmitted by TVA to end-use consumers—to enter into new, twenty-year all-requirements contracts. These contracts require each distribution utility to purchase all of its electricity from TVA and in turn obligate TVA to supply the utility's required power. The contracts' terms extend by one year annually (making them "evergreen"). Cancellation requires twenty years' notice, and upon giving such notice, the distribution utility loses a discounted rate and other contractual protections. For the small utilities located deep within TVA's service area, insulated from the open access and non-discrimination rules governing transmission service in the rest of the country, there looked to be little choice but to sign.

3. TVA AND THE POWER FIGHT, *supra* note 1, at 35.

4. The "bulk power system" refers to the infrastructure used to generate electricity and transmit it at high voltages from power plants to local substations. Once power has been transmitted to a substation, it is stepped down to a lower voltage and distributed to end-use consumers. One or several utilities can perform different functions in this supply chain.

5. *Public Power for the Valley*, TVA, https://www.tva.com/energy/public-power-partnerships. Specifically, TVA serves 118 municipal utilities and thirty-five rural electric cooperatives, as well as fifty-eight industrial customer and seven federal government installations. *Id.*

6. TVA, 2019 INTEGRATED RESOURCE PLAN: VOL. I – FINAL RESOURCE PLAN 1-3, https://www.tva.com/environment/integrated-resource-plan/2019-integrated-resource-plan.

7. *Energy*, TVA, https://www.tva.com/about-tva/learn-about-tva/energy; Kristi E. Swartz, *TVA plans major increase in carbon-free power*, E&E NEWS (July 13, 2022), https://www.eenews.net/articles/tva-plans-major-increase-in-carbon-free-power/.

Or sue. In 2021, four of TVA's utility customers asked the Federal Energy Regulatory Commission ("FERC") to enable them to purchase power from non-TVA suppliers, to be transmitted along TVA power lines, thus allowing them to avoid signing TVA's rigid new supply contracts. The utilities lost their case at FERC but brought new attention to the all-requirements contracts under which customers in the Tennessee Valley and other pockets of the country buy power.

The question this article seeks to answer is why, unguided by the private shareholder's profit motive, TVA systematically amassed increasing levels of monopoly and monopsony power over the course of the twentieth and early twenty-first century to become a dominant power broker of the Southeast by 2019. To answer that question, this article describes TVA's ascendance, its ever-increasing accumulation of power, and the threats to that power that emerged in the late twentieth and early twenty-first century with electric sector restructuring and the clean energy transition.[8]

Perhaps because TVA is unlike any other electric utility in the United States, this story has received relatively little coverage in recent legal literature.[9] But TVA's singular combination of features—its set of "internal and external institutional incentives"[10]—is worthy of study to better understand dynamics in the Tennessee Valley and, potentially, to instruct modern public power movements.

Part II of this article discusses TVA's twentieth-century history: how and why it started using all-requirements contracts in its early years; legislative changes throughout the latter half of the century that increased its need for control over its customers; and the evolution of its contract terms during that period. The twentieth-century saw the development of features that today make TVA unique among actors in the electric power generation and transmission business in the United States: its self-regulation, its reliance on debt financing, and its immunity from open-access transmission policy.

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8. This methodology is inspired, in part, by Professors Klass and Chan's study of rural electric cooperatives' adoption of clean energy. *See* Alexandra B. Klass & Gabriel Chan, *Cooperative Clean Energy*, 100 N.C. L. REV. 1, 38-40 (2021). Professors Klass and Chan analyze the historical development of rural electric cooperatives to identify features that help to explain their behavior with respect to adoption of clean energy. *See id.* at 6-7.

9. Legal observers paid a great deal of attention to TVA's electric power program in its early years, when its constitutionality was still in question. Scholarship focused in later decades on TVA v. Hill, 437 U.S. 153 (1978), and on TVA's environmental compliance record. Recent scholarship discussing TVA's power program, at least briefly, includes Arjuna Dibley, *When Does "Leviathan" Innovate? A Legal Theory of Clean Technological Change at Government-Owned Electric Utilities*, 47 HARV. ENV'T L. REV. 135 (2023); Ryan Thomas Trahan, *Counting Carbon: Forward-Looking Analysis of Decarbonization*, 27 HASTINGS ENV'T L. J. 110 (2021); Michael P. Vandenbergh, Jim Rossi, & Ian Faucher, *The Gap-Filling Role of Private Environmental Governance*, 38 VA. ENV'T L. J. 1 (2020); Barry Cushman, *The Judicial Reforms of 1937*, 61 WM. & MARY L. REV. 995 (2020); Mary Kathryn Nagle, *Environmental Justice and Tribal Sovereignty: Lessons from Standing Rock*, 127 YALE L.J. F. 667 (2018); Shelly Welton, *Clean Electrification*, 88 U. COLO. L. REV. 571 (2017); Richard Schmalensee, *Socialism for Red States in the Electric Utility Industry*, 12 J. COMP. L. & ECON. 477 (2016); Steven A. Ramirez, *The Law and Macroeconomics of the New Deal at 70*, 62 MD. L. REV. 515, 551-53 (2003). *See also* Conor Harrison & Shelly Welton, *The states that opted out: Politics, power, and exceptionalism in the quest for electricity deregulation in the United States South*, 79 ENERGY RSCH. & SOC. SCI. 1, 3 (2021) (assessing effects of electricity restructuring in the South but leaving the unique cases of Tennessee and Virginia to future researchers).

10. Klass & Chan, *supra* note 8, at 40.

Part III details events that began in 2019, when TVA amended its all-requirements contracts such that they effectively never end, analyzing the motivations for that model in light of TVA's historical development and customers' responses. Part IV and V discuss recent legal conflicts arising out of those contracts and what they have to say about TVA's past and future in a changing electric sector.

II. TWENTIETH CENTURY HISTORY OF TVA

A large body of scholarship discusses TVA's rich history, particularly from its founding years to the mid-to-late twentieth century. That history helps to explain the development and continued utility of the all-requirements contract in TVA's power supply regime. Throughout its history, TVA faced threats to its legitimacy and continuity from competitors, customers, and lawmakers. Each time, it responded to these threats by bolstering its economic dominance in the region. Increasingly restrictive all-requirements contracts bound the Tennessee Valley to TVA and vice-versa, allowing TVA to retain power notwithstanding mounting debt, rate increases, customer discontent, and political pressures in the latter half of the century.

A. 1933: The Founding

TVA was founded to address a practical problem. During World War I, the federal government needed a source of nitrates, an essential ingredient for explosives. Acting under the authority of the National Defense Act of 1916, the Wilson administration set out to build two nitrate plants and an associated hydroelectric power project, later called the Wilson Dam, in Muscle Shoals, a section of the Tennessee River in Alabama known for its hydropower potential. In total, the Wilson administration spent approximately $129 million in public funds building the nitrate and power facilities.[11]

After the war, Congress and the executive branch spent more than a decade debating the fate of the Muscle Shoals facilities: should they be owned and operated by private or public actors, and for what purpose? It was largely thanks to the efforts of Nebraskan Senator George Norris, notwithstanding fervent opposition by investor-owned utilities ("IOUs") in the region and vetoes by Presidents Harding, Coolidge, and Hoover, that TVA as a public power institution was born. Over this period, Senator Norris both attempted to enact legislation creating a public administrator for Muscle Shoals and managed to combat legislation privatizing it, until President Roosevelt took office in 1932 and embraced his vision.[12]

1. The 1933 Act

The Tennessee Valley Authority Act,[13] signed into law by President Roosevelt on May 18, 1993, created a federally-chartered corporation to "maintain[] and

11. C. HERMAN PRITCHETT, THE TENNESSEE VALLEY AUTHORITY: A STUDY IN PUBLIC ADMINISTRATION 5-7 (1943).

12. For a more detailed account of this origin story, *see id.* at 5-30.

13. Tennessee Valley Authority Act of 1933, Pub. L. No. 73-17, 48 Stat. 58 (codified as amended at 16 U.S.C. § 831–831ee) [hereinafter TVA Act of 1933].

operat[e] the properties now owned by the United States in the vicinity of Muscle Shoals, Alabama, in the interest of the national defense and for agricultural and industrial development, and to improve navigation in the Tennessee River and to control the destructive flood waters in the Tennessee River and Mississippi River Basins."[14] It vested TVA's authority in a three-member Board of Directors, appointed by the President with the advice and consent of the Senate.[15]

Most of the original TVA Act focuses on TVA's non-power missions: river development, regional economic development, and nitrogen operations. Power was addressed in a few provisions as a somewhat supplementary component of the original TVA project.[16]

Specifically, section 5(*l*) authorizes the TVA Board to "produce, distribute, and sell electric power, as herein particularly specified."[17] Sections 10 through 12 provide those specifics. TVA is "empowered and authorized to sell the surplus power not used in its operations."[18] While it can sell that power to "States, counties, municipalities, corporations, or individuals," it is required to "give preference to States, counties, municipalities, and cooperative organizations of citizens or farmers, not organized or doing business for profit, but primarily for the purpose of supplying electricity to its own citizens or members."[19] Sales to industrial customers are a "secondary purpose," intended to "secure a sufficiently high load factor" and subsidize "domestic and rural usage."[20] Importantly, TVA's power contracts can last "a term not exceeding twenty years."[21]

Section 12 defined TVA's original electric service area: "In order to place the board upon a fair basis for making such contracts and for receiving bids for the sale of such power," TVA was authorized "to construct, lease, purchase, or authorize the construction of transmission lines within transmission distance from the place where generated."[22] This "transmission distance" was understood to be

14. TVA Act of 1933 § 1 (codified as amended at 16 U.S.C. § 831). For discussion of the decision to create TVA as a corporation, see PRITCHETT, *supra* note 11, at 22-27, 29.

15. TVA Act of 1933 § 2(a), (g) (codified as amended at 16 U.S.C. § 831a).

16. ERWIN C. HARGROVE, PRISONERS OF MYTH: THE LEADERSHIP OF THE TENNESSEE VALLEY AUTHORITY, 1933-1990, at 123-24 (1994); TWENTIETH CENTURY FUND, THE POWER INDUSTRY AND THE PUBLIC INTEREST 175 (Edward Eyre Hunt ed., 1944) ("The Act clearly makes the generation of power a secondary purpose of the TVA."). Section 5 is the main provision of the 1933 Act enumerating TVA's substantive powers. Subsections 5(a)–(k) and 5(m)–n) generally relate to TVA's nitrogen manufacturing and river navigation mandates. *See, e.g.*, TVA Act of 1933 § 5(j) ("The board is hereby authorized . . . [u]pon the requisition of the Secretary of War or the Secretary of Navy to manufacture for and sell at cost to the United States explosives or their nitrogenous content."). Only subsection 5(*l*) relates to power.

17. TVA Act of 1933 § 5(*l*) (codified as amended at 16 U.S.C. § 831d(*l*)).

18. *Id.* § 10 (codified as amended at 16 U.S.C. § 831i).

19. *Id.*

20. *Id.* § 11 (codified as amended at 16 U.S.C. § 831j). Load factor is the ratio between a utility's peak and average demand. A high load factor is economically desirable for a utility because most of the time, the utility only needs to generate enough power to meet its average demand, but it must still have enough generating capacity on hand for its peak demand. ALEXANDRA VON MEIER, ELECTRIC POWER SYSTEMS: A CONCEPTUAL INTRODUCTION 140 (2006).

21. TVA Act of 1933 § 10.

22. *Id.* § 12.

200 to 300 miles.[23] TVA was authorized to acquire real estate and use it to "construct dams, reservoirs, power houses, power structures, transmission lines, navigation projects, and incidental works in the Tennessee River and its tributaries, and to unite the various power installations into one or more systems by transmission lines."[24]

Section 10 provided: in areas "within reasonable distance of any of its transmission lines," TVA is authorized to "construct transmission lines to farms and small villages that are not otherwise supplied with electricity at reasonable rates, and to make such rules and regulations governing such sale and distribution of such electric power as in its judgment may be just and equitable."[25] Buyers from TVA are required to agree "that the electric power shall be sold and distributed to the ultimate consumer without discrimination as between consumers of the same class."[26] Finally, TVA was directed to set "reasonable, just, and fair" rates for retail sales of TVA power by for-profit customers.[27]

The non-discrimination and "just and reasonable" principles incorporated into the 1933 law had been part of state and federal public utility law for decades. They delegate broad discretion to regulators to ensure that utilities provide fair service to captive customers.[28] FERC and state public utility commissions enforce these standards with respect to investor-owned utilities and some cooperate and municipal utilities. But because TVA regulates itself—with no formal federal or state oversight over its rates and terms of service, except when its actions spark interest in Congress—TVA determines for itself whether its practices are in the public interest.[29]

23. *See* TVA AND THE POWER FIGHT, *supra* note 1, at 53.

24. TVA Act of 1933 §§ 4(i)-(j) (codified as amended at 16 U.S.C. §831c).

25. *Id.* § 10.

26. *Id.* § 12 (codified as amended at 16 U.S.C. § 831k).

27. *Id.* TVA was also permitted to interconnect with neighboring transmission systems "for the mutual exchange of unused excess power upon suitable terms, for the conservation of stored water, and as an emergency or break-down relief." *Id.*

28. *See* William Boyd, *Just Price, Public Utility, and the Long History of Economic Regulation in America*, 35 YALE J. REGUL. 721, 755–57 (2018).

29. By contrast, other federal power marketing agencies set their rates in the first instance, subject to FERC review under a set of statutory criteria. *See Bonneville Power Admin.*, 186 FERC ¶ 61,171, at P 10 (2024) (explaining that FERC reviews whether Bonneville's power and transmission rates: (1) are "sufficient to assure repayment of the federal investment in the Federal Columbia River Power System over a reasonable number years after meeting Bonneville's other costs"; (2) are based on total system costs; and (3) equitably allocate transmission costs between federal and non-federal power); DEP'T OF ENERGY, DELEGATION ORDER NO. S1-DEL-RATES-2016 § 1 (2013) ("Commission review [of Southwestern Power Administration, Southeastern Power Administration, and Western Area Power Administration power and transmission rates] will be limited to: (a) whether the rates are the lowest possible to customers consistent with sound business principles, (b) whether the revenue levels generated by the rates are sufficient to recover the costs of producing and transmitting electric energy including the repayment, within the period of cost recovery permitted by law, of the capital investment allocated to power and costs assigned by Acts of Congress to power for repayment; and (c) the assumptions and projections used in developing the rate components that are subject to Commission review.").

2. 1935 Amendments

In August 1935, as TVA set about expanding its power generation and transmission operations,[30] Congress amended the TVA Act to bolster the legal authority for its activities.[31] In the 1930s, rival investor-owned utilities and the newly-formed Edison Electric Institute[32] countered the political salience and success of public power, a fundamental threat to their existence, by attacking TVA's power program in the courts.[33] In *Ashwander v. TVA*,[34] decided in February 1935, Judge Grubb of the Northern District of Alabama had held TVA's power program *ultra vires* and unconstitutional, finding no "substantial relation" between TVA's burgeoning power utility program and sales of incidental surplus power generated in bona fide pursuit of a permissible constitutional function, such as "regulation of navigation or national defense."[35] Responding to this decision, the new section 9a specified:

> The Board is hereby directed in the operation of any dam or reservoir in its possession and control to regulate the stream flow primarily for the purposes of promoting navigation and controlling floods. So far as may be consistent with such purposes, the Board is authorized to provide and operate facilities for the generation of electric energy at any such dam for the use of the Corporation and for the use of the United States or any agency thereof, and . . . whenever an opportunity is afforded, to provide and operate facilities for the generation of electric energy in order to avoid the waste of water power, to transmit and market such power as in this act provided, and thereby, so far as may be practicable, to assist in liquidating the cost or aid in the maintenance of the projects of the Authority.[36]

The 1935 law also amended an existing provision of the Act to expressly authorize TVA to "construct such dams . . . in the Tennessee River and its tributaries, as in conjunction with [its existing dam projects] will . . . promote navigation on the Tennessee River and its tributaries and control destructive flood waters."[37] In characterizing the construction of hydroelectric dams and the generation and sale

30. *See infra* Part II.B.2.

31. *Norris TVA Bill Voted by Senate*, N.Y. TIMES (May 15, 1935), https://nyti.ms/3YVVaG8.

32. The Edison Electric Institute ("EEI") was founded in 1933 out of the ashes of the National Electric Light Association ("NELA"). In the 1920s, the private utility sector waged a campaign against public power. A Federal Trade Commission report "disclosed that individually and through [NELA], the power companies had for years engaged in every conceivable medium of publicity and propaganda. [M]uch of the publicity concerned politics as well as kilowatts – the horrors of government ownership, which the NELA characterized as Bolshevistic, socialistic, inefficient, and generally odious; and the contrasting accomplishments of private enterprise. . . . As a final insult the public paid for its own indoctrination. Utility accountants normally charged off propaganda costs as operating expenses, in the same manner as salaries or fuel." The report "brought the NELA into such disrepute that the industry gave up altogether and dissolved the association," replacing it with EEI. "The founders of the EEI declared that the new association would 'divest itself of all semblance of propaganda activities' and 'assume an attitude of frankness and ready cooperation in its dealings with the public.'" TVA AND THE POWER FIGHT, *supra* note 1, at 21-23. *See also* RICHARD F. HIRSCH, POWER LOSS: THE ORIGINS OF DEREGULATION AND RESTRUCTURING IN THE AMERICAN ELECTRIC UTILITY SYSTEM 41 (1999).

33. *See* HIRSCH, *supra* note 32, at 108, 112-19.

34. 9 F. Supp. 965 (N.D. Ala. 1935), *rev'd*, 78 F.2d 578 (5th Cir. 1935), *aff'd*, 297 U.S. 288 (1936).

35. *Id.* at 966-67.

36. Pub. L. No. 74-412 § 5, 49 Stat. 1075, 1076 (codified at 16 U.S.C. § 831h-1).

37. *Id.* § 2 (codified at 16 U.S.C. § 831c(j)).

of power as incidental to and supportive of the projects of navigation and flood control, these amendments sought to firmly cement TVA's power program within the federal government's enumerated constitutional powers.

Regarding wholesale rates for this newly strengthened power program, the amendments directed that it was the policy of the Act to set rates at levels which "when applied to the normal capacity of the Authority's power facilities, will produce gross revenues in excess of the cost of production of said power," in order to "as soon as practicable . . . make the power projects self-supporting and self-liquidating."[38]

Congress also bolstered TVA's ability to transact with distribution utilities in two critical respects. First, it authorized TVA "to include in any contract for the sale of power such terms and conditions, including resale rate schedules," and to issue "rules and regulations as in its judgment may be necessary or desirable for carrying out the purposes of this Act."[39] TVA would proceed to exercise this authority to the utmost, resulting in friction in the latter half of the twentieth century and continuing into the modern day.

Second, Congress authorized TVA to "acquire existing electric facilities used in serving farms and small villages,"[40] and to extend credit to municipal and cooperative utilities seeking to acquire private power lines.[41] These authorities enabled TVA to embark on its strategy of power program expansion in the later 1930s and 1940s, described below.

3. TVA's Place in the New Deal Regime

Though its footprint and functions have always been circumscribed, TVA has an outsized role in American history and society as a hallmark of President Roosevelt's New Deal legacy and a rare triumph for large-scale public power in a sector otherwise dominated by private corporations.

TVA played a part in three major projects of American governance. The first, of which TVA was only one component, is what Jason Scott Smith describes as the New Deal's "public works revolution," in which federally funded infrastructure "remade the built environment that managed the movement of people, goods, electricity, water, and waste," thereby "justify[ing] the new role of the state in American life."[42] Thus, President Roosevelt imagined TVA as being "charged with the broadest duty of planning for the proper use, conservation and development of the natural resources of the Tennessee River drainage basin and its adjoining territory for the general social and economic welfare of the Nation."[43] Through

38. *Id.* § 8 (codified at 16 U.S.C. § 831m).

39. *Id.* § 6 (codified at 16 U.S.C. § 831i).

40. Pub. L. No. 74-412 § 6, 49 Stat. 1075, 1076 (codified at 16 U.S.C. § 831i).

41. *Id.* § 7 (codified at 16 U.S.C. § 831k-1).

42. JASON SCOTT SMITH, BUILDING NEW DEAL LIBERALISM: THE POLITICAL ECONOMY OF PUBLIC WORKS, 1933–1956, at 2-3, 255, 262 (2006); *see also* Jason Scott Smith, *Why Privatizing the TVA Would Be a Dam Shame*, BLOOMBERG (Apr. 19, 2013), http://www.bloomberg.com/news/2013-04-19/why-privatizing-the-tva-would-be-a-dam-shame.html.

43. THOMAS K. MCCRAW, MORGAN VS. LILIENTHAL: THE FEUD WITHIN THE TVA 4 (1970) (citing House Doc. 15, 73d Cong., 1st Sess. (1933)) [hereinafter MORGAN VS. LILIENTHAL]. *See also* PRITCHETT, *supra* note

TVA's activities across the fields of power generation and transmission, flood control and navigation, fertilizer manufacturing, agriculture, conservation, and scientific and economic research, the federal government expanded its influence in the Tennessee Valley—and achieved policy goals in the region—using infrastructure development, education, and demonstration.[44] As the New Deal consensus came under attack at the end of the twentieth century, so too did TVA's public works mission.

The second project was rural electrification. Though IOUs grew at rapid speed and scale and access to electric service spread across the United States in the late nineteenth and early twentieth century, farms and rural communities were left behind. By 1930, 10.4% of American farms had access to electric service. By contrast, 84.8% of urban and rural non-farm residences were electrified—including almost every city or town in the country with a population above 250 people.[45] Advocates for rural electrification envisioned bold plans that would combine electrification with rural development. Morris L. Cooke, the most prominent early proponent of federal intervention in rural electrification and first head of the Rural Electrification Administration ("REA"), saw federally planned rural electrification as promising "a revived agriculture and reinspiration in small town life," one element of a larger plan to "build[] the Great State" and "plac[e] the government of our individual states on a plane of effective social purpose."[46] As governor of New York, Franklin Roosevelt supported rural electrification as a first step in his objective of "the great fundamental of making country life in every way as desirable as city life."[47] Notwithstanding some early ad hoc efforts,[48] it took the large-scale intervention of the federal government alongside concerted efforts of farmer-owned cooperative associations to bring electricity to rural America. TVA and the REA were the New Deal entities tasked with leading the federal charge.

11, at 18-22, 27-30; TWENTIETH CENTURY FUND, *supra* note 16, at 173 ("The Tennessee Valley Authority is the culmination of a gradual extension of federal responsibility to embrace not only navigation, flood control and strategic materials for national defense, but electric power, relief of unemployment and improvement of living conditions in backward areas. The TVA represents a unification of all these objectives in a single regional program."); Charles McCarthy, *TVA and the Tennessee Valley*, 21 TOWN PLAN. REV. 116, 117 (1950).

44. *See* McCarthy, *supra* note 43, at 117-24, 125-28.

45. U.S. CENSUS BUREAU, *Chapter S: Energy*, *in* BICENTENNIAL EDITION: HISTORICAL STATISTICS OF THE UNITED STATES, COLONIAL TIMES TO 1970, 811, 827 (1975), https://www.census.gov/library/publications/1975/compendia/hist_stats_colonial-1970.html; *see* Carl Kitchens & Price Fishback, *Flip the Switch: The Impact of the Rural Electrification Administration 1935–1940*, 75 J. ECON. HIS. 1161, 1163 (2015).

46. PHILIP J. FUNIGIELLO, TOWARD A NATIONAL POWER POLICY: THE NEW DEAL AND THE ELECTRIC UTILITY INDUSTRY, 1933-1941, at 127 (1973); *see also* DAVID M. KENNEDY, FREEDOM FROM FEAR: THE AMERICAN PEOPLE IN DEPRESSION AND WAR, 1929-1945, at 63 (1999) ("[Senator] Norris . . . remembered the inky black nights of his frugal rural childhood and saw in government hydroelectric projects the means to shed light over the darkened countryside.").

47. FUNIGIELLO, *supra* note 46, at 128-29 (quoting an address delivered by Franklin D. Roosevelt at the State College of Agriculture, Cornell University, on February 14, 1930).

48. Approximately fifty rural electric cooperatives operated in the United States by 1935 but struggled to secure a wholesale power supply. TWENTIETH CENTURY FUND, *supra* note 16, at 122; *see* D. CLAYTON BROWN, ELECTRICITY FOR RURAL AMERICA: THE FIGHT FOR THE REA 13-15 (1980). Rural electric cooperatives were widespread and successful in Europe and Canada. *Id.* at 16-17.

Finally, TVA (again along with the REA) was a key actor in "the struggle to free the consumer from the monopoly of holding company control."[49] In the early twentieth century, as utilities slow-walked or outright refused to extend electric service to rural areas, they also engaged in abusive practices, amassed monopoly status in the territories they did serve, and used that monopoly status to charge inflated rates.[50] Public power proponents convinced Congress and President Roosevelt that TVA could address these problems: monopoly abuses, by generating franchise competition—"competition between public and private entities for the right to serve,"[51] which would pressure investor-owned utilities to improve service and decrease prices;[52] and exorbitant prices, by serving as a "yardstick." TVA would be required to set "the lowest possible rates,"[53] making it a point of comparison with other utilities, shaming those engaging in price-gouging into lowering their rates, and perhaps even generating momentum for the public power movement.[54] Thus, TVA was established as a vehicle both for expanding access to electricity for rural residents of the Tennessee Valley and for mitigating the harmful effects of monopoly more generally in the electric sector.

B. 1933–1941: The TVA Power Program Takes Shape

In its first decades, TVA became the dominant power utility in the Tennessee Valley. Its tool of choice for achieving dominance (over its competitors and its customers) was the all-requirements contract.[55] Three factors explain why TVA

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49. FUNIGIELLO, *supra* note 46, at 122. Even within the New Deal coalition, there was a divide between "those who viewed the power question as a death struggle between the public and private traditions, and those who wanted to bring cheap electricity to as many citizens as possible, irrespective of public or private ownership." TVA AND THE POWER FIGHT, *supra* note 1, at 105. Within the first TVA Board of Directors, Chairman Arthur E. Morgan held the latter point of view, and David. E. Lilienthal the former. Lilienthal's vision won out after protracted battle. *Id.* at 54.

50. *See* MORGAN VS. LILIENTHAL, *supra* note 43, at 3 ("Roosevelt believed that the public was being systematically milked by private utilities, which set their rates artificially high in order to pay for dividends on watered stock. At the same time, the private companies had often showed extreme reluctance to extend their transmission lines into low-usage, low-profit rural areas, and Roosevelt intended that electricity should be made widely available to farmers. [T]wo of the goals of TVA's power operations would be to establish a yardstick in the Southeast, and to promote rural electrification.").

51. Harvey L. Reiter, *Competition Between Public and Private Distributors in a Restructured Power Industry*, 19 ENERGY L.J. 333, 337 (1998).

52. *Id.* at 339-41, 348. *See also* Tenn. v. FCC, 832 F.3d 597, 603 (6th Cir. 2016) (describing benefits of franchise competition in the telecommunications industry).

53. TVA Act of 1933 § 11 (codified at 16 U.S.C. § 831j).

54. *See* TVA AND THE POWER FIGHT, *supra* note 1, at 30, 61, 70-73; *see also* PRITCHETT, *supra* note 11, at 17-18, 27 (quoting a 1932 campaign speech in which Roosevelt asserted that public power could "be forever national yardstick to prevent extortion against the public and to encourage the wider use of that servant of the people—electric power."); *see also* Power Auth. of N.Y. v. FERC, 743 F.2d 93, 105 (2d Cir. 1984) (The yardstick idea is regarded as somewhat of a failure because of theoretical and pragmatic difficulties in comparing rates between utilities).

55. *See* HARGROVE, *supra* note 16, at 54-55 (explaining that TVA's relationship with its customers was one of "domination rather than democracy"; TVA determined the wholesale and retail rates in its all-requirements contracts, resisted state regulation, and prohibited appointment of local elected officials to distribution utility boards); *see also* PRITCHETT, *supra* note 11, at 110-11 (describing friction in TVA's relationship with and management of its customers).

aggressively expanded from the start. First, the rural Tennessee Valley was sparsely electrified, and TVA's leaders believed that public power was best suited to bring electricity to the farm. Second, TVA economists believed that high power demand was required to achieve low rates, a touchstone principle of the public power project. Third, TVA needed customers for its rapidly-expanding power supply. Importantly, for municipalities and especially rural electric cooperatives, the all-requirements contract evolved (both inside and outside of TVA territory) as a solution to the inverse problem: insufficient power supply for an eager base of would-be electricity consumers.[56]

That utilities in TVA territory would procure all their electric needs from TVA seems mundane today, with TVA's monopoly in the Tennessee Valley secure. But in the 1930s, TVA's fledgling power program was threatened by powerful competitors seeking to retain their effective monopolies in sections of the region. Its financial and political stability depended upon securing an outlet for its power.[57] While rural, unserved customers had little choice but to buy power from TVA, and were eager to do so, larger municipalities had previously been served by private companies and posed a threat of defection—especially if TVA had not lived up to its promise of low rates. Thus, the all-requirements contract was fundamental to TVA's survival in the region.

1. Rationales for Expansion

In the 1930s and 1940s, the leaders of TVA's power program worked to secure demand from municipalities and rural electric cooperative utilities for TVA power. TVA sought to secure load for several reasons. First, TVA's leaders believed that public power could bring widespread access to electricity to the farm. In 1929, fewer than one percent of farms in the Tennessee Valley had electric power.[58] Four IOUs served the area. Those utilities in turn were subsidiaries of two national holding companies, Commonwealth & Southern Corporation and Electric Bond & Share Company.[59] The IOUs owned generation, transmission, and distribution infrastructure. For the most part, they generated, transmitted, and distributed power straight to end-use customers (residents and businesses). In electrified localities, IOUs owned the existing distribution systems. In a minority of cases, where municipal or cooperative utilities distributed power, they were nevertheless dependent upon IOUs for generation and transmission.[60]

TVA's early leaders were aligned with the public power movement, which saw the failings of private power to provide equitable access to electricity between

56. *See* BROWN, *supra* note 48, at 73, 90-91; *see also* Proposed Rule, *60-Day Notice of Proposed Information Collection: Wholesale Contracts for the Purchase and Sale of Electric Power and Energy*, 55 Fed. Reg. 38,930, 38,930 (Sept. 21, 1990).

57. *See* HARGROVE, *supra* note 16, at 44.

58. Carl Kitchens, *The Role of Publicly Provided Electricity in Economic Development: The Experience of the Tennessee Valley Authority, 1920-1955*, 74 J. ECON. HIST. 389, 400 tbl. 2A (2014).

59. For the story of how Electric Bond & Share—a New York-based holding company formed by General Electric—came to the Southeast, *see* Conor Harrison, *The historical-geographic construction of power: electricity in Eastern North Carolina*, 18 LOCAL ENV'T 469, 475 (2013).

60. PRITCHETT, *supra* note 11, at 67.

rural and non-rural communities and sought to supplant private utility company service (to varying degrees) with publicly-owned and provided service and to introduce public power to unserved areas.[61] They were not satisfied with mere coexistence with existing private utilities. This movement believed that public power was necessary for the public interest, not just in Tennessee but nationwide.[62]

Second, TVA saw high levels of demand as necessary to realize its vision of yardstick rates. As discussed above, some of TVA's founders and proponents (including President Roosevelt) envisioned using TVA rates as a point of comparison (a yardstick) with IOU rates.[63] Early on, there was a question of how the yardstick would function—and, critically, how to achieve sufficiently low rates. In 1933, TVA adopted a "low cost, high usage" rate design, which required high levels of usage to justify low rates.[64] Its first set of rates were so low as to be promotional—given TVA's small customer base, it could not operate as a going concern with so little revenue.[65] However, TVA economists theorized—correctly—that low rates would attract increased demand, which, in turn, would make those low rates economically sound.[66]

Third, TVA desperately needed an outlet for its expanding electric generating capacity. The TVA Act directed TVA to present a plan to Congress for "unified development of the Tennessee River System."[67] In 1936, it did, proposing the construction of nine high dams on the Tennessee River.[68] By January 1942—not quite nine years after its creation—TVA owned ten operating hydroelectric dams

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61. HARGROVE, *supra* note 16, at 35, 40-41 (discussing TVA Director David E. Lilienthal's public power vision and distrust of utilities, which conflicted with the views of Board Chairman Arthur Morgan but ultimately prevailed in TVA's early internal power struggles).

62. *See* FUNIGIELLO, *supra* note 46, at 256-64 (discussing the composition and competing visions within the New Deal-era public power movement).

63. *See supra* Part II.A.3.

64. TVA AND THE POWER FIGHT, *supra* note 1, at 59.

65. *Id. But see* Kitchens, *supra* note 58, at 412-15. There is some debate over the empirical basis for TVA's 1933 rates. *Compare* TWENTIETH CENTURY FUND, *supra* note 16, at 179 ("TVA rates were not . . . drawn out of a hat. Operating data were available from past generating experience at Wilson Dam, and from the results of operation under low rates in public plants like that at Tacoma, Washington, together with the results of an exhaustive three-year study of the costs of distributing electricity made by the New York State Power Authority."), *with* TVA AND THE POWER FIGHT, *supra* note 1, at 60 ("The valuation [of the Wilson Dam], though vital to the rates finally set, would be essentially arbitrary. . . . The ratemakers disagreed among themselves over many details, but they all knew that prices had to be set quickly. They accordingly took short cuts, employed arbitrary figures and methods, and finished their work in a ridiculously brief time. Most of the consultants were highly qualified economists, but their work in this case was basically (and necessarily) an exercise in intuition.").

66. *See, e.g.*, TVA, POWER ANNUAL REPORT FOR THE FISCAL YEAR ENDED JUNE 30, 1960, at 22 (1960) [hereinafter 1960 ANNUAL REPORT] ("It is axiomatic that low costs can result in low prices. Not so well recognized is the other side of the coin—low prices, or low electric rates, can lead to lower unit costs through increased consumption and the economies of mass production. TVA's policy of low rates has led to large and rapid increases in the use of electricity."); *see also* TWENTIETH CENTURY FUND, *supra* note 16, at 179 (explaining that its government backing allowed TVA to experiment with "the effects of rates and sales conditions upon both demand and costs").

67. Pub. L. No. 74-412 § 2 (codified as amended at 16 U.S.C. § 831c(j)).

68. TVA, ANNUAL REPORT OF THE TENNESSEE VALLEY AUTHORITY FOR THE FISCAL YEAR ENDED JUNE 30, 1938, at app. c, § 3(j) (1938).

with a capacity of 836.6 megawatts.[69] It had acquired two and constructed the other eight, in the course of which it developed "one of the largest construction organizations in the country."[70] And it had plans to reach a total of nineteen dams, with a total capacity of 2.3 gigawatts.[71] Thus, from its earliest years, TVA was presented with the challenge of finding customers for its power in order to justify its program of expansion.[72]

2. TVA's Expansion Strategy

How would TVA secure the customers it needed, given the presence of IOUs already serving some municipalities in the Valley? TVA could conceivably have built duplicative facilities and competed with existing companies for consumers on the basis of price or quality of service. It also could have sold power from its hydroelectric facilities to the existing utilities for their distribution to end-use consumers. The former path was financially and technically daunting, though TVA did pursue a limited duplication strategy described below. The latter path was mostly foreclosed by the preference clause of the TVA Act, which required TVA to give preference in electricity sales to public entities and nonprofit cooperatives over private customers[73] (though TVA sold power from the Wilson Dam to Commonwealth & Southern for a time).[74] Indeed, municipalities were already clamoring for TVA power.[75] And TVA's power program leaders were pessimistic about the prospects for fair dealing with private utilities.[76]

Thus, TVA embarked on a program of (1) acquiring the existing transmission facilities of the incumbent utilities; (2) building its own new generation and transmission; (3) facilitating municipalities' and cooperatives' acquisition of existing distribution facilities, or financing (via the Public Works Administration ("PWA") and, later, the REA) new construction where no distribution facilities yet existed; and (4) signing all-requirements contracts with its new distribution utility customers. By the close of the 1930s, TVA had used this strategy to achieve near-total control over the generation of electricity and its transmission of electricity to communities in the Tennessee Valley.

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69. TWENTIETH CENTURY FUND, *supra* note 16, at 178. For a diagram of its construction progress as of 1940, *see* TVA, ANNUAL REPORT OF THE TENNESSEE VALLEY AUTHORITY FOR THE FISCAL YEAR ENDED JUNE 30, 1940, at ix (1940) [hereinafter 1940 ANNUAL REPORT].

70. TWENTIETH CENTURY FUND, *supra* note 16, at 177.

71. *Id.* at 178.

72. *See* PRITCHETT, *supra* note 11, at 75; TWENTIETH CENTURY FUND, *supra* note 16, at 182; Kitchens, *supra* note 58, at 394. When it inherited the Wilson Dam, TVA also inherited a contract under which it sold power from the dam to a subsidiary of Commonwealth & Southern. Until it had built or bought more transmission lines, TVA had to keep selling the power to the subsidiary, because it was the only buyer in the area and TVA didn't have the infrastructure to transmit the power to a (legally preferred) municipality or cooperative. *See* TVA AND THE POWER FIGHT, *supra* note 1, at 41-43; *see also* McCarthy, *supra* note 43, at 117. Like TVA of the early 1930s, suppliers seeking to sell power in the region today have only one potential customer: TVA.

73. 16 U.S.C. § 831i.

74. *See* PRITCHETT, *supra* note 11, at 394.

75. TVA AND THE POWER FIGHT, *supra* note 1, at 59.

76. *See* Reiter, *supra* note 51.

In 1934, TVA entered into contracts with the subsidiaries of Commonwealth & Southern and Electric Bond & Share to acquire certain circumscribed portions of their transmission and distribution facilities in the Tennessee Valley, in exchange for which TVA agreed not to serve the companies' existing customers outside of its newly acquired territory.[77]

This arrangement faltered when Commonwealth & Southern and Electric Bond & Share discovered the effectiveness of staving off TVA competition in the courts.[78] Starting in September 1934, utilities challenged the legality of TVA and related New Deal programs. This litigation was ultimately unsuccessful in securing the legal relief the utilities sought. In *Ashwander v. TVA* (1936),[79] the Supreme Court disagreed with Judge Grubb and held that it was constitutional for the federal government to sell surplus power from the Wilson Dam as an incident to its war and commerce powers.[80] In *Alabama Power Co. v. Ickes* (1938),[81] the Court unanimously dismissed a challenge to the PWA's authority to issue loans and grants to municipalities for the construction of duplicative electric distribution systems, holding that existing utility companies operating without exclusive franchises were not immune from duplicative competition by municipalities and thus suffered no judicially cognizable injury.[82] Finally, in *Tennessee Electric Power Co. v. TVA* (1939),[83] the Court cited *Alabama Power* in again dismissing for lack of cognizable injury a claim by TVA's competitors that TVA's power program (except for its Wilson Dam operations) was an unconstitutional exercise of federal power, observing that no state law "confer[red] on the [investor-owned utilities] the right to be free of competition"[84]

After their third loss at the Supreme Court, the utilities came back to the negotiating table. Faced with uncertainty and the prospect of losing customers to municipal systems carrying cheap TVA power, the holding companies finally sold their facilities to TVA.[85] In the meantime, however, TVA pursued a temporary strategy of expansion through existing municipal utilities and duplication.[86]

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77. TVA AND THE POWER FIGHT, *supra* note 1, at 65-66.

78. *Id.* at 69. This treatment may be an understatement of the boldness and effectiveness of the litigation strategy, led by Wendell Wilkie, then Chairman of Commonwealth & Southern. Wilkie's strategy apparently came to be known as the "thirty million dollar yell" because while the utilities ultimately lost in court, their tactics allowed Commonwealth & Southern to sell its southeastern properties to TVA at double the originally negotiated price. *See* George D. Haimbaugh Jr., *The TVA Cases: A Quarter Century Later*, 41 IND. L.J. 197, 198 (1966).

79. 297 U.S. 288 (1936), *aff'g* 78 F.2d 578 (5th Cir. 1935), *rev'g* 9 F. Supp. 965 (N.D. Al. 1935).

80. *Id.* at 330, 332–339. See *supra* Part II.A.2 for discussion of 1935 TVA Act amendments provoked by the district court decision in *Ashwander*.

81. 302 U.S. 464 (1938).

82. *Id.* at 478–80.

83. 306 U.S. 118 (1939).

84. *Id.* at 118, 139-40 (1939).

85. PRITCHETT, *supra* note 11, at 72-73.

86. In 1933, TVA signed a preliminary agreement with Tupelo, Mississippi, to begin supplying wholesale power by February 1934. *See* TVA AND THE POWER FIGHT, *supra* note 1, at 64-65; *Federal Contract Cuts Power Rates*, N.Y. TIMES (Nov. 19, 1933), https://nyti.ms/3zngJEM. Unlike other municipalities, Tupelo already owned its own distribution facilities and was relatively close to the Wilson Dam. TVA AND THE POWER FIGHT, *supra* note 1, at 65.

TVA also promoted rural electrification—and thereby secured additional outlets for its power—by facilitating the formation of rural electric cooperatives. Several years before the creation of the REA, TVA advised and financed the formation of these farmer-owned utilities, sold them the distribution facilities that it acquired from the incumbent IOUs, and supplied their power. The REA largely took over TVA's cooperative organization and financing activities in 1935.[87]

Most of TVA's customers had to wait until 1939, however, because most municipalities did not yet own their own distribution lines. On May 12, 1939, TVA, Commonwealth & Southern, twenty-four municipalities (including Nashville and Chattanooga), and eleven cooperatives signed an agreement under which Commonwealth & Southern would sell the electric properties of its Tennessee subsidiaries for aggregate consideration of $78.6 million, with generation and transmission properties going to TVA and distribution properties going to the various new municipal and cooperative distribution utilities.[88] Municipalities and cooperatives that had not signed on by May 1939 could join the agreement at any time.[89] TVA agreed to supply credit to any distributor that had insufficient funding to purchase a system itself.[90] And TVA agreed to enter into power supply agreements, according to its standard form contract, with each distributor party.[91]

Thus, TVA carried out "a program of negotiation and purchase which put practically every city in Tennessee, as well as many in adjacent states, in the power business."[92] TVA effectuated its own expansion and cemented for itself an outlet

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87. PRITCHETT, *supra* note 11, at 73-74. *See, e.g.*, *Amended Contract between TVA and Tishomingo County Electric Power Ass'n* (Jan. 10, 1939), *in* ANNUAL REPORT OF THE TENNESSEE VALLEY AUTHORITY FOR THE FISCAL YEAR ENDED JUNE 30, 1939, at 388 (1940) [hereinafter 1939 ANNUAL REPORT] ("Whereas, association has . . . since July 19, 1935 purchased power at wholesale from Authority . . . and Whereas, Authority has heretofore financed the acquisition and construction by association of all rural electric transmission and distribution lines now owned and operated by association and the existing power contract . . . contains covenants and obligations inconsistent with other borrowings by association; and Whereas, association and Authority mutually desire to cancel and rescind said contract and to adopt this amended power contract in order that Association may receive the benefit of a loan proposed to be made to it for the construction of additional rural electric lines by United States of America; acting through the Administrator of the Rural Electrification Administration. . . .").

The REA, now called the Rural Utilities Service, has long required generation and transmission (G&T) cooperative borrowers to sign all-requirements contracts with their distribution utility member-owners. For documentation of this historical practice, see, e.g., Ala. Power Co. v. Ala. Elec. Cooperative, 394 F.2d 672, 675-76 (5th Cir. 1968), *cert. denied*, 393 U.S. 1000 (1968); *Proposed Rule, Wholesale Contracts for the Purchase and Sale of Electric Power and Energy*, 55 Fed. Reg. 38,930, 38,930–31 (Sept. 21, 1990). The requirement continues today. *See 60-Day Notice of Proposed Information Collection: Wholesale Contracts for the Purchase and Sale of Electric Power*, 87 Fed. Reg. 42,996 (July 19, 2022).

88. *See Contract between the Commonwealth & Southern Corp., TVA, City of Nashville, City of Chattanooga et al., Dated as of May 12, 1939, for the Purchase and Sale of the Electric Properties of the Tennessee Electric Power Co. and Southern Tennessee Power Co.*, *in* 1939 ANNUAL REPORT, *supra* note 87, at 236, 238-256.

89. *Id.* at 238.

90. *Id.* at 239.

91. *Id.* at 239, 241. To the extent Commonwealth & Southern retained distribution facilities, TVA agreed to sell it power for the lesser of 20 years or whenever the facility was taken over by a municipality or cooperative. *Id.* at 241.

92. PRITCHETT, *supra* note 11, at 73. This dynamic occurred on a smaller scale for the City of Knoxville. Knoxville received power from The Tennessee Public Service Company. Knoxville threatened to establish its

for its ever-increasing generation capacity by acquiring the IOUs' bulk power systems, facilitating local acquisition of distribution systems, and—one by one—signing its standard all-requirements power supply contract with local utilities.

3. TVA's Early All-Requirements Contracts

TVA entered into 110 virtually identical power supply contracts by 1940, largely with municipal and cooperative distribution utilities (also called Local Power Companies, or LPCs) but also with some industrial customers and a few IOUs. Taking effect upon acquisition of necessary facilities from the IOUs, the contracts required TVA to supply its new municipal and cooperative utility customers their "entire power requirements," and required the customer utilities to purchase all such requirements only from TVA, for twenty-year terms.[93] The contracts contained no provision for termination, extension, or renewal by either party.[94] The distributors agreed to buy power from TVA and resell power to customers according to uniform schedules set out unilaterally by TVA.[95] However, if TVA lowered its rates for another customer, it agreed to offer those lower rates to the distributor (unless unique conditions justified differential treatment).[96]

By 1951, TVA served ninety-five municipal and fifty cooperative distribution utilities pursuant to all-requirements contracts, under which TVA set its own wholesale rates and its customers' retail rates, all without regulatory oversight.[97]

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own municipal utility and build duplicative distribution lines (with PWA funding). The utility sued, arguing that Knoxville did not have authority to contract with a construction company to build distribution facilities. *See* Tenn. Pub. Serv. Co. v. Knoxville, 170 Tenn. 40, 43 (Tenn. 1936). The Supreme Court of Tennessee held that the utility had standing to sue: "[w]hether the city can, lawfully, make such contracts, and having made them, can lawfully compete with complainant are questions which complainant, having a property right in its franchise, is entitled to have adjudicated," though the franchise was nonexclusive. *Id.* at 45-46. But it upheld Knoxville's ability to acquire and operate a distribution system. *Id.* at 53. Following the decision, the utility agreed to sell its facilities to TVA and Knoxville. *See* TVA, THE COST OF DISTRIBUTING POWER 10 (1939), https://hdl.handle.net/2027/uiug.30112066401826; *Ratify Sale to Knoxville*, N.Y. TIMES (July 13, 1938), https://nyti.ms/3zrRlNO.

93. *See, e.g.*, *Contract between TVA and City of Athens, Tenn.* §§ 1-2 (May 15, 1939), *in* 1939 ANNUAL REPORT, *supra* note 87, at 163 [hereinafter Athens Contract]; *Contract between TVA and Blue Ridge Electric Membership Corp.* §§ 1-2 (Dec. 12, 1938), *in* 1939 ANNUAL REPORT, *supra* note 87, at 190 [hereinafter Blue Ridge Contract]. If the power needs of the municipality increased by a defined demand threshold, TVA would be obligated to meet the excess demand—provided it had power available, and certain notice requirements were met. *See, e.g.*, Athens Contract § 2, *supra* note 93 (3,300 kilowatt threshold); Blue Ridge Contract § 2, *supra* note 93 (300 kilowatt threshold). An appendix to TVA's 1939 Annual Report contains the 110 contracts between TVA and municipal and cooperative utilities that TVA had executed by that year.

94. The exception was a contract with Bells Light & Power, a privately-owned utility serving Bells, Tennessee. This contract allowed for termination by TVA with five years' notice, as required by section 10 of the TVA Act. *See Contract between TVA and Bells Light & Water Co.* § 9 (Feb. 1, 1939), *in* 1939 ANNUAL REPORT, *supra* note 87, at 179; *see also* 16 U.S.C. § 831i.

95. *See, e.g.*, Athens Contract § 4–5, Terms and Conditions § 15, *supra* note 93; Blue Ridge Contract § 4, Terms and Conditions § 14, *supra* note 93.

96. *See, e.g.*, Athens Contract, Schedule of Terms and Conditions § 13, *supra* note 90; Blue Ridge Contract, Schedule of Terms and Conditions § 12, *supra* note 90.

97. TVA, ANNUAL REPORT OF THE TENNESSEE VALLEY AUTHORITY FOR THE FISCAL YEAR ENDED JUNE 30, 1951, at 13 (1951).

It had chased private electric utilities out of Tennessee and secured for itself a monopoly territory in which to offload the power from its massive hydroelectric projects.[98] And it was building more transmission lines to reach more unserved rural customers. The all-requirements supply contract was a fundamental part of this story.

As TVA matured and its mission and finances evolved, so too did the all-requirements contract. By the late 1950s, TVA's original contracts had lapsed or were soon to lapse, and it began to renew its agreements with its distributors. Its second and third rounds of contracts (from the late 1950s/early 1960s, and late 1970s/early 1980s, respectively) looked similar to the original set, with the exception of two key changes that shifted the balance of power between the parties in favor of TVA.

First, they provided for termination. Starting ten years after the contract's effective date, either party could terminate the contract with four years' notice.[99] Second, should the distributor exercise its termination right, TVA was "under no obligation from the date of receipt of such notice [to terminate] to make or complete any additions to or changes in any transformation or transmission facilities for service" to the distributor, unless the distributor "agrees to reimburse TVA for its nonrecoverable costs in connection with the making or completion of such additions or changes."[100] The contracts still did not contain renewal provisions; TVA materials suggest that there was a practice of ad hoc renewal.[101] This was the state of the TVA all-requirements contract until the late 1980s.

C. 1949–1959: Congress Ends TVA Appropriations and Builds the TVA Fence

In the mid-twentieth century, TVA expanded its power capacity to meet the growing demand of its distribution customers and to power the war effort. This expansion triggered a political battle with threatened neighboring utilities, one that only ended (or, perhaps more accurately, went on an extended hiatus) in 1959 when TVA's power program became independent of congressional appropriations and Congress drew a "fence" outside of which TVA could not serve. These two changes arguably created the most important constraints within which TVA operates today and explain much about its 2019 evergreen all-requirements contract.

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98. *See* Kitchens, *supra* note 58, at 398.

99. *See, e.g.*, *Power Contract between TVA and City of Oxford, Miss.* (1970) [hereinafter Oxford Contract], *in* TVA, ANNUAL REPORT OF THE TENNESSEE VALLEY AUTHORITY FOR THE FISCAL YEAR ENDED JUNE 30, 1970, at A71 (1970) [hereinafter 1970 ANNUAL REPORT]; *see also* 1960 ANNUAL REPORT, *supra* note 66, at 16.

100. *See, e.g.*, Oxford Contract, *supra* note 99; *see also* 4-County Elec. Power Ass'n v. TVA, 930 F. Supp. 1132, 1135 (S.D. Miss. 1996) (describing a supply contract between TVA and a Mississippi cooperative "executed October 31, 1978, for a twenty-year term" that "requires that TVA supply and 4-County purchase from TVA all of its power for distribution to 4-County's customers and authorized either party to terminate the contract on four years' notice to the other"). The *4-County* court describes these terms as "[l]ike each of the preceding contracts between the parties," *id.*, but that claim is not quite accurate. The parties' 1938 power supply contract did not provide for termination by either party, with or without notice. *See Contract between TVA and 4-County Electric Power Association* (1938), *in* 1939 ANNUAL REPORT, *supra* note 87, at 272-74 (1940).

101. In fiscal year 1960, 92 distributors had renewed their contracts for a second twenty-year term; only Memphis chose to (temporarily) "follow a different course and begin to provide its own power supply." 1960 ANNUAL REPORT, *supra* note 66, at 16.

Together, they made TVA existentially dependent upon the continued loyalty (voluntary or coerced) of its existing customers.

During World War II, TVA scaled up its electric generation capacity. By 1945, its system consisted of twenty-six hydroelectric dams, producing twelve billion kilowatt hours of energy per year. About 75% of this output went to the war effort.[102]

In the aftermath of the war, TVA conceived of itself as a power company and took steps to further that mission. As Erwin Hargrove explains, "[i]t became TVA doctrine that the supply of energy was the [principal] stimulus for demand and that therefore TVA must always stay ahead of existing demand . . . in order to meet future needs."[103] Pursuing this vision in the late 1940s and early 1950s, TVA initiated a strategy of further expanding its generating capacity. President Truman and the Democratic majority in Congress approved appropriations for nine new TVA coal plants starting in 1949 and continuing in the 1950s.[104]

This course of action created "prolonged partisan political struggle" in Congress.[105] Investor-owned utilities in the Southeast saw TVA's growing capacity and feared government-backed competition in their service territories.[106] President Eisenhower was skeptical of the entire TVA project; he felt that federal appropriations meant "the nation's taxpayers would be forever committed to providing cheap power for the people in the TVA region," and "justice to other regions requires some kind of adjustment."[107] In the face of this contestation and uncertainty, TVA began to seek independence from congressional appropriations.[108]

Congress resolved this conflict in 1959 by ceasing appropriations to TVA's power program and authorizing TVA to issue bonds to fund the program, up to a maximum debt limit of $750 million.[109] Principal and interest on the bonds were to be repaid solely with revenue from power sales.[110] The legislation also provided

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102. HARGROVE, *supra* note 16, at 60; PRITCHETT, *supra* note 11, at 38–41.

103. HARGROVE, *supra* note 16, at 127.

104. *Id.* at 126. *See also Coal*, TVA, https://www.tva.com/energy/our-power-system/coal; TVA, AGING COAL FLEET EVALUATION 10 (2021), https://www.tva.com/environment/environmental-stewardship/environmental-reviews/nepa-detail/cumberland-fossil-plant-retirement (select "Aging Coal Fleet Evaluation" under "Related Documents").

105. HARGROVE, *supra* note 16, at 125.

106. Wellington Wright, *TVA Not Interested in Expansion, Clapp Says*, ATLANTA CONST. (Mar. 8, 1949), available at ProQuest Historical Newspapers: The Atlanta Constitution (1946-1984).

107. HARGROVE, *supra* note 16, at 142. He also accused TVA of "creeping socialism." *Id.* at 141.

108. *See* Hardin v. Ky. Utils. Co., 390 U.S. 1, 6-7 (1968).

109. Pub. L. No. 86-137, 73 Stat. 280 (1959) (codified as amended at 16 U.S.C. § 831n-4). As passed by Congress, the legislation gave Congress authority to veto TVA's new construction plans. To convince President Eisenhower to sign the bill into law, TVA's Chairman promised him that the House and Senate would immediately pass a new bill striking this provision. *See* Richard E. Mooney, *Eisenhower Signs T.V.A. Bond Bill; Acts After Congress Pledges Deletion of Clause Held Threat to His Powers*, N.Y. TIMES (Aug. 7, 1959), https://www.nytimes.com/1959/08/07/archives/eisenhower-signs-t-v-a-bond-bill-acts-after-congress-pledges.html; Pub. Law No. 86-157, 73 Stat. 338 (1959). The amendments also continued the existing requirement that TVA make installment payments to the Treasury reimbursing it for previous appropriations. *See* Letter from Elmer B. Staats, U.S. Comptroller General, to Joe L. Evins, U.S. Congressman (Apr. 27, 1973), https://www.gao.gov/assets/b-114850-096389.pdf.

110. Pub. L. No. 86-137, 73 Stat. at 281.

that "[b]onds issued by the Corporation hereunder shall not be obligations of, nor shall payment of the principal thereof or interest thereon be guaranteed by, the United States."[111]

In exchange for its financial independence, section 15d(a) of the amendments prohibited TVA from making "contracts for the sale or delivery of power which would have the effect of making the Corporation or its distributors, directly or indirectly, a source of power supply outside the area for which [they] were the primary source of power supply on July 1, 1957."[112] It thus restricted TVA from serving new distribution utility customers outside of its existing footprint, creating TVA's "Fence."[113] The purpose of this provision was to end franchise competition between private utilities and TVA.[114]

The 1959 legislation sheltered TVA from politics and the specter of privatization, at least temporarily, at the expense of two new, fundamental constraints the presence of which helps to explain TVA's doubling-down on control over customers and sustained resistance to competition and open access. First, TVA would be funded solely through issuance of debt, paid off by revenues from sales to distribution utilities. While this arrangement would make TVA independent of the annual appropriations process, it would still require Congress to raise TVA's debt ceiling and tied its financial fate and capacity for expansion to its ability to generate power revenues.[115] Second, TVA was forbidden from expanding its customer base outside of its existing service territory. Congress thus tied TVA's ability to survive to its ability to maintain a sufficient customer base, while drawing for TVA what it had, until then, lacked: a circumscribed service territory.

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111. *Id.* at 282 (codified as amended at 16 U.S.C. § 831n-4(b)). In spite of this, TVA benefits from its federal affiliation. *See, e.g.*, *Moody's assigns a Aaa rating to TVA's note offering*, MOODY'S INVESTOR SERV. (Mar. 27, 2023), https://www.moodys.com/research/Moodys-assigns-a-Aaa-rating-to-Rating-Action--PR_475274 ("TVA's Aaa rating . . . incorporates a one-notch uplift to reflect a high probability of extraordinary support from the Government of United States of America.").

112. *Id.* at 280–281 (adding TVA Act § 15d) (codified as amended at 16 U.S.C. § 831n-4(a)).

113. *The Great Compromise*, TVA, https://www.tva.com/about-tva/our-history/tva-heritage/the-great-compromise. Hargrove describes a conversation between President Eisenhower and the TVA Board during negotiations to pass the bill in which "Eisenhower broke in irritably to say that he wanted to sign and that the private utilities wanted him to do so. He said he was receiving calls from their presidents at night and that 'they would give me a golf course in Georgia if I would sign it.'" HARGROVE, *supra* note 16, at 152.

In *Hardin v. Kentucky Utilities Co.*, 390 U.S. 1 (1968), the Supreme Court held that it would defer to TVA's determination of what constitutes an "area," so long as it found the determination had "reasonable support in relation to the statutory purpose of controlling, but not altogether prohibiting, territorial expansion." *Id.* at 9.

114. *See Hardin*, 390 U.S. at 6-7.

115. In 1999, Congress ended appropriations for TVA's non-power programs. TVA, 2001 ANNUAL REPORT 27 (2001), https://web.archive.org/web/20130411193257/http://www.tva.com/finance/reports/pdf/fy2001ar.pdf [hereinafter 2001 ANNUAL REPORT]. This move was highly contested. Members of Congress from non-TVA states saw appropriations for TVA development programs as unfair subsidies. Other IOUs in the Southeast, which formed groups called "TVA Watch" and "TVA Reform Alliance," opposed appropriations, as well, because forcing TVA to pay for non-power programs with power program revenues would increase its rates, thus reducing downward pressure on IOU rates. Members from TVA states opposed ending appropriations. *See The Future of the Tennessee Valley Authority and its Non-Power Programs: Hearing before the Subcomm. on Water Res. & Env't of the H. Comm. on Transport. & Infrastructur*e, 105th Cong. (1997), http://commdocs.house.gov/committees/Trans/hpw105-27.000/hpw105-27_0f.htm.

D. 1960s–1990s: TVA Takes on Debt and Raises Rates

In the second half of the twentieth century, TVA racked up debt expanding its generating capacity and raised rates. This dynamic introduced tension into TVA's relations with its distribution utility customers.

In 1966, TVA initiated a program of nuclear power plant construction. Between 1950 and 1960, residential electricity demand in TVA's service territory had increased fourfold. TVA projected another doubling between 1960 and 1968,[116] as well as continued demand from the Vietnam War effort.[117] By this point, TVA already operated a large generation portfolio, including fourteen gigawatts of coal-fired capacity (eleven plants)[118] and four gigawatts of hydroelectric capacity (forty-seven dams).[119] But to meet the expected doubling of demand, TVA changed gears. Nuclear power was particularly attractive to TVA (and the rest of the electric power industry) because it provided an opportunity to hedge against the price of coal, it was (in the normal course) less polluting than coal, and nuclear plants were seen as less costly to construct than coal plants.[120] Thus, TVA set out to expand its capacity and achieve a power mix of approximately 50% nuclear, 20% fossil fuels, and 30% hydroelectric.[121] It announced plans to build seven nuclear power plants, consisting of seventeen individual reactors with approximately nineteen gigawatts of generating capacity.[122]

To fund this ambitious construction project, TVA issued debt. Congress continuously raised its statutory debt limit—without much scrutiny into the prudence of the nuclear program or responsiveness to concerns of stakeholders that TVA should invest in energy efficiency and renewable energy instead of central power plant buildout.[123] In 1966, Congress raised TVA's debt limit from $750 million to $1.75 billion. In 1970, it was increased again to $3.5 billion; in 1976, to $15 billion; and finally, in 1979, to $30 billion.[124] Indeed, by late 1980, TVA debt had

116. Will Davis, *TVA Prepares to Write Final Nuclear Chapters*, NUCLEAR NEWSWIRE (Apr. 17, 2015), https://www.ans.org/news/article-1686/tva-prepares-to-write-final-nuclear-chapters/#sthash.y8TgXNQ0.dpbs.

117. HARGROVE, *supra* note 16, at 186.

118. Davis, *supra* note 116; *see also Coal*, TVA, https://www.tva.com/energy/our-power-system/coal.

119. Davis, *supra* note 116.

120. HARGROVE, *supra* note 16, at 185–86.

121. HARGROVE, *supra* note 16, at 185.

122. Davis, *supra* note 116. This phenomenon—projections of rapidly escalating demand, met with calls to for a large buildout of nuclear power infrastructure—may resonate with modern electric sector observers.

123. *See Increasing the Tennessee Valley Authority Bond Ceiling*: *Hearing before the Sen. Comm. on Env't & Pub. Works*, 96th Cong. 33-38 (1979) (testimony of Dan Feather and Louise Gorenflo, Tennessee Valley Energy Coalition) ("[O]n the issue of the debt ceiling that there has been an inadequate public participation in this in the valley. There has been no public hearing, no public forum. We are going to be the ones who are stuck with the bill.").

124. HARGROVE, *supra* note 16, at 185, 188, 223.

reached $17 billion.[125] Its debt peaked in 1997 at $27.4 billion[126] before lowering gradually to $23.6 billion in 2010[127] and $19.5 billion today.[128]

Unfortunately, TVA's nuclear program was plagued with difficulties. Most fundamentally, TVA's expectations for ever-increasing demand proved incorrect. The 1970s energy crisis reduced electricity demand nationwide.[129] In a familiar problem, TVA would have no outlet for its increased capacity. Additionally, its projects experienced safety issues,[130] regulatory hurdles, and cost overruns.[131] Inflation in the 1970s imperiled power plant construction across the country.[132] In response, TVA mothballed most of its planned nuclear construction, but not before expending hundreds of millions of dollars in the construction process.[133]

Because TVA was newly freed from the shackles of federal appropriations and because it could not sell *more* power, TVA increased its electricity rates to raise revenue necessary to pay off its mounting debt. In 1967, it increased residential rates for the first time,[134] citing inflation.[135] In 1970, it raised rates again—

125. HARGROVE, *supra* note 16, at 225.

126. US. GOV'T ACCOUNTABILITY OFFICE, GAO-06-810, TENNESSEE VALLEY AUTHORITY: PLANS TO REDUCE DEBT WHILE MEETING DEMAND FOR POWER 10 (2006), https://www.gao.gov/products/gao-06-810.

127. TVA, ANNUAL REPORT (FORM 10-K) 56 (Nov. 19, 2010), https://tva.q4ir.com/financial-information/sec-filings/sec-filings-details/default.aspx?FilingId=7570042.

128. TVA, ANNUAL REPORT (FORM 10-K) 45 (Nov. 14, 2023), https://tva.q4ir.com/financial-information/sec-filings/sec-filings-details/default.aspx?FilingId=17052755.

129. HARGROVE, *supra* note 16, at 189.

130. *See* HIRSCH, *supra* note 32, at 66.

131. By 1977, the costs of building Browns Ferry and Sequoyah reached tripled their estimates; Watts Bar and Bellefonte doubled. *See* HARGROVE, *supra* note 16, at 189.

132. *Id.* at 187-89.

133. Caroline Payton, *Nuclear Ghosts and the Atomic Landscape of the American South*, ENV'T & SOC'Y PORTAL (Oct. 2015), https://www.environmentandsociety.org/arcadia/nuclear-ghosts-and-atomic-landscape-american-south. The Browns Ferry project was completed in 1974, three years later than planned. Sequoyah was completed by 1982, eight years late. Watts Bar's first unit was completed in 1996, compared to a 1977 planned deadline; its second unit was completed in 2016. *See Watts Bar Unit 2 Complete and Commercial*, TVA (Oct. 19, 2016), https://www.tva.com/newsroom/watts-bar-2-project. Three plants (Hartsville, Phipps Bend, and Yellow Creek) were cancelled by 1984, some while construction was underway. And after being idled in 1988, restarted in 1993, cancelled in 2006, and revived in 2009, the Bellefonte project was finally cancelled in 2021. *See* Dave Flessner, *The end of an era: TVA gives up construction permit for Bellefonte nuclear plant after 47 years*, CHATTANOOGA TIMES FREE PRESS (Sept. 20, 2021) https://www.timesfreepress.com/news/2021/sep/17/end-eratvgives-constructipermit-bellefonte-nu/; Rod Walton, *TVA withdraws construction permit for abandoned Bellefonte nuclear project after judge nixes sale to private group*, POWER ENG'G (Sept. 17, 2021), https://www.power-eng.com/nuclear/tva-withdraws-construction-permit-for-abandoned-bellefonte-nuclear-project-after-judge-nixes-sale-to-private-group/.

134. This was not TVA's first rate increase for non-residential customers. *See* John N. Popham, *T.V.A. to Increase Rate to Big Users*, N.Y. TIMES (June 26, 1951), https://nyti.ms/42TjdIm.

135. HARGROVE, *supra* note 16, at 187. This rate change "contained an automatic annual adjustment to reflect changes in the cost to TVA of money and fuel," the first escalation under which occurred in August 1969. *See* 1970 ANNUAL REPORT, *supra* note 99, at 33.

this time by 23%—citing rising costs of coal and interest rates.[136] In 1972, it increased rates by 9%, citing coal costs and rising interest on its borrowing for its nuclear program.[137] Rates rose again at least seven times throughout the 1980s.[138] By-and-large, TVA attributed the increases to the nuclear program,[139] though they also incorporated the costs of a 1980 consent decree between TVA and the Environmental Protection Agency addressing TVA's non-compliance with the Clean Air Act.[140]

It was during the buildout of TVA's ambitious nuclear program that two key moments in the development of TVA's all-requirements contract took place. As noted above, until the 1980s, TVA's all-requirements contracts with its distribution utilities had twenty-year terms and required four years' notice for termination. In 1989, faced with an imminent surplus of generating capacity, TVA began offering a "Growth Credit Program" to its distributors, intended to incentivize demand growth. For eight years, enrolled distributors would apply bill credits to the retail power bills of new industrial customers or existing industrial customers who increased their demand. TVA would reimburse the distributor 110% of the value of the credits allotted. In exchange for this attractive incentive, TVA extended participating distributors' termination notice requirement to ten years from four.[141] It also added an important new provision:

> [B]eginning on the tenth anniversary of [its] effective date, and on each subsequent anniversary thereof . . . this contract shall be extended automatically without further action of the parties for an additional 1-year renewal term beyond its then-existing time of expiration.[142]

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136. *See TVA to Raise Rates*, N.Y. TIMES (July 17, 197), https://nyti.ms/40MpjJj; *see also T.V.A. Chief Defends Plan to Increase Power Rates,* N.Y. TIMES (Aug. 2, 1970), https://nyti.ms/40QuBTz; 1970 ANNUAL REPORT, *supra* note 96, at 28.

137. *TVA Will Increase Rates by 9 Per Cent,* ATL. CONST. (Nov. 30, 1972), available at ProQuest Historical Newspapers: The Atlanta Constitution (1946-1984).

138. *See* Tom Madden, *TVA Nuclear Program Stirs Controversy*, L.A. TIMES (Oct. 19, 1980), available at ProQuest Historical Newspapers: Los Angeles Times (1923-1995); Rebecca Ferrar, *TVA to raise its rates by 9.95%*, KNOXVILLE NEWS-SENTINEL (Feb. 14, 2006), available at ProQuest Central: News Sentinel (1994-current).

139. Madden, *supra* note 138.

140. *See Increasing the Tennessee Valley Authority Bond Ceiling*: *Hearing before the Sen. Comm. on Env't & Pub. Works*, 96th Cong. 5-6 (1979) (statement of Sen. Muskie) ("For years TVA has been among the largest polluters in the nation. Their recalcitrance was an embarrassment to those of us who believe that the public mission of the agency demanded a broader, more progressive view of power production."). *See also* TVA, ANNUAL REPORT OF THE TENNESSEE VALLEY AUTHORITY FOR THE FISCAL YEAR ENDED SEPTEMBER 30, 1981, VOL. II-APPENDIXES 12 (1981).

141. *4-County Elec. Power Ass'n*, 930 F. Supp. at 1135-36. *See, e.g.*, Letter from G. Douglas Carver, Manager, Distributor Marketing and Services, TVA, to Dr. James Edward Jones, Chairman, Board of Public Utilities, Clinton, Tenn. (Oct. 1, 1989) (on file with author) (memorializing an amendment to Clinton's power supply contract providing for its participation in the Growth Credit Program); Letter from G. Douglas Carver to Joe F. Lester, Chairman, Board of Electric Light & Waterworks Comm'rs, Morristown, Tenn. (Oct. 1, 1989) (on file with author) (memorializing an amendment to Morristown's power supply contract providing for its participation in the Growth Credit Program).

142. *See, e.g.*, Letter from G. Douglas Carver, Manager, Distributor Marketing and Services, TVA, to Dr. James Edward Jones, Chairman, Board of Public Utilities, Clinton, Tenn., *supra* note 141; Letter from G. Douglas

For the first time, TVA contracts contained an automatic annual one-year term extension. Each year that the contract is in place, its termination date extends by an additional year.

In 1994, TVA established an "Enhanced Growth Credit Program," which was "similar in form and purpose" to the 1989 program, but was unavailable to distributors that "did not have, and maintain, a 10-year contractual commitment" with TVA—meaning a distributor that had exercised its ten-year termination notification right was ineligible for the enhanced incentive program.[143] 147 of TVA's then-160 distributors agreed to participate in the Enhanced Growth Credit Program.[144] After all, in the midst of a period of frequent rate increases, any distributor that declined the industrial rate discount in favor of retaining its four-year termination period or that exercised its termination right risked losing cost-conscious industry and subjecting residents and businesses to markedly higher electric rates than their neighbors. This was apparently the first example of a practice TVA came to use again in 2019.

By the mid-1990s, most of TVA's all-requirements power supply contracts contained twenty-year terms, annual one-year term extensions, and ten-year termination notice requirements.

E. 1980s–2000s: TVA Survives Electric Sector Restructuring

At the end of the twentieth century, a series of watershed reforms aimed at introducing competition to the electric sector left TVA mostly unscathed. The twentieth-century electric utility sector was characterized by IOU dominance over generation, transmission, and distribution.[145] Starting in the 1970s, however, the energy crisis and rapidly increasing electricity costs put pressure on utilities[146] and spurred industrial customers to build (or threaten to build) their own sources of generation.[147] In the 1990s and 2000s, Congress, FERC, and the states responded to these conditions with a wave of competition-oriented reforms to electric sector regulation. This surge of activity included the Energy Policy Act of 2005, which gave federal regulators newfound authority to order TVA to transmit power at rates and pursuant to terms and conditions that were non-discriminatory and "comparable to those that . . . it charges itself." This law posed a potential challenge to TVA's longstanding policy of refusing to transmit non-TVA power to TVA customers within the Fence.

Carver, to Joe F. Lester, Chairman, Board of Electric Light & Waterworks Comm'rs, Morristown, Tenn., *supra* note 141.

143. *4-County Elec. Power Ass'n*, 930 F. Supp. at 1136.

144. *Id.* at 1138. The program was terminated in 2010. *See* Letter from Kenneth R. Breeden, Executive Vice President, Customer Relations, TVA, to Herbert Ward, Chairman, Clinton Utilities Board (Aug. 20, 2010) (on file with author).

145. *See* Ari Peskoe, *Is the Utility Transmission Syndicate Forever?*, 42 ENERGY L.J. 1, 4–6, 11–18 (2021); Jeffrey D. Watkiss & Douglas W. Smith, *The Energy Policy Act of 1992: A Watershed for Competition in the Wholesale Power Market*, 10 YALE J. REGUL. 447, 451 (1993).

146. HIRSCH, *supra* note 32, at 68–69.

147. Peskoe, *supra* note 145, at 19.

1. Reform at FERC and TVA's Transmission Service Guidelines

Starting in the late 1970s and continuing into the 1990s, policymakers in Congress and at FERC designed and implemented a series of landmark reforms intended to weaken IOU control over the electric power industry in order to facilitate competition.[148] In 1996, FERC issued Order No. 888, the first in a line of "open-access" orders. Order No. 888 restructured wholesale transmission service by requiring IOUs under its jurisdiction to provide comparable, open-access transmission service at non-discriminatory rates to all customers. This ended each utility's *de facto* preference for its own power plants. If non-FERC-jurisdictional utilities wanted to take service from jurisdictional IOUs' open-access tariffs, they would have to adopt functionally equivalent terms—a policy called "reciprocity."[149] TVA was a non-jurisdictional utility within the meaning of Order No. 888.[150]

Unlike other non-jurisdictional federal power marketing administrations and state-owned utilities, TVA did not file a voluntary open-access tariff, and never has.[151] Instead, it adopted its first set of Transmission Service Guidelines. The Guidelines defined an "eligible customer" for TVA transmission service to exclude any entity that FERC "is prohibited from ordering by Section[212] of the Federal Power Act"—*i.e.*, a customer seeking to transmit power to be consumed inside the TVA Fence.[152] The Guidelines confirmed TVA's policy of refusing to transmit third-party power for consumption within its territory, which is inconsistent with Order No. 888's requirements for jurisdictional utilities. That policy is still in place today.[153]

148. HIRSCH, *supra* note 32, at 73, 86–88

149. *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. & Transmitting Utils.*, Order No. 888, FERC STATS. & REGS. ¶ 31,036, at 31,755-31,763 (1996) (cross-referenced at 75 FERC ¶ 61,080) (1996); *see* Peskoe, *supra* note 145, at 22.

150. FERC issued Order No. 888 pursuant to its authority under sections 205 and 206 of the Federal Power Act ("FPA") to remedy undue discrimination in interstate transmission service. Order No. 888, FERC STATS. & REGS. ¶ 31,036 at 31,634-31,635; *see* 16 U.S.C. §§ 824d–824e. This authority extends only to transmission service by "public utilities," 16 U.S.C. §§ 824d(b), 824e(a), a group defined to exclude TVA, *id.* § 824(e). *See also* Order No. 888, FERC STATS. & REGS. ¶ 31,036 at 31,858 ("TVA is not a public utility under section 201(e) of the FPA and, thus, is not required to file a non-discriminatory open access transmission tariff under this Rule.").

151. Each federal power marketing administrations has sought to develop and file acceptable reciprocity tariff—not all successfully, in their most recent forms. *See W. Area Power Admin.*, 182 FERC ¶ 61,206 (2023) (granting in part the Western Area Power Administration's petition for a declaratory order requesting that the Commission qualify its tariff as an acceptable reciprocity tariff); *Bonneville Power Admin.*, 145 FERC ¶ 61,150 (2013) (denying Bonneville's petition for a declaratory order requesting that the Commission qualify its tariff as an acceptable reciprocity tariff); *Sw. Power Admin.*, 130 FERC ¶ 61,224 (2010) (finding that the Southwestern Power Administration's tariff qualifies as an acceptable reciprocity tariff).

152. *See* TVA, TRANSMISSION SERVICE GUIDELINES: FY 2021 EDITION § 1.15 (2020), http://www.oatioasis.com/woa/docs/TVA/TVAdocs/TSG%20FY2021.pdf; *infra* notes 275-76 and accompanying text (describing TVA's interpretation of the FPA).

153. TVA, TRANSMISSION SERVICE GUIDELINES: FY2023 EDITION § 1.15 (2022), http://www.oatioasis.com/woa/docs/TVA/TVAdocs/TSG%20FY2023.pdf.

2. Reform in Congress

Though TVA was unaffected by FERC's reforms in the 1990s, distinct reform efforts took place in Congress. Throughout the 1990s, Congress debated a number of TVA reform proposals as part of its broader restructuring efforts. Some of TVA's largest customers, including Knoxville and Memphis, supported proposals that involved dismantling the TVA Fence, thereby allowing TVA to compete for customers outside of its 1950s territory and opening TVA territory to competition from outsiders; restructuring contracts with distributors to allow for termination notice of only one or two years; and subjecting TVA to FERC rate regulation.[154] Others proposed stripping TVA of its power to set customers' retail rates and introducing mechanisms for contesting TVA's wholesale rates.[155] Even more dramatic suggestions included privatizing TVA altogether[156] or prohibiting TVA from building new plants.[157]

TVA saw the writing on the wall.[158] Some customers were able to take advantage of this political momentum to negotiate more favorable contracts with TVA.[159] Moreover, TVA endorsed a "consensus" position formulated with "the

154. Rebecca Farrar, *House eyes TVA's future: Deregulation timing debated*, KNOXVILLE NEWS-SENTINEL (Sept. 14, 1999), available at ProQuest Central: News Sentinel (1994-current).

155. *Id.*

156. *See, e.g.*, Adam Thierer, *A Five Point Checklist for Successful Electricity Deregulation Legislation*, HERITAGE FOUND. (Apr. 13, 1998), https://www.heritage.org/government-regulation/report/five-point-checklist-successful-electricity-deregulationlegislation.

157. *See, e.g.*, Farrar, *supra* note 159; Richard Powelson, *Bill would force TVA to sell nuclear, coal plants*, KNOXVILLE NEWS-SENTINEL (June 15, 2000), available at ProQuest Central: News Sentinel (1994-current) (describing a bill that would force TVA to sell its operating nuclear and coal plants). Unlike many members of TVA-state congressional delegations, Senator Mitch McConnell championed IOU efforts to weaken TVA. *See* Ken Silverstein, *The future of TVA*, UTIL. BUS. (Aug. 2000), available at ProQuest Central: Utility Business (1998-2002); TVA Distributor Self-Sufficiency Act of 2001, S. 608, 107th Cong. (2001), https://www.congress.gov/bill/107th-congress/senate-bill/608?s=1&r=16. Southeastern IOUs eagerly supported bringing competition to TVA while stridently (and successfully) resisting restructuring efforts in their own territories. *See* Harrison & Welton, *supra* note 9.

158. *See* TVA, 2000 ANNUAL REPORT 19 (2000) [hereinafter 2000 ANNUAL REPORT]; *The Future of the Tennessee Valley Authority and its Non-Power Programs*: *Hearing before the Subcomm. on Water Res. & Env't of the H. Comm. on Transport. & Infrastructure*, 105th Cong. (1997), http://commdocs.house.gov/committees/Trans/hpw105-27.000/hpw105-27_0f.htm (testimony of TVA Chairman Craven Crowell).

159. John J. Fialka, *New Deal Undone: Using Savvy Tactics, Bristol, Va., Unplugs From a Federal Utility*, WALL ST. J. (May 27, 1997) ("In recent months, the TVA's five biggest customers . . . have banded together. [T]he cities are . . . studying the law, hiring consultants and getting bids from outside suppliers. [The] president of the Nashville Electric Service[] points out the Big Five consortium constitutes 30% of the TVA's market and carries considerable political clout in Congress. As Congress focuses on the electricity industry, he notes, there will be proposals to privatize the giant agency, or to carve it up. If the TVA allows more 'flexibility' in its prices and contracts, he suggests, 'we have the ability to help them, politically.' Without such concessions, 'we're just going to have a knock-down, drag-out battle. . . . That will probably harm both of us.'"). Memphis threatened to leave TVA in the early 2000s. *See* Ed Hicks, *As deregulation looms, MLGW ponders generating own power*, MEMPHIS BUS. J. (2000), available at ProQuest Central: Memphis Business Journal (1999-2004). It ultimately decided to stay, but negotiated a favorable contract. The Kentucky cities of Hopkinsville, Glasgow, and Bowling Green all gave notice of termination in the early 2000s, later rescinded. When Bristol, Virginia gave its notice of termination, TVA allegedly retaliated. *See The Application of the Antitrust Laws to the Tennessee Valley Authority and the Federal Power Marketing Administrations*: *Hearing Before the Comm. on Judiciary*, 105th Cong. (Oct. 22, 1997) (statement of Sen. Boucher) (describing retaliatory tactics deployed by TVA after Bristol

vast majority of [its] distributors" and a coalition of industrial customers. This group proposed: (1) permitting TVA to sell power outside the Fence; (2) permitting customers to buy power from other suppliers; (3) removing "statutory impediments" (though perhaps not TVA-imposed impediments) to other suppliers wheeling power into the Fence area; (4) renegotiating supply contracts and giving customers a statutory right to terminate with three years' notice; and (5) reducing TVA's regulatory oversight over its customers.[160]

In May 2000, three senators from TVA states introduced a bill containing the endorsed provisions.[161] In addition to dismantling the TVA Fence,[162] the bill would have directed TVA and its distributors to make "good faith efforts" to renegotiate their contracts.[163] If those efforts failed, distributors could terminate their relationship with TVA or opt for a partial requirements contract (with two to three years' notice).[164] TVA would be prohibited from unduly discriminating against a supplier that exercised its termination or partial requirements rights.[165] The bill would have subjected TVA to full FERC rate regulation[166] and eliminated TVA's authority to oversee and regulate its distributors' rates and practices.[167] Finally, it would have subjected TVA to federal antitrust law.[168] The bill failed to make any progress.

Ultimately, despite TVA's embrace of a reform proposal, congressional restructuring left TVA mostly untouched,[169] with one important exception. The Energy Policy Act of 2005 added section 211A to the Federal Power Act, giving FERC new authority to order certain utilities—including TVA—to provide open-

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gave notice of termination, including "scare tactics," "predatory pricing . . . by offering to sell TVA power to Bristol's largest customers for 2 percent less than whatever the price the City of Bristol could offer," and "pursu[ing] the City of Bristol for alleged stranded investments.").

160. 2000 ANNUAL REPORT, *supra* note 158, at 19. This consensus position was first adopted by TVA and its distributors in September 1999, and was reaffirmed in May 2000 with support of a coalition of industrial customers. *See* 2001 ANNUAL REPORT, *supra* note 115, at 27.

161. S. 2570, 106th Cong. (2000).

162. *Id.* § 2.

163. *Id.* § 5(a).

164. *Id.* § 5(b)–(c).

165. S. 2570 § 5(d); *see infra* Part IV (discussing discrimination allegations against TVA by 4-County Electric Power Association).

166. *Id.* §§ 6, 8.

167. *Id.* § 7.

168. *Id.* § 9. TVA is exempt from antitrust law. *See* McCarthy v. Middle Tenn. Elec. Membership Corp., 466 F.3d 399, 414 (6th Cir. 2006); *see also The Application of the Antitrust Laws to the Tennessee Valley Authority and the Federal Power Marketing Administrations*: *Hearing before the Comm. on Judiciary*, 105th Cong. (1997). By contrast, investor-owned utilities are subject to federal antitrust law. *See* Otter Tail Power Co. v. U. S., 410 U.S. 366, 373-74 (1973); Reiter, *supra* note 51, at 336 nn.8, 9.

169. The culmination of Congress's work was the Energy Policy Act of 2005. Pub. L. No. 109–58, 119 Stat. 594 (2005). That legislation repealed the Public Utilities Holding Company Act of 1935, thus "paving the way for a wave of utility mergers and perhaps ushering in a new era of IOU transmission dominance." Peskoe, *supra* note 145, at 63; *see also* Tyson Slocum, *The Failure of Electricity Deregulation: History, Status, and Needed Reforms*, at 5 (Mar. 2007), https://www.ftc.gov/sites/default/files/documents/public_events/Energy%20Markets%20in%20the%2021st%20Century:%20Competition%20Policy%20in%20Perspective/slocum_dereg.pdf.

access transmission service on non-discriminatory terms. This law challenged TVA's Transmission Service Guidelines.

Sections 210, 211, and 211A of the FPA. In 1978, Congress had enacted sections 210 and 211 of the FPA. Section 210 authorized FERC, upon application of "any electric utility," to order the physical interconnection of the transmission facilities of another electric utility with the applicant. Likewise, section 211 authorized FERC, upon application of "any electric utility," to order "transmitting utilities" to provide transmission service to the applying utility.[170] Because the FPA defines "electric utility" and "transmitting utility" to include TVA, sections 210 and 211 allow FERC to reach TVA, unlike most other provisions of the FPA.[171]

Section 210 chipped away at TVA's insulation from competition, though FERC's power to order TVA's interconnection with neighboring systems is inherently less potent than its power to order TVA to transmit power over its transmission system. In its *East Kentucky Power Cooperative* orders,[172] FERC acted under its section 210 authority to order TVA to interconnect with a neighboring generation & transmission ("G&T") cooperative's transmission system so that the cooperative could serve a departing TVA customer located at the edge of the TVA Fence. Importantly, the G&T competitor already had or would build transmission facilities to reach the customer and sought only interconnection service, not transmission service; FERC emphasized that interconnection was only necessary for "certain coordination services" from TVA.[173] Thus, although *East Kentucky Power Cooperative* demonstrates that FERC has meaningful authority to order TVA to interconnect (and provide related services) under section 210, that authority does not necessarily help customers reachable only through TVA transmission facilities.

Section 211, in contrast, posed a problem for TVA's maintenance of its generation and transmission monopoly. Section 211 conflicted with TVA's longstanding policy not to transmit power generated by third-parties for consumption within TVA's territory.[174] Were section 211 applicable to TVA, customers deep within the Fence could access outside sources of generation without building

170. FPA § 211, 16 U.S.C. § 824j(a).

171. 16 U.S.C. §§ 796(22), (23) (defining "electric utility" and "transmitting utility" to include TVA).

172. *See E. Ky. Power Cooperative*, 111 FERC ¶ 61,031 (2005) (proposed order); *E. Ky. Power Cooperative*, 114 FERC ¶ 61,035 (2006) (final order), *order denying reh'g*, 115 FERC ¶ 61,347 (2006); *E. Ky. Power Cooperative*, 121 FERC ¶ 61,255 (2007) (granting motion to terminate proceedings for mootness and denying TVA's request to vacate prior *East Kentucky* orders).

173. *See E. Ky. Power Cooperative*, 114 FERC ¶ 61,035 at P 35; *E. Ky. Power Cooperative*, 115 FERC ¶ 61,347 at PP 13-14. The departing customer, Warren Rural Electric Cooperative Corporation, ultimately decided to remain with TVA. *See E. Ky. Power Cooperative*, 121 FERC ¶ 61,255 (2007). But two other Kentucky distribution utilities (the municipal utilities of Paducah and Princeton) left TVA. *See* James Bruggers, *Bad bet traps Paducah in coal-fired nightmare*, COURIER J. (Feb. 13, 2015), https://www.courier-journal.com/story/tech/science/environment/2015/02/13/paducah-power-bets-coal-loses-prairie-state-energy-campus/23322435/.

174. TVA, TRANSMISSION SERVICE GUIDELINES: FY2023 EDITION § 1.15 (2022), http://www.oatioasis.com/woa/docs/TVA/TVAdocs/TSG%20FY2023.pdf.

duplicative transmission, creating potential competition for TVA's generation business.

In 1992, Congress solved this problem for TVA: section 211 orders had to "meet the requirements" of section 212, which Congress amended to provide at subsection (j) that FERC could not order TVA to provide transmission service to another utility if the power to be transmitted would be consumed within the TVA Fence.[175] Indeed, in 2002, the Commission found that section 212(j) prohibited it from ordering TVA to transmit power from a third-party supplier to an industrial customer inside the Fence.[176]

The Energy Policy Act of 2005 complicated TVA's happy state of affairs by adding section 211A to the FPA. This new section allowed FERC to order an "unregulated transmitting utility"—including TVA—"to provide transmission services . . . at rates that are comparable to those that the [utility] charges itself; and . . . on terms and conditions (not relating to rates) that are comparable to those under which the [utility] provides transmission services to itself and that are not unduly discriminatory or preferential."[177] The import of this provision for TVA—whether FERC would wield its new authority to chip away at TVA's total control over transmission service—remained unresolved until FERC's 2021 decision in *Athens Utilities Board v. TVA*,[178] discussed in detail below.

III. MODERN HISTORY OF TVA AND THE ALL-REQUIREMENTS CONTRACT

TVA today is in a position of near-insurmountable advantage over its customers. As discussed above, TVA has supplied electricity to distribution utilities through all-requirements contracts since the very beginning of its power program. By the end of the twentieth century, TVA's contracts still required customers to purchase all of their power requirements from TVA. During the twenty-year term of the contract, customers could not buy even a fraction of their power needs from non-TVA suppliers. They also could not build their own generation or permit end users to enjoy on-site (distributed) generation. Second, the contracts required ten years' notice prior to cancellation by either party. Third, the contract terms extended by one year annually. A utility manager had to anticipate whether, in ten years' time, the utility would want to leave TVA. And because the contracts continuously extended, only affirmative termination provided a potential opportunity for renegotiation or exit. Moreover, between receiving written notice of termination and the contract's effective termination date, TVA was not obligated to complete any additions or changes to its transmission facilities serving the utility unless it was reimbursed by the utility.

175. FPA § 212, 16 U.S.C. § 824k(j); *see* Fialka, *supra* note 159.

176. The supplier, Tennessee Power Company, asked FERC to order TVA to transmit the power under section 211 (relying on a claim that the industrial customer was not covered by the section 212(j) prohibition because TVA was not the "primary" supplier in the customer's area as of 1957, invoking a carveout from the 212(j) prohibition, *see infra* note 253). FERC denied the request, finding it was prohibited from issuing the requested order by section 212(j). *See Tenn. Power Co.*, 100 FERC ¶ 61,092, at PP 8-9 (2002).

177. FPA § 211A, 16 U.S.C. §§ 824j-1(a), (b).

178. 177 FERC ¶ 61,021, *order on reh'g*, 177 FERC ¶ 62,162 (2021), *order on reh'g*, 179 FERC ¶ 62,045 (2022); *see infra* Part IV.A.

Furthermore, under TVA's Transmission Service Guidelines, TVA refused to transmit power from suppliers outside the Fence to distribution utilities inside the Fence. Should a utility choose to leave TVA after the requisite ten-year notice period, it would be required to plan, permit, and build redundant transmission infrastructure to bring its new supplier's power to its distribution grid.

Yet another key moment in the development of the all-requirements contract took place in 2019, when TVA's Board of Directors adopted a resolution entitled "Long Term Partnership Option for Local Power Companies"[179] and thereby approved a new, considerably different power supply contract to be offered to its customers.[180] Aware of threats to its security and continuity—particularly, customer dissatisfaction with rising rates, resulting in potential for defection to distributed generation or competitive suppliers—TVA used its existing monopoly power and strategies familiar from its history to shepherd its customers into a maximally restrictive, long-term relationship. The 147 utilities that have signed the contract have ceded their one source of bargaining power vis-à-vis TVA—the threat of defection—and are handcuffed to a newly-emboldened TVA for the foreseeable future. But in turn, TVA garnered meaningful resistance from small and large customers.

A. Key Terms of the 2019 All-Requirements Contracts

The all-requirements contract approved by the TVA Board in August 2019 contained several categories of relevant provisions.

More stringent provisions governing term, termination, and extension. The 2019 contracts maintained the same term of twenty years. However, the amount of notice required for termination of the contract by either party was increased to twenty years. Additionally, the contract would "be extended automatically . . . for an additional 1-year renewal term beyond its then-existing time of expiration," starting "on the first anniversary of the effective date."[181]

Favorable rate provisions for utilities that do not exercise right to terminate. In a reprisal of the tactics employed in TVA's Growth Credit Program and Enhanced Growth Credit Program,[182] the 2019 contracts give distributors a 3.1% discount on their wholesale power costs (excluding fuel costs).[183] However, if a distributor gives TVA its twenty years' notice of termination, its discount is "reduced and phased out in 10 equal percentages over each of the following ten years" following the notice.[184]

179. *See* Complaint Ex. C, Protect our Aquifer v. TVA, 654 F. Supp. 3d 654 (W.D. Tenn. 2023) (No. 2:20-cv-02615-TLP-atc) (Minutes of Meeting of TVA Board of Directors, at 28) (Aug. 22, 2019) [hereinafter TVA August 2019 Board Meeting Minutes].

180. *See id.* Ex. B (TVA's Long Term Agreement Form) [hereinafter 2019 Long-Term Agreement].

181. *Id.* § 1.

182. *See supra* Part II.D.

183. 2019 Long Term Agreement, *supra* note 180, § 2(a).

184. *Id.* § 2(c).

The contracts also constrain TVA somewhat from increasing wholesale rates. If TVA raises its non-fuel rates either (1) "by more than 10% . . . during any consecutive five-fiscal-year period . . . within 20 years of the Effective Date, compared to the [rates] applied as of the end of the TVA fiscal year immediately preceding that consecutive five-year period" or (2) by more than 5% above 2019 rates before September 30, 2024; and (3) if the parties engage in good-faith contract renegotiations and cannot come to an agreement, then the contract termination period is reduced to ten years.[185]

Other benefits for utilities that do not exercise right to terminate. The 2019 contract provides that if "TVA elects, in its sole discretion," to offer additional benefits "to other distributors of TVA power because they have executed a similar long-term agreement" then "Distributor will [also] receive the additional benefits."[186] If a utility exercises its right to terminate the contract, however, it loses this right. Thus, for the following twenty years, the departing customer must continue to buy its power from TVA—but any discounts or incentives that TVA chooses to offer to other utility customers will not be offered to the departing utility.

Power supply flexibility for utilities that do not exercise right to terminate. The 2019 contract originally provided that "TVA commits to collaborating with Distributor . . . to develop and provide enhanced power supply flexibility, with mutually agreed-upon pricing structures, for 3-5% of Distributor's energy [by] October 1, 2021." If the parties cannot agree on an arrangement, the distributor "may elect . . . to terminate this Agreement," by "deliver[ing] a notice of termination to TVA under the 'Term of Contract' section of the Power Contract."[187] This agreement to collaborate was only available to non-terminating utilities. In February 2020, responding to customer pressure, the TVA Board accelerated the availability of the 5% self-generation cap from October 2021 to June 2020.[188]

Improvements during termination period. As in previous contracts, upon notice of termination, "TVA will have no obligation to make or complete any additions to or changes in any transformation or transmission facilities for service to [the distributor], unless [the distributor] . . . agrees to reimburse TVA for its non-recoverable costs" for the changes.[189]

Remedies for default. If a distributor consumes power not supplied by TVA without TVA's consent, it has defaulted and "must pay TVA an amount equal to TVA's losses of revenue and load served, and for all actual expenses incurred by

185. *Id.* § 2(a). It is somewhat ambiguous from the terms of the contract whether in this case a ten-year terminating utility would be entitled to a credit phase-out.

186. *Id.* § 2(d).

187. 2019 Long Term Agreement, *supra* note 180, § 2(e).

188. Press Release, TVA, TVA Green Lights Local Power Company Electric Generation (June 22, 2020), https://www.tva.com/newsroom/press-releases/tva-green-lights-local-power-company-electric-generation; Press Release, TVA, TVA Board Adopts Principles of Public Power Flexibility (Feb. 13, 2020), https://www.tva.com/Newsroom/Press-Releases/TVA-Board-Adopts-Principles-of-Public-Power-Flexibility.

189. *Id.* § 1.

TVA and resulting from" the default "over the remaining term of the Power Contract."[190]

B. Rationales for the 2019 All-Requirements Contract

The TVA Board's "Long Term Partnership Option for Local Power Companies" resolution explained that "[a]dding certain defaults and remedies provisions to the wholesale power contract will strengthen the long-term commitments made by the parties."[191] TVA was explicit about the benefits it expected from keeping distributors tightly bound to it over the long term. The concerns that drove the adoption of the contract tie back to the issues TVA faced throughout the twentieth century.

Demand certainty. First, longer-term contracts would increase certainty about demand. TVA's failure to accurately project future demand was one of the downfalls of its 1970s nuclear program (in stark contrast to the success of its "low cost, high usage" strategy in the 1930s and 1940s). Two modern conditions have only increased the risk to TVA of load defection and uncertainty: the rise of competitive markets for generation—which increases distribution utilities' ability to procure competitively priced wholesale power from suppliers other than TVA—and the prevalence and attractiveness of cheap, clean distributed generation, which decreases the amount of power a distribution utility needs to procure from *any* supplier.

TVA's 2019 Integrated Resource Plan ("IRP") captures these concerns in a section discussing potential sources of inaccuracy in TVA's forecasted demand between 2019 and 2038.[192] The 2019 IRP highlights two major threats to the accuracy of TVA's demand forecasts: (1) "competitive pressures"—*i.e.,* distributors' and industrial customers' ability to cancel their contracts with TVA and switch to another supplier; and (2) the availability of inexpensive self-generation.[193] The longer-term contract—requiring a terminating customer to give twenty years' notice to terminate—obviates both of these concerns, because TVA's generation planning process occurs on a twenty-year time frame.[194] In other words, locking in customers to a guaranteed twenty-year term at the start of a twenty-year generation plan nullifies the main source of demand uncertainty

190. *Id.* §§ 3(b), (f).

191. TVA August 2019 Board Meeting Minutes, *supra* note 179, at 28.

192. TVA, 2019 INTEGRATED RESOURCE PLAN: VOL. I – FINAL RESOURCE PLAN (2019), https://www.tva.com/environment/environmental-stewardship/integrated-resource-plan [hereinafter TVA 2019 IRP].

193. TVA 2019 IRP, *supra* note 192, at 4-2. *See also* TVA, ANNUAL REPORT (FORM 10-K) 49 (2022), https://tva.q4ir.com/financial-information/sec-filings/sec-filings-details/default.aspx?FilingId=16202878 [hereinafter TVA 2022 10-K] ("As the amount of [distributed energy resources] grows on the TVA system, the need for TVA's traditional generation resources may be reduced. . . . If TVA were unable to compensate for the resulting decrease in demand for TVA electricity, TVA's cash flows, results of operations, and financial condition could be negatively impacted, likely resulting in higher rates and changes to TVA's operations.").

194. *See* TVA 2019 IRP, *supra* note 192, at ES-3, ES-4. *See also* EPA, STATE ENERGY AND ENVIRONMENT GUIDE TO ACTION: ELECTRICITY RESOURCE PLANNING & PROCUREMENT 7, 9 (2022), https://www.epa.gov/statelocalenergy/energy-and-environment-guide-action ("IRP planning horizons are typically 10–30 years, and the frequency of IRP updates are commonly 2–3 years.").

over that period, because no customer can leave without breaching the contract. The primary remaining sources of uncertainty are unplanned fluctuations in demand from increased or decreased household or industrial energy usage, whether due to changing economic activity or energy conservation[195] and efficiency measures. To that end, the Board resolution perhaps understated the matter when it said that "increasing the length of TVA's wholesale power contracts with its LPCs" would "provide more certainty in TVA's long-term generation and financial planning."[196]

Creditworthiness and financing. Second, longer-term contracts bolster TVA's financial condition and thus provide certainty that TVA can continue to take on new long-term debt, meet existing debt obligations, and maintain its creditworthiness. TVA relies exclusively on debt for its financing: unlike an IOU, it cannot raise equity.[197] TVA already has a large debt obligation to service—$19.5 billion—and intends to incur more debt in the coming years to finance new investments.[198] Years of rate increases, used to cut down its debt from a peak of $27.4 billion in 1997, have already caused great dissatisfaction—and risk of defection—among its customers.[199]

To achieve its financial goals, TVA must maintain creditworthiness (*i.e.*, its ability to attract lenders) despite the threat of customer defection. TVA and observers view long-term commitments from distributors as supporting creditworthiness because (1) the long-term commitments reduce the risk of decreased power revenues;[200] and (2) the long-term commitments secure TVA's ability to set and raise its rates as it wishes without imminent risk of losing frustrated customers.[201] For TVA, long-term contracts don't just guarantee energy sales: they guarantee

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195. In the 2019 IRP, TVA noted that the Tennessee Valley region's economy "tends to be more sensitive to economic conditions impacting the demand for manufactured goods," and that it expects such economic conditions to "slow the pace of demand increase for all goods and services, including power," during the tail end of the IRP period. *See* TVA 2019 IRP, *supra* note 192, at 4-2.

196. TVA August 2019 Board Meeting Minutes, *supra* note 179, at 28.

197. *See* 16 U.S.C. § 831n–4; *The Tennessee Valley Authority and Financial Disclosure: Hearing Before the S. Comm. on Banking, Housing and Urban Affairs*, 107th Cong. (2002) (statement of Alan L. Beller, Director, Division of Corporation Finance, SEC) (describing TVA's financing practices) [hereinafter Beller Testimony].

198. TVA 2019 IRP, *supra* note 192, at ES-3. Until 2005, TVA was exempt from federal securities laws, a gap that caused consternation given its extensive borrowing. *See* Beller Testimony, *supra* note 197. In December 2004, Congress added certain filing requirements for TVA. *See* Consolidated Appropriations Act, Pub. L. No. 108-447 § 604, 118 Stat. 2809, 3267 (2005) (codified at 15 U.S.C. § 78nn(a)).

199. *See, e.g.*, Press Release, Athens Utils. Bd., *supra* note 2.

200. *See* TVA 2022 10-K, *supra* note 193, at 46, 49 ("A significant portion of TVA's total operating revenues is concentrated in a small number of LPCs. . . . The loss of customers could have a material adverse effect on TVA's cash flows, results of operations, or financial condition, and could result in higher rates, especially because of the difficulty in replacing customers due to the fence. A significant loss of customers could also impact investor confidence, resulting in TVA paying higher rates on its securities.").

201. *See Moody's assigns a Aaa rating to TVA's note offering*, *supra* note 111 ("TVA's rating benefits from . . . the Board's statutory authority to set TVA's electric rates and long-term contractual arrangements with creditworthy counterparties which, among other things, provide TVA with regulatory control over their retail rates and fund transfers. These attributes, combined with TVA's size, scale, and economic importance within the Tennessee Valley, translate into a more predictable and stable financial profile relative to all other public power and investor-owned utilities.").

long-term control over wholesale and retail rates charged for those sales. TVA has 153 locked-in customers and unilateral authority to increase its prices—an authority that can be constrained only by goodwill, politics, or an act of Congress.

The Board resolution states that the 2019 contracts were expected to bolster TVA's financing capacity. Specifically, "increasing the length of TVA's wholesale power contracts" would "ensure that TVA has the revenue necessary to satisfy its long-term financial obligations as they come due."[202] Additionally, in its 2022–2026 financial plan, TVA states that the widespread adoption of the new contracts creates "better alignment of customer contract terms with TVA's overall financial obligations" and "clos[es] the gap between TVA's committed revenues and long-term obligations."[203]

Benefit sharing. Finally, TVA offers a third justification for the contracts: a rising tide lifts all boats. The Board Resolution states that the contracts will "help[] fulfill TVA's statutory obligation to sell power at rates as low as are feasible." It also states that "the financial benefits from [the] long-term contracts" would be "shared with [customers] that agree to extend the termination notice requirement to 20 years in the form of monthly bill credits equal to a percentage of the amount that distributors pay TVA through base rates that are subject to adjustment."[204]

C. Distribution Utilities React

TVA began offering the 2019 all-requirements contract to its distribution utilities before it received formal Board approval, [205] and many utilities signed immediately following the board meeting.[206] The TVA Board approved the contract form at its meeting on Thursday, August 22, 2019.[207] 131 utilities were signed on

202. TVA August 2019 Board Meeting Minutes, *supra* note 179, at 28.

203. TVA, STRATEGIC PLAN: FY 2022–2026, at 23 (2022), https://www.tva.com/about-tva/reports (available under "Additional Reports").

204. *Id. See also* Letter from Dan Pratt, Vice President for Customer Delivery, TVA, to Wes Kelley, President & CEO, Huntsville Utils., *in* Huntsville Utilities Electric Board Meeting 18 (Oct. 21, 2019), https://s3.documentcloud.org/documents/6659542/Huntsville-Utilities-Electric-Board-Package-Oct.pdf.

205. *See* Email from Jeff Lyash, CEO, TVA, to TVA Distrib. Util. Managers, *in* Emails Between Distribution Utility Managers 5 (Aug. 12, 2019), https://www.documentcloud.org/documents/6569887-Kelley08-16-19.html#document/p3/a543858.

206. *See* Email from Mark Iverson, Gen. Manager, Bowling Green Mun. Utils., to TVA Distrib. Util. Managers, *in* Emails Between Distribution Utility Managers 4 (Aug. 15, 2019), https://www.documentcloud.org/documents/6569887-Kelley08-16-19.html#document/p3/a543858 ("I'm understanding that a lot of LPCs are anxious to begin the program credits as soon as possible, and are ready to sign the [long-term partnership proposal] contract next week.").

207. *See* TVA August 2019 Board Meeting Minutes, *supra* note 179, at 1, 28-29. The City of LaFollette Board of Public Utilities, serving 22,000-plus electric customers in northeast Tennessee, signed its agreement that same day. Motion to Intervene and Answer in Opposition and Protest of the Coalition of LPCs to Complaint/Petition at 5, *Athens Utils. Bd.*, 177 FERC ¶ 61,021 (Feb. 22, 2021) (FERC Docket Nos. EL21-40, TX 21-1).

by October 2019.[208] By November 2022, TVA had executed the 2019 agreements with 147 customers.[209]

TVA's largest customers did not agree to TVA's new terms immediately. While Nashville Electric Services (409,000 electric customers, representing 8% of TVA's sales)[210] signed the agreement in September 2019,[211] Chattanooga Electric Power Board (186,000 customers), Huntsville Utilities (195,000 customers), and Knoxville Utilities Board (205,000 customers) signed on in January, February, and March 2020, respectively.[212]

The Memphis Light, Gas and Water Division (MLGW) (415,000 customers,[213] representing 9% of TVA's operating revenue[214]) did not agree to the new contract, instead maintaining its existing five-year evergreen contract[215] And initiating an integrated resource planning process to consider leaving TVA and instead procuring power from the Midcontinent Independent System Operator (MISO), the independent electric grid operator for the central United States.[216] MLGW is perhaps the utility with the most bargaining power over TVA, given

208. TVA, ANNUAL REPORT (FORM 10-K) 10 (2019), https://d18rn0p25nwr6d.cloudfront.net/CIK-0001376986/ef40623a-8d16-484b-8174-6399d80d74c0.html.

209. TVA 2022 10-K, *supra* note 193, at 11. *See also* Memorandum from Wes Kelley, President/CEO of Huntsville Utils., to Elec. Bd. of Huntsville Utils., *in* Huntsville Utilities Electric Board Meeting 14 (Oct. 15, 2019) ("[T]he agreement states that if TVA provides additional benefits to utilities with 'similar long-term agreements,' those who already signed will have the option to enjoy those benefits. I believe a good number of those that executed the agreement 'as is' did so knowing the door was open for others to improve the agreement. Of course, this tactic only works if some utilities forego the immediate bill credits and push for changes.").

210. Jeffrey M. Panger, *Tennessee Valley Authority In Review: How the TVA's Relationship With Local Power Companies Is Evolving*, S&P GLOB. RATINGS (Mar. 18, 2021), https://www.spglobal.com/ratings/en/research/articles/210318-tennessee-valley-authority-in-review-how-the-tva-s-relationship-with-local-power-companies-is-evolving-11858648.

211. Caroline Eggers, *Memphis may leave TVA to reduce costs and carbon. That could raise bills in Nashville*, NASHVILLE PUB. RADIO (Aug. 30, 2022), https://wpln.org/post/memphis-may-leave-tva-to-reduce-costs-and-carbon-that-could-raise-bills-in-nashville/.

212. For the number of electric customers (and percentage of TVA sales) for each utility, see Panger, *supra* note 210. For the dates each utility signed onto the agreement, see Press Release, EPB, EPB Board Approves Long Term Agreement with TVA (Jan. 24, 2020), https://epb.com/newsroom/press-releases/epb-board-approves-long-term-agreement-tva/ (Chattanooga); Dave Flessner, *Huntsville, Alabama approves long-term contract with TVA*, CHATTANOOGA TIMES FREE PRESS (Feb. 28, 2020), https://www.timesfreepress.com/news/2020/feb/27/huntsville-alabama-approves-long-term-contract-tva/ (Huntsville); Maggie Shober, *The Good, the Bad, and the Ugly: How KUB's New Contract Sells Its Customers Short*, S. ALL. FOR CLEAN ENERGY (Mar. 13, 2020), https://cleanenergy.org/blog/the-good-the-bad-and-the-ugly-how-kubs-new-contract-sells-its-customers-short/ (Knoxville).

213. *See* Panger, *supra* note 210.

214. TVA 2022 10-K, *supra* note 193, at 11.

215. Samuel Hardiman, *MLGW votes against signing 20-year deal with Tennessee Valley Authority*, COMMERCIAL APPEAL (Dec. 7, 2022), https://www.commercialappeal.com/story/news/local/2022/12/07/mlgw-board-votes-against-20-year-contract-with-tennessee-valley-authority/69708172007/.

216. *See Power Supply Alternatives IRP*, MLGW, https://www.mlgw.com/about/PowerSupplyAlternativesIRP. Though MLGW management recommended staying with TVA and signing the 2019 evergreen contract, the MLGW Board voted to continue with its existing, rolling contract with its five-year termination period. *See* MLGW, 2022 ANNUAL REPORT 2, https://www.mlgw.com/images/content/files/pdf/2022CombinedAnnualReport_FinalWEB.pdf.

Memphis's size and proximity to the border of the TVA Fence.[217] As discussed above, longstanding TVA policy is to refuse to transmit power from a third-party supplier to a distributor within its Fence. Thus, distributors are effectively unable to purchase and consume third-party power—and non-incumbent suppliers are effectively unable to serve customers inside the Fence—unless they build duplicate transmission lines to bring the power to their systems. This was the very problem TVA faced when it sought to sell power from the Wilson Dam in the 1930s. Only utilities located close to the TVA Fence border—like MLGW—might feasibly build duplicative lines.[218]

TVA's large, urban utilities face relatively high levels of pressure from their retail customers and elected officials to increase their use of renewable energy.[219] Some, like Nashville Electric Services, serve municipalities that must comply with legally binding renewable portfolio standards or targets.[220] And because these utilities represent large portions of TVA's customer base and operating revenues, they may have individual bargaining power over TVA that their smaller peers do not. Thus, some of these utilities sought to exact special renewables deals as concessions from TVA in exchange for signing on to the long-term contracts.[221] They also were able to negotiate with TVA over contractual language. In joint negotiations between TVA, Knoxville, Chattanooga, and Huntsville, the distributors exacted several concessions from TVA, including: "extend[ing] the rate protection provisions beyond the initial term of 20 years to extend the full life of the contract; agree[ing] that if TVA were sold without [the distributor's] consent, [its] contract term would revert to five years;" and "agree[ing] that if the 20-year agreement

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217. *See* Panger, *supra* note 210.

218. Like MLGW, North Georgia Electric Membership Cooperative—TVA's largest customer in Georgia—is located close to the TVA Fence and is considering leaving TVA. *See* Dave Flessner, *TVA fights to keep its biggest customer as Memphis and other distributors eye split with utility*, CHATTANOOGA TIMES FREE PRESS (May 27, 2020), https://www.timesfreepress.com/news/2020/may/27/tva-fights-keep-its-biggest-customer-memphis/; *TVA wholesale increase, inflation driving up electric rates for NGEMC members*, NORTH GEORGIA ELECTRIC MEMBERSHIP COOPERATIVE (Sept. 27, 2024), https://www.ngemc.com/node/136 ("NGEMC's current contract (executed in 1976) requires the co-op to purchase 100% of its wholesale power from TVA with a five-year exit clause. NGEMC continues efforts to obtain flexibility from TVA to buy power from other potential suppliers.").

219. James Bruggers, *Southern Cities' Renewable Energy Push Could be Stifled as Utility Locks Them Into Longer Contracts*, INSIDE CLIMATE NEWS (Dec. 16, 2019), https://insideclimatenews.org/news/16122019/tva-rate-lock-in-renewable-energy-cities-nashville-memphis-knoxville/.

220. *See* NASHVILLE, TENN. CODE ch. 2.32.080 (renewable portfolio standard requiring that certain percentages of energy consumed by the Nashville metropolitan government come from carbon-free and/or renewable sources each year, starting with 53% carbon-free (including 22.5% renewable) in 2020 and reaching 100% renewable (excluding hydroelectric power) by 2040); MEMPHIS & SHELBY CTY. DIVISION OF PLAN. & DEV., MEMPHIS AREA CLIMATE ACTION PLAN 65-70, https://www.develop901.com/osr/memphisClimateActionPlan (targeting 100% carbon-free energy in electric supply by 2050).

221. *Id.* (explaining that Nashville "is looking for its own special deal with TVA"); Press Release, TVA, Vanderbilt, NES, TVA and Silicon Ranch Partner on Landmark Renewable Energy Deal (Jan. 22, 2020), https://www.tva.com/newsroom/press-releases/vanderbilt-nes-tva-and-silicon-ranch-partner-on-landmark-renewable-energy-deal (announcing an agreement between TVA, Nashville Electric Service, Vanderbilt University, and Silicon Ranch to develop a 35 MW solar project to serve Vanderbilt); Shober, *supra* note 212 (describing Knoxville Utility Board's decision to sign the long-term contract in exchange for TVA's agreement to "pursue 212 [MW] of solar for KUB and pass the clean energy and financial savings onto KUB customers").

were terminated, the cost for ongoing transmission improvements would be determined on a reasonable cost basis."[222] It was only once these terms were negotiated that the three utilities signed onto the contract.[223]

As of late October 2019, approximately twenty-three utilities of various sizes still had not signed new contracts.[224] Publicly-available communications between leaders of certain TVA distribution utilities and between the CEO and Board of Directors of Huntsville Utilities distill some of the major concerns with the contracts. These concerns can be divided into four categories.

*1. Fairness concerns about the structural coerciveness of the TVA-distribution utility relationship***.** This concern took two forms. First, in exchanging the long-term commitments for the 3.1% rate reduction, TVA's distribution utilities might be sacrificing their major source of power relative to TVA—bargaining power over contract renewal.[225] Second, the arrangement puts distribution utilities at the mercy of future TVA leadership. The evergreen contract put the interests of TVA's distribution utilities in the hands of future federal governments, whose make-up is unpredictable and who answer to a national, not regional, electorate.[226]

*2. Long-term stability concerns about the structural coerciveness of the TVA-distribution utility relationship***.** Elaborating on the above concern, the CEO of Huntsville Utilities argued that distribution utilities' loss of bargaining power would sacrifice long-term peace and risk changing the character of electric utility relationships in the TVA region.

> I believe contract renewals created a healthy tension that gave TVA's customers the impression they have a choice in their future. . . . TVA is unique. It has unilateral authority to make power supply, transmission, rate, and regulatory decisions for its customers. [I]f discussions with TVA were to become pointless, instead of plotting to leave the Valley, those upset would be stuck with little recourse [other] than directing their efforts at stripping TVA of its exceptional authority and/or its assets.[227]

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222. Board Meeting Minutes, Knoxville Utils. Bd., at 9847–48 (Mar. 12, 2020), https://www.kub.org/uploads/Minutes_-_March_12,_2020.pdf.

223. *Id.* at 9848.

224. Memorandum from Wes Kelley to Electric Board of Huntsville Utils., *supra* note 209, at 17.

225. *See id.* at 14 ("[T]his reminds me of the story of Jacob and Esau, with Esau trading his birthright for a bowl of stew. In our situation, I worry the bill credits accompanying this proposal might be our bowl of stew."); Email from Mark Iverson, Gen. Manager, Bowling Green Mun. Utils., to TVA Distrib. Util. Managers, *supra* note 206, at 2 ("Twenty one years from now, there will no longer be rate protection provisions. What leverage will our successors have in dealing with TVA?").

226. *See* Memorandum from Wes Kelley, President/CEO of Huntsville Utils., to Elec. Bd. of Huntsville Utils., *supra* note 209, at 20 ("This is not only a business concern but a political one as well. . . . Huntsville will be obligated to pay the 20-year bills of whomever a future TVA Board puts into leadership—a board appointed by whoever is elected President and confirmed by those then in control of the U.S. Senate. Such conditions should reasonably lead to increased interest in the political process by TVA's long-term partners.") *Cf.* Email from Mark Iverson, Gen. Manager, Bowling Green Mun. Utils., to TVA Distrib. Util. Managers, *supra* note 206, at 4 (expressing concern about "burdening a future [utility] board" and management with a 20-year commitment made by a predecessor).

227. *See* Memorandum from Wes Kelley, President/CEO of Huntsville Utils., to Elec. Bd. of Huntsville Utils., *supra* note 209, at 15. *But see* Email from Mark Iverson, Gen. Manager, Bowling Green Mun. Utils., to TVA Distrib. Util. Managers, *in* Emails Between Distribution Utility Managers 1 (Aug. 16, 2019),

3. Differences between the status of TVA's distribution utility customers and transmission-dependent utilities outside of TVA territory that may make the all-requirements contract structure inappropriate. The CEO of Huntsville Utilities argued:

> While such arrangements are common in our industry, TVA is not a common entity. Due to its federal ownership, TVA is unable to provide its "partners" with financial equity or governance over the infrastructure funded through such commitments. . . . Contractually, [Huntsville Utilities] is entering into a purchase power agreement, and as such, does not have a direct say in the governance or operations of the infrastructure built with its money. TVA is eager to connect [Huntsville Utilities] to its long-term liabilities, but not its assets.[228]

In this regard, TVA distributors are unique among otherwise similar utilities elsewhere in the country. This position may explain why so many distributors quickly signed onto the agreement: if TVA is seen by Congress as failing and is privatized, TVA distributors will have no equity to show for their years of payments into the TVA system. This concern first emerged in late-1950s debates over TVA's future.[229]

4. Specific components of the contract. The CEO of Huntsville Utilities expressed to the Huntsville Utilities Board of Directors that notwithstanding "philosophical concern[s] with the contract, . . . a pragmatic decision need[ed] to be made," and thus recommended seeking to negotiate certain terms with TVA before signing. These terms included the provision freeing TVA of its responsibility to add to or change facilities serving a utility after it gives notice of termination; certain types of rate increases excluded from the rate cap; the prohibition on facilitating distributed generation; and "the ability for Congress to override the wholesale power contract."[230] As noted above, Huntsville and several other large customers successfully negotiated with TVA over some, but not all, of these controversial provisions.

IV. LITIGATION RESPONDING TO THE CONTRACTS

In addition to the political opposition to the 2019 agreement described above, two legal challenges arose in the months and years following its approval and implementation. In *Athens Utilities Board v. TVA*,[231] four small municipal and cooperative utilities that did not wish to enter into the agreement asked FERC to

https://www.documentcloud.org/documents/6569887-Kelley08-16-19.html#document/p3/a543858 ("I will admit this is largely psychological. Practically speaking, an LPC's negotiating position today is much the same as it would be after adopting this proposal. The option of leaving TVA is a fantasy for most, given TVA's transmission exemption. With either a five-year agreement or a twenty-year agreement, politics remains our strongest negotiating tool.").

228. Memorandum from Wes Kelley, President/CEO of Huntsville Utils., to Elec. Bd. of Huntsville Utils., *supra* note 209, at 14, 20.

229. *See Tennessee Valley Authority Financing*: *Hearings Before the H. Subcomm. on Flood Control of the Comm. on Pub. Works*, 85th Cong. 172–73 (May 6–7, 1957).

230. Memorandum from Wes Kelley, President/CEO of Huntsville Utils., to Elec. Bd. of Huntsville Utils., *supra* note 209, at 15.

231. 177 FERC ¶ 61,021, *order on reh'g*, 177 FERC ¶ 62,162 (2021), *order on reh'g*, 179 FERC ¶ 62,045 (2022).

order TVA to wheel power to them from third-party suppliers. In *Protect Our Aquifer v. TVA*,[232] environmental groups challenged the contracts for failure to comply with required environmental reviews and for violating the provision of the TVA Act limiting TVA's power supply contracts to twenty-year terms. TVA won both cases.

Before diving into these cases, it is helpful to consider briefly the backdrop of deference to TVA ratemaking against which they arose. All-requirements provisions are common in the energy sector; they have survived antitrust and other legal scrutiny where applicable[233]—and TVA is exempt from federal antitrust laws altogether.[234] But why didn't the plaintiffs mount legal challenges to the other coercive terms of the contract, such as the termination of rate caps or the phase-out of the rate discount for terminating utilities?

The answer may lie in the considerable deference courts have historically afforded to TVA in contract disputes. In a line of cases dating to the 1970s, courts have deemed TVA's rates and calculation thereof to be nonjusticiable.[235] One decision from a federal district court rejecting statutory and contract law challenges to benefits conditioned on a contract's duration illustrates the deference afforded to TVA rates and the high bar challengers must meet.[236]

In 1996, 4-County Electric Power Association, a Mississippi cooperative utility, accused TVA of discriminating against it for exercising its right to give ten years' notice to terminate its all-requirements contract. Shortly after 4-County gave notice,[237] TVA adopted the Enhanced Growth Credit Program, a rate credit available only to utilities with ten-year contractual commitments to purchase

232. 654 F. Supp. 3d 654 (W.D. Tenn. 2023).

233. *See Ala. Power Co.*, 394 F.2d at 676 (immunizing the REA's requirement that borrower cooperatives enter into long-term all-requirements contracts from antitrust scrutiny); *id.* at 677-80 (Godbold, J., dissenting) ("The complaint . . . sets out a classic case of an exclusive supply contract which violates Section 3 of the Clayton Act because it forecloses in the relevant market a substantial share of the line of commerce affected. . . .While I view the violation as otherwise unquestionable, if there be any question the 35-year duration lays it to rest. It is an exclusive dealing arrangement that can foreclose the Power Company for the rest of the twentieth century. . . . Nor do I have any doubt that the contracts, and the effects alleged, constitute restraints violating the Sherman Act. . . . Standing alone the contracts violate the antitrust laws. As part of a wider course of dealings they violate the antitrust laws and so characterize that broader spectrum as to make it a violation." (citations omitted)).

234. *See supra* note 168.

235. *See, e.g.*, *McCarthy*, 466 F.3d at 406 (observing that a "long line of precedent exists establishing that TVA rates are not judicially reviewable" and "by virtue of TVA's having been granted by Congress full discretionary authority with respect to setting rates, TVA's rate-making decisions are beyond the scope of judicial review under the APA"). *See also* Holbrook v. TVA, 527 F. Supp. 3d 853 (W.D. Va. 2021), *aff'd*, 48 F. 4th 282, 291-92 (4th Cir. 2022), *cert. denied*, 143 S. Ct. 2608 (2023).

236. *4-County Elec. Power Ass'n*, 930 F. Supp. at 1132.

237. 4-County decided to leave TVA in December 1993 due to "concerns over the agency's troubled nuclear program, its inability to control electric rates and its massive debt." Nita Chilton McCann, *4-county withdrawal could cost remaining customers millions*, MISS. BUS. J. (May 1, 1995), available at ProQuest Central: The Mississippi Business Journal (1986-2012).

power from TVA—and therefore unavailable *only* to 4-County unless it withdrew its termination notice.[238]

In *4-County Electric Power Association v. TVA*,[239] 4-County argued that TVA's refusal to allow it to participate in the program was purely punitive and thus arbitrary and capricious, in violation of the Administrative Procedure Act.[240] Rejecting this argument, the court found that the design of the incentive program was an unreviewable component of TVA ratemaking–and that even if judicial review were available, TVA's decision was reasonable.[241] 4-County also argued that TVA's actions violated section 11 of the TVA Act, which states: "It is declared to be the policy of the Government so far as practical to distribute and sell the surplus power generated at Muscle Shoals *equitably* among the States, counties, and municipalities within transmission distance."[242] The court disagreed, interpreting "equity" to merely require that TVA offer its customers an "opportunity to participate . . . on exactly the same basis as all other distributors, i.e., subject to the condition of its agreeing to a ten-year commitment." It found "nothing discriminatory" in TVA's development of an incentive available for all customers except the one exercising its termination rights.[243]

Repeating its conclusion that TVA had treated 4-County fairly and in good faith, the court also rejected 4-County's breach of contract, breach of the implied covenant of good faith and fair dealing, and breach of fiduciary duty claims.[244] Finally, 4-County argued that its supply contract was substantively unconscionable because if it was "interpreted as urged by TVA, then for eight years, 4-County will not have access to the same [incentive program] that is available to virtually every other TVA distributor, and will have no recourse to other suppliers."[245] The court held that this claim was improperly raised, but noted that "[f]or the reasons

238. *See 4-County Elec. Power Ass'n*, 930 F. Supp. at 1136; *TVA accused of blocking 4-County's participation in program*, KNOXVILLE NEWS SENTINEL (June 9, 1995), available at ProQuest Central: News Sentinel (1994-current); *see also supra* Part II.D.

239 930 F. Supp. 1132, 1135 (S.D. Miss. 1996)

240. 5 U.S.C. §§ 551–559.

241. *4-County Elec. Power Ass'n*, 930 F. Supp. at 1137–38.

242. TVA Act of 1933 § 11 (codified as amended at 16 U.S.C. § 831j) (emphasis added).

243. *4-County Electric Power Ass'n*, 930 F. Supp. at 1138–39. 4-County also alleged that TVA violated section 11 by offering the incentive to its industrial retail customers without a 10-year commitment. The court found that "since TVA's wholesale customers (distributors) are in a different class than TVA's directly-served retail customers, there is no basis for a claim of discrimination." *Id.* at 1139. As support for this proposition, the court offered the following citation: "*See* 16 U.S.C. § 831k ("electric power shall be sold and distributed to the ultimate consumer without discrimination as between consumers of the same class")." *Id.* at 1139. However, the quoted provision, when recited in full, is inapplicable:

> *All contracts entered into between [TVA] and any municipality or other political subdivision or cooperative organization shall provide that* the electric power shall be sold and distributed to the ultimate consumer without discrimination as between consumers of the same class, and such contract shall be voidable at the election of the Board if a discriminatory rate, rebate, or other special concession is made or given to any consumer or user by the municipality or other political subdivision or cooperative organization.

16 U.S.C. § 831k (emphasis added).

244. *4-County Elec. Power Ass'n*, 930 F. Supp. at 1139-43.

245. *Id.* at 1143.

that the court has fully discussed with respect to plaintiff's other claims, the court would have granted summary judgment for TVA on this claim in any event."[246]

4-County did not appeal the decision.[247] No other adjudicator had occasion to weigh in on this set of facts until the 2019 contracts litigation arose.

A. *Athens Utilities Board v. TVA*

Most of TVA's smaller customers signed the 2019 contracts almost immediately, and most of its largest customers negotiated to exact concessions before signing. Importantly, though, some smaller utilities also resisted. Four prominent hold-outs were Athens Utilities Board, Gibson Electric Membership Corporation, Joe Wheeler Electric Membership Corporation, and Volunteer Energy Cooperative, which in aggregate serve 215,000 customers.[248] Like their larger peers, these four utilities resisted signing the new, evergreen contract, citing "increasing bundled contract prices" and "draconian provisions."[249] But unlike their larger peers, they were not able to extract attractive concessions from TVA.

Instead, the utilities looked to alternative sources of power supply to meet their demand. They worked with a consultant to conduct a competitive bidding process and found that third-party supply "would enable [their] members to realize significant savings as compared to the rates [they] currently pay TVA."[250] Predictably, when the utilities requested TVA to provide transmission-only ("unbundled") service for wheeling power from a third-party supplier to their distribution systems over TVA transmission lines, TVA refused, citing its policy of refusing to wheel non-TVA power to the TVA service territory, as codified in its Transmission Service Guidelines and reaffirmed in a Board Resolution:[251] "A departing customer must make the necessary arrangements to deliver third-party supply to its load without relying on the transmission system in any way."[252]

Those refusals were dated November 19, 2020. On January 11, 2021, the four utilities filed a document styled "complaint and petition" asking FERC to take

246. *Id.* at 1143 n.9.

247. After its win, TVA sued 4-County for $65 million in stranded costs, threatened to move a $470 million planned coal plant out of the cooperative's service territory, and used other tactics to encourage 4-County to remain in TVA. 4-County's CEO explained: "'We just couldn't win. . . . They visited our customers and basically made us out to be villains. . . . It was extremely hardball." 4-County soon canceled its termination notice. *See* Fialka, *supra* note 159.

248. *See* Complaint and Petition at 7-9, *Athens Utils. Bd.*, 177 FERC ¶ 61,021 (Jan. 11, 2021) (FERC Docket Nos. EL21-40, TX21-1) [hereinafter Complaint and Petition]. Joe Wheeler Electric Membership Corporation withdrew from the case and signed the 2019 agreement in August 2021. *See* Dave Flessner, *North Alabama power company gives up fight to break up TVA power fence*, CHATTANOOGA TIMES FREE PRESS (Aug. 31, 2021), https://www.timesfreepress.com/news/2021/aug/31/tva-power-battle-shifts/.

249. Complaint and Petition, *supra* note 24, at 3, 12.

250. *Id.* at 62 (affidavit of Eric T. Newberry, Jr., General Manager of Athens Utilities Board); *id.* at 101 (Affidavit of Elaine Johns, President and CEO of EnerVision, Inc.).

251. *See supra* Part II.E.

252. Complaint and Petition, *supra* note 248, at Ex. No. LPC-007 (Letter from TVA Vice President of Customer Delivery to Eric Newberry (Nov. 19, 2020)) (citing TVA Board's "Reaffirmation of Policy on Requests to use the TVA Transmission System to Deliver Power to Local Power Companies").

action. Specifically, the utilities asked FERC to exercise its authority under section 211A of the Federal Power Act to order TVA to provide unbundled transmission service and, under section 210, to require continued interconnection of the distributors to the TVA transmission system.[253]

Relevant statutes. FERC does not have authority over TVA's rates under sections 205 and 206 of the FPA, which direct FERC to ensure that public utility rates are just, reasonable, and not unduly discriminatory or preferential.[254] As described briefly above, however, FERC has some authority over transmission service provided by utilities whose rates it does not ordinarily regulate.[255]

Congress enacted sections 210, 211, and 212 of the FPA in 1978 and added subsection 212(j) as part of the Energy Policy Act of 1992. Section 210 gives FERC authority to order the interconnection of the transmission facilities of any "electric utility"—including TVA—with the facilities of another electric utility requesting such interconnection, if it finds the interconnection to be in the public interest.[256] Section 211 authorizes FERC to order a "transmitting utility"—including TVA—to provide transmission service to an electric utility applicant, after notice and opportunity for a hearing, if the Commission "finds that such order meets the requirements of section 212 and would otherwise be in the public interest."[257] As relevant to TVA, section 212 states at subsection (j):

> *Equitability within territory restricted electric systems.* With respect to an electric utility which is prohibited by Federal law from being a source of power supply . . . outside an area set forth in such law, no order issued under section 211 may require such electric utility . . . to provide transmission services to another entity if the electric energy to be transmitted will be consumed within the area set forth in such Federal law, unless the order is in furtherance of a sale of electric energy to that electric utility.[258]

Section 212(f) operates in the other direction: it requires FERC to stay any section 210 or 211 order if the order "would result in violation of the third sentence of section 15d(a)" of the TVA Act, prohibiting TVA from selling power outside the Fence.[259] Therefore, standing on its own, section 212 prohibits FERC from using section 211 to cross the TVA Fence in either direction.

In 2005, Congress added section 211A to the FPA. That provision, titled "Open access by unregulated transmission utilities," defines an "unregulated transmission utility" to include TVA.[260] It states, as relevant here:

253. *Id.* at 1–2.

254. 16 U.S.C. §§ 824(e)–(f), 824d–824e; *see* 177 FERC ¶ 61,021, at P 8 ("As an instrumentality of the United States, TVA is not a 'public utility' under the terms of the FPA and is therefore not subject to Commission regulation under sections 205 and 206 of the FPA.").

255. *See supra* Part II.E.

256. 16 U.S.C. §§ 824i(a)–(c); *id.* § 796(22)(B) (defining "electric utility" to include TVA and municipal and cooperative utilities). *See supra* Part II.E.2.

257. *Id.* § 824j; *id.* § 796(23) (defining "transmitting utility" to include TVA by reference to 16 U.S.C. § 824(f)).

258. *Id.* § 824(j). The provision proceeds to exempt from this prohibition Bristol, Virginia, which was then in the process of leaving TVA. *See* Fialka, *supra* note 159.

259. 16 U.S.C. § 824(f).

260. *Id.* § 824j-1(a).

> [T]he Commission may, by rule or order, require an unregulated transmission utility to provide transmission services
> (1) at rates that are comparable to those that the unregulated transmitting utility charges itself; and
> (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential.[261]

Section 211A also states that FERC "shall exempt" from an order issued under that provision a utility that "meets other criteria the Commission determines to be in the public interest."[262]

Parties' Arguments. The petitioning utilities asked FERC to order TVA to provide them with unbundled (transmission-only) service using its section 211A authority and to order TVA to provide interconnection service under section 210.[263] The petitioners analogized to *Iberdrola Renewables v. Bonneville Power Administration*,[264] the first FERC proceeding to apply section 211A. In *Iberdrola*, owners of wind generation challenged a policy of the Bonneville Power Administration—a federal power marketer under the Department of Energy umbrella—that ordered wind generators to curtail production without compensation during high water periods, when federal hydropower plants produced more power than the transmission system could handle. FERC found that the policy resulted in non-comparable transmission service: the "non-Federal renewable resources are similarly-situated to Federal hydroelectric and thermal resources for purposes of transmission curtailment because they all take firm transmission service," yet Bonneville's policy curtailed the non-federal resources "without causing similar interruptions to firm transmission service held by Federal resources."[265] While FERC was reluctant to exercise its section 211A authority,[266] it did so in this "compelling case" because the policy "significantly diminishes open access to transmission," which section 211A was meant to protect.[267]

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261. *Id.* § 824j-1(b). This authority is "subject to section 212(h)" which prohibits FERC from directing a utility to transmit power directly to a retail (not wholesale) customer. *Id.* § 824k(h). The FPA reserves regulation of retail sales to the states. *See* Matthew R. Christiansen & Joshua C. Macey, *Long Live the Federal Power Act's Bright Line*, 134 HARV. L. REV. 1360, 1372, 1395–96 (2021); Jim Rossi, *Energy Federalism's Aim*, 134 HARV. L. REV. 228, 239 n.71 (2021).

262. 16 U.S.C. § 824j-1(c).

263. *Athens Utils. Bd.*, 177 FERC ¶ 61,021 at P 11.

264. 137 FERC ¶ 61,185 (2011), *order on reh'g*, 141 FERC ¶ 61,233 (2012), *aff'd sub. nom.* Nw. Requirements Utils. v. FERC, 798 F.3d 796 (9th Cir. 2015). A limited set of orders discussed section 211A before *Iberdrola*. *See Preventing Undue Discrimination & Preference in Transmission Serv.*, Order No. 890, 118 FERC ¶ 61,119, at P 192 (2007) (declining to adopt a generic rule to implement section 211A); *Town of Edinburgh v. Ind. Mun. Power Agency*, 132 FERC ¶ 61,102, at PP 20-21 (2010) (exercising discretion under section 211A to decline to review claim due to pendency of judicial proceedings that might resolve section 211A issues); *Transmission Plan. & Cost Allocation by transmission Owning and Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051, at P 815 (2011) (declining to adopt a generic rule under section 211A to require unregulated transmission utilities to participate in regional transmission planning processes).

265. *Iberdrola*, 137 FERC ¶ 61,185 at P 62.

266. *Id.* P 32 ("[W]e expect that the need to use this statutory authority would be rare.").

267. *Id.* PP 32-33; *see also Nw. Requirements Utils*., 798 F.3d at 808 (explaining that the text, title, and legislative history of section 211A evince that it "was designed to foster an open and competitive energy market by promoting access to transmission services on equal terms").

The *Athens Utilities Board* petitioners argued that their case fell neatly under *Iberdrola*. Like the Bonneville policy, TVA's favored TVA's own generation (analogous to federal hydroelectric resources) "over the power suppliers that could otherwise serve the LPCs' supply needs" (analogous to the similarly-situated non-federal wind resources) by denying those suppliers access to transmission service to wheel power to customers inside the Fence, privileging transmission access for TVA-owned or procured generation.[268] Additionally, like the wind generators, the petitioners "and/or entities seeking to serve their load" were "similarly situated to any other prospective TVA transmission customers" (outside the Fence), for whom TVA would wheel power, because TVA was as "operationally capable" of wheeling power into its territory as it was across it.[269] Finally, the utilities explained that TVA's policy threatened open-access principles:

> TVA's outright refusal to provide unbundled transmission service to Petitioners effectively locks them into TVA's excessive bundled rates and precludes Petitioners[] from seeking any meaningful supply alternatives. In other words, TVA has created a supply monopoly within its considerable footprint that stifles all competition. TVA has taken advantage of this arrangement to charge unreasonably high bundled rates, with no incentive to efficiently manage the costs it imposes on its captive wholesale customers. . . . [W]ithout open access to the TVA transmission system, Petitioners would have no choice but to duplicate the local existing transmission system—which they continue to pay for—or sign the New Power Contract—which perpetuates TVA non-competitive monopoly with a 20-year evergreen term. The avoidance of duplicating bulk transmission systems was a fundamental premise to the Commission's promotion of open access policies.[270]

Thus, as in *Iberdrola*, the conditions justifying a section 211A order—lack of comparable service for similarly situated customers, resulting in impairment of the open-access principle—were met.

In its response, TVA relied on a conception of the 1957 Fence as an "equitable two-way barrier" keeping TVA inside its territory (via TVA Act section 15d(a) and FPA section 212(h)) and keeping other utilities out (via FPA section 212(j)).[271] It argued that Congress did not intend for section 211A to disturb this state of affairs,[272] and that interpreting the provision according to the petitioners' view—

268. *Athens Utils. Bd.*, 177 FERC ¶ 61,021 at P 19 (citing Complaint and Petition, *supra* note 248, at 32).

269. *Id.* PP 17, 19-20 (quoting Complaint and Petition, *supra* note 248, at 33-34).

270. Complaint and Petition, *supra* note 248 at 3-4.

271. *Athens Utils. Bd.*, 177 FERC ¶ 61,021 at P 41 (citing Protest, Answer, and Motion to Intervene of TVA at 19, *Athens Utils. Bd.*, 177 FERC ¶ 61,021 (Feb. 22, 2021) (FERC Docket Nos. EL21-40, TX21-1) [hereinafter TVA Answer]).

272. TVA Answer, *supra* note 271, at 20-22 (noting that Congress considered and rejected proposals to give FERC "full jurisdiction over TVA's transmission system" and to tear down the Fence in both directions); *id.* at 30 (arguing that Congress would not "casually and silently [do] what it previously had explicitly declined to do").

unbounded by 212(j)[273]—would upend the Fence and "conflict[] with the TVA Act."[274]

Rather, TVA offered an alternative conception. TVA argued that sections 211 and 212(j) and (f) continue to govern requests for *new* transmission service;[275] section 211A merely "gives the Commission discretionary authority to oversee the rates and non-rate terms and conditions for transmission service that is *already being provided*, but not to order new wheeling service."[276] Under section 211A, the Commission could evaluate existing transmission service—whether provided voluntarily or pursuant to a section 211 order—and act if the rates, terms, and conditions are non-comparable or unduly discriminatory.[277] *Iberdrola* comported with this proposed framework because Bonneville already provided transmission service and was ordered to revise the terms and conditions of that service to achieve comparability.[278]

Even were FERC to agree with the petitioners' interpretation of section 211A, TVA argued, FERC should still deny their request for two reasons. First, the facts at hand did not meet the "non-comparability" and "similarly situated" criteria. Comparability was a "flexible" standard, TVA argued, not always requiring identical service and taking into account "potential impediments or consequences," like those that "would harm TVA's remaining customers" in the event the petitioners succeeded.[279] And the petitioners were not "similarly situated" to customers located outside of the Fence: wheeling power to petitioners would result in a "cost-shift problem" that would not arise from serving outside-the-Fence customers.[280]

Second, TVA argued that FERC should exercise its discretion to deny the request for a petition, noting that it had done so "on a number of occasions" and had expressed its expectation that it would use section 211A rarely.[281] TVA set forth a number of reasons why an order would not be in the public interest: an

273. Responding to the contention that section 211A, unlike section 211, does not reference section 212(j) (and vice versa)—and thus does not mean to incorporate its restriction—TVA argued that this silence "does not mean that Congress meant to eliminate that restriction on FERC's wheeling authority. That point is further demonstrated by the numerous other restrictions on the Commission's wheeling authority that Congress did not attempt to exhaustively list in section 211A but which would nevertheless still apply to any order issued under section 211A," like § 211(b), which TVA stated prohibits wheeling orders that the Commission finds would "unreasonably impair the continued reliability of electric systems" at issue. TVA Answer, *supra* note 271, at 33–35.

274. *Athens Utils. Bd.*, 177 FERC ¶ 61,021 at PP 44-46 (citing TVA Answer, *supra* note 271, at 27). Specifically, such an interpretation would allegedly conflict with the TVA Act by contradicting the Fence provision, *id.* P 44, interfering with the TVA Board's statutory authority to operate its transmission system, *id.* P 46, and reducing its revenues, thereby impairing the TVA Board's authority to engage in discretionary ratemaking and to execute its multi-fold mission, *id.* PP 45-46.

275. *Id.* P 49.

276. *Id.* P 44 (citing TVA Answer, *supra* note 271, at 26-27) (emphasis added).

277. *Id.* PP 49-51 (citing TVA Answer, *supra* note 271, at 36).

278. 177 FERC ¶ 61,021, at P 51; TVA Answer, *supra* note 271, at 39 n.51.

279. TVA Answer, *supra* note 271, at 50-51.

280. *Id.* at 52.

281. *Id.* at 39.

order resulting in load loss would shift stranded costs onto remaining customers; the order would incentivize inequitable "cherry-picking"[282] of TVA customers; it would create a free-rider problem; and it would impair TVA's ability to pursue its "broad set of responsibilities."[283]

Finally—strikingly—TVA stated that open-access principles were "not compelling" in TVA territory, where there was "no longstanding policy favoring competition" and, allegedly, no congressional intent to change that.[284]

The Commission Order. FERC dismissed the case in four paragraphs, holding that "[its] authority under section 211A is discretionary," and therefore "declin[ing] to issue a rule or order" requiring TVA to wheel power to the utility petitioners.[285] The order "clarif[ed]" that section 211A did not establish freestanding requirements for unregulated transmitting utilities, and thus was not capable of being violated: it explained that FERC's "jurisdiction under section 211A(b)(1) is not invoked automatically" by some utility action; rather, FERC "has the discretion to choose to exercise, or as relevant here to instead choose not to exercise, this authority."[286]

What might that aforementioned "authority" entail? FERC spoke to the question only briefly, and opaquely, in a footnote restating the statutory text: "section 211A authorizes the Commission, at its discretion, to act to achieve certain results should the Commission choose to do so (e.g., to require an unregulated transmitting utility to provide transmission service at 'comparable' rates)."[287]

The Commission's terse and unilluminating holding was followed by separate statements from each of the four participating commissioners.[288] Chairman Glick concurred, stating without further explanation that he did not "believe that Congress intended to give this Commission the authority to ignore the [Fence] when it enacted the Energy Policy Act of 2005." He shared his view that the Fence was a "vestige of a bygone era" that Congress should replace with open access and competition.[289]

Commissioner Danly also concurred and concluded that FERC "probably does not have the authority under FPA section 211A" to issue the requested order." He opined that while section 211A "authorizes the Commission to require government-owned utilities to provide the type of service petitioners seek," that authority

282. TVA stakeholders sometimes refer to FPA section 212(j) as the "Anti-Cherry-Picking Amendment." *Athens Utils. Bd.*, 177 FERC ¶ 61,021 at P 9.

283. TVA Answer, *supra* note 271, at 43-44.

284. *Athens Utils. Bd.*, 177 FERC ¶ 61,021 at P 58 (quoting TVA Answer, *supra* note 281, at 46). *Compare* McCarthy, *supra* note 43, at 127 (explaining that in the 1930s, TVA studied and issued three reports to Congress on the issue of inequitable freight-rate structures that disadvantaged the South and restricted the market for southern manufactured goods; the Interstate Commerce Commission conducted an investigation and in 1945 issued a ruling requiring the railroads to remove the North-South rate disparity).

285. *Athens Utils. Bd.*, 177 FERC ¶ 61,021 at P 89.

286. *Id.* P 90.

287. *Id.* P 90 n.187.

288. Chairman Richard Glick and Commissioners James Danly, Alison Clements, and Mark Christie participated in the decision. Commissioner Neil Chatterjee did not participate.

289. *Athens Utils. Bd.*, 177 FERC ¶ 61,021 (Glick, Chairman, concurring at PP 1-2).

with respect to TVA is "limited by Section 212(j)" and by the need to harmonize the FPA with the TVA Act.[290]

Commissioner Christie concurred to write that "[c]hanging the basic statutes governing the Tennessee Valley Authority is the prerogative of Congress," not FERC, but made a suggestion to that end. He suggested that Congress amend the TVA Act to require TVA to procure power on a "competitive, least-cost, non-discriminatory basis" to reduce power supply costs while avoiding the potential cost-shifting implications of allowing customers to leave TVA.[291]

Commissioner Clements dissented. She first concluded that the Commission had the necessary authority to grant the petitioners' request under the plain language of section 211A. Quoting the Ninth Circuit's 2015 decision dismissing a challenge to *Iberdrola*, Commissioner Clements observed that Congress enacted section 211A to "prevent[] anticompetitive behavior by utilities that seek to stifle competitors' generation through control over generation," taking a "further step in the legislative and administrative effort to progressively open energy markets."[292] To accomplish this goal, she explained, section 211A(b) permits the Commission to "require an unregulated transmitting utility to provide transmission services" at rates, terms, and conditions comparable to those under which it serves itself. TVA's interpretation—that section 211A only applies once a utility *already* provides transmission service—would directly contradict this grant of authority and "read open access out of the statute." That Congress intended FERC to be able to order new transmission service was supported by section 211A(h), providing that "[t]he provision of transmission services under [211A](b) does not preclude a request for transmission services" under section 211.[293]

Commissioner Clements then argued that no other provisions of the Federal Power Act nor the TVA Act cut against section 211A's plain meaning. Section 212(j), she argued, applies only to section 211 orders; Congress could have revised the FPA to limit section 211A with section 212(j), but did not.[294] In fact, it enacted a savings clause in section 212 providing that "except as provided in . . . this section, such sections shall not be construed as limiting or impairing any authority of

290. *Id.* (Danly, Comm'r, concurring at P 2).

291. *Id.* (Christie, Comm'r, concurring at P 2). This policy was proposed by Senator Mitch McConnell in a 2001 bill, S. 608, the TVA Distributor Self-Sufficiency Act of 2001. *See supra* note 154.

292. *Athens Utils. Bd.*, 177 FERC ¶ 61,021 (Clements, Comm'r, dissenting at P 2) (quoting *Nw. Requirements Utils.*, 798 F.3d at 808 (cleaned up)).

293. *Id.* (Clements, Comm'r, dissenting at P 3) (citing FPA § 212A(h), 16 U.S.C. § 824j-1(h)).

294. *Id.* (Clements, Comm'r, dissenting at P 4 n.12) (citing *E. Ky. Power Cooperative*, 111 FERC ¶ 61,031 at P 20 n.17 ("Section 212(j) . . . provides that with respect to [TVA,] *no order issued under section 211* may require such electric utility (or a distributor of such electric utility) to provide transmission services to another entity if the electric energy to be transmitted will be consumed within the area set forth in such federal law, unless the order is in furtherance of a sale of electric energy to that electric utility.") (emphasis in original). *See also E. Ky. Power Cooperative*, 115 FERC ¶ 61,347 at P 13 ("[Congress] limited the section 212(j) prohibition to section 211 transmission orders. It did not extend the section 212(j) prohibition to section 210 interconnection orders. . . . [S]ome provisions of section 212 explicitly apply to only sections 210 or 211, while other portions apply to both.").

the Commission under any other provision of law."[295] And section 211 was simply a different tool in the Commission's toolbox—not a reason for reading section 211A differently.[296] Finally, Commissioner Clements argued that the TVA Act does not affect the Commission's authority under section 211A. Rather, TVA must carry out its statutory mission in accordance with applicable law, including section 211A orders.[297]

Commissioner Clements next concluded that granting the petition would have furthered the public interest by enabling petitioners to procure lower-cost power and thus "supplying a modicum of competition and its associated benefits to the region."[298] Regarding the interest cutting in the other direction—that of customers remaining in TVA—Commissioner Clements wrote that TVA failed to provide persuasive evidence of "significant[] impact," and that those customers might, in fact, be benefited by an adjustment to TVA's incentives.[299]

Epilogue. FERC's decision was issued on October 21, 2021. On February 18, 2022, the petitioners petitioned for D.C. Circuit review.[300] On September 7, the Gibson Electric Membership Corporation board resolved to sign its long-term contract.[301] On October 28, the petitioners filed a motion to voluntarily dismiss the case.[302] The remaining utilities do not appear to have signed the long-term agreement to date.

Analysis. FERC's decision in *Athens Utilities Board* was made expressly in terms of discretion—while the Commission had some authority to "require an unregulated transmitting utility to provide transmission service at comparable

295. *Athens Utils. Bd.*, 177 FERC ¶ 61,021 (Clements, Comm'r, dissenting at P 10) (citing FPA § 212(e), 16 U.S.C. § 824k(e)(1)).

296. *Id.* (Clements, Comm'r, dissenting at P 12).

297. *Id.* (Clements, Comm'r, dissenting at PP 6, 8-9) (citing *Iberdrola*, 137 FERC ¶ 61,185, wherein FERC rejected claims that Bonneville's organic statute took precedence over the FPA).

298. *Id.* (Clements, Comm'r, dissenting at P 13). *See also E. Ky. Power Cooperative*, 111 FERC ¶ 61,031 at P 38 ("[T]he requested interconnections would encourage the conservation of energy and capital by providing Warren with access to more economical sources of power. As a result of the interconnection, Warren and its customers would be able to purchase power at lower rates than they pay TVA. We also find that an order directing TVA to interconnect with EKPC would optimize the use of existing facilities by allowing increased competition.").

299. *Athens Utils. Bd.*, 177 FERC ¶ 61,021 (Clements, Comm'r, dissenting at P 14 n.31) (citing "inconsistency between TVA's assertion that the loss of 3.6% of TVA's total load would cost its other customers $3.3 billion through 2040, and the statements of its CEO and other executive officers elsewhere that 10% loss of load would "not really [cause] a material impact" and would not "create a significant financial impact for us [or] create a significant rate issue for our customers").

300. Petition for Review, Athens Utilities Board v. FERC, No. 22-1024 (D.C. Cir. Feb. 18, 2022). The FPA requires parties to first request rehearing at FERC before seeking judicial review of an order. *See* 16 U.S.C. §§ 825*l*(a)–(b). The *Athens Utilities Board* petitioners' request was denied by operation of law on April 22, 2022. *See Athens Utils. Bd. v. TVA*, 179 FERC ¶ 62,045 (2022).

301. Kyle Peppers, *Gibson EMC board resolves to sign long-term contract with TVA*, WBBJ TV (Sept. 7, 2022), https://www.wbbjtv.com/2022/09/07/gibson-emc-board-resolves-to-sign-long-term-contract-with-tva/.

302. *See* Unopposed Motion for Voluntary Dismissal, Athens Utilities Board v. FERC, No. 22-1024 (D.C. Cir. Oct. 28, 2022); *see also* Maggie Shober, *Local Utilities Withdraw Appeal for Transmission Access from TVA*, S. ALL. FOR CLEAN ENERGY (Oct. 24, 2022), https://cleanenergy.org/blog/local-utilities-withdraw-appeal-for-transmission-access-from-tva/.

rates,"[303] it exercised its discretion not to use that authority to grant a request to order TVA to wheel power to utilities inside its Fence. Given that three commissioners supported dismissal with only one dissent, it is worth noting that the Commission majority's precedent-creating order did not itself outright embrace TVA's interpretation and disclaim section 211A over TVA. This might suggest that the Commission left the door open to future attempts to introduce some minimal level of competition to TVA with section 211A.

The three commissioners concurring in the judgment suggested—with varying degrees of confidence, and altogether unconvincingly—that FERC likely had no authority to force TVA to wheel power into its borders. No concurring commissioner offered his own statutory interpretation of the text of section 211A, perhaps because confronting that language means reaching the opposite result. The dissent was clearly correct in its interpretation of the plain meaning of section 211A.

TVA and the concurring commissioners' arguments that reconciling the FPA and the TVA Act requires reading section 211A differently were similarly unavailing. Commissioner Danly cited in his concurrence TVA's claim that "section 211A conflicts with [the] TVA Act" and argued that because "when possible, conflicting statutory provisions must be interpreted in harmony with one another," section 211A must be read to be limited by section 212(j).[304]

As an initial matter, section 211A can be harmonized with the TVA Act without construing the statutory text to say that which it does not. The Fence, a product of political compromise specific to the moment in which it was established, keeps TVA inside its 1957 borders without speaking to the rights of outside-the-Fence suppliers. The Fence was built to protect neighboring IOUs from the type of territorial expansion that TVA had embarked upon in the region not long before.[305] It was not designed to work in the other direction. Nor should it have been: in 1959, generation and transmission were a bundled business across the country; only several decades after the Fence was built did competitors for incumbent utilities' generation business emerge. Section 211A, enacted in modern electric sector conditions, by its plain terms permits the Commission to override TVA's Transmission Service Guidelines (a regulation, not a statute) and order TVA to provide transmission service into its service territory—the opposite direction of the Fence, responding to modern and different conditions than those present in 1959. Section 211A and the TVA Act do not conflict.

Nor does section 211A conflict with section 212(j). Section 212(j) applies to orders issued pursuant to section 211, not to orders issued pursuant to section 211A. As the dissent explains, sections 211 and 211A are different tools in the Commission's toolbox; they have different triggers[306] and apply to different sets

303. *Athens Utils. Bd.*, 177 FERC ¶ 61,021 at P 90 n.187.

304. *See id.* (Danly, Comm'r, concurring at P 2) (internal citations omitted).

305. *See supra* Part II.C.

306. Section 211 orders must be requested by an electric utility, a federal power marketing agency, or wholesale power generator. 16 U.S.C. § 824j(a). Section 211A requires no such request and permits the Commission to take unilateral action. *See id.* § 824j-1(b).

of entities,[307] among other distinctions. Section 211A(h) honors the provisions' unique roles: "The provision of transmission services under [section 211A(b)] does not preclude a request for transmission services under section [211]."[308] Congress empowered the Commission to order comparable transmission service into TVA territory using the mechanism it created in section 211A; it left intact the section 211 wheeling mechanism, applying to a broader range of companies, and TVA's protection from orders thereunder. These two statutory mechanisms can operate simultaneously—giving full meaning to their plain terms—and need not be read to conflict.

But even if the plain text of section 211A was indeed read to irreconcilably conflict with a policy reflected in the TVA Act or sections 211 or 212(j) of the FPA, the solution is not to invent a strained interpretation of these provisions. Rather, an irreconcilable conflict would necessarily lead to the conclusion that in enacting section 211A, Congress impliedly repealed any such policy.[309] With section 211A, Congress established conditions under which the Commission could order "open access by unregulated transmitting utilities."[310] It defined (completely anew) "unregulated transmitting utilities" to include TVA. It incorporated a number of restrictions on those orders, including some by reference to section 212, but did not choose to incorporate the restriction in section 212(j). If, in 1959 or 1992, Congress created a prospective policy restricting any future exercise of Commission authority to order wheeling into TVA, we must conclude that Congress repealed that policy in 2005.

Only a strained interpretation of the text of the Federal Power Act—combined with an expansive reading of the TVA Act, unsupported assumptions about congressional intent, and disregard for section 211A's explicit open access policy—could justify dismissing the *Athens Utilities Board* petition. The *Athens Utilities Board* majority's decision not to adopt such a strained interpretation in the majority order suggests that should this issue come before the Commission again, it would have a second chance to consider the issue.

B. Protect Our Aquifer v. TVA

In August 2020, three Southeast-based environmental groups challenged TVA's approval and implementation of the evergreen contracts under the APA.[311] The plaintiffs—Protect Our Aquifer, Energy Alabama, and Appalachian Voices—

307. Section 211A orders apply to "unregulated transmitting utilities," *id.* § 824j-1(b), which includes *only* publicly or cooperatively-owned utilities that own or operate facilities for the transmission of electricity in interstate commerce, *id.* § 824j-1(a) (citing *id.* § 824(f)). Section 211 orders apply to "transmitting utilities," *id.* § 824j(a), which includes "unregulated transmitting utilities" in addition to any other entity that owns, operates, or controls facilities used for the interstate transmission of electricity for wholesale sales, *id.* § 796(23).

308. 16 U.S.C. § 824j-1(h).

309. "[R]epeals by implication are not favored." TVA v. Hill, 437 U.S. 153, 154 (1978). Nevertheless, where two statutory provisions "are in irreconcilable conflict," such that they are incapable of coexistence, the later-enacted provision constitutes an implied repeal of the earlier-enacted provision to the extent of the conflict. Radzanower v. Touche Ross & Co., 426 U.S. 148, 154-55 (1976).

310. 16 U.S.C. § 824j-1.

311. 5 U.S.C. §§ 551, 553-559, 701-706.

claimed that TVA had violated procedural and substantive requirements of the National Environmental Policy Act ("NEPA")[312] and the TVA Act and asked the court to utilize its authority under APA to issue a judgment "enjoining, setting aside, vacating, or reforming" the 2019 contracts.[313]

The plaintiffs claimed that TVA violated NEPA by failing to conduct and publish an environmental impact analysis before executing the contracts. TVA's monopoly power figured into the alleged connection between the contracts and environmental impacts: the plaintiffs claimed that the contracts "effectively insulate TVA from competition," which "will forever constrain the development of renewable energy in the TVA region, resulting in greater emissions of greenhouse gases and other pollutants." This would also "have lasting and harmful consequences for the Valley's aquifers and surface water resources," on which fossil fuel-powered generators rely. And the contracts were "likely to result in increased electricity demand," which would "exacerbat[e] TVA's greenhouse gas emissions, other pollution, and water consumption."[314] The failure to consider these effects, the plaintiffs argued, violated NEPA and injured the plaintiffs by depriving them of important information that they historically relied upon for their advocacy.[315]

The plaintiffs also alleged that the approval and implementation of the contracts violated section 10 of the TVA Act, which authorizes TVA "to enter into contracts for [sale of surplus power] for a term not exceeding twenty years."[316] Despite their formal ("purported") term of twenty years, the contracts effectively "never expire[] with the passage of time" because of their automatic renewal, twenty-year termination periods, and withholding of rate discounts and protections upon notice of termination.[317]

In response, TVA argued that the plaintiffs lacked standing to bring either of their claims.[318] On the NEPA claim, TVA argued that it had reasonably determined that the contracts were not subject to NEPA, because they would merely continue the status quo: "TVA's generation facilities would continue to supply all of the LPC's power requirements just as they did before the LTAs were executed."[319]

TVA also contested the plaintiffs' TVA Act claim, claiming that judicial review was unavailable for TVA's supply contract terms, and, in the alternative, its contract did not violate the twenty-year limit. TVA argued that "Congress gave it to discretion to make rates"; that "defining the length of the [evergreen contract]

312. 42 U.S.C. §§ 4321-4370m-12.

313. Amended Complaint at P 191, *Protect Our Aquifer*, 654 F. Supp. 3d. 654 (No. 2:20-cv-02615-TLP-atc) [hereinafter Amended Complaint].

314. *Id.* PP 231-33.

315. *Id.* P 5.

316. 16 U.S.C. § 831i.

317. Amended Complaint, *supra* note 313, at PP 84-87, 245-46.

318. *See* TVA Motion to Dismiss at 15-20, *Protect Our Aquifer*, 654 F. Supp. 3d. 654 (No. 2:20-cv-02615-TLP-atc); TVA Motion for Summary Judgment at 39-44, *Protect Our Aquifer*, 654 F. Supp. 3d 654 (No. 2:20-cv-02615-TLP-atc).

319. TVA Motion for Summary Judgment, *supra* note 318, at 28-30.

qualifies as ratemaking"; and thus, the court "should decline to review the [contract] term."[320] TVA claimed that it exercises its "exclusive authority to set rates for the sale of TVA electricity . . . primarily through the contracts it enters into with LPCs"[321] and cited a line of precedent "recogniz[ing] the broad discretion Congress gave the board to set power rates and the terms and conditions of TVA's power contracts."[322] Contract length was one such term, and was therefore unreviewable.[323] Moreover, TVA argued, the contract term did not exceed twenty years: "the amended section contemplates three separate, distinct periods of fixed duration: an initial term of 20 years, automatic or evergreen 1 year renewal term(s), and a termination notice period." Advancing a formalist argument that did not recognize the interactions between these provisions and other provisions, TVA concluded that "there are no circumstances under which the [contract] is for a term exceeding 20 years."[324]

At the motion to dismiss stage, Judge Thomas L. Parker of the Western District of Tennessee ruled for the plaintiffs, holding that they had met their burden to establish standing on both claims[325] and had successfully shown that judicial review was available for the contract terms. On reviewability, Judge Parker explained that TVA had not provided "clear and convincing evidence that Congress intended to eliminate judicial review" for TVA contract terms.[326] Notwithstanding TVA's broad rate-making authority, Congress had expressly limited its supply contract terms to twenty years. The court found that it had jurisdiction to review whether TVA "clearly violate[d]" the TVA Act.[327]

Following an embattled period of discovery,[328] TVA finally prevailed against the plaintiffs on summary judgment. On their TVA Act claims, the court found that the plaintiffs did not meet the increased evidentiary burden required to establish standing following discovery.[329] In a footnote, the court opined that it nevertheless would have ruled for TVA on the merits.[330]

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320. Protect Our Aquifer v. TVA, 554 F. Supp. 3d 940, 948 (W.D. Tenn. 2021).

321. TVA Motion to Dismiss, *supra* note 318, at 3-4 (citing 16 U.S.C. § 831a(g)(1)(L)).

322. *Id.* at 8-10.

323. *Id.* at 9.

324. TVA Motion for Summary Judgment, *supra* note 318, at 22-23.

325. *Protect Our Aquifer*, 554 F. Supp. 3d. at 952-53, 956.

326. *Id.* at 949-50.

327. *Id.* at 950.

328. *See* Protect Our Aquifer v. TVA, No. 2:20-cv-02615-TLP-atc, 2022 WL 341014 (W.D. Tenn. Jan. 24, 2022) (order granting in part motion to complete the administrative record).

329. *See Protect Our Aquifer*, 654 F. Supp. 3d at 668-684.

330. *Id.* at 684 n.8 ("Defendant's contractual regime—with a twenty-year initial term, twenty-year termination notice requirement, and an evergreen provision—is a deliberate attempt at maximizing TVA's Congressional authority under Section 10. Defendant's push for these contractual provisions may be zealous, extravagant, and some might say excessive. But they are not unlawful. . . . Section 10 is silent on evergreen provisions, which are legally valid under federal common law of contracts. . . . And as for termination, Section 10 . . . has no explicit notice requirement for contracts for the sale of power to public utilities. . . . And so, termination notice in contracts for the sale of public power falls within Defendant's discretion—so long as the contract's length is for a term of twenty years." (internal citations omitted)).

The Court found that the plaintiffs did have standing to bring their NEPA claims, particularly due to the informational injuries they suffered from TVA's decision not to conduct and publish an environmental review.[331] But it decided that TVA's decision was a reasonable one and granted TVA's motion for summary judgment.[332] The plaintiffs did not appeal.

Beyond its disposition in favor of TVA, *Protect Our Aquifer* contained subtle wins and losses for both sides. The court's finding that TVA's contract term was reviewable under the APA was a genuine win for the plaintiffs and future parties seeking to hold TVA accountable. It illustrated that the discretion often afforded to TVA ratemaking will not necessarily extend to every component of TVA's relations with its contractual counterparties. On the other hand, the court's dictum about the permissibility of the "never-ending" contracts suggests that courts are comfortable affording TVA deference even after finding grounds for judicial review. Finally, the court's denial of standing to plaintiffs on their TVA Act claim illustrated its hesitancy to recognize the connection between TVA's monopoly power and future greenhouse gas emissions.

V. EPILOGUE: EFFORTS AT REFORM IN THE FIVE YEARS SINCE THE 2019 ALL-REQUIREMENTS CONTRACTS

TVA prevailed in *Athens Utilities Board* and *Protect Our Aquifer*. FERC and the district court left largely unchecked TVA's ever-growing dominance over its customers, competitors, and other stakeholders. Few existing legal levers remain to bring the benefits of open access to the Tennessee Valley through FERC or the courts.

As important as the potential foreclosure of legal pathways for challenging TVA is the power imbalance these cases left intact. By successfully defending its 2019 contracts, TVA effectively insulated itself from meaningful political pressure. As customers observed when the contracts were first introduced, the threat of distributors' departure created leverage to negotiate with TVA over prices, fuel mix, and other points of contention. The 2019 contracts—together with TVA's transmission dominance—obviate its customers' ability to bring TVA to the negotiating table.[333]

A few customers remain able to leave TVA. MLGW and North Georgia Electric Membership Cooperative, for example, both retained contracts with five-year termination periods and are located on the border of the Fence. These customers can leverage their ability to exit to gain concessions from TVA.[334]

One pathway to external legal oversight remains. Provoked specifically by FERC's decision in *Athens Utilities Board*, Congress—the only body with unquestionable political power and legal authority to affect change at TVA—began paying attention. In January 2022, the House of Representatives Committee on Energy and Commerce sent a letter to TVA expressing "concern[] that TVA's

331. *Id.* at 686-87.
332. *Id.* at 688-92.
333. *See supra* Part III.C.
334. *See supra* note 220 and accompanying text.

business practices are inconsistent with [its] statutory requirements to the disadvantage of TVA's ratepayers and the environment" and asking TVA to respond to sixteen detailed questions about its rates, energy mix, energy efficiency practices, compliance with PURPA, compliance with Biden Administration carbon emissions targets, and participation in and funding of lobbying against environmental regulations for the electric sector.[335]

In September 2022, Representative Steve Cohen of Memphis—who touts himself as "a vocal critic" of TVA[336]—introduced legislation that would eliminate the TVA Fence, repeal FPA section 212(j), and subject TVA to the full gamut of FERC regulation.[337] In January 2023, Representative Tim Burchett of Knoxville introduced legislation to increase the transparency of TVA board meetings; the legislation is co-sponsored by Cohen and Representative Diana Harshbarger of Kingsport, Tennessee.[338] Cohen also introduced legislation seeking to reduce the salary of TVA's CEO (currently the highest paid employee of the federal government).[339] This growing pressure on TVA only increased after it ordered rolling blackouts across its territory in December 2022, two days before Christmas.[340]

Reform efforts in Congress gained further momentum in light of TVA's 2024/2025 IRP process. In May 2023, TVA initiated development of its 2024 IRP. A coalition of environmental groups pushed back on what they alleged was a lack of opportunity for broad stakeholder participation and transparency in the IRP process.[341] In March 2024, Representatives Burchett and Cohen introduced the TVA Increase Rate of Participation (IRP) Act, which would establish an Office of Public Participation at TVA, increase opportunities for public comment on TVA IRPs, and mandate disclosure of certain information in TVA IRPs.[342]

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335. Letter from Reps. Frank Pallone, Jr., Bobby L. Rush, Diana DeGette, & Paul D. Tonko, House Comm. on Energy and Com., to TVA CEO Jeffrey J. Lyash (Jan. 13, 2022), https://cleanenergy.org/wp-content/uploads/TVA-Letter-re-business-practices-and-adherence-to-TVA-Act.pdf.

336. *See* Press Release, Congressman Chen Introduces Tennessee Valley Authority Reform and Consumer Protection Act (Sept. 29, 2022), https://cohen.house.gov/media-center/press-releases/congressman-cohen-introduces-tennessee-valley-authority-reform-and.

337. *See* TVA Reform and Consumer Protection Act, H.R. 9042, 117th Cong. (2022). The bill would also strike the 20-year limit on the duration of TVA's supply contracts.

338. *See* Tennessee Valley Authority Transparency Act of 2023, H.R. 404, 118th Cong. (2023).

339. *See* H.R. 7673, 117th Cong. (2022); H.R. 6761, 117th Cong (2022). *See also* Toby Sells, *Cohen Bill Would Likely Lower TVA CEO Salary*, MEMPHIS FLYER (May 6, 2022), https://www.memphisflyer.com/cohen-bill-would-likely-lower-tva-ceo-salary.

340. Austyn Gaffney, *TVA Reaches an Inflection Point*, SIERRA (Feb. 18, 2023), https://www.sierraclub.org/sierra/tva-reaches-inflection-point; Anila Yoganathan, *3 takeaways from TVA's report to Tennessee lawmakers about December's rolling blackouts*, KNOXVILLE NEWS SENTINEL (Feb. 8, 2023), https://www.knoxnews.com/story/news/local/tennessee/2023/02/08/tva-takeaways-december-rolling-blackouts-tennessee-lawmakers/69881921007/.

341. Amanda Durish Cook, *Nonprofits Attempt to Force a More Transparent TVA IRP Process*, RTO INSIDER (Nov. 5, 2023), https://www.rtoinsider.com/60520-nonprofits-force-more-transparent-tva-irp-process/. TVA released a draft IRP for public comment in September 2024. TVA, 2025 INTEGRATED RESOURCE PLAN, https://www.tva.com/environment/integrated-resource-plan.

342. TVA Increase Rate of Participation Act, H.R. 7595, 118th Cong. (2024); *see also* Amanda Durish Cook, *Tenn. Congressmen Introduce Bill to Make TVA IRP Process More Public*, RTO INSIDER (Mar. 10, 2024), https://www.rtoinsider.com/73350-tenn-reps-introduce-bill-tva-irp-process-more-public/.

Like the wave of reforms that preceded them in the 1990s, these efforts have not become law. But they may nonetheless have some effect in pressuring TVA to change in order to stave off further threats of reform. In 2024, for example, the TVA Board assembled a task force to examine CEO compensation and adopted reforms such as lowering end-of-year incentive payments[343] and tying performance measures to addition of renewable energy generating capacity, energy conservation, and demand response to the TVA system.[344]

VI. CONCLUSION

TVA has a complex role to play in the Tennessee Valley region. With its lack of state or federal regulatory oversight, its plenary rate-setting authority, and its persistent insulation from open access mandates, TVA has greater monopoly and monopsony power than perhaps any other utility in the United States. It has exercised this power to unilaterally increase rates, make short-sighted investment decisions, and coerce its customers into signing deeply one-sided contracts. For communities of the Tennessee Valley, TVA has been a longstanding and frequent perpetrator of environmental injustice,[345] including the 2008 Kingston coal ash environmental disaster, in which a dike failure released 5.4 million cubic yards of coal ash from the Kingston Fossil Plant into the Emory River.[346]

On the other hand, TVA is a politically accountable arm of the federal government, with leadership appointed by the President and confirmed by the Senate. It is among the many transformative government projects championed by FDR's New Deal. It is a major employer of unionized workers in the Tennessee Valley.[347]

343. Daniel Dassow, *TVA board, let by Biden picks, asserts power to overhaul CEO's record-high salary*, KNOXVILLE NEWS-SENTINEL (May 10, 2024), https://www.knoxnews.com/story/news/local/2024/05/10/tva-board-reduces-ceo-pay-as-highest-paid-federal-job-faces-scrutiny/73627788007/.

344. *See* TVA, CURRENT REPORT (FORM 8-K), at 3 (Sept. 17, 2024), https://tva.q4ir.com/financial-information/sec-filings/sec-filings-details/default.aspx?FilingId=17847608.

345. *See., e.g*, Pearl Walker & Rev. Michael Malcom, *TVA must address its history of environmental injustice*, THE TENNESSEAN (Nov. 3, 2022), https://www.tennessean.com/story/opinion/contributors/2022/11/03/opinion-tva-must-address-history-environmental-injustice-coal-ash-spill-kingston/69614931007/; Chloe Hilles, *Long burdened by a coal plant, South Memphis residents say no to coal ash in their backyard*, ENERGY NEWS NETWORK (Aug. 22, 2022), https://energynews.us/2022/08/22/long-burdened-by-a-coal-plant-south-memphis-residents-say-no-to-coal-ash-in-their-backyard/; Dulce Torres Guzman, *Public records show TVA planned coal ash storage months before informing Memphians*, TENN. LOOKOUT (May 12, 2022), https://tennesseelookout.com/2022/05/12/public-records-show-tva-planned-coal-ash-storage-months-before-informing-memphians/; Oliver Houck, *Unfinished* Stories, 73 U. COLO. L. REV. 867, 921–42 (2002). *See also* NANCY L. GRANT, TVA AND BLACK AMERICANS: PLANNING FOR THE STATUS QUO, at xv–xvii, xxix–xxxi (1990).

346. *See* Inspection Report: Review of the Kingston Fossil Plant Ash Spill Root Cause Study and Observations about Ash Management, TVA Office of the Inspector Gen. (July 23, 2009), https://www.oversight.gov/sites/default/files/oig-reports/TVA/2008-12283-02.pdf; Joel K. Bourne, Jr., *Coal's Other Dark Side: Toxic ash that can poison water and people*, Nat'l Geographic (Feb. 19, 2019), https://www.nationalgeographic.com/environment/article/coal-other-dark-side-toxic-ash.

347. TVA 2022 10-K, *supra* note 193, at 39.

Its corporate purpose is to further economic development of the Tennessee Valley region and better the lives of its residents,[348] not to maximize shareholder profits.

Understanding TVA's actions—here, its pursuit of control over its customers and resistance to reform—requires understanding its legal, political, and economic history and the institutional features that evolved from that history. TVA's reliance on debt financing, its large outstanding debt obligations, and its Fence explain why it is incentivized to retain customers. Its statutory self-regulation and immunity from open-access transmission policy enable it to do so through more onerous measures, and with less accountability, than those available to other utilities.

In a press release following a 2023 TVA price hike,[349] the Assistant General Manager of Athens Utilities Board lamented: "We have a hard time understanding why TVA can't operate more like a true public power provider."[350] He captures the problem perfectly. TVA is the definitive American public power provider. Yet to secure its own continuity, it systematically behaves like a market power-seeking private corporation. Throughout its history, TVA has secured its dominance in the Tennessee Valley through an ever-increasingly-burdensome all-requirements relationship with its customers. In recent years, that dominance has been threatened by the rise of market competition and affordable clean energy in the electric sector. TVA will surely continue to be a site of contestation as these forces clash.

348. *See* McCarthy, *supra* note 43, at 116 ("[TVA] is . . . convincing proof that the economic problems of a great river valley were capable of solution through democratic means.").

349. TVA raised its rates 4.25% in October 2023 and 5.25% in October 2024. *See* Dave Flessner, *TVA to boost electric rates this fall by biggest amount in a decade*, CHATTANOOGA TIMES FREE PRESS (Aug. 22, 2024), https://www.timesfreepress.com/news/2024/aug/22/tva-to-boost-electric-rates-this-fall-by-biggest/. Together, these rate hikes fall just under the 10% cap established in the 2019 contracts. *See supra* note 185 and accompanying text.

350. Press Release, Athens Utils. Bd., *supra* note 2.

INNOVATING SMART GRID: A UTILITY CASE STUDY OF "POWERING" PARADOX

By Lawrence Luong[*]

Synopsis: Since enactment of the American Recovery and Reinvestment Act (ARRA) in 2009, billions of public and private investment dollars have gone into deploying smart grid projects which utilities typically consider high risk. This article offers an analysis of utility smart grid innovation through research on U.S. power sector deployment and, specifically, from a case study of how a municipal utility implemented its smart grid with AARA funding. Examining the "SmartSacramento" project that digitized electric distribution infrastructure at the Sacramento Municipal Utility District (SMUD), data gathered from former project team members revealed creative decision-making and adaptive practices functioning to navigate tensions within a risk-averse organization to successfully innovate. SMUD's experience developing its smart grid highlights lessons for electric sector decision-making as utilities pursue innovation pathways to reduce carbon emissions from their operations. Among key implications of this research is that utility sector stakeholders may be well advised to examine ways their organizations might "power" paradoxes to innovate towards a lower carbon future.

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I. INTRODUCTION

U.S. federal investment in smart grid innovation that began with the $4.5 billion American Recovery and Reinvestment Act of 2009 (ARRA) has continued under the Bipartisan Infrastructure Law.[1] The Department of Energy (DOE) is currently administering $10.5 billion in grid modernization funding through the Grid Resilience and Innovation Partnerships (GRIP) program of which $3 billion is designated for smart grid projects.[2] The term smart grid used in this article refers to an electric grid operating with networked power meters commonly known as smart meters, sensors, software, and automated system interconnections designed to enhance system reliability by enabling efficient communications, monitoring,

1. The statute also commonly known as the Infrastructure Investment and Jobs Act authorizes the Department of Energy to administer over $62 billion for energy infrastructure investments that includes $14 billion in financial assistance to States, Indian Tribes, utilities, and other entities who provide products and services for enhancing the reliability, resilience, and efficiency of the electric grid. *See Bipartisan Infrastructure Law Grid Resilience*, NAT'L ENERGY TECH. LAB., https://netl.doe.gov/bilhub/grid-resilience (last visited Aug 1, 2024) (citing Bipartisan Infrastructure Law §§ 40,101, 40,103, and 40,107 (Infrastructure Investment and Jobs Act, Pub. L. No. 117-58, §§ 40,101, 40,103, 40,107, 135 Stat. 429, 904, 907, 915 (2021))).

2. *See Grid Resilience and Innovation Partnerships (GRIP) Program*, U.S. DEP'T OF ENERGY, https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program (last visited Jun 28, 2024) [hereinafter *GRIP Program*].

evaluation, and control through information technology.[3] Maturing from the ARRA-funded Smart Grid Investment Grant (SGIG) a decade ago that spurred nationwide upgrades from analog power meters to first generation digital metering systems, national smart grid policy implemented through GRIP aims today to:

> increase the flexibility, efficiency, and reliability of the electric power system, with particular focus on increasing capacity of the transmission system, preventing faults that may lead to wildfires or other system disturbances, integrating renewable energy at the transmission and distribution levels, and facilitating the integration of increasing electrified vehicles, buildings, and other grid-edge devices.[4]

Policy support directed towards smart grid has resulted in widespread adoption of advanced metering infrastructure (AMI) across the nation. The Federal Energy Regulatory Commission's (FERC) 2023 National Assessment of Demand Response and Advanced Metering indicated there were 115.3 million advanced meters operating in the U.S. out of 162.8 million total electric meters in 2021, marking a 70.8% penetration rate.[5] Growth of smart meters has thus been significant considering 2007 figures reported in FERC's first national assessment showed 6.7 million advanced meters used by consumers out of 144.4 million total meters (4.7% penetration rate).[6]

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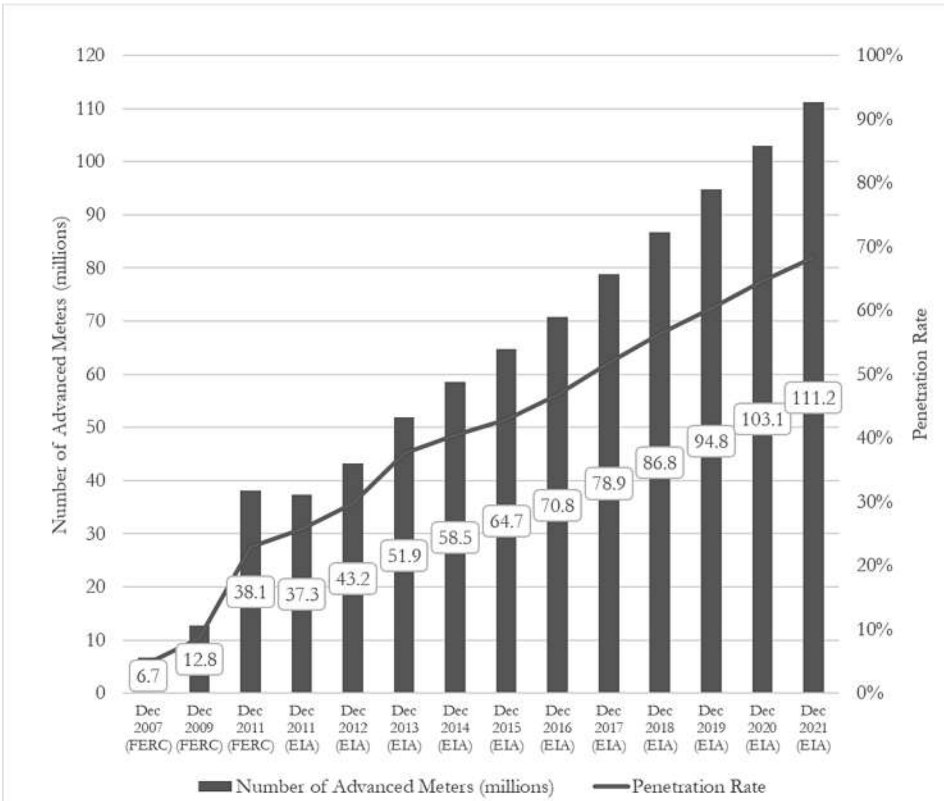
3. For adapting definitions of 'smart grid,' *see* You Zheng et al., *Proceeding with Caution: Drivers and Obstacles to Electric Utility Adoption of Smart Grids in the United States*, 93 ENERGY RES. & SOC. SCI. 1, 2 (2022) ("overlay of networked power meters, sensors, software, and automated system interconnections enabling greater efficiency and reliability of electricity management and use"); Jason Dedrick et al., *Adoption of Smart Grid Technologies by Electric Utilities: Factors Influencing Organizational Innovation in a Regulated Environment*, 25 ELEC. MKT. 17, 18 (2015) ("an electric grid whose operations employ information technology for communications," monitoring, evaluation, and control through information technology).

4. *GRIP Program*, *supra* note 2; *see* Derek Ryan Strong, *Impacts of Diffusion Policy: Determinants of Early Smart Meter Diffusion in the US Electric Power Industry*, 28 INDUS. & CORP. CHANGE 1343, 1345 (2019) (noting that integration of information and communication technologies into power grids is providing deeper levels of situational awareness of grid operations and capabilities through real-time sensing, control, and automation of power flow).

5. *2023 Assessment of Demand Response and Advanced Metering*, FERC 4-5 (Dec. 19, 2023), https://www.ferc.gov/news-events/news/ferc-staff-issues-2023-assessment-demand-response-and-advanced-metering; *Table 10.05 Advanced Metering Count by Technology Type, 2013 through 2022*, ENERGY INFO. ADMIN., https://www.eia.gov/electricity/annual/html/epa_10_05.html (last visited June 17, 2024) (U.S. Energy Information Administration data for 2022 indicates AMI meters installed totaled 118,722,741 out of 164,098,901 (72% penetration rate)).

6. *2023 Assessment of Demand Response and Advanced Metering*, *supra* note 5, at 4-5.

U.S. Advanced Meter Growth (2007-2021)[7]



Tracking the implementation of SGIG, a limited but growing body of research focusing on utility smart grid innovation[8] has emerged over the past decade. Diffusion policies influencing adoption of smart meters[9] within the U.S. power industry has been examined.[10] Scholars have analyzed factors impacting utility

7. *Id.* at 5, Fig. 2-1.

8. *See* Ernest J. Moniz, *Stimulating Energy Technology Innovation*, 141 DAEDALUS 81, 82 (2012) (innovation refers to "an integrated system, comprised of four interrelated components: Invention: discovery, creation of knowledge, and generation of prototypes; Translation: creation of a commercial product or process; Adoption: deployment and initial use of a new technology; and Diffusion: increasing adoption and use of a technology.").

9. Smart meters and 'advanced meters' will be used interchangeably in this article to refer to the same devices. *See* Strong, *supra* note 4, at 1344 (noting smart meters enable dynamic pricing of electricity at the retail level and provide basis for further industry innovation related to consumer engagement on electricity and home automation technology; "Smart meters refer to advanced electric meters based on digital technology that are capable of measuring and recording electricity consumption data in hourly intervals, or less, and capable of two-way communication between the electric power utility and the consumer.").

10. *Id.*

smart grid innovation given the regulated structure of the U.S. power sector[11] as well as those influencing smart grid adoption among investor- and community-owned utilities.[12] The institutional and organizational processes which drive innovation and deployment of smart meters have also been examined in a study of Washington State's utility sector.[13]

This article adds to the smart grid literature with findings from a case study of how such innovation[14] operated at a granular level within an individual U.S. municipal utility that executed a SGIG-funded smart grid deployment. The qualitative study examines SMUD's accomplishment a decade ago of its "SmartSacramento" grid modernization project. The research aims to illuminate decision-making of the teams that achieved SmartSacramento to identify insights assisting utility systems undertaking grid modernization and policymakers involved in advancing smart grid innovation as an energy policy matter. As U.S. electric utilities implement substantial investments of financial and human capital to modernize and upgrade power distribution systems, "know[ing] not only how to innovate but also how to make their innovation processes effective"[15] is essential for industry managers and policymakers to understand. Applying an organizational psychology lens, analysis of SmartSacramento from this study revealed team members practicing what scholars have labelled "paradox mindset," animated by and navigating tensions within the organization to achieve SmartSacramento. The implications of this research could prove strategic as utilities strive to decarbonize[16] at the pace and scale climate scientists predict will be required to avert the worst effects of human-caused climate change. In the highly regulated, organizationally risk-averse environment of the electricity sector, innovation in smart grid technologies provides an opportunity to examine how technology advancement vital to transitioning the electric grid towards a lower carbon future is achieved with resource constraints, siloed business units, resistance to change, and institutional inertia distinguishing utilities in full operation. In short, the research presented here

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11. *See generally* Dedrick et al., *supra* note 3.

12. *See generally* Zheng et al., *supra* note 3; Yue Gao et al., *A Spatial Analysis of Smart Meter Adoptions: Empirical Evidence from the U.S. Data*, 14 SUSTAINABILITY 1 (2022).

13. *See* Meghan Elizabeth Kallman & Scott Frickel, *Nested Logics and Smart Meter Adoption: Institutional Processes and Organizational Change in the Diffusion of Smart Meters in the United States*, 57 ENERGY RES. & SOC. SCI. 1 (2019).

14. Guoqiang Peter Zhang et al., *The Payback of Effective Innovation Programs: Empirical Evidence from Firms That Have Won Innovation Awards*, 23 PROD. & OPER. MGMT. 1401, 1408 (2014) ("By definition, innovation implies a deviation from conventional course of behaviors . . . [for which] firms . . . question their own assumptions and premise of existing practices . . . [in a] process [that] forces firms to think about new ways of combining resources[,] [] re-link knowledge components, . . . [and] coordinat[e] among separate units within the firm.").

15. *Id.* at 1418.

16. *For a livable climate: Net-zero commitments must be backed by credible action,* U.N., https://www.un.org/en/climatechange/net-zero-coalition (last visited Jul 14, 2024) ("The science shows [] that in order to avert the worst impacts of climate change and preserve a livable planet, global temperature increase needs to be limited to 1.5°C above pre-industrial levels. Currently, the Earth is already about 1.1°C warmer than it was in the late 1800s, and emissions continue to rise. To keep global warming to no more than 1.5°C – as called for in the Paris Agreement – emissions need to be reduced by 45% by 2030 and reach net zero by 2050.").

sheds light on utility innovation capabilities[17] by analyzing how innovation occurs within a U.S. electric utility, a topic which has yet to be studied in any systematic manner.

Accordingly, the remainder of this article is structured as follows: Section II recaps the federal policy context that led to current support for smart grid innovation. Section III discusses studies of U.S. smart grid deployment highlighting the results of grid modernization policy fostering ongoing smart grid buildout. The case study of SMUD's SmartSacramento implementation will be presented illustrating how team decision-making operated to innovate smart grid. Analysis of the research is informed and framed by innovation literature addressing the interrelated concepts of ambidextrous leadership, skunkworks, and paradox theory. Relying on studies to date of utility smart grid adoption,[18] Section IV discusses the effects organizational features such as size, ownership structure and regulatory choices have on smart grid development. Section V highlights implications of the SmartSacramento case study as utility mangers and policymakers nationwide navigate industry decarbonization efforts. Section VI describes recommendations for utility sector action. Section VII notes the study's limitations and identifies opportunities for additional research, and Section VIII concludes the discussion.

II. U.S. SMART GRID: FEDERAL POLICY CONTEXT

U.S. federal energy policy advancing smart grid technology – the suite of digital power meters, backend control systems, data gathering and processing technologies, and telecommunications utilities rely upon today to manage electric distribution and transmission networks – can be traced to the Energy Production and Conservation Act of 1976 (EPCA).[19] EPCA, enacted as a direct response to the oil embargo and energy crises of the 1970s, required the DOE to develop "design proposals" to promote energy conservation through improved electricity rate design which included reflecting the "marginal cost of service and/or time of use."[20] Time-of-Use (TOU) rates adjust electricity prices based on the time of day when energy is consumed thereby incentivizing consumers to use electricity during off-peak hours, reducing demand during peak times and enhancing grid stability.[21]

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17. *See* Zhang et al., *supra* note 14, at 1417 (noting that "firms' true innovation capabilities are often hard to observe directly").

18. Processes by which innovations are adopted include the transition from evaluation to deployment, routinization, and incorporation into organizational processes. *See generally* Zheng et al., *supra* note 3, at 2.

19. *See* Erwin Rose, *Smart Meters and Federal Law: What Is the Role of Federal Law in the United States in the Deployment of Smart Electricity Metering?*, 27 ELEC. J. 49, 51 (2014).

20. *See* James W. Moeller, *Electric Demand-Side Management Under Federal Law*, 13 VA. ENV'T L. J. 57, 62–64 (1993) (explaining directive to DOE on rate design set forth under 42 U.S.C § 6803 (a)(2)). While EPCA's provisions applied to federal agencies, manufacturers of residential appliances, and state energy conservation agencies, the statute did not impose energy conservation requirements on electric utilities. *Id*. at 63.

21. *See, e.g.*, *What Are Time-of-Use (TOU) Rates?*, CAL. PUB. UTIL. COMM'N, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-rates#:~:text=Time%2Dof%2Duse%20is%20a%20rate%20plan%20in%20which,in%20summer%20months%20than%20in%20winter%20months (last visited Oct. 20, 2024).

A. PURPA

Congress later broadened the basis for federal involvement in electricity under the Public Utility Regulatory Policy Act of 1978 (PURPA),[22] seeking to advance electricity conservation, efficient deployment and use of energy infrastructure by electric utilities, and equitable retail rates for electric consumers while regulating wholesale energy.[23] Title I of PURPA requires that electric utilities consider and potentially adopt as part of their ratemaking processes regulatory standards designed to encourage energy conservation, efficient resource use, and fair consumer rates. The statute mandates that state regulatory authorities and non-regulated electric utilities consider adopting standards to design rates reflecting the cost of providing service, discouraging declining block rates (lower rates for higher consumption) as such rates may not promote energy conservation, encouraging adoption of time-of-day rates reflecting the cost of electricity production fostering off-peak usage, suggesting rate designs reflecting seasonal variations in electricity demand, consider rates for customers willing to have their service interrupted during peak demand times, and encouraging utilities to implement technologies and practices to manage and reduce peak electricity loads.[24] Section 2621, as amended, provides additional "must-consider" standards including integrated resource planning to anticipate future energy needs of utilities, energy efficiency measure to reduce overall power demand and improve system reliability, and programs enabling consumers to adjust energy consumption in response to time-based power pricing information made directly accessible by electricity providers via smart grid applications.[25]

Since its enactment, "PURPA has garnered attention" for the statute's "successful promotion of cogeneration and small power production" yet its "principal target is retail regulatory policy for public utilities."[26] The statute established five standards for retail electric power rates and services summarized as follows:

> First, the provision of services should ordinarily exclude the installation of 'master meters' for multi-unit residential buildings. Second, the rates should not increase

22. *See generally* Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117 (codified as amended in scattered sections of 16 U.S.C.). General provisions applicable to this discussion can be found in 16 U.S.C. §§ 2601-2645 setting forth definitions, goals, and the specific regulatory and policy provisions introduced by PURPA.

23. Rose, *supra* note 19, at 52 (internal quotes omitted).

24. *See* 16 U.S.C. § 2621(d)(1)-(6) (2024).

25. *See id.* § 2621((d)(7)-(9), (16)-(21)).

26. Moeller, *supra* note 20, at 67–68 (noting that "PURPA devotes particular attention to electric power conservation, energy efficiency and equitable rates for utility consumers," reflected prior to its 1992 amendment the six policies for retail electric power rates and services set forth under Section 111 [16 U.S.C. § 2621(d)(1)-(6)]: (i) rates should reflect the actual cost of electric power generation and distribution; (ii) rates should not decline with increases in electric power use unless the cost of providing the power decreases as consumption increases; (iii) rates should reflect the daily variations in the actual cost of electric power generation; (iv) rates should reflect the seasonal variations in the actual cost of electric power generation; (v) rates should offer a special 'interruptible' electric power service rate for commercial and industrial customers; and (vi) each electric utility must offer load management techniques to their electric customers that will be practicable, cost effective and reliable, as determined by the state public utility commission).

> under automatic adjustment clauses, unless specific requirements are met. Third, services should ***provide information to electric utility customers concerning electric power rates***. Fourth, the services may not terminate electric power service except in accordance with specified procedures. Finally, 'no electric utility may recover from any person other than the shareholders . . . of such utility any direct or indirect expenditure by such utility for promotional or political advertising.' [emphasis added] [citations omitted][27]

"Congress designed PURPA to increase competition in wholesale and retail sales, and a key element of that involve[d] providing price signals through improved demand response."[28] The statute "expand[ed] federal reach in part due to the recognition that interstate wholesale markets cannot function efficiently without meaningful and dynamic retail price signals" for which:

> PURPA establishe[d] standards for 'cost of service' that fostered a policy rationale for improved metering, including 'time-of-day' rates, as well as 'interruptible rates' (for industrial and commercial users) and 'load management techniques,' and a general requirement that individual units have their own meters rather than one 'master meter' per building.[29]

Still, given the statute's express time limit of two years from enactment for states to complete determinations of its "must-consider" standards,[30] PURPA's impact on expansion of smart grid infrastructure nationally was arguably limited, particularly in comparison to direct federal funding of AMI buildouts under ARRA.

Subsequent to PURPA, the Energy Policy Act of 1992[31] "increased federal support for integrated resource planning (considering conservation and efficiency along with production), energy efficiency, and [demand side management]."[32] As a consequence, the statute "built up pressure for [advanced metering]" but did not explicitly address metering.[33]

B. EPAct '05 and EISA

Direct federal involvement in the promotion of advanced metering was effectuated under the Energy Policy Act of 2005[34] (EPAct '05) which amended PURPA.[35] While it did not mandate consumers receive dynamic pricing, EPAct '05 established new "must-consider" federal standards on "net metering" and

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27. *Id.* at 68–69 (citing 16 U.S.C. § 2623 *et seq*. and noting that Section 113 of PURPA "resembles Section 111 to the extent that the adoption and implementation of the five additional standards by state PUCs is not required," requiring only that the state commissions consider each standard and whether a particular standard should be implemented).

28. Rose, *supra* note 19, at 52.

29. *Id.* (citing 16 U.S.C. § 2623(b)(1)).

30. *See* 16 U.S.C. § 2622(b) (2024) (requiring states begin consideration within one year after the date of enactment of the Energy Policy Act of 2005 (by August 8, 2006) and to complete their determinations within two years (by August 8, 2007)).

31. Energy Policy Act of 1992, 42 U.S.C. §§ 13201-13574 (2024).

32. Rose, *supra* note 19, at 52.

33. *Id.*

34. Energy Policy Act of 2005, 42 U.S.C. §§ 15801-16539 (2024).

35. *See* Rose, *supra* note 19, at 52; *see also* 16 U.S.C. § 2622(b).

"time-based metering and communications" that furthered federal policies promoting advanced metering to deliver such energy use detail to consumers. Section 1252 titled "Smart Metering" specifically provided a standard on "time-based metering and communications" as follows:

> . . . [E]ach electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule . . . The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology . . . Each electric utility . . . shall provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such a rate, respectively.[36]

To carry out federal demand response policy goals, EPAct '05 directed DOE to "educat[e] consumers on the availability, advantages, and benefits of advance metering and communications technologies, including the funding of demonstration or pilot projects" among related steps "in support of demand response."[37] "[U.S. energy] policy has sought to expand the participation of the demand side in electricity markets and for prices in retail markets to reflect the time-varying costs of generating electricity" with "[t]ime-based rates [] intended to incentivize changes in consumption behavior to reduce peak demand."[38]

The Energy Independence and Security Act of 2007[39] (EISA) established smart grid deployment as U.S. policy to support "modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth" and achieve identified energy policy goals[40] collectively constituting "Smart Grid."[41] "Federal policy [] increasingly recognize[d] the need for improved demand response as part of the effort to improve interconnectivity and efficiency."[42] EISA established new federal standards for "'integrated resource planning,' 'rate design modifications to

36. Rose, *supra* note 19, at 53 (citing EPAct '05 provision codified as 16 U.S.C. § 2621(d)(14)(A), (C) (2024).

37. *Id.*

38. Strong, *supra* note 4, at 1345.

39. Energy Independence and Security Act of 2007, 42 U.S.C. §§ 17381-17392 (2024).

40. 42 U.S.C. § 17381 (2024) ("(1) Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid; (2) Dynamic optimization of grid operations and resources, with full cyber-security; (3) Deployment and integration of distributed resources and generation, including renewable resources; (4) Development and incorporation of demand response, demand-side resources, and energy-efficiency resources; (5) Deployment of ''smart'' technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation; (6) Integration of ''smart'' appliances and consumer devices; (7) Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning; (8) Provision to consumers of timely information and control options; (9) Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid; and (10) Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.").

41. *See id.*

42. Rose, *supra* note 19, at 53.

promote energy efficiency investments,' 'consideration of smart grid investments,' and 'smart grid information,' further strengthening the imperative for [advanced metering]."[43] Federal policy support for a 'smart grid' as stated in EISA identified "[d]eployment of 'smart' technologies . . . for metering, communications concerning grid operations and status, and distribution automation."[44]

Congress instructed federal agencies under EISA to effectuate smart grid nationally. DOE was directed to set up a federal Smart Grid Task Force[45] and Congress funded a federal program DOE would administer, in consultation with the FERC and other appropriate agencies, electric utilities, states, and other stakeholders, to support "Smart Grid Technology Research, Development, and Demonstration."[46] EISA further required the FERC to publish a "National Assessment of Demand Response" and "National Action Plan on Demand Response."[47]

C. Economic Stimulus Bills of 2008 and 2009

U.S. energy policy support for smart grid shifted to nationwide deployment by the time the U.S. financial crisis took hold in 2007-2008. The Emergency Economic Stabilization Act of 2008[48] (Stabilization Act) provided accelerated tax depreciation for smart meters from twenty to ten years incentivising advanced metering investments.[49] Federal policy by this stage sought to undertake nationally what scholars have called the "digital electricity transition,"[50] the evolution from

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43. *Id.*

44. *Id.*; *see* Strong, *supra* note 4, at 1345 (noting that metering technology is integrally tied to the structure of retail electricity rates which are ultimately limited by capabilities of power meters).

45. 42 U.S.C. § 17383(b) (2022).

46. 42 U.S.C. § 17384(a) (2022) ("(1) to develop advanced techniques for measuring peak load reductions and energy-efficiency savings from smart metering, demand response, distributed generation, and electricity storage systems; (2) to investigate means for demand response, distributed generation, and storage to provide ancillary services; (3) to conduct research to advance the use of wide-area measurement and control networks, including data mining, visualization, advanced computing, and secure and dependable communications in a highly-distributed environment; (4) to test new reliability technologies, including those concerning communications network capabilities, in a grid control room environment against a representative set of local outage and wide area blackout scenarios; (5) to identify communications network capacity needed to implement advanced technologies; (6) to investigate the feasibility of a transition to time-of-use and real-time electricity pricing; (7) to develop algorithms for use in electric transmission system software applications; (8) to promote the use of underutilized electricity generation capacity in any substitution of electricity for liquid fuels in the transportation system of the United States; and (9) in consultation with the Federal Energy Regulatory Commission, to propose interconnection protocols to enable electric utilities to access electricity stored in vehicles to help meet peak demand loads.").

47. 42 U.S.C. § 8279(a)-(b) (2022).

48. Emergency Economic Stabilization Act of 2008, 12 U.S.C. §§ 5201-5261 (2024).

49. *See* 26 U.S.C. § 168(e)(3)(D) (2023) (codifying Section 305 of the Stabilization Act accelerating tax depreciation period from 20 to 10 years for certain energy property including smart meters and smart grid systems); *see also*, Strong, *supra* note 3, at 1347; Rose, *supra* note 19, at 54.

50. Ryan Thomas Trahan & David J. Hess, *Who Controls Electricity Transitions? Digitization, Decarbonization, and Local Power Organizations*, 80 ENERGY RSCH. & SOC. SCI. 1 (2021).

analog to digital technologies within the power sector which "represent[ed] a fundamentally changed approach to electricity management."[51] The following example illustrates that fundamental change established for utility operations:

> In the analog era, responding to an outage often meant relying on the long experience and deep system knowledge of line engineers as a crucial variable in identifying and responding to the issue. Today's outage management systems use [Geographical Information System] GIS and real-time monitoring data (including from [System Control and Data Acquisition] SCADA and AMI systems), together with automated algorithms, to analyze system data to predict the location and sequences of propagating outages . . . if a single customer (or the system) reports an outage, the system may predictively trace the problem to a meter and initiate communication; if two neighbors report outages, then an algorithmic prediction might be made that the issue is traceable to the transformer; and so on up the grid network, fuse, line, and substation breaker. As that data reporting is fed into the master network control, the operator (or system) may communicate with switches, relays, and reclosers to isolate and/or resolve the problem.[52]

In wake of the Great Recession, the federal government began implementing ARRA in 2009 which included $4.5 billion for grid modernization.[53] ARRA specifically provided over $3.48 billion to fund the SGIG administered by the DOE.[54] "[T]he . . . (ARRA) emphasized innovation, particularly in the clean technology and renewable energy sectors . . . [with] the largest ever one-time investment in upgrading the U.S. electrical infrastructure, mitigat[ing] some of the risk of innovation, and support[ing] utilities in sharing their experiences throughout the electric industry."[55] Through the SGIG program, DOE together with industry invested approximately $9.5 billion in 99 cost-shared projects involving more than 200 participating electric utilities and other organizations to "modernize the electric grid, strengthen cybersecurity, improve interoperability, and collect an unprecedented level of data on smart grid operations and benefits."[56] A summary of benefits and costs of smart grid technologies is provided in Figure 1.

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51. *Id.* at 3.

52. *Id.* at 4.

53. American Recovery and Reinvestment Act of 2009, Pub. L. No. 111-5, 123 Stat. 115 (2009).

54. *See 2009 American Recovery and Reinvestment Act*, U.S. DEP'T OF ENERGY, https://www.energy.gov/oe/2009-american-recovery-and-reinvestment-act (last visited Jun 22, 2024).

55. Kallman & Frickel, *supra* note 13, at 4.

56. *2009 American Recovery and Reinvestment Act*, *supra* note 54.

Figure 1: Benefits and Costs Resulting from Smart Grid Technologies[57]

Technology	Grid Benefits	Benefits Beyond the Grid		Investment and Operation & Maintenance Costs
		Environmental	Others	
Advanced Metering Infrastructure	-Lower billing costs due to a more autonomous systems; -Lower costs related to billing complaints once the AMI system provides a more timely and accurate procedure; -Potential infrastructure cost savings once the AMI may help avoid or delay investments and integrated and responsive voltage regulation; -Lower costs related to the theft of electricity; -Potential reduction on network operation costs once AMI allows obtaining helpful information to define a more proper network operation; -Lower electricity quality monitoring costs.	-Benefits resulting from avoided emissions; -Better operation of the networks, namely due to better management of the load flows and to the development of Demand Response technologies; -Energy efficiency in delivery and use of electricity; -Faster integration of distributed renewable generation; - Ability to create a market of emissions.	-Potential lower energy costs once AMI can provide information on electricity prices and consumption patterns; -Potential income resulting from more active participation in electricity markets, as well as in providing system services; -Electricity cost savings resulting from energy sharing in collective self-consumption activity. **Retailers/aggregators:** -Development of new pricing strategies, which can help in attracting new customers; -Possibility of developing new activities such as aggregating production, consumption, or storage capacity. **Society:** -More efficient electricity usage and higher self-generation integration based on renewable resources contribute to less dependence on energy imports.	Deployment of a suitable AMI implies costs related to investment and related to the operation and maintenance of the system. Investment costs are mainly related to: -Smart devices to be installed at user points; -Communication network; -Installation of the devices and communication systems; -Software for data collection, analysis and storage. Data collection, analysis, storage, and system management result in operation and maintenance costs. Another cost that can be important is associated with the necessary updating of security systems against cyberattacks, which will have to be maintained over the years.
Advanced, Substation, Feeder Automation	-Lower financial losses related to energy not distributed and compensations for violation of quality of service indicators. As well, ASFA allows a faster and more automated and autonomous network reconfiguration after a fault/outage situation; -Optimization of assets and efficient operation of the network; -More intelligent asset management, including better planning of preventive and corrective maintenance; -Ability to prevent potential failures, detect and predict disturbances, fluctuations and monitor equipment health; -Improved management of distributed energy resources, including microgrid operation and storage management; -Easier accommodation of distributed generation (DG) storage systems in a plug-and-play regime.	Avoided emissions resulting from: -A more efficient operation of the networks; -More easy and coordinated integration of DG, mainly renewable generation; -Lower downtime of renewable-based distributed generators due to network unavailability.	**Consumers:** -A more reliable system and high-quality electricity for the digital society; -A more secure system, reducing the possibility of power blackouts. **Society:** -Higher integration of DG, including self-generation, contributing to less dependence on energy imports.	Implementation of an ASFA includes investment costs in hardware and software resources, namely: -Sensors: smart relays, phasor measurement units, voltage and current measurement units, remote fault indicators (that detect current and voltages levels on feeders that are outside usual operating boundaries); -Actuators: circuit breakers, capacitor bank switches, automatic voltage regulators, reclosers, and load tap changer controllers; -Fast communication platforms; -SCADA equipment; -Wide range of software applications, including SCADA software, online and offline applications for monitoring and diagnostics of primary substations and line equipment, communication protocols, and Digital Twin software platforms. The maintenance costs are related to the equipment installed to establish the ASFA. ASFA is expected to operate autonomously but with some staff costs. The necessary updating and maintenance of security systems against cyberattacks is another cost to consider.

57. *See* Vítor Marques et al., *Greater than the Sum: On Regulating Innovation in Electricity Distribution Networks with Externalities*, 79 UTIL. POL'Y 1, 3-4 (2022).

According to DOE, the ARRA investments "helped utilities take [] first steps" mitigating risks associated with adopting new smart grid technologies, share learnings preparing the industry to "meet the needs of a growing digital economy, enable greater levels of clean energy deployment, and strengthen the electric grid to be more resilient to natural disasters and cyberattacks."[58] Researchers have commented that deployment of DOE's SGIG funds produced large-scale deployment of smart grid technologies providing utilities "critical operational experience . . . mov[ing] from the cycle of pilot projects to full-scale deployment in utility operations."[59]

Deployment of smart grid technologies, for example, is credited with enabling restoration of electric service within four days to CenterPoint Energy's nearly one million customers in Houston who lost power when Hurricane Harvey hit Texas in 2017.[60] CenterPoint's decade of investment in smart grid technologies[61] allowed the utility to locate, isolate, and repair outages more efficiently.[62]

III. U.S. SMART GRID INNOVATION: DEPLOYMENT STUDIES

The adoption and diffusion of smart grid technology have been the focus of increasing research on smart grid innovation by U.S. utilities.[63] Studies on smart grid advancements have attempted to illuminate technology adoption decisions in highly regulated sectors such as electric utilities.[64] Organizational choices by utilities to pursue smart grid development are made in context of their operations as legal monopolies under state and federal regulation.[65] Utilities face many of the

58. *The American Rescue and Reinvestment Act Highlights: Jumpstarting a Modern Grid*, U.S. DEP'T OF ENERGY, (Oct. 2014), https://www.energy.gov/sites/prod/files/2014/12/f19/SGIG-SGDP-Highlights-October2014.pdf [hereinafter *Jumpstarting a Modern Grid*].

59. Kallman & Frickel, *supra* note 13, at 5 (citing *Jumpstarting a Modern Grid*, *supra* note 58, at 2).

60. Zheng et al., *supra* note 3, at 1.

61. CenterPoint Energy was awarded a $200 million SGIG grant for its smart grid project completed in 2015 featuring installation of 2.2 million advanced meters, distribution system automation/upgrade for 187 of 1,516 circuits, distribution management systems, supervisory control and data acquisition (SCADA) communications network, equipment condition monitors, and 187 smart relays. *See Jumpstarting a Modern Grid*, *supra* note 58, at 21.

62. Zheng et al., *supra* note 3, at 1. As of the writing of this article, CenterPoint Energy in Houston reported more than 2 million homes and businesses without power in and around the nation's fourth-largest city after Hurricane Beryl swept into Texas on July 8, 2024. Mark Vancleave & Juan A. Lozano, *Beryl Weakens to Tropical Depression after Slamming into Texas as Category 1 Hurricane*, AP, https://apnews.com/article/hurricane-beryl-texas-7dfd5353671ee30d0c6d11518ea5a370 (last visited Jul 9, 2024) (reporting that the utility was bringing in thousands of additional workers to restore power with top priority for places such as nursing homes and assisted living centers).

63. *See generally* Strong, *supra* note 4; Dedrick et al., *supra* note 3; Zheng et al., *supra* note 3; Kallman & Frickel, *supra* note 13.

64. *See, e.g.*, Strong, *supra* note 4, at 1343 (noting "[s]ectoral innovation systems in heavily regulated industries are strongly influenced by public policy, and regulation can play a definitive role in the diffusion of new technologies by either enabling or hindering adoption").

65. *See* Dedrick et al., *supra* note 3, at 20 (noting that "[i]n the case of electric utilities, the role of regulation is pervasive"); Kallman & Frickel, *supra* note 13, at 2 (identifying subject Washington State utilities as "legal monopolies within their established geographic service areas" which "function at the state level as oligopolies within the electricity districts they serve").

same competitive forces that private firms in unregulated industries do as well as constraints on their business and technology decisions.[66] "[Investor-Owned Utilities] IOUs must deliver profits to shareholders as if they operated in a private market[;] [community-owned utilities], on the other hand, are not allowed to earn profits, but they also are not allowed to charge too much or too little for the power they provide."[67] Furthermore, risks associated with technology innovation in a business that powers the lives of its customers are high. "[R]esearchers have noted that smaller LPOs [Local Power Organizations (municipal utilities, local government departments, electricity cooperatives, community choice aggregators)]" tend to take "a conservative position [] based partly on the traditional organizational focus of utilities on reliability and affordability and partly on an imputation of lack of customer demand for sustainable change."[68] "Of greatest relevance . . . is the recognition of the financial barriers that small electricity cooperatives face . . . many [] have fewer than 10,000 end users."[69] Uncertainty with cost recovery for deploying smart meters allowed by state public utilities commissions delay technology adoption decisions of IOUs.[70] "Given the relative lack of competition among utilities, heavy state and federal regulation, and high risks of technological change, utilities have few obvious incentives for developing and implementing new, and largely untested, smart metering technology."[71] Nonetheless, utilities small and large, cooperatives (co-ops), municipal systems, and IOUs have innovated, deploying smart grid infrastructure nationwide. Industry innovation research has sought to explain how utilities achieve smart grid innovation. We now turn to consider what the studies indicate.

A. Washington State Study

Researchers applying an analytic model of "institutional logics"[72] found that ARRA funding was instrumental in helping Washington State's otherwise risk-averse utilities to pursue and complete deployment of smart grid. With electric utilities, "[i]nstitutional norms include reliance on non-utility organizations (e.g. vendors, academic researchers, national labs) to drive innovation, knowledge sharing and cooperation among utilities who do not compete directly with one another, and reliance on public funding to reduce the cost and risk of investment in new

66. Kallman & Frickel, *supra* note 13, at 2.

67. *Id*.

68. *See* Trahan & Hess, *supra* note 50, at 2.

69. *See id.* at 2, 7 (noting that with respect to broader national energy transition "[d]igitialization presents a fundamental yet separable set of challenges for the [Local Power Organization (municipal utility, local government department, electricity cooperative, or community choice aggregator)] and the community it serves").

70. *See* Strong, *supra* note 4, at 1347.

71. Kallman & Frickel, *supra* note 13, at 2.

72. *Id.* at 4 (defining the term to refer to "shared practices, beliefs and values that govern how a particular social world works.") (quoting PATRICIA THORNTON & WILLIAM OCASIO, INSTITUTIONAL LOGICS 101 (R. Greenwood, C. Oliver, R. Suddaby & K. Sahlin-Andersson eds., SAGE 2008); *see* Zheng et al., *supra* note 3, at 3 (explaining the framework "looks at how cultural schema shape organizational behavior" with individual organizations having their own internal cultures which operates and interacts with larger external cultures).

innovations."[73] "[I]n Washington's electric power field, innovation emerge[d] through collaborative networked partnerships among like organizations, because regulation *prohibits* competition. [emphasis in original]"[74] The study found that collaboration among public, private, and cooperatively owned utilities, institutional processes and organizational changes "nested" across different governance scales (local, state, and federal) "dr[iving] the deployment and adoption of smart meters."[75]

Personnel from the state's IOUs, co-ops, Public Utility Districts (PUDs), and municipal utilities constituted the bulk of the fifty-two respondents interviewed by the researchers.[76] The remainder of those interviewed represented Washington utility trade groups, technology firms, university and national labs, and consumer advocacy groups.[77] The study found that "[a]lthough utilities are the dominant actors in the Washington energy field, they do not act independently . . . their behavior is conditioned through relationships with other organizational actors at other levels, all of whom . . . make decisions guided by institutional logics . . . ."[78]

B. SmartSacramento Case Study

In October 2009, DOE awarded SMUD an SGIG grant totalling $127.5 million to execute its project titled "SmartSacramento." Combined with SMUD's own capital and other grant funding, the project budget totalled nearly $360 million[79] to "[i]nstall a comprehensive regional smart grid system from transmission to the customer that include[d] 600,000 smart meters, dynamic pricing, 100 electric vehicle charging stations and 50,000 demand response controls including programmable smart thermostats, [and] home energy management systems."[80] The scope of SMUD's smart grid work covered the Electric Distribution Systems, AMI, and Customer Systems categories[81] targeted by the SGIG.

1. Innovation Achievements

During the subsequent three-year grant implementation period, SMUD (with approximately 2,100 employees at the time) organized internal teams to complete over fifty subprojects across eight main topic areas (Advanced Metering Infrastructure, Distribution Automation, Consumer Behaviour Study informing electric

73. Zheng et al., *supra* note 3, at 3.

74. Kallman & Frickel, *supra* note 13, at 8.

75. *Id.* at 1-2.

76. *Id.* at app. A.

77. *Id.* at 2-3.

78. Kallman & Frickel, *supra* note 13, at 4.

79. *SmartSacramento: 2009-2014*, SMUD 3 (Aug. 2013), https://www.smud.org/-/media/Documents/Corporate/About-Us/Energy-Research-and-Development/SmartSacramento-Fact-Sheet.ashx (Report pursuant to DOE Award No. OE0000214) [hereinafter SmartSacramento].

80. *Recovery Act Selections For Smart Grid Investment Grant Awards - By Category*, U.S. DEP'T OF ENERGY 7, https://www.energy.gov/oe/articles/recovery-act-selections-smart-grid-investment-grant-awards-category-updated-november (last visited Jun 22, 2024).

81. The four project types under the SGIG were Electric Transmission Systems, Electric Distribution Systems, Advanced Metering Infrastructure, and Customer Systems. *See Jumpstarting A Modern Grid*, *supra* note 58, at 7.

pricing, Demand Response, Customer Applications, Technology Infrastructure, Cyber Security, and Research and Development). Collectively, this smart grid implementation digitized SMUD's power metering infrastructure, facilitating two-way electric meter data flow between the utility and its customers and enabling real-time operations visibility into its distribution operations for the first time in the utility's existence.

The largest portion of the SmartSacramento budget ($137.6 million) went to replacing 620,000 existing analog power meters with new smart meters, a foundational step enabling wireless communication for automated meter reading, improved bill accuracy, remote service connect/disconnect capability, enhanced outage management, and improved power theft detection. The new AMI system helped SMUD transition from manual meter operations mainly through automated meter reading and automated service switching saving the utility approximately $31.8 million in meter operation costs from project initiation through March 31, 2014.[82] Software platforms for meter data management and analysis were installed to organize, analyze, and make AMI data accessible to SMUD's enterprise systems that served to improve load forecasting and capital investment planning.[83]

SmartSacramento enabled SMUD's introduction to customers of time-based rate programs. With its advanced metering infrastructure[84] installed, SMUD created rate programs "based on TOU, critical peak pricing (CPP) [see Figure 2], and TOU combined with CPP."[85] Through early program offerings, selected SMUD customers could opt into the new rate programs or choose to keep their existing rates. Additional customers were placed on the new rates but were able to opt out. SMUD evaluated "the relative merits of these programs in terms of load impacts, customer acceptance, and cost effectiveness . . . aim[ing] [] to provide customers with greater control over their electricity bills and reduce peak electrical loads."[86] In 2018, SMUD defaulted its residential customers to its "Time of Day (TOD)" rate resulting in 98% of that customer group being included, enabling the utility to achieve an 8% (approx. 130 MW) peak customer load shift beginning in 2019.

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82. *Id.* at 58. Additionally, SMUD avoided an estimated 1.2 million vehicle miles previously required to manually read meters from project initiation through March 31, 2013. *Id.* at 59. Based on SMUD's prior use of gasoline cars and light-duty trucks to read meters, and assuming 23.4 miles per gallon per vehicle, SMUD avoided consuming 51,000 gallons of gasoline. *Id.*

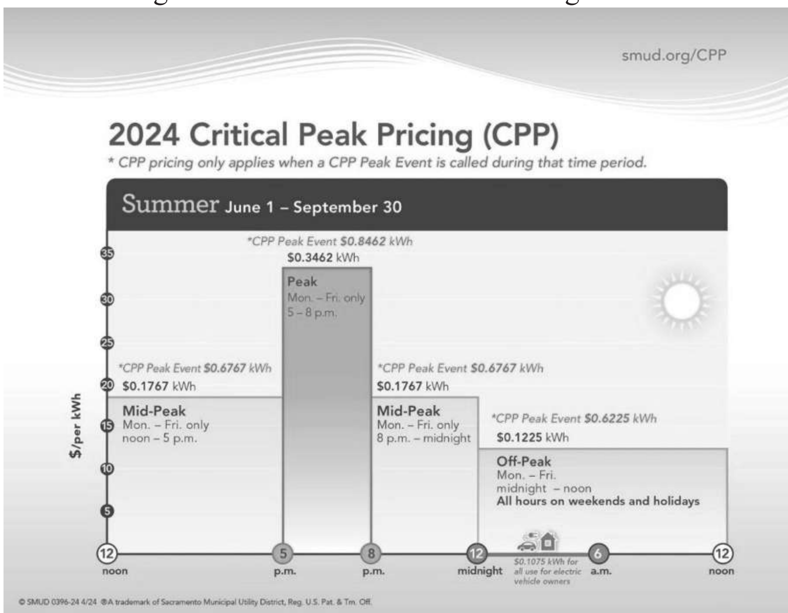
83. *See Jumpstarting A Modern Grid*, *supra* note 58, at 59.

84. SMUD's AMI utilized Landis+Gyr meters operating on Silver Spring Networks' two-way mesh network technology. *See SmartSacramento*, *supra* note 79, at 5.

85. *Jumpstarting A Modern Grid*, *supra* note 58, at 58.

86. *Id.*

Figure 2: SMUD Critical Peak Pricing Illustration[87]



Through SmartSacramento, SMUD modernized its distribution systems by deploying automated sectionalizing and restoration (ASR)[88] "equipment, reclosers, capacitor banks, and remote fault indicators integrated with SMUD's energy management system on 171 distribution circuits."[89] This equipment automatically

87. *Critical Peak Pricing*, SMUD, https://www.smud.org/Rate-Information/Residential-rates/Critical-Peak-Pricing (last visited Aug 1, 2024) ("CPP is designed to allow SMUD's customers to help reduce demand on the electric grid during times when energy demand is at its highest or there are emergency conditions with the power system." "Customers on CPP receive a discount of $0.020 on Time-of-Day off-peak and mid-peak prices from June 1 to September 30. The peak price is the same as the Time-of-Day peak price. During CPP Peak Events, an additional charge is added to the current time period's price. CPP Peak Events can be called any time of the day during the summer months (June 1 through September 30), including weekends and holidays, and only one event can be called per day. Events last 1 to 4 hours with a maximum of 50 hours total per summer. Events may span more than one time-of-day period. For example, an event may start during the mid-peak time period and end during the peak time period." SMUD notifies "participating customers a day in advance before a CPP event is called, though the utility may call the event with shorter notice during emergency situations." The following "prices and time periods are only for summer months." "Customers on CPP will have the same Time-of-Day Rate time periods and prices during non-summer months (October - May). All prices are measured in kilowatt hour (kWh): Off-Peak, Midnight – noon, Monday through Friday, all day on weekends and holidays ($0.1225 per kWh). This is a discount on the standard Time-of-Day off-peak price of $0.1425 per kWh; Mid-Peak, Noon – 5 p.m. and 8 p.m. – midnight, Monday through Friday ($0.1767 per kWh). This is a discount on the standard Time-of-Day mid-peak price of $0.1967 per kWh; Peak, 5 p.m. – 8 p.m., Monday through Friday ($0.3462 per kWh); EV discount, Midnight – 6 a.m., every day, all year long, including weekends and holidays ($0.1075 per kWh); CPP Peak Events ($0.5000 kWh + the price of the applicable time period when the event occurs. (Example: Peak price of $0.3462 + CPP Peak Event price of $0.5000 for a total of $0.8462 kWh)").

88. This equipment is commonly known in the power sector as fault location isolation and service restoration (FLISR).

89. *Jumpstarting A Modern Grid*, *supra* note 58, at 58.

responds to power disruptions by isolating faulted sections of circuits and rerouting power to customers. Among evaluations SMUD conducted with its SGIG funding, the utility determined that if the ASR and line automation upgrades deployed through SmartSacramento had been implemented in 2007–2012, the measures would have reduced the impact of outage events by 37% in terms of customer-minutes interrupted (a reliability metric of the total number of customers and the minutes they were without power known as SAIDI[90]), and the proportion of customers impacted (known as SAIFI[91]) by 41% based on historical reliability performance of SMUD's distribution grid and the observed performance of the ASR system.[92] Evaluating outage data over eighteen months from April 2013 through September 2014, a follow-up assessment showed that fully installed and operational[93] ASR and line automation upgrades would have achieved comparable reductions of 32% and 36% in SAIDI and SAIFI, respectively.[94]

Other improvements generated from the SGIG-funded SmartSacramento project included (i) system efficiency gains achieved through integrated voltage control from capacitor controllers and increase in distribution capacity through reduced energy losses on SMUD's distribution system, (ii) installation of nearly 10,000 residential and small commercial home area network (HAN) devices to provide customers with options to more conveniently manage their energy use, (iii) implementation of advanced energy management control systems with automatic demand response capability at customer facilities, (iv) deployment of programmable communicating thermostats and load-control switches that support load reduction or load shifting during periods of peak demand, and (v) installation of electric vehicle charging stations and advanced metering equipment at twenty parking spaces on college campuses and sixty residences across SMUD's service territory.[95]

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90. SAIDI is the "System Average Interruption Duration Index." SAIDI is calculated by summing the customer minutes of interruption (CMI) for sustained outages over a given period of time and dividing that total sum of CMI by the total number of customers served. CMI is determined for each sustained outage by multiplying the number of customers interrupted by the minutes they were interrupted for each outage/outage step. A sustained outage at SMUD is any outage greater than one minute.

91. SAIFI is the "System Average Interruption Frequency Index." SAIFI is calculated by summing the number of customers impacted by sustained outages over a given period of time and dividing that total sum of customers impacted by the total number of customers served. A sustained outage at SMUD is any outage greater than one minute.

92. *Theoretical Reliability Improvement: Line Automation & Automatic Sectionalizing and Restoration (ASR) Projects, Selected Feeder Outages from 2007 – 2012*, SMUD 4-5 (Dec. 27, 2023) (Report pursuant to DOE Award No. OE0000214).

93. Issues with communication systems caused line automation inoperability in 16 out of the 46 outages evaluated. Of the 30 outages where line automation was operable, the report noted "devices performed their automatic protective function and isolated the faulted section when applicable" resulting in actual reductions of 28% and 19% of SAIDI and SAIFI, respectively.

94. *2013-2014 Reliability Improvement Summary: Line Automation & Automatic Sectionalizing and Restoration (ASR) Projects*, SMUD (Dec. 23, 2014) (Report pursuant to DOE Award No. OE0000214, 9, Table 12).

95. *See generally SmartSacramento*, *supra* note 79; SMUD's service territory covers the geographic region encompassing California's capital city of Sacramento across approximately 900 square miles that includes Sacramento County and portions of Placer and Yuba Counties.

In short, SmartSacramento marked SMUD's transition from an analogue-metered electric utility to a modern smart grid-based system. The municipal utility which began service in 1946 was able in 2012 to detect lights were out in its service territory without someone reporting the outage. Before SmartSacramento's implementation, real-time visibility into functioning of SMUD's distribution system (i.e., SMUD's grid operators could tell instantly when power was out at a customer's location) and day-to-day distribution operations did not co-exist. SmartSacramento changed that by implementing a utility-wide innovation effort that transformed SMUD's power distribution system.

2. The Paradoxical Matter of Utility Innovation

SmartSacramento also marked SMUD's nearly seventy years of operations before the utility modernized its distribution system. Slow and incremental technological change is customary in the power sector. Utilities are risk averse. This reality juxtaposed with the fact SmartSacramento was executed on schedule as promised by SMUD raised the question addressed in the present research: How does a risk-averse utility innovate? Perhaps those who joined the teams implementing this grid modernization represented technical experts and staff more inclined to take risks conducive to innovation. Some of the interview data gathered for this study corroborated this theory, supporting the narrative that their achievement established the foundational grid infrastructure and customer programs SMUD today is building upon to become the first large utility in the U.S. to achieve a 100% carbon-free power generation portfolio by 2030.[96] However, a less obvious but more instructive issue is presented in the question itself: risk-aversion *and* innovat(ion) are contradictory yet interdependent concepts. SMUD's achievement of SmartSacramento represents paradox, a contradiction that demonstrated itself to be interdependent with the risk-averse utility culture from which the smart grid innovation project emerged. The research presented here sought to explain this and other related paradoxes characterizing the electric utility industry.

SMUD's goal to become carbon-free by 2030 is itself paradoxical. Utility-scale long-duration battery storage beyond four hours needed to achieve such goal is not currently feasible (reflecting underlying paradox of reality and fantasy). SMUD's target also assumes achievement of innovation magnitudes greater than it has ever achieved given its risk averse company culture (risk aversion – risk-taking). The utility aims to reach "Zero by 2030" keeping customer rate increases in coming years to less than inflation while managing mounting operational cost pressures (financial security – financial risk). Such interrelated, conflicting demands and expectations generate tension. For SMUD, there is considerable tension between its current reality and the zero-carbon power portfolio it strives to realize.

Today, SMUD is among utilities nationwide grappling with decarbonization, shifting from reliance on fossil fuel-powered electricity production to low- and even non-carbon-emitting generation. SMUD is one of over 2000 public power

96. *See generally 2030 Zero Carbon Plan*, SMUD (Apr. 2021), https://www.smud.org/-/media/Documents/Corporate/Environmental-Leadership/ZeroCarbon/2030-Zero-Carbon-Plan-Technical-Report.ashx.

systems[97] serving a quarter of the U.S. population including major metropolitan areas such as Los Angeles, New York, Seattle, Orlando, Austin, and Phoenix. In SMUD's case, its annual carbon emissions from power generation totals approximately 2 million metric tons.

The utility's strategic plan to reach Zero by 2030 calls for its natural gas plants, which SMUD relies upon to keep the lights on for 1.5 million residents to be re-designed to run on low- or non-carbon emitting fuel sources such as hydrogen. Utility-scale batteries currently still in early development would need to provide power when intermittent energy such as wind and solar are unavailable. Carbon emitted from natural gas-fired power generation would need to be piped into the ground and stored with carbon capture and sequestration to be demonstrated at utility scale. SMUD's plan to reach Zero by 2030 thus relies on technologies dependent on innovation to create solutions and scale them for wide use among the 3,000 electric utilities both public and private operating in the U.S. power sector.

In short, achieving Zero by 2030 requires that SMUD innovate – creating new solutions to operate carbon-free – at an unprecedented scale and speed. Yet, major tensions exist to accomplish such innovation: What resources—i.e., financial and staffing—are available to undertake the R&D needed? Why is SMUD busy with tomorrow's technology when it has a grid to manage today? How does any particular SMUD project make sense for an employee's career? The SMUD teams that executed SmartSacramento more than a decade ago faced many, if not all, of these same dilemmas. This study attempted to unpack their experience to provide strategic considerations for utility managers and policymakers involved in electric utility innovation efforts such as sector decarbonization.

3. Analytic Framework

This section summarizes the analytic framework applied in the research.

a. Ambidextrous Leadership

Within organizational psychology, the concept of "ambidextrous leadership" refers to the ability to both *explore*[98] creative ideas necessary for innovation and to *exploit*[99] innovations to materially benefit the organization.[100] This theoretical model posits that organizations that innovate with sustained success do so balancing demands for *exploration* of new alternatives, investing for future gains, and

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97. *See* Stephanie Lenhart et al., *Municipal Utilities and Electric Cooperatives in the United States: Interpretive Frames, Strategic Actions, and Place-Specific Transitions*, 36 ENV'T INNOVATION & SOCIETAL TRANSITIONS 17, 18 (2020) (noting that along with municipal systems, there are over 900 cooperative utility systems serving towns and localities across the U.S. "founded on shared principles of democratic accountability, local governance, and local rate regulation").

98. Kathrin Rosing et al., *Explaining the Heterogeneity of the Leadership-Innovation Relationship: Ambidextrous Leadership*, 22 LEADERSHIP Q. 956, 957 (2011) ("Explore" in the literature refers to organizational behavior associated with "increasing variance, experimentation, searching for alternatives, and risk taking.").

99. *See id* ("Exploit" refers to organizational behavior that features reducing variance, adherence to rules, alignment, and risk avoidance).

100. *See, e.g.*, *id*; Shuanglong Wang et al., *A Double-Edged Sword: The Effects of Ambidextrous Leadership on Follower Innovative Behaviors*, 38 ASIA PAC. J. MGMT. 1305 (2020).

exploitation of current capabilities seeking to maximize present profits.[101] *Exploration* features experimentation and ideation for 'radical' innovation typified by research and development (R&D) work; *exploitation* involves implementing ideas through processes and routines required for planning, performance of day-to-day operations, and for incremental innovation.[102]

Exploration involves learning that is "generative" (knowledge creation departing from a firm's existing knowledge base); "divergent" (generating multiple solutions from various perspectives of problem domain, seeing connections to provide meaningful 'gestalt' whole of domain); and "individual" (individual-based, intuitive).[103] In contrast, exploitation involves learning that is "adaptive" (incremental knowledge building based on firm's existing knowledge base), "convergent" (efficient, practical problem solving), and "organizational" (collective).[104] Researchers have observed that "[t]ension between divergent and convergent learning exists because creative energy without effective organizational control could lead to a fragmented organization without any synergy that is needed when exploiting opportunities."[105]

Studies have found numerous factors influencing organizational ambidexterity. "[P]sychological safety has a significantly positive impact on innovation performance."[106] CEO "transformational leadership" "can drive close to half of the organizational innovation outcomes" in a company.[107] Management able to "reconcile the contrasting and often conflicting definitions of exploration and exploitation" facilitates innovative work behavior of employees through knowledge-sharing.[108] Absent such knowledge-sharing, research has found ambidextrous leadership *negatively* impacts innovative work behavior.[109] "Distributed leadership" where multiple leaders throughout a firm "manage [] existing tensions that

101. Andrea Fosfuri & Thomas Rønde, *Leveraging Resistance to Change and the Skunk Works Model of Innovation*, 72 J. ECON. BEHAV. & ORG. 274, 276 (2009).

102. *See, e.g.,* Syed Arslan Haider et al., *How Does Ambidextrous Leadership Promote Innovation in Project-Based Construction Companies? Through Mediating Role of Knowledge-Sharing and Moderating Role of Innovativeness*, 26 EUR. J. INNOVATION MGMT. 99, 103 (2021) (explaining that gaining new external or tacit knowledge in the form of research and development is linked to irregular innovation and change, which is called 'exploration,' while developing current and overt knowledge is associated with incremental innovation known as 'exploitation').

103. Catherine L. Wang & Mohammed Rafiq, *Organizational Diversity and Shared Vision*, 12 EUR. J. INNOVATION MGMT. 86, 88-89 (2009).

104. *Id.* at 95-96.

105. *Id.* at 95.

106. Fuqiang Zhao et al., *Impact of Ambidextrous Human Resource Practices on Employee Innovation Performance: The Roles of Inclusive Leadership and Psychological Safety*, 26 EUR. J. INNOVATION MGMT. 1444, 1457 (2023).

107. Abdelrahman Zuraik & Louise Kelly, *The Role of CEO Transformational Leadership and Innovation Climate in Exploration and Exploitation*, 22 EUR. J. INNOVATION MGMT. 84, 96 (2019).

108. Haider et al., *supra* note 102, at 112.

109. *Id.* at 111 (finding that "leadership support without knowledge-sharing cannot cope and attain the desired results at the workplace [citation], as knowledge is an integral part of spreading awareness throughout the organization at almost every level of department through affective participation of a project leader in order to bring innovativeness to projects").

are based on different managerial [,][] knowledge capabilities and leadership functions" has been found to "boost[] ambidextrous innovation."[110]

b. Skunkworks

Separate and relatedly, "skunkworks" refers to innovation by teams operating in secret and/or separately outside typical organizational rules or norms.[111] The concept is named after the "Skunk Works" unit of Lockheed Martin, which functioned autonomously in complete secrecy within the company after WWII, developing cutting-edge military technology including "Stealth" fighter jets which evade radar.[112] Technology firms including Apple, IBM, Intel, and Siemens have implemented skunkworks to develop breakthrough technologies. Scholars have observed skunkworks "gives researchers the necessary autonomy, independence and freedom to escape the established lines of thought and to produce novel ideas" and "help to overcome the resistance that radical innovations meet inside the organization."[113]

F-117A Nighthawk Stealth Fighter aircraft flies over Nellis Air Force Base, Nevada, during U.S. Air Force joint service experimentation process dubbed Millennium Challenge 2002.[114]

110. Sarra Berraies et al., *Distributed Leadership and Exploratory and Exploitative Innovations: Mediating Roles of Tacit and Explicit Knowledge Sharing and Organizational Trust*, 25 J. KNOWLEDGE MGMT. 1287, 1305, 1308 (2021); *accord* Ruiqian Jia et al., *Ambidextrous Leadership and Organizational Innovation: The Importance of Knowledge Search and Strategic Flexibility*, 26 J. KNOWLEDGE MGMT.781 (2022).

111. *See* Shane Greenstein, *What Does a Skunk Works Do?,* 36 IEEE MICRO 70 (2016).

112. *See* BEN R. RICH & LEO JANOS, SKUNK WORKS: A PERSONAL MEMOIR OF MY YEARS AT LOCKHEED (1994).

113. *See* Fosfuri & Rønde, *supra* note 101, at 281.

114. *F-117A Nighthawk*, WIKIMEDIA COMMONS, https://en.wikipedia.org/wiki/File:F-117_Nighthawk_Front.jpg (last updated Aug. 11, 2021).

While research on actual skunkworks are rare, Donada et al. gained access to European automaker Peugeot's skunkworks group to study their development of a secret, low-emission vehicle propulsion system known as *Hybrid Air*.[115] Directors from different R&D departments were instructed by management to "make expertise available [for the project], even if it disrupted their department; this project was priority, even though they could not know what it was."[116] The Hybrid Air team operated without formal rules or organizational structures to foster speed and agility. An engineer in the study noted that, "[i]t was a phenomenal cohesion . . . [w]e trusted one another and developed a team spirit."[117] The team drew more than 100 people throughout the main organization and from external partners that "came together in a cross-functional platform, representing competencies in vehicle integration, powertrain development, marketing, and after-sales support."[118] Within two years, the Hybrid Air team delivered a Citroen model fully equipped with the newly invented Hybrid Air technology.

While the project demonstrated successful *exploration*, the lesson of Hybrid Air was failed *exploitation*. Electric mobility became the market choice for low emission transportation as Hybrid Air was being developed. Peugeot shut down its skunkworks unit shortly after Hybrid Air's unveiling and its participants were returned to positions within the main organization. "[T]he Hybrid Air team not its achievements have been reintegrated into the main organization because of 'not invented here' syndrome," the researchers noted.[119] "Hybrid Air members became 'skunks' to others, who avoided them."[120] Donada et al. thus observed a "double tension between the employees of the main organization who rejected Hybrid Air team members and the latter who no longer accepted the processes of the central organization."[121] "Skunkworks projects leave traces that can be hard to cope with threatening the feasibility of exploitation at the wider organizational level," an equipment manufacturer interviewed told the researchers.[122]

c. Paradox Theory

Paradox theory posits that actors need to accept, engage, and navigate tensions rather than attempt to resolve them. This organizational management theory assumes that competing demands and tensions cannot be resolved because they are contradictory, interdependent, and persistent over time. "[U]nderstanding and

115. *See* Carole Donada et al., *Managing Skunkworks to Achieve Ambidexterity: The Robinson Crusoe Effect*, 39 EUR. MGMT. J. 214 (2021).

116. *Id.* at 218.

117. *Id.* at 219.

118. *Id.* at 218.

119. Donada et al., *supra* note 115, at 219-20.

120. *Id.* at 220.

121. *Id*.

122. *Id.*

managing these tensions is central to successful innovation."[123] The nature of such tensions and their management can produce outcomes akin to a double-edged sword, sparking innovation and spurring anxiety from increased stress. Early paradox theorists treated the nature of competing demands as a matter of trade-offs and dilemmas involving choices among options.

Smith & Lewis (2022) defined paradox as "interdependent, persistent contradictions that lurk within our presenting dilemmas" that often leads to "reductionist thinking" reflecting a mindset that limits the ability to find more "holistic solutions" to difficult problems.[124] A more productive and sustainable way for people and organizations to address issues holistically the authors argue is to apply a "paradox mindset" – the extent to which one is accepting of and energized by tensions.[125]

4. Research Questions and Methodology

This study sought to answer the following questions:

> (1) What does the achievement of innovation demonstrated by the SmartSacramento teams reveal about the effect of navigating paradoxes at SMUD?
> (2) What are the practical implications for decision-making at SMUD and the U.S. power sector as utilities innovate towards a low carbon future?

In-person interviews of thirteen current SMUD employees randomly selected from a list of former SmartSacramento project team members[126] were conducted for the study. Data from twelve interviews were included in the results.[127] Each of the interviews lasted 30-35 minutes. While they were all involved in SmartSacramento, the employees interviewed varied in their roles, responsibilities, level of seniority within the organization, and departments at SMUD from which they participated on the project.

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123. Ronald Bledow et al., *A Dialectic Perspective on Innovation: Conflicting Demands, Multiple Pathways, and Ambidexterity*, 2 INDUS. & ORG. PSYCHOL. 305, 306 (2009).

124. WENDY K. SMITH & MARIANNE W. LEWIS, BOTH/AND THINKING: EMBRACING CREATIVE TENSIONS TO SOLVE YOUR TOUGHEST PROBLEMS 5, 26 (2022).

125. *See id.* at 92-95 (explaining that "[t]hose with a high paradox mindset tend to accept tensions as natural, valuable, and energizing" such that when confronted with dilemmas, they ask "how can I accommodate A and B at the same time"); *see also* Craig L. Pearce et al., *Toward a Theory of Meta-Paradoxical Leadership*, 155 ORG. BEHAV. & HUMAN DECISION PROCESSES 31 (2019); Ella Miron-Spektor et al., *Microfoundations of Organizational Paradox: The Problem Is How We Think about the Problem*, 61 ACAD. MGMT. J. 26, 29-30 (2018) (finding that when employees experience tensions those with a paradox mindset are more likely to approach tensions as opportunities, gaining energy as they search more broadly for integrative solutions, and thereby enabling superior in-role job performance and innovation).

126. Staff members who were not members of executive management during SmartSacramento's implementation were selected since the study sought to assess decision-making at the project team level distinct from executive management decision-making for the project.

127. Data from one former team member was excluded from the research because the participant lacked sufficient knowledge of team decision-making.

The interviews were completed between June and October 2022 via MS Teams. At the start of each interview, participants were informed that their responses would remain confidential with no attribution by name, job title, or role to anything they shared to elicit candid responses. The interviews were recorded with permission of participants and transcribed using the voice-to-text software, *Otter.ai*. The video camera of the interviewer was turned off during interviews to avoid influencing responses given by participants who might otherwise react to the interviewer's facial expressions.

During the semi-structured interviews, all participants provided comments, reflections, and examples of their own and their team's operations, decisions impacting their portion of the project, and personal impressions from their experience on the project. Participants were asked to recall the reporting structure of their teams, their respective roles and responsibilities, how their teams made decisions, whether conflicts arose and if so how those were dealt with, what they attributed to their team's performance, and their impressions of SMUD management's role in their teams' ability to execute their work. In December 2022, participants received via email a final inquiry, asking each to complete the following sentence: "SMUD is in the business of __________." Responses were received from seven participants.

Additionally, managers at two other municipal utilities, one from the Pacific Northwest (Pacific Manager) and another located in the Southeastern U.S. (Southeast Manager) were interviewed to illicit feedback on how innovation has operated to implement innovations at their respective systems. Each of the managers were interviewed separately for sixty minutes via MS Teams to obtain background on innovations at their respective utilities and answers to questions regarding how decision-making operated at the team level of their organizations to realize their projects. Their confidentiality was assured as well to ensure candid responses. Interviews were recorded with permission of both managers with video camera of the interviewer turned off and transcripts generated by *Otter.ai*. Information from those interviews provided a reference point to compare and gauge responses of the SMUD participants.

Interview data was coded using categories based on organizational innovation literature. Coding was based on timeline (pre-, during-, post-SmartSacramento), ambidextrous organizations (exploitative, exploratory, innovative result(s)), skunkworks (management support, autonomy, individual empowerment), and paradox (conflicts/tensions/dilemmas, navigation, outcomes) (see Figure 3).

Secondary sources of information obtained internally from SMUD as well as public sources were reviewed for this research to triangulate the data gathered including SMUD's SGIG grant application submitted to the U.S. DOE, reliability evaluation reports generated pursuant to the grant, SMUD's post-project summary report also submitted to DOE, DOE post-SGIG summary reports, and SMUD's "Zero Carbon by 2030 Plan."

Figure 3: Interview Data Coding

Coding Chart [Excerpts]

Ambidex	Skunk	Paradox	Description	Examples	outcome(s)
Explore	empwrmt.	employee vs. management	Being given authority as senior manager to make decisions generated sense of empowerment [during]	What worked [with SGIG] was allowing our small team full reins, full authority to figure out solutions. (SMUD #2, 8/22/22)	software app syncing device communications
Explore	Autonomy	freedom v. regulation	Reflecting on freedom in organization that is usually hierachical, risk averse [during]	It's abnormal at SMUD...This was a lot more innovative, a lot more trusting, a lot more authority to make decisions. (SMUD #12, 10/27/22)	work fed infrastructure upgrade work
Exploit	Autonomy [exercised to create rules]	rules vs. autonomy; combine rules into autonomy	Project charter development [during project]	[C]ame up with idea of...project charter so that you know exactly what you need to do or what the team's goal is. (SMUD #5, 10/10/22)	SGIG teams management
Explore & Exploit	Autonomy; Mgmt Support	rules vs. autonomy; combining rules into autonomy	Resourcing support; running decisions through steering committee [during project]	I felt I had pretty much the run of it. You know, whatever it took to get it done. There was something I couldn't get done within my control. It was bringining it up to the steering committee, and they would be there to support and get me what I needed. (SMUD #10, 10/13/22)	work contributing to distrib. automation
Explore & Exploit	Mgmt support	individual v. group decisions; mixing explore/exploit methods	Decision-making practice at SGIG team level [during project]	At the individial team levels, decisions were made using a collaborative effort with input from various SGIG subject matter experts, and also check-ins with oher parts of the organization here at SMUD. (SMUD #9, 10/12/22)	customer programs development
Explore	Autonomy	risk taking vs. risk maanagement	Commenting on scope of decision making within teams [during project]	I was given a huge amont of freedom to develop the tools and documents that we needed to be successful. I was given a lot of freedom within the sandbox that were were operating...confident that the risks could be constrained within that sandbox of decisions that we madee. (SMUD #4, 10/07/22)	work fed connecting customer apps
Exploit		empwrmt vs. mistakes/costs	Identifying tension between empowering team members and dealing with concerns with associated mistakes/costs. [post project]	A tension point that I've observed absolutely is empowering people to make decisions give people more creativity and freedom, which then can enable innovation. I think what I have observed is where there is concern about...going out to left field or things like that, or that there's budgetary constraints that people don't think about, then that's where SMUD tends to micromanage. (SMUD #3, 8/23/22)	Commentary re empowerment of decision making at SMUD

5. Findings

Decision-making tensions permeate the daily work lives of utility personnel. They deal with tensions at the organization level. "We can talk about decision-making . . . [i]t's really just in futility," one SMUD interviewee remarked.[128] "Decision by committee can be death by a thousand swords," another commented.[129] Pacific Manager characterized a decision made by an executive that had lasting impact on the utility's innovation project as follows: "The grid has worked this way . . . for the last fifty years, dammit if we're gonna put anything new in it."[130] Utility employees also manage team tensions. ("[I]f I got involved . . . it would have just been . . . extra . . . entropy within that [team decision-making] process.")[131] They struggle with personal choices that reflect tensions. ("I remember people even asking me specifically about [SmartSacramento] . . . asked if I was sure I wanted to [work on the project] because . . . it was a career risk";[132] "that job comes up only . . . once in your career . . . I knew that I needed to interview . . . I got it and I left the [SmartSacramento] project."[133])

In short, the SmartSacramento teams were emersed in competing demands, tensions, dilemmas, and conflicts to execute their work contributing to the overall innovation effort. Underlying those discomforting, anxiety-provoking situations interviewees experienced paradox: risk aversion – innovation requiring risk taking; resource need – resource creation; micro-management – autonomy. Data from interviews revealed that the SmartSacramento teams worked to advance the project with, rather than against, these tensions that exist at SMUD.

a. Teams Created Resources Within A Resource-Constrained Organization

To the question of "what challenges did the SmartSacramento teams face?" the predominate response from interviewees centered on resources – staffing, time, and tools to complete project deliverables. Few had the fortune as one interviewee shared of being "empowered with staff resources"[134] to execute additional work associated with SmartSacramento. Within utilities, innovation projects are in addition to, rarely in lieu of an employee's existing duties. "Everything still had to get done,"[135] explained one former project team member. "All that [existing work] couldn't get dropped. We just had to manage that."[136] Organizational researchers

128. Interview with former SmartSacramento team member No. 1, SMUD (Aug. 22, 2022).

129. Interview with former SmartSacramento team member No. 3, SMUD (Aug. 23, 2022).

130. Interview with Pacific Manager, SMUD (Oct. 24, 2022).

131. Interview with Southeast Manager, SMUD (Nov. 1, 2022).

132. Interview with former SmartSacramento team member No. 11, SMUD (Oct. 14, 2022).

133. Interview with former SmartSacramento team member No. 5, SMUD (Oct. 10, 2022).

134. Interview with former SmartSacramento team member No. 2, SMUD (Aug. 22, 2022).

135. Interview with former SmartSacramento team member No. 10, SMUD (Oct. 13, 2022).

136. *Id.*; *see also*, Gail Reitenbach, *Vermont Electric Cooperative Takes Wise Approach to Smart Grid Projects*, 155 POWER 44, 46 (2011) (explaining Vermont Electric Cooperative's experience developing solution enabling energy usage display for customers to view their usage details by "[w]orking part time, in addition to their regular responsibilities, VEC's IT staff wrote the software" given lack of affordable vendor option).

have noted that "[t]ensions intensify under conditions of resource scarcity."[137] SMUD committed to a thirty-six-month project completion timeline. Under that deadline, the teams found themselves tackling one resource dilemma after another.

During the implementation, the SGIG project manager hit a roadblock with a senior manager. The project team had identified a staffing need critical to the project's progress. The team informed the project manager of the senior manager's refusal to help. One of the SMUD interviewees recalled the incident as follows:

> [The Project Manager] met with the director . . . at the time. It was a senior director . . . and said 'if we're not getting the support, we're going to hire our own.' He said 'go ahead' . . . We did. We actually hired [] internal[ly] [from] SMUD. So I posted some limited term positions, and we hired two people directly from [the director's group], and they moved over onto the team and it really did speed up some of the things that we were working on . . . I was very proud of [Project Manager] when she did this.[138]

While the Project Manager's actions might seem expected, utility culture is highly differential to organizational hierarchy. SMUD's management practice typically does not condone managers confronting senior managers on resourcing decisions of which staffing is generally paramount.

"We are very risk averse," another interviewee put it.[139] Group decision-making among managers at SMUD typically follows a "consensus" model pursuant to which managers from across the organization engage in collective decision-making. Commenting on the inefficiencies and delays such consensus decision making can create, another interviewee characterized this feature of SMUD's processes as "too many cooks in the kitchen."[140] Decisions requiring senior leadership approval follows a "layered' approach" as one former team member described it:

> Typically, at SMUD and I think many . . . utilities . . . there's a layered approach to approvals. The team comes up and give three options and they go to their next layer up and ask, 'Hey, we got these three options.' Oftentimes, they're afraid to actually even make a recommendation, they just want to lay out 'here's my three options.' Only say which one they prefer if they're asked, and there's a discussion and a group discussion. Not always super clear who gets to make the decision. Then it goes that way back up through the next layer.[141]

Hence, upon receiving the senior manager's response, the SmartSacramento team hired staff needed directly from the manager's group. The comment of being "proud" that the project manager stood up to secure needed resources for the team indicates this served to foster team morale. Still, the solution the project manager found did not resolve the underlying paradox embedded in SMUD's culture favoring status quo (tradition) while SmartSacramento teams were asked to innovate quickly (change). In this instance, hiring internally adapted an effective, albeit temporary, solution to the dilemma of technical expertise needed on the SmartSacramento team at that time to move the project forward.

137. Miron-Spektor et al., *supra* note 125, at 27.

138. Interview with former SmartSacramento team member No. 11, *supra* note 132.

139. Interview with former SmartSacramento team member No. 2, *supra* note 134.

140. Interview with former SmartSacramento team member No. 3, *supra* note 129.

141. Interview with former SmartSacramento team member No. 12, SMUD (Oct. 27, 2022).

Another project team found itself in a struggle between two departments over a software solution. The team was responsible for securing software that would run new distribution automation devices, and thus turned to SMUD units using existing software that had elements of the application the team sought. However, the units each viewed their own software as competing and superior to the other. Caught between the two, the SmartSacramento team negotiated their way to a solution.

> [W]e would go to [Department 1], we would say 'we'd like to do this' and they would say 'no', and then we'd go back and we would talk to . . . [Department 2] and say 'this is what we'd like to do to change this and [Department 1] would like to do that.' So, we became this kind of almost foreign affairs negotiator between departments . . . to develop a project or a process that would work for both organizations.[142]

The team thus faced a zero-sum resource conflict between warring business units. The primary underlying paradox involved existing versus new technology. Those in the SmartSacramento team effectively paved an alternate path to obtaining the software needed to run new meters by mediating between the two business units each of which saw only their own technical solution operating at SMUD. "We found a way through difficult problems,"[143] another team member put it. "Difficult problems didn't linger and iterate . . . [as] sometimes this happens within our utility today."[144] The SmartSacramento teams created resources in a resource-constrained environment that moved the project along to completion.

b. Teams Adapted Exploitative Measures To Leverage Their Exploratory Reach

SmartSacramento team members cited "autonomy" – being able to make decisions independent of SMUD's regular processes – for their ability to perform their best work to complete projects. "What worked . . . was allowing our small teams full reigns, full authority to figure out solutions,"[145] recalled one former team member. Another said, "I was given a huge amount of freedom to develop the tools . . . we needed to be successful."[146] And still another commented, "not having a tremendous amount of oversight structure – that was key to being able to do things quickly, to make adjustments as . . . we needed."[147] Paradoxically, these same SmartSacramento team members who identified autonomy as a driver of their success imposed structure and rules on themselves.

SMUD management had the SmartSacramento teams self-organize. Free to choose how they would operate, the teams established a steering committee composed of department leads from across the organization. Project decisions were brought to the steering committee for discussion during regularly scheduled project update meetings. Interviewees credited the steering committee for providing

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142. Interview with former SmartSacramento team member No. 7, SMUD (Oct. 11, 2022).

143. Interview with former SmartSacramento team member No. 4, SMUD (Oct. 7, 2022).

144. *Id.*

145. Interview with former SmartSacramento team member No. 2, *supra* note 134.

146. Interview with former SmartSacramento team member No. 4, *supra* note 143.

147. Interview with former SmartSacramento team member No. 10, *supra* note 135.

guidance from multiple relevant business units on project decisions. "I think there was a real value of having that steering committee because there are multiple perspectives,"[148] recalled one former team member. "There were people very focused on customer experience . . . [others] . . . were focused on marketing communications, people on the grid side . . . you weren't just relying on a single person making a decision based on their perspective. We're getting input from a bunch of folks."[149]

The teams also established written "charters" setting forth each of the team's respective project missions. These "charters" originated from a dilemma in the nature of the SmartSacramento projects. Some projects had clearly defined specifications such as installation of particular number of reclosers, which are switches on the utility's power distribution network. Other projects lacked a defined scope or objective. The operative underlying paradox here was ambiguity and definitiveness. "[T]hat's where we came up with the project charters to at least come up with some guidelines to be able to help direct people on what that the result would be."[150]

From an organizational ambidexterity view, the teams adapted exploitative measures (guidelines, definitions, date-certain installation schedules, decision-oversight processes) and applied them to their exploratory context (radical innovation sought through SmartSacramento, autonomous decision-making, taking "full reigns" to figure out solutions). The effect of combining these team governance features was – freedom. "I felt like I had the authority and the advocacy and support to do anything within . . . the charter of SmartSacramento to explore,"[151] noted one interviewee. In other words, the structure that the SmartSacramento teams set up for decision-making empowered team members to take risks to accomplish their project goals. Another former team member put it this way: "I was given a lot of freedom within the sandbox that we were operating but at the same time there was an organization with the appropriate and necessary path or mission where we did feel confident that the risks could be contained within that sandbox of decisions that were being made."[152]

Hence, by establishing written guidelines and ceding decision review to the larger group at SMUD (group-control), the SmartSacramento teams helped themselves by reinforcing their autonomy (self-control). The team's decision to implement a formal oversight process in the steering committee provided a means to establish leadership buy-in of project decisions. That in turn provided team members confidence that their exploratory work innovating had the blessing of leadership even if only through a cursory review process ("I would just tell [the steering committee] this is what I'm going to do, any comments, questions?"[153]). The SmartSacramento teams essentially operated as an ambidextrous unit able to both

148. Interview with former SmartSacramento team member No. 12, *supra* note 141.

149. *Id.*

150. Interview with former SmartSacramento team member No. 5, *supra* note 133.

151. Interview with former SmartSacramento team member No. 7, *supra* note 142.

152. Interview with former SmartSacramento team member No. 4, *supra* note 143.

153. Interview with former SmartSacramento team member No. 12, *supra* note 141.

innovate and implement within the larger utility focused on exploitative work necessary to keep the lights on.

c. Teams Experimented As Cross-Functional Innovation Units

"We were not set up for testing anything like this,"[154] one interviewee shared. Dilemmas arising from resource constraints were compounded for the SmartSacramento teams with complications of trying to operate outside of SMUD's existing electric grid the way it was designed (manifesting underlying paradox of present and future).

SmartSacramento was an effort to transform the way the SMUD's electrical distribution worked. The promise of a "two-way," interconnected system of "smart" meters through which the utility could measure customer energy usage was just that: a promise requiring creation of real-world technology to realize it. The tension under which the SmartSacramento teams worked stemmed in significant part from the need to create solutions under time constraints of the project schedule. And so, they improvised, drawing from their collective expertise.

A former member of the meter replacement team explained their predicament needing to test new meters being installed without a proper testing tool. The team "jerry-rigged" one. "[T]he first [tool] was kind of a 'belt and bootstraps' thing,"[155] described the former member. A meter technician "evolved" a meter testing device in the form of a small meter box into which a meter socket could be placed allowing the meter being tested to communicate within SMUD's meter shop. The device "pinged" the new meter to ensure its proper functioning. This prototype "ping" device formed the basis of a scaled version later built to test entire banks of meters allowing the team to replace existing units with new meters assured that they functioned properly once installed. The meter testing tool developed by the team continues to be used today at SMUD.

154. *Id.*
155. *Id.*

"Ping" testing devices (attached to middle row of smart meter bank) in operation and on display at SMUD's offices.

Iterating the "ping" testing device to address their dilemma of having to test new meters without an existing tool is noteworthy because the teams operated under tight constraints of time and resources. In SmartSacramento's case, teams had the benefit of funding made available by the SGIG grant to undertake the research and development. That was the point of the grant. Yet, creating solutions such as the ping tool under deadline underscores the type of ingenuity that national smart grid policies have sought to incent among utilities such as SMUD. The teams that worked on SmartSacramento functioned as an innovative unit able to draw on expertise at SMUD as needed to further adapt to dilemmas that came their way throughout the project.

The former team members interviewed cited the decision to "centralize" SmartSacramento team members into one physical location within SMUD as being critical to the teams' effective operation. A core set of approximately a dozen staff members (there were dozens of other team members spread across SMUD business units involved in project implementation) working on the project were grouped into a cluster of office cubicles on the same floor of SMUD's headquarters building. Interviewees noted that their physical proximity with one another fostered team cohesiveness and cross-function. "Everyone was brainstorming and innovating new ideas . . . that is the result of the energy that is created when you have a dedicated 'moonshot' team."[156]

Others identified "empowerment" of decision-making by SMUD leadership. From SMUD's publicly-elected Board, to executive management, through team leads managing day-to-day work of the project teams, the project was made a priority. This empowerment, which interviewees understood from their own experience at the utility to be unprecedented, was cited by one interviewee as the basis of creative solutions for conflicts their team encountered.

A customer claimed SMUD's meter changeout as part of SmartSacramento cut power to his house, killing his expensive pet fish. SMUD's designated customer care team typically handles such complaints. Given options spanning potential negative press from the complaint, prospect of getting management involved, and addressing an issue within the team member's control, the team member went out to an aquarium shop where workers there said the fish that the customer claimed died couldn't have been in the same tank, "they'd kill each other."[157] "Interesting," the team member recalled thinking before buying a $300 gift certificate and personally delivering it to the customer's house.[158]

The SmartSacramento teams navigated paradoxes at SMUD in part by finding 'win-win' solutions. Resolving the customer's fish casualty claim is the SMUD customer department's job *and* the team will help them accomplish it; jerry-rigging a meter testing tool is slow to help test meters *until* the tool is proven to work allowing teams to move fast after testing; rules and procedures can bog down decision-making *and* teams exercised autonomy within those parameters.

d. Teams Discovered Navigating Utility Paradoxes Is Paradoxical

The SmartSacramento teams had to work through competing ideas and resolve differences to progress. As one former team members put it: "Yeah, it wasn't easy . . . [t]here were a lot of hard decisions . . . spirited debate if not arguments even sometimes yelling matches to figure out how to move forward."[159] Innovating for SmartSacramento "wasn't easy." Teams had to make "a lot of hard decisions." They even had "yelling matches" to decide how to proceed. In other words, the teams navigated tensions with the larger organization and in their own teams.

Additionally, project team members explained that after SmartSacramento ended in 2013, they experienced personal tensions. "[O]nce we left that project and started going back to our organizations, a lot of us felt somewhat lost because we didn't have that cohesiveness going forward . . . we kind of went back to difficulties,"[160] recalled one former team member. Another team member described feeling that "problems sounded hard again"[161] after the project's end.

156. Interview with former SmartSacramento team member No. 7, *supra* note 142.

157. Interview with former SmartSacramento team member No. 12, *supra* note 141.

158. *Id.*

159. Interview with former SmartSacramento team member No. 4, *supra* note 143.

160. Interview with former SmartSacramento team member No. 8, SMUD (Oct. 12, 2022).

161. Interview with former SmartSacramento team member No. 4, *supra* note 143.

"Feeling lost" and going "back to difficulties" following the achievement of a significant innovation undertaking is noteworthy. The SmartSacramento team members rejoined the main exploitative SMUD organization after living in an exploratory SmartSacramento world in which teams experienced autonomous decision-making and even physical grouping into a designated location akin to operations of a skunkworks unit within the company. This suggests that navigating paradoxes woven into SMUD's culture is itself paradoxical. The experience of the SmartSacramento teams indicates that by executing the project, SMUD generated innovation along with emotional dissonance among participating employees. Thus, similar to the findings from research on Peugeot's Hybrid Air team, the data provided by former SmartSacramento team members suggests that there is both gain *and* pain from innovating.

Still, the feedback from team members was not that SmartSacramento harmed them. On the contrary, team members saw themselves as growing with and from the project. The former team member who had heard comments from a colleague that SmartSacramento was a risky career move recalled personally reflecting "who even thinks that?"[162] Indeed, SmartSacramento drew employees onto project teams who were the "doers" as another former member called them – "folks who get stressed out but then think about how [they] can make [] things happen."[163] Several team members who worked on SmartSacramento were later promoted to senior management positions within SMUD, with a few even being promoted to become executives. "It was a renaissance time,"[164] recalled another former team member of the SmartSacramento period.

IV. FACTORS IMPACTING UTILITY SMART GRID INNOVATION

SMUD was one of eighty-one utilities funded by the SGIG that installed over 16.3 million smart meters nationwide.[165] The policy goal of SGIG to deliver grid efficiencies and modernization through smart grid technologies seems to have grown more acute given the frequency and severity of extreme whether events today associated with climate change and consequent demands placed on the power grid. For context, the U.S. averaged 8.5 weather/climate disasters resulting in at least $1 billion in damage from 1980–2023 (CPI-adjusted); the annual average for the most recent five years (2019–2023) is 20.4 events (CPI-adjusted).[166] The power sector is now the U.S. economy's third-highest emitting sector of greenhouse gases, having been first as recently as 2016.[167] Understandably, utility

162. Interview with former SmartSacramento team member No. 11, *supra* note 132.

163. Interview with former SmartSacramento team member No. 1, *supra* note 128.

164. Interview with former SmartSacramento team member No. 7, *supra* note 142.

165. *See AMI and Customer Systems: Deployment Status*, U.S. DEP'T OF ENERGY (2019), https://www.smartgrid.gov/archive/recovery_act/deployment_status/ami_and_customer_systems (last visited Jul 13, 2024).

166. *U.S. Billion-Dollar Weather and Climate Disasters, 1980 - Present*, NAT'L CTRS. FOR ENV'T INFO., https://www.ncei.noaa.gov/archive/accession/0209268 (last visited Jul 8, 2024).

167. *2024 Sustainable Energy in America Factbook*, BLOOMBERGNEF & BUS. COUNCIL FOR SUSTAINABLE ENERGY 24 (Feb. 28, 2024), https://assets.bbhub.io/professional/sites/24/2024-BCSE-BNEF-Sustainable-Energy-in-America-Factbook.pdf.

researchers have noted that "neither firms nor regulators can afford to ignore the potential value and risks of smart grid technologies, nor to make poorly informed decisions about their adoption."[168] Utilities and industry regulators understand that "intelligent monitoring, communication, control, and self-healing technologies are the core of the modernization of the distribution network . . . a crucial step in responding to the increasing demands for electricity and services from the digital society while reducing the environmental impacts at the lowest cost."[169] Yet, smart grid technologies can deliver such value to electricity providers and the customers they serve only if their systems choose to expend limited financial and technical resources for smart grid innovation i.e. adoption and deployment of AMI.

With industry now undertaking investment of billions of dollars in public and private funding to upgrade existing U.S. smart grid infrastructure under the DOE's GRIP program, a practical question arises: are utilities and regulators making decisions involving smart grid informed by evidence of how innovation operates at utilities? Federal grants supporting development of next generation smart grid infrastructure and applications, for instance, will be awarded to perhaps dozens of utilities. Learnings from those federally-subsidized smart grid innovation projects is intended to demonstrate and apply technology solutions that help modernize through smart grid technologies utility distribution systems across the country. Whether and how quickly the latter goal can be accomplished assumes utilities ranging from large IOUs serving tens of millions of ratepayers to co-ops that may serve a few thousand customers are prepared as organizations to innovate, e.g. replace existing smart grid infrastructure with grid-edge enabled metering devices. This then begs the question: What organizational capabilities enable a utility to innovate?

Kallman & Frickel (2019) alluded to this issue in their study of AMI deployment by Washington State utilities, noting that one branch of literature contends innovation "happen[s] within organizations" while another "argue[s] that innovation is distributed across, and predicted by, inter-organizational networks and systems."[170] Both appears to be the case for the U.S. electric utility sector. Studies have identified as drivers of utility smart grid innovation falling into broad categories of organizational and regulatory factors.

A. Organizational Factors

1. Utility Size, Ownership Form, and Management

"In terms of organizational factors, larger utilities have higher adoption rates," observed Zheng et al. (2022) who conducted a combination qualitative and

168. *See* Zheng et al., *supra* note 3, at 8.

169. Marques et al., *supra* note 57, at 2.

170. Kallman & Frickel, *supra* note 13, at 3.

quantitative study of factors impacting utility smart grid deployment.[171] Evaluating both investor- and community-owned utilities nationwide, the researchers tested the influence of utility size, ownership form, regulatory and organizational factors on adoption of smart grid technologies.[172] Through interviews with professionals from co-ops (thirty-seven individuals), municipals (thirty-eight), and IOUs (seventy-eight) and online survey responses of 132 utility representatives from these three sub-sectors, they found "[u]tility size [] was significant and positive in each model [tested], indicating that larger utilities had more extensive adoption of smart grid technologies."[173] Moreover, after controlling for size, the study also found that "IOUs have higher levels of adoption than their cooperative and municipal counterparts."[174] The researchers found in an earlier smart grid study "smaller and more nimble cooperatives and municipals are more innovative than their larger and highly-regulated IOU counterparts."[175] They attributed the difference to the ownership form of utilities: because IOUs are subject to lengthy approval processes to set prices or make investment decisions, "their decision-making autonomy is constrained"; municipals, on the other hand, do not typically need regulator approval for rate setting or infrastructure investments, resulting in "greater autonomy to invest in smart grid and use pricing to create incentives for customers to reduce peak demand."[176] However, in their subsequent study of smart grid deployment by utilities, the group found results consistent with predictions by other scholars associating larger utilities and IOUs with "greater financial and technical resources."[177]

Organizational innovation research clarifies the 'greater financial and technical resources' explanation for innovative outcomes. The size of an organization impacts innovative results because "larger agencies are more likely than their smaller counterparts to use . . . innovation support strateg[ies] [fostering] introduc[tion] [of] novel innovations, and gain large benefits from their innovation efforts."[178] The "financial, human and intellectual resources" leveraged by larger innovative agencies "enable them to spread and absorb the risk and cost involved in innovation, compared to their smaller counterparts."[179] "[B]y dint of their size, larger agencies are more bureaucratic and formalized" which "can make it harder

171. Zheng et al., *supra* note 3, at 8; *accord* Strong, *supra* note 4, at 74 (noting that "[d]iffusion research has typically found a positive association between firm size and the initial adoption of a technology").

172. Zheng et al., *supra* note 3, at 8.

173. *Id.* at 6.

174. *Id.*

175. *Id.*; *see* Dedrick et al., *supra* note 3, at 22 (finding from industry interviews "a few utilities regarded their smaller size as an advantage, enabling them to respond more flexibly and to try out technologies without facing bureaucratic delays").

176. Dedrick et al., *supra* note 3, at 24.

177. Zheng et al., *supra* note 3, at 8.

178. Nuttaneeya (Ann) Torugsa & Anthony Arundel, *Rethinking the Effect of Risk Aversion on the Benefits of Service Innovations in Public Administration Agencies*, 46 RES. POL'Y 900, 906 (2017) (finding that small public service agencies of between 1 to 49 employees achieved high benefits from their service innovations only in a low risk-averse organizational culture combined with an integrated risk management strategy).

179. *Id.* at 902.

to experiment with new ideas, but these same processes can make it easier to manage risk by enhancing predictability and reducing uncertainty, for instance when decisions are repeatedly scrutinized and responsibility shared through formal approval processes."[180] In smaller agencies by contrast, "the limited resource base and lesser formalization of decision-making processes (which make managers bear the cost of potential failure [citation omitted]) could constrain organizational learning opportunities and consequently make it difficult for managers to minimize the negative effects of risk and hence to effectively operate in a high risk-averse culture."[181] The findings from SmartSacramento which featured teams establishing a formal steering committee that reviewed and approved workgroup decisions as well as customized team charters for individual project groups illustrate such use of formal innovation risk management processes.

Researchers from the Zheng et al. group found in their earlier study of investor-owned and municipal utilities that "[l]eadership by top management was mentioned consistently by utilities that have advanced farthest in smart grid adoption."[182] They noted that "[o]ne manager argued that the kinds of organizational changes required can only be made through top-down mandate."[183] In SmartSacramento's case, former project team members expressed recognition that SMUD management directed business units to dedicate personnel to the project's execution, and that SMUD's leadership from the utility's Board of Directors down through work group managers prioritized successful execution of the SGIG-funded project.[184] Thus, data from the former SmartSacramento teams lends support to the notion that utility leadership can and does influence utility-wide innovation efforts.[185]

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180. *Id.*

181. *Id.* (explaining that research suggests small agencies with high risk aversion would less likely be able to obtain high benefits from their innovations even with the use of appropriate strategies that allow them to manage risk).

182. Dedrick et al., *supra* note 3, at 21-22 (reporting results from qualitative study qualitative study involving 15 interviews with 20 representatives of 12 utilities between IOUs and municipals); *see* Zheng et al., *supra* note 3, at 8-9 (Interestingly, the researchers later found the opposite when surveying a larger group of utilities, that "[t]op management leadership was not a significant predictor of smart grid adoption . . . ."). The disparate findings may reflect fact that the researchers surveyed respondents from utilities regarding smart grid innovation at their systems without focus on their participation in SGIG projects years before the survey whereas respondents from utilities interviewed for their initial study were comprised of AARA grant recipients whose smart grid projects involving management overseeing their utility's execution of federal funding as was the case for SmartSacramento.

183. Dedrick et al., *supra* note 3, at 22.

184. Among comments shared, interviewees noted that "[t]he best decision SMUD made was putting all of the different work groups that touched SGIG under one executive…[that] allowed us to be nimble" (Interview with former SmartSacramento team member No. 2, *supra* note 134), that "[m]anagement…pull[ed] together a team of subject matter experts throughout the district that had expertise…to deliver on the…scope in that [SmartSacramento] application" (Interview with former SmartSacramento team member No. 8, *supra* note 160), and that "uniform messaging from…our Board, to our CEO to all of our executives, the SGIG project portfolio, was [that] our strategic and tactical focus for the three years [] we were planning and operating those pilots (Interview with former SmartSacramento team member No. 4, *supra* note 143).

185. *See id.*; Zuraik & Kelly, *supra* note 107; see *generally* Haider et al., *supra* note 102; Berraies et al., *supra* note 110; Jia et al., *supra* note 110.

Consistent with findings from SmartSacramento, the earlier study by the Zheng et al. group indicated that among the utility respondents "interviewees discussed the need for changes such as breaking down organizational barriers and siloes, and creating cross-functional teams to implement different projects."[186] Similar to the disorientation expressed by former SmartSacramento team members at the conclusion of the project, representatives from both IOUs and municipal systems interviewed "spoke of challenges in managing change in organizations unaccustomed to rapid transformational change."[187] This indicates that at minimum, utility-wide innovation efforts such as SmartSacramento are not an emotionally neutral exercise for utility personnel and can actually result in employees experiencing dissonance undertaking innovation within existing risk-averse organizational cultures of electricity providers.

2. Risk Aversion

The smart grid literature addresses power sector innovation from the understanding that utilities are risk averse.[188] "This internal risk aversion is reinforced by the status of most utilities as local monopolies working within external rules and norms that constrain them from using innovation to pursue potentially profitable business options . . . as firms in other industries do."[189] More generally, innovation in public services such as electricity provision "inherently involves risks" with costs (risks) of such innovation "almost certainly measurable, specific, and traceable to the decisions of individuals" while "benefits . . . are often uncertain, difficult to measure and diffused over numerous recipients."[190] For the electric sector under pressures to innovate towards decarbonized operations, this poses a problem since "[r]isk aversion, together with the uncertainty avoidance[191] associated with the results of innovative processes, raise barriers to innovation and the transition to other technological paradigms."[192] However, the lesson from utility adoptions of smart grid is that innovation by investor- and community-owned systems alike appears to be that implementing risk management measures tailored to a given utility's culture enables innovation outcomes.

186. *Id.* at 26 ("In the words of one respondent, organizational siloes need to be smashed, which can only be accomplished with top management leadership.").

187. *Id.*

188. *See, e.g.,* Zheng et al., *supra* note 3, at 8 (concluding "smart grid adoption was mainly motivated by the desire for operational improvement, including reliability, efficiency, and cost reduction . . . consistent with [their] interviews and with prior research [citations] showing that utilities as organizations tend to be risk averse").

189. *Id.*

190. *See* Torugsa & Arundel, *supra* note 178, at 901 (explaining how risk dynamics at issue with public service innovation results in underestimation of relative gains together with higher penalties for failure compared to rewards for success, negatively impacting risk perception and undermining incentives to innovate).

191. *See* Logan L. Watts et al.,, *Uncertainty Avoidance Moderates the Relationship between Transformational Leadership and Innovation: A Meta-Analysis*, 51 J. INT'L. BUS. STUD. 138, 139 (2020) (using the term "uncertainty avoidance" to refer to "the extent to which the members of a culture feel threatened by uncertain or unknown situations").

192. *See* Marques et al., *supra* note 57, at 5.

While convention may hold that "risk-averse culture in public agencies is a cause of management ineffectiveness and a significant barrier to successful innovation,"[193] research involving public service organizations throughout the European Union revealed public managers "work[ed] effectively around risk and achieve[d] high benefits from [their] innovations."[194] Of the 3,699 agencies surveyed in the study, 54% reported a risk-averse culture they associated with either high or medium importance in preventing innovation and yet 71% of those identified risk-averse agencies introduced a service innovation.[195] Moreover, "a significantly higher percentage of agencies with a high risk-averse culture (34.4%) develop[ed] a novel innovation than agencies with a low risk-averse culture (28.2%)."[196] The researchers concluded that an organization's level of risk aversion "is a relevant but not deterministic condition for high innovation benefits; rather, the ability of managers in risk-averse agencies to implement appropriate combinations of strategies for managing risk is what drives innovation success."[197]

The data from U.S. smart grid studies supports this argument that risk management drives innovation success. On the IOU side, decisions to undertake smart grid innovation depends on whether regulatory environments under which they operate provide sufficient planning security. Cost recovery allowed by an applicable state public utilities commission is consistently mentioned as a deciding factor for smart grid deployments.[198] Federal grants made available to utilities through ARRA provided financial incentive for IOUs "to be able to plan long-term" mitigating the financial risk of smart grid investments.[199] SmartSacramento team members responded to the utility's risk aversion by adapting measures practiced within the organization to manage an inherently risky process to innovate. At the institutional level, the "nested institutional logics" observed in Washington State's smart grid deployment was in a practical sense a spreading of innovation risk across organizations such that IOUs "joined forces with other smaller regional utilities . . . effectively creating an inter-organizational innovation network through incentives offered at the federal level . . . to move one Washington city

193. Torugsa & Arundel, *supra* note 178, at 901.

194. *Id.* at 909 (recommending policies fostering effective innovation in public services by providing support and training of managers to assist in developing context specific sets of strategies for agencies with varying levels of risk aversion and transitioning from risk aversion to risk awareness for management).

195. *Id.* at 902; *see id.* at 903 (defining 'service innovation' as "introduction of a service that is new or significantly improved with respect to its characteristics or intended uses . . . ranging from highly novel or transformative innovations that make significant changes to current services to minor incremental changes"); *see also id.* at 903 (explaining example of incremental service innovation could be the replacement of diesel buses with electrical buses in a transportation system whereas a transformative service innovation might introduce a zero emissions public transport system closely integrated with other policies to significantly reduce carbon and nitrogen oxide emissions).

196. Torugsa & Arundel, *supra* note 178, at 902.

197. *Id.* at 901.

198. *See, e.g.*, Dedrick et al., *supra* note 3, at 23 (quoting IOU interviewees explaining their utilities decided on smart grid project cancellation or proceeding based on PUC cost recovery determinations).

199. *See* Kallman & Frickel, *supra* note 13, at 5.

towards "Smart City"[200] status."[201] By implementing their respective innovation risk management measures, IOUs, the SmartSacramento teams, and utility partners in Washington State were able to successfully execute their smart grid innovation projects. "Managers in high risk-averse organizations exhibit a higher propensity to develop an integrated [risk management] strategy and consequently they are likely to be able to work effectively around risk [and] to develop novel innovations . . . ."[202]

Research has also found that "[i]n risk-averse organizational environments, managerial attitudes to risk play a vital role in influencing staff perceptions and behaviors concerning risk."[203] Data from former SmartSacramento team members to the effect that they felt "empowered" by SMUD management to make decisions suggests that the attitude towards innovation risk which management applied at SMUD framed risk in a manner that fostered innovative performance.[204]

3. Subject Matter Expertise

Zheng et al. found from their study of investor- and publicly-owned systems that while "[a] utility's internal knowledge and skill base were not found to influence [smart grid] adoption" the quantitative data from their research showed that internal expertise "emerged as the third most important barrier to adoption."[205] This apparent dichotomy in the study's findings, the researchers determined, "suggest that new skills are needed for smart grid adoption, but that internal skill levels may not be a critical factor if needed skills are available externally through contractors or consultants."[206]

However, data obtained from the former SmartSacramento team members underscored that subject matter expertise within SMUD was pivotal to their ability to navigate innovation obstacles. Faced with the dilemma of testing new smart meters without existing tools, team members of the metering team created and tested a "belts-and-bootstraps" prototype "ping" device which once proven to work was scaled to test banks of meters. Likewise, team members developing software to run new distribution automation devices developed a solution that met the needs of warring business units by mediating between them. In the case of

200. *Id.* (explaining that goal of project was to create regional smart grid that included updated and automated distribution systems, roll out AMI at homes and businesses, and to pilot a Smart Home project).

201. *Id.*

202. Torugsa & Arundel, *supra* note 178, at 909 (finding that among surveyed agencies "the share of high risk-averse innovators that possess[ed] high levels of process and communication innovations, deploy an active management strategy, and more importantly have an integrated strategy in place, [was] significantly higher than the share of low risk-averse agencies").

203. *Id.* at 903 (citing Barry Bozeman & Gordon Kingsley, *Risk Culture in Public and Private Organizations*, 58 PUB. ADMIN. REV. 109 (1998) (testing and refuting assertion that public managers are inherently more risk averse than their private sector counterparts)).

204. *See, e.g.*, Interviews with former SmartSacramento team members, *supra* notes 128-135, 141-143, 160.

205. Zheng et al., *supra* note 3, at 9.

206. *Id.*

SmartSacramento, subject matter expertise was combined with creativity and ingenuity to generate solutions moving the smart grid project along to completion with utility tensions in operation.

While assistance from contractors or consultants may be an option available if budgets and project timelines allow, the experience conveyed by SmartSacramento team members and even co-ops that implemented smart grid projects indicates that innovation within utilities depend on internal subject matter experts expanding their existing work duties to accommodate the organization's effort. When Vermont Electric Cooperative (VEC) needed software developed to connect the utility's network server to software managing their AMI data so that their members could view energy usage data, the co-op found few vendors that could do the work, and bids beyond what the organization could afford.[207] "Working part time, in addition to their regular responsibilities, VEC's IT staff wrote the software between late 2008 and May 2009" for the 35,000 member-customer system serving 74 towns throughout more than 2,000 square miles of rural northern Vermont.[208] As one former SmartSacramento team member relayed the realities of innovating within SMUD, "[e]verything still had to get done" and that those involved in supporting SmartSacramento "just had to manage" their expanded workloads.[209]

B. Regulatory Factors

"Federal and state policies and regulations[210] prominently shape the adoption environment of utilities with respect to technology choice in general and smart meters in particular."[211] Federal policies have supported national adoption of smart meters and TOU rates "despite the lack of legal jurisdiction, which rests with the authority of state to regulate the distribution and retail sale of electricity."[212] "[R]ecognition of demand response as a viable and important resource in electricity markets has been a persistent, overriding policy objective [driven by] [t]he Federal Energy Regulatory Commission [which] has acted as a change agent for the diffusion of demand response in wholesale markets . . . ."[213] The acceleration of tax depreciation for smart meters from twenty to ten years under EESA and

207. Reitenbach, *supra* note 136, at 46 (recounting VEC's investment in smart grid upgrades of the co-op's system before a DOE grant under ARRA was awarded in 2009 to complete remaining 20% of their smart meter installation).

208. *Id.* at 44, 46.

209. See Interview with former SmartSacramento team member No. 10, *supra* note 135.

210. *See* Rahmatallah Poudineh et al., *Innovation in Regulated Electricity Networks: Incentivising Tasks with Highly Uncertain Outcomes*, 21 COMPETITION & REG. NETWORK INDUS. 166, 185 (2020) (commenting that the task of regulation is to devise scheme which balances risk sharing with incentives because on the one hand, the regulator wants the firm to undertake innovation, but for this to happen, [the regulator] needs to renumerate the firm for its costs when undertaking risky activity; on the other hand, the regulator does not want to distort the firm's incentives by giving it full insurance for activities whose risks are actually manageable by the firm).

211. *See* Strong, *supra* note 4, at 1347.

212. *Id.*; *see* Section II discussion of U.S. federal smart grid policy development background.

213. *See* Strong, *supra* note 4, at 1347.

the nearly $3.5 billion of ARRA funding DOE deployed through the SGIG catalyzed utility installation of over 16 million smart meters.

Along these lines, state legislation and regulatory rulings have directly supported or mandated deployment of smart meters by IOUs. State legislative actions have been found to have a "significant and positive impact on smart meter adoptions" by mandating utility cost recovery frameworks for metering projects and reducing policy uncertainty for utilities through data security and customer information privacy legislation.[214] For example, California requires that its large IOUs develop detailed smart grid plans. Other policies that can indirectly affect smart meter adoption include the power market structure within a particular geographic region. Because "[s]mart meters enable time-varying pricing at the retail level," in states where competitive wholesale and retail markets exist, "utilities . . . may be more likely to adopt smart meters in order to reflect these costs in prices."[215] Additionally, regulatory allowance of lost revenue recovery via mechanisms such as lost margin recovery (e.g. "de-coupling") "removes disincentives for investments in energy efficiency."[216]

From interviews of both IOUs and community-owned system personnel, researchers found that "regulatory factors were very important for IOUs, while only of minor importance to municipals and cooperatives."[217] "[R]egulatory environment matters strongly to IOUs [because their] investments require approval by state-level utility regulators [whereas] [m]unicipals and cooperatives were concerned with reducing costs . . . and empowering customers . . . ."[218] The approval of state public utilities commissions of smart grid projects were determining factors for IOUs interviewed in another study. "We requested a rate increase, but the commission only approved one-third of it," recounted one IOU respondent who added, "this caused us to cancel a pilot project on smart grid."[219] In contrast, another IOU interviewee noted that their PUC "encouraged [the utility] to submit the application for [] ARRA smart grid funding" and once obtained the IOU "got the regulatory approval for moving forward" on the adoption.[220] Consequently, the researchers reported that "[a]mong our interviewees, the regulatory environment ranged from obstacle to driver."[221] More specifically, the study noted that a "characteristic comment" from IOU respondents was, "[w]e try to be proactive in our discussion and relationship with the public utility commission so that we are open and transparent to what we're doing . . . Those relationships are always key, internally and externally."[222] Evaluation of their data revealed that "formal aspects of

214. *See* Gao et al., *supra* note 12, at 10.

215. Strong, *supra* note 4, at 1348.

216. *See id.*

217. Zheng et al., *supra* note 3, at 5 (noting survey data revealed that meeting legislative or regulatory requirements was the second-most important motivator to pursue smart grid innovations for IOUs while it was near the bottom of the list for municipals and co-ops).

218. *Id.*

219. Dedrick et al., *supra* note 3, at 23.

220. *Id.*

221. *Id.*

222. Zheng et al., *supra* note 3, at 6-7.

regulation (e.g. published evaluation criteria) may matter less than the quality of relationships between utility representatives and regulators in smart grid adoption."[223]

V. IMPLICATIONS FOR A DECARBONIZING POWER SECTOR

Innovating for a lower carbon future poses huge dilemmas for utilities nationwide. The system deliverables involved are specific (e.g. a 'micro-grid' that keeps a section of town lit when the rest of the city goes dark) and general (e.g. ensure regional grids can recover from weather-related disasters becoming more destructive and frequent with climate change); incremental (e.g. training workers needed to maintain the modern utility) and radical (e.g. running a utility's natural gas plant using hydrogen produced from electrolysis of water); as well as technical (e.g. engineering solutioning) and social (e.g. people solutioning). Such innovations involve billions of dollars of capital investment. "[W]e as a [municipal] utility . . . have to be prudent in our expenditures . . . we have ratepayers and obviously want[] to be judicious in our rates," noted Southeast Manager, who explained that funding of their dedicated innovation projects requires management's "buy-in" for requests are typically met with "a lot of skepticism."[224]

SMUD is among the largest municipal utilities in the country. The community-owned utility, established under California law and governed by a publicly-elected Board of Directors, is guided in its operations by competing interests and considerations of the utility's stakeholders, management, other utilities including its neighboring investor-owned utility (Pacific Gas & Electric) and the organization's values past and present. Yet, in terms of innovation, the conflicting and often contradictory demands and tensions generated therefrom are not themselves the challenge. As paradox academics have put it: "the problem is not the problem; the problem is in the way we think about the problem."[225]

The issues raised by this study are particularly relevant to utilities such as SMUD which generally spend little time analyzing their innovation initiatives. Surfacing, let alone analyzing, tensions that may very well cause anxiety and discomfort is not typical management practice even in a forward-thinking utility such as SMUD. SmartSacramento thus highlights a potential blind spot for leadership of utilities such as SMUD – the need to diagnose paradoxical dynamics that may be restricting their utility's ability to innovate, and how those challenges might be managed and leveraged to move the utility productively over time towards a low-carbon future.

The challenge of accomplishing SmartSacramento teams faced a decade ago contextualizes the obstacle SMUD now faces as an organization moving towards Zero by 2030. As a former team member recalled, "we were trying to solve very difficult and complex things and in sometimes very short time periods."[226] Legal

223. *Id.* at 7.

224. Interview with Southeast Manager, *supra* note 131.

225. Miron-Spektor et al., *supra* note 125, at 27 (citing PAUL WATZLAWICK ET AL., CHANGE: PRINCIPLES OF PROBLEM FORMATION AND PROBLEM RESOLUTION (1974)).

226. Interview with former SmartSacramento team member No. 8, *supra* note 160.

scholars have criticized the "lack of progress to date" by "utilities and their regulators" to transition away from fossil fuel power generation and reduce carbon emissions, "continu[ing] to dig the climate hole deeper while they are operating."[227] SMUD is today trying to solve "very difficult and complex things" within a "very short time period." The persistent paradoxes such as resource scarcity and urgency to innovate with which SmartSacramento teams grappled over a decade ago is today cast in the form of its Zero by 2030 goal.

Yet, unlike SmartSacramento, Zero by 2030 is SMUD's company mission, not simply a priority project involving cross-functional teams. The SmartSacramento teams as this research has found developed "organic" solutions themselves to address day-to-day conflicts and dilemmas. In doing so, they managed to secure staffing needed for the project, "jerry-rigged" solutions, combined exploitative and exploratory practices to maneuver their way to project completion, and they also explored their way to "win-win" solutions, leveraging SMUD's existing exploitative operations processes to execute SmartSacramento. After deftly pivoting, adjusting, and adapting to myriad conflicts, demands, and pressures to accomplish the smart grid project, they experienced costs exacted on the organization. Team members returned to the main organization after SmartSacramento feeling "lost" and problems became "hard again." In essence, SmartSacramento demonstrated SMUD teams functioning as a 'complex adaptive system'[228] – containing a large number of agents which "interact, learn, and, most crucially, adapt to changes in their selection environment in order to improve."[229]

This research is not intended to imply that SmartSacramento represents a model of how innovation ought to happen for SMUD or any other utility. Each utility, its culture, and innovation project is unique. Moreover, the paradox of innovation success has been studied and research indicates it exists. "Success motivates us to stick with that option, until we get stuck in a rut," noted Smith & Lewis (2022), citing research on the "S" curve depicting "how choices lead us from progress to stagnation and, ultimately, decline."[230] Without getting afield of this article, utilities such as SMUD are well advised to think creatively to start new "S" curves while traversing the one they may be on rather than reapplying innovation playbooks that worked in prior contexts.[231] The more pertinent lesson to be drawn, it seems, is whether utilities individually and the electric sector at large are

227. *See, e.g.*, Joel B. Eisen & Heather E. Payne, *Rebuilding Grid Governance*, 48 BYU L. REV. 1057, 1079-1080 (2023) (commenting that "[u]tilities are enthusiastic about 'grid modernization' programs and large . . . (AMI) installation, but there is no big climate payoff as yet").

228. Tim Sullivan, *Embracing Complexity*, 89 HARV. BUS. REV. 89 (2011); *see* Gokce Sargut & Rita Gunther McGrath, *Learning to Live with Complexity: How to Make Sense of the Unpredictable and the Undefinable in Today's Hyperconnected Business World*, 89 HARV. BUS. REV. 68 (2011).

229. *See* Edward J. Oughton et al., *Infrastructure as a Complex Adaptive System*, COMPLEXITY (2018), https://www.proquest.com/scholarly-journals/infrastructure-as-complex-adaptive-system/docview/2135024893/se-2.

230. SMITH & LEWIS, *supra* note 124, at 46.

231. *See generally* Bledow et al., *supra* note 123; GREG SATELL, MAPPING INNOVATION: A PLAYBOOK FOR NAVIGATING A DISRUPTIVE AGE (2017).

gathering pertinent data on how innovation operates to maintain sustained innovation efforts necessary to meet challenges such as sector decarbonization. As one innovation scholar put it, "[e]ven if a company has the resources for [rapid innovation], how can [] teams be freed to move quickly enough and be motivated to sustain a focused effort long enough to build a sustainable advantage" in their arena of operation.[232]

Nonetheless, the implications of this study can assist utility stakeholders in approaching their innovation endeavors in more strategic and productive way. Two primary lessons emerging from this research can be summed up as follows: (1) The Battery Paradox, and (2) Innovation Learning Paradox.

A. The Battery Paradox

A battery has a positive and negative charge, yet that is irrelevant to whether either is subjectively "good" or "bad." Both charges are needed to produce power. Moreover, the value that a battery offers is not in the power it provides so much as when its stored energy can be tapped. For utilities, the promise of batteries lies in their ability to provide instant back-up power for intermittent generation resources (e.g. when the sun is not shining on solar panels, or when the wind is not turning wind turbines). Thus, a battery's "power" as an energy resource hinges on its ability to deliver electricity instantly when needed.

Data from this study revealed that the frame – assumptions and beliefs – which utility personnel apply to innovation is that it is positive (good) while risk aversion is negative (bad). The data indicates that this frame has prompted the wrong questions to be asked. There is sound reason in the electric utility industry to be risk averse.[233] The performance of a utility is measured not only in terms of reliability and affordable rates, but in also in terms of ensuring the safety of employees handling high voltage electrical equipment. Decisions can at times be matters of life or death. In the U.S., utilities face regulatory liabilities upwards of $1 million per day if the lights go out due to utility negligence. Risk aversion is, therefore, adaptive in the power sector and cannot be segregated from what may deemed its opposite – innovation. To innovate as an electric utility in any sustainable manner is to also simultaneously tend to the system's competing demands to ensure reliability and safety. The point here is that utilities pursing projects for a low carbon future should determine what frame they are applying to innovation.

Electric utilities such as SMUD are today undertaking R&D to expand the duration of utility-scale batteries to upwards of 10 hours so that energy and timing of demand can coincide to deliver reliable power. 'Long-duration' battery storage is a technological and engineering challenge that will cost millions of dollars and countless research hours to solve. "It's a very complicated business that that we

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232. Jerome S. Engel, *Accelerating Corporate Innovation: Lessons from the Venture Capital Model*, 54 RES. TECH. MGMT. 36, 37 (2011).

233. *See* Kallman & Frickel, *supra* note 13, at 2 (noting "risks associated with technological innovation in electricity provision are very high: if not successfully designated and implemented, changes to the electrical grid could produce catastrophic energy loss, consumer dissatisfaction and a host of other problems").

operate,"[234] noted one former SmartSacramento team member. Innovating solutions such as long-duration batteries is neither simple nor certain.

Yet, certainty and simplicity constitute the frame utilities apply to innovation. "INNOVATION" is emblazoned across sleek images of solar panels and towering windmills amidst green fields featured in utility advertisements. Messaging utilities such as SMUD convey outside their organizations portray innovation not only as destined but already here. Internally, the innovation task is posed as achieving SMUD's "Zero Carbon vision." Such framing belies the organizational dilemma faced by public power systems, exploitative in operating complicated utility systems to provide electricity, and exploratory in developing radical innovations needed to decarbonize the grid. That exploration as SmartSacramento illustrated involves the utility functioning as a 'complex adaptive system'[235]. For a utility, that system features "[m]any stakeholders [] involved in [the] organization['s] innovation . . . emerg[ing] through processes in which [] contributions of different actors are integrated"[236]. In this sense, the utility 'emerges' as an innovation organization by its individual teams making decisions and quickly improvising[237] through interaction with others both in exploratory and exploitative capacities. Therein lies the battery paradox. While the battery may be presented as simple, with utilities applying an innovative frame of certainty, delivering the promise of battery solutions requires the utility adapt to complexities posed by underlying paradoxes.

Keeping the lights on while concurrently pursuing yet-to-exist solutions to operate reliably is not self-evident. The worlds from which utility employees show up for work is anything but conducive to connecting with that apparently self-evident concept. These worlds include a parent choosing between working extra hours or spending time with their child; a world in which an employee juggles meeting a supervisor's expectations and those of executives; worlds in which keeping the lights on is all that employees have capacity to do because they are dealing with personal health issues. Those worlds are filled with competing demands. Tensions employees bring to SMUD, which is a culturally risk-averse institution, and those Zero by 2030 creates in their lives do not mesh for many SMUD employees. Expecting them to mesh assumes the underlying paradoxes can be resolved. Can resource scarcity, for instance, be definitively reconciled with innovation within a utility such as SMUD? Perhaps a more productive approach may be to acknowledge as utility managers or energy sector policymakers as the case may be that the two concepts are irreconcilable, which generates tension, and still the organization will persist in exploring paths to develop resources

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234. Interview with former SmartSacramento team member No. 4, *supra* note 143.

235. *See, e.g.*, Sullivan, *supra* note 228.

236. *See* Oughton et al., *supra* note 229.

237. *See* Hugh M. Pattinson & Arch G. Woodside, *Capturing and Reinterpreting Complexity in Multifirm Disruptive Product Innovations*, 24 J. BUS. & INDUS. MKTG. 61, 73 (2009) (concluding that subject technology company's success innovating relied on "[b]rilliant and fast improvising" demonstrating its skill to "create-apply-destroy-recreate-apply applications quickly with little time during the process for focusing long on mistakes and obstacles" reflecting "try this now" doing instead of "what if" thinking).

necessary to execute innovation projects by managing tensions[238] while continuing to keep the lights on.

SmartSacramento highlights a utility operating as a complex adaptive system innovating within the main organization oriented towards maintaining power for customers. The teams that achieved SmartSacramento executing a comprensive grid infrastructure upgrade project prioritized by the entire leadership chain at SMUD. They self-structured, even self-selected their participation in projects. They leveraged autonomy to adapt approaches that grew out of the needs of that particular innovation project. They were empowered to develop their own pathways to adjust to and work with competing demands and dilemmas that characterize innovative work at SMUD, work that itself generates additional tensions for team members and the organization. Those elements combined, changed, and were adapted to achieve SmartSacramento whose value was greater than the sum of its parts. Operationalizing these lessons from SmartSacramento to inform SMUD's decision-making to achieve Zero by 2030, therefore, is in not simply a matter of trying to re-create steps taken to achieve SmartSacramento. Based on this study, SMUD and other electric utilities may want to practice innovating for a low carbon future from the vantage of *powering paradoxes* – dealing with rather than attempting to eliminate competing demands, tensions, and conflicts – experienced by its employees who live and work in a paradoxical electric sector.

B. Innovation Learning Paradox

Identifying the costs of a business, applying tried and true processes to track where costs are being generated, developing assumptions of cost drivers and analyzing how costs ought to be properly allocated to make budget decisions – these are quintessential exploitative functions, essential to properly running a public power utility. A utility's financial controller must trace costs to their origins based on data gathered, assembled, and analyzed to build a case for budget decisions.

The stories utilities tell themselves about how innovation happens within their systems are based on frames – sets of assumptions and beliefs through which people perceive the world. Data from this study suggests SMUD has internalized its version of the story of SmartSacramento; the utilities employing the managers from the Pacific Northwest and Southeast have their own for their respective innovation projects. While each utility has stories fitting their respective innovation journeys, the operative issue for SMUD and public power systems nationwide as they execute plans for a low-carbon future harkens back to the inconspicuous yet vital role of the financial controller: What is the data giving rise to those stories? Is the utility making innovation decisions involving major investments of its already-limited financial and strained staff resources based on evidence rather than stories developed from frames operating within their organizations?

Thus, another key implication of the findings from this research is that power utilities ought to assess whether their systems are making evidence-based decisions to build toward a low carbon future. This can be labeled the Innovation Learning Paradox – innovation is both forward and backward looking.

238. *See* SMITH & LEWIS, *supra* note 124.

SmartSacramento highlights forward thinking. Visioning, planning for that vision, and executing steps of that visions to create the future we seek – these are all part of the exploratory exercise of innovation.

Backward thinking includes work such as this study, probing innovation projects to find nuggets of wisdom from heavy lifts to innovate. Utilities such as SMUD, and federal energy policy stakeholders for that matter, have a challenge to collect and analyze data from the past to inform the future they seek to innovate towards. For instance, DOE's implementation of its current GRIP program will involve collection of technical outcomes to be detailed copiously by grant recipients through compliance reporting, yet information on how utility teams actually achieve the innovations U.S. energy policy seeks from the power sector could remain ignored. Gathering such team functioning information is an exploitative exercise requiring deliberate processes such as the utilities research highlighted in this article. SMUD's ability to operate ambidextrously in this regard could provide significant strategic insights as it proceeds with plans the utility estimates could cost upwards of $4 billion to achieve Zero by 2030, a paradoxical goal by an electric system not unlike power systems across the country that operated for decades before smart grid provided transparency into their distribution grid to know lights were out without someone calling in to inform the utility. Hence, a consideration for energy policymakers is whether valuable data on how innovation functions at the utility level instructive for effectuating and accelerating innovation required to meet decarbonization goals are going unnoticed.

Tackling increasingly complex, seemingly intractable problems in the electrical utility industry such as eliminating carbon emissions requires taking stock of the frame(s) through which innovation challenges are perceived. Learning from SmartSacramento that working with conflicting and contradictory dilemmas SMUD faces is a big part of how that innovation happened seems to be a critical lesson. Just as a controller must conduct proper analysis to determine actual cost drivers within a utility to figure out what to do about them, innovation requires proper diagnosis to assess what makes it work within an organization to determine how lessons learned can be leveraged and, in turn, how that might help create the low carbon future utilities and policymakers envision.

VI. RECOMMENDATIONS

A. *Utility Managers*

This article has attempted to illuminate through SmartSacramento the tensions, conflicts, dilemmas project teams lived during its implementation. Based on the data gathered from former project team members, the overall theme that emerged involved teams facing, dealing with, and even internalizing the tensions inherent in a large-scale innovation effort within SMUD. This article argues that SMUD and other U.S. utilities may want to approach innovation from a vantage of managing paradoxes which is a leadership challenge for any utility moving toward a low carbon future.

To assist managers of utilities to think through their innovation challenges, the following P-O-W-E-R framework is offered:

- **P** stands for paradox. What is/are the paradox(es) at play with a given innovation challenge? If all a utility sees is the conflict between grid operations and R&D, it is likely missing the point. Get to the paradox to unwind often intertwined, conflicting, and contradictory issues that have companies, teams, and individuals intractably stuck.
- **O** is for opposition. Innovation roadblocks and/or or hang-ups are in the eyes of the utility perceiver. Instead of succumbing to a given conflict/dilemma, managers may want to ask how their system might re-cast the challenge. Can you view the opposition from a different vantage that allows your system to apply a paradox mindset to the problem?
- **W** is for wins. These must be diagnosed as carefully as any major failure (it's a paradoxical world). SmartSacramento was a success for SMUD on multiple levels. At the same time, a more complete story of SmartSacramento can be revealed if SMUD is deliberate in uncovering why things worked. That knowledge should be incorporated into the thinking that goes into strategizing for the next innovation endeavor. In other words, mine your wins for nuggets of wisdom.
- **E** is for energy. How much time/effort is your team or utility pouring into wasted spinning over conflicts and tensions. Accepting the contradictions and competing demands can relieve wasted energy. Become more energy efficient and energy effective by acknowledging tensions before moving on to directing your utility's energy at innovating with those tensions in existence.
- **R** is for retry. SmartSacramento underscores the value of iterating solutions. We might not have the killer app for every problem we hit with innovative effort. For utilities facing daunting prospects of moving to net zero or zero carbon, remember that innovation is not about perfection. Greg Satell in his book, "Mapping Innovation" put it this way:

> We expect innovations to be well dress, smooth talking, and brilliantly executed, but the reality is that the innovation process is anything but those things. It is not smooth or shiny. It stutters. It is often overweight and poorly groomed, with dark circles under its eyes from overwork. It comes into the world stumbling and falling, only later to gain Olympic prowess.[239]

B. Utility Innovation R&D

Likewise, federal stakeholders, particularly DOE, should consider the gap in utility innovation R&D highlighted in this article. National innovation undertakings such as DOE's administration of the $3 billion in smart grid funding under GRIP for cost-shared projects will involve utilities deploying next generation smart grid technologies. These projects will produce a plethora of utility technical data similar to information reported by utility awardees of SGIG a decade ago

239. SATELL, *supra* note 231, at 195.

informing decisions by federal energy stakeholders impacting grid reliability, functioning of grid management applications building upon existing smart metering infrastructure, and potential returns on current investments in U.S. smart grid upgrades. Just as the agency accomplished with SGIG,[240] DOE will likely be gathering and documenting 'lessons learned' from implementation of GRIP. Yet, along with the technical information from GRIP implementation, scores of project teams throughout the electric sector will be generating qualitative data from their experiences executing federally-funded smart grid development that illuminate how and why utilities are able to innovate. These insights could prove particularly important to understand as utilities and U.S. energy policy steer power sector innovation towards low and even non-carbon emitting operations. Absent deliberate research and analysis of utility team data, decisions on how billions of dollars of public and private funding to modernize grid distribution and transmission will be spent based could rely on rather consequential assumptions about how innovation supposedly works or fails to work within the highly regulated power sector. Thus, in addition to capturing and summarizing technical details from utilities learned from connecting, integrating, and operating next generation smart grid technologies, DOE has an opportunity to study the workings of utility team innovation nationwide through the GRIP program. This type of utility-level research provides a more complete data set for policymakers and industry making substantial grid investments to try innovating solutions to operate reliably in a low carbon future.

To this end, DOE should consider developing through its administration of GRIP reports on not only what is being innovated – e.g. AMI systems equipped with grid-edge technologies,[241] integration of Distributed Energy Resource Management Systems with utility Outage Management Systems, end-to-end secure communications network between edge-enabled consumer devices and utility systems – but the 'how' and 'why' of utility innovation based upon evidence from utility innovation implementations. As the federal agency most directly involved

240. *See generally Smart Grid Investment Grant Program Final Report*, U.S. DEP'T OF ENERGY (Dec. 2016), https://www.energy.gov/sites/prod/files/2017/01/f34/Final%20SGIG%20Report%20-%202016-12-20_clean.pdf (detailing major findings and key results of national execution of SGIG program); *see id.* at 52 (Of particular relevance to the point made here, DOE explains under Section 5 of the report titled 'Deployment Lessons learned and Conclusions' that "SGIG project experiences produced a wealth of information and lessons learned that can be applied by all utilities developing and deploying smart grid systems" which "cover the gamut of smart grid program implementation, from management and planning, to technology deployment and cybersecurity, to consumer engagement and education.").

241. *See Communications with the Grid Edge: Unlocking Options for Power System Coordination and Reliability*, U.S. DEP'T OF ENERGY 2 (June 2023), https://www.energy.gov/sites/default/files/2023-07/Communications%20with%20the%20Grid%20Edge%20-%20Unlocking%20Options%20for%20Power%20System%20Coordination%20and%20Reliability_0.pdf (defining 'grid edge' to be the "boundary zone where the utility ends and customer premises equipment [] starts . . . begin[ning] at the meter interface (the utility demarcation point) . . . [and] contain[ing] all equipment, software solutions, and controls owned by the customer . . . [which] could be homeowners, businesses, and industrial or commercial facilities"). Integration of grid edge devices including rooftop solar systems, electric vehicle charging stations, and energy storage solutions into grid operations given the increasing magnitude of these edge loads (both positive and negative) is the vision of grid edge technologies. *See id.*

with industry smart grid innovation, DOE is in position to build a nationwide dataset gathered from utilities on their respective team decisions, organizational structuring, and interactions between and among members. Utilities awarded GRIP funding for instance could host project-based DOE research fellows to perform data gathering and analysis on innovation practices by leveraging DOE's existing workforce development initiatives through Oak Ridge National Lab's ORISE[242] program. In partnership with other national labs, DOE could commission studies to be undertaken post-project similar the research presented in this article documenting key data points and themes to be drawn from individual GRIP-funded projects. The project-based information gathered from the ground level of innovation processes can inform regulatory decision-making on grid modernization by DOE or other government agencies, identify where implementation challenges exist, and design programmatic solutions addressing issues based on data generated by project-based experience of a broad representation of utility systems. By capturing such project-specific data, DOE would develop intelligence on power sector innovation that could prove pivotal for sustained industry innovation needed to effectuate federal energy policy targeting decarbonization by utilities.

VII. LIMITATIONS AND FURTHER RESEARCH

Because the SmartSacramento study addressed a smart grid project completed over a decade ago, there is a potential for recall bias – systemic error that occurs when participants do not remember previous events or experiences accurately or omit details. Recall of events by interviewees were consistent across the interviews conducted. For instance, the firing of a vendor that had performed poorly during the project came up during multiple interviews. Each person who commented on this event independently provided generally similar explanations as to the circumstances of the situation and outcomes, and even similar commentary to the effect that it was not something usual for SMUD to fire a vendor. Likewise, while interviewees recalled events specific to their individual roles and project involvement, similar themes emerged across responses including decision autonomy, solution iteration, integrative solutioning as tensions arose, and experiencing personal tensions from working on the project after it was completed. Thus, to the extent there was recall bias, the relative coherence of themes and information interviewees independently provided suggested that recall bias did not materially impact the veracity of the data in this research.

Separately, confirmation bias – seeking and paying attention to information which confirms one's beliefs and assumptions – may have influenced this research. As an employee of SMUD, I as author of this study carried my own frames into these interviews reflecting sentiments shared regarding decision-making tensions many experience at SMUD. While I attempted to mitigate bias of which I was aware (e.g. turning off video during interviews) and took measures to control them, my research methodology may have nonetheless introduced bias by virtue

242. *See generally STEM Internships and Fellowships*, OAK RIDGE INST. FOR SCI. & EDUC., https://orise.orau.gov/internships-fellowships/index.html (last visited Aug. 5, 2024).

of turning the microscope so to speak on my employer. The findings presented in this article should be viewed with these limitations in mind.

Further study of utility-specific innovation is warranted. Qualitative studies of other utilities, empirical evaluation of systems undertaking innovation are the types of research that will be needed to gain the comprehensive perspective on innovation practice still largely academic and non-actionable for the average utility. Studies addressing challenges presented by novelty and uncertainty that is core to innovation along the lines of research by Thayer, et al. (2018)[243] within the electric sector is ripe for further research.

For example, participants in this study spoke in very positive terms of SmartSacramento colleagues being "decisive" and "visionary" and generally antithetical to the "consensus" relied upon to make decisions. The consensus culture acknowledged and uniformly scorned by SMUD interviewees raises an interesting question: is this a "bad" thing? It has developed over time at SMUD for a reason. What are those reasons and, applying paradox theory, might lessons underlie another paradox SMUD could leverage to its advantage.

Research conducted by Rothman and Melwani (2017) on emotional ambivalence – feeling pulled in different directions, feeling uncertain, having mixed emotions – posits that "leaders experience emotional complexity in the face of contradictions between stakeholders and demands."[244] Uncertainty and difficulties may help people be "cognitively flexible," which refers to thinking more broadly about concepts in comprehensive and inclusive manners.[245] In other words, perspectives on decisiveness may inadvertently be undermining accuracy in judgement when making decisions. The consensus that SMUD teams revert to in their decision-making, paradoxically, could have adaptive characteristics conducive to organizational innovation.

VIII. CONCLUSION

As part of the study, participants were asked via email to complete the following statement: "SMUD is in the business of ________." The following represent the responses provided: providing reliable electricity service at reasonable rates; making sure that our customers have cheap and reliable power; continuously innovating solutions to meet our community's evolving energy needs.

Such statements are accurate in that they describe purposes SMUD serves as a municipal utility. It is noteworthy how concepts such as "cheap and reliable power," as conflicting and contradictory as they may be, are normal to those at SMUD. Given the findings from this research, an argument could be made that as

243. *See* Amanda L. Thayer et al., *Addressing the Paradox of the Team Innovation Process: A Review and Practical Considerations.*, 73 AM. PSYCH. 363 (2018).

244. Naomi B. Rothman & Shimul Melwani, *Feeling Mixed, Ambivalent, and in Flux: The Social Functions of Emotional Complexity for Leaders*, 42 ACAD. MGMT. REV. 259, 264 (2017).

245. *Id.* at 269 (summarizing research suggesting on the one hand that state emotional complexity can lead to more cognitive flexibility, and other literature suggesting that emotional complexity can lead to more rigidity). What appears to differentiate these two paths the researchers noted is whether individuals become preoccupied with trying to cope with and reduce their feelings of conflict and contradiction or whether they stay open to their contradictory feelings. *Id.*

far as innovation is concerned, a utility such as SMUD engaged in the type of company-wide innovation endeavors such as SmartSacramento is in the business of "managing tensions to innovate."

Innovation at the scale needed to decarbonize utilities being undertaken by utilities nationwide involves substantial investments of labor and financial resources. SMUD is one of thousands of U.S. public power systems who likely share many of the organizational tensions revealed by the utility professionals interviewed for this research. The question for these utilities is whether they can find ways to make their paradoxical worlds work for them to realize a lower carbon future.

ADDRESSING ENERGY INSECURITY UPSTREAM: ELECTRIC UTILITY RATEMAKING AND RATE DESIGN AS LEVERS FOR CHANGE

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Synopsis: Millions of Americans are impacted by energy insecurity each year, in part due to unaffordable and inequitable electricity rates. The electric ratemaking process presents opportunities to confront issues of affordability and equity or to instead entrench traditional approaches. State legislatures, public utility commissions (PUCs), and advocates all play vital roles in making the former a reality. Historically, ratemaking has been criticized as an insular and highly technical process that caters to utilities rather than customers. But states like California and New York are making strides by broadening PUC legal authority to include explicit consideration of equity issues, adjusting incentives and values within the rate formula, implementing novel rate designs alongside other low-income customer protections, and instituting measures to make ratemaking a more procedurally just process. Other states should replicate these efforts, and those that have started making progress must continue, as energy insecurity persists.

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I. INTRODUCTION

The inability to adequately meet basic household energy needs, known as energy insecurity, is an increasingly prevalent problem in the United States.[1] Energy insecurity has economic, physical, and behavioral dimensions, but this article will focus on affordability of energy bills. With rising electricity prices, lower income households must dedicate a higher proportion of monthly income to electricity bills, contributing to cost of living disparity in America. Burdened by energy costs, households may be forced to choose between basic life necessities (the "heat or eat" dilemma)[2] or turn to dangerous electricity cost-saving measures– energy insecurity is thus a significant public health and social issue.

To date, the emphasis on understanding energy affordability gaps that fuel energy insecurity has been largely at the household level with a particular focus on income and energy consumption patterns. This article seeks to instead interrogate the structural drivers of unaffordable energy bills by examining electric utility rate design and the ratemaking process from an equity perspective. It examines substantive rate designs, as well as the procedural justice, or lack thereof, throughout the ratemaking process.[3] For the purposes of this article, energy equity is defined as a process toward the fair distribution of the benefits and burdens of energy production and consumption. Following the principles of environmental justice, energy equity aims to ensure that all communities, particularly disinvested, overburdened, and low-income groups, have fair access to affordable, reliable, and clean energy. This includes addressing disparities in how energy systems impact

1. *See* Diana Hernández, *Understanding 'energy insecurity' and why it matters to health*, SOC. SCI. & MED. (Aug. 21, 2016), https://www.sciencedirect.com/science/article/pii/S0277953616304658?via%3Dihub/.

2. Diana Hernández, *Energy insecurity and health: America's hidden hardship*, HEALTH AFFS.: HEALTH POL'Y BRIEF (June 29, 2023), https://www.healthaffairs.org/do/10.1377/hpb20230518.472953/; Robert Fleishman et al., *Energy Insecurity - What Is It, and Why Does It Matter?*, 45 ENERGY L. J. 67, 69 (2024).

3. The scope of this article does not reach all contributing factors to energy insecurity, such as inflation and rising fuel prices, as well as other aspects of ratemaking that impact bill prices, such as energy and capacity markets.

different populations in terms of cost, accessibility, and environmental burdens. Following these principles, equitable utility rates consider the varying abilities of different customer segments to pay, as well as their differing energy needs and consumption patterns. They prevent undue financial strain that could lead to chronic or acute energy insecurity, unhealthy coping mechanisms, or shut-offs which result in complete loss of access to power due to non-payment.[4] With the aid of ten expert interviews,[5] this article identifies numerous levers for equity intervention. To aid in conceptualization of these levers, it showcases efforts by public utility commissions (PUCs) in California and New York as present-day attempts to integrate equity considerations into the ratemaking process. The objective of this article is to stimulate discourse surrounding the regulatory and political barriers to equitable rates nationwide and provide potential paths of action for regulators and advocates.

II. Utility Law Landscape

At the federal level, the Federal Energy Regulatory Commission (FERC) regulates the wholesale sale of electricity and transmission in interstate commerce pursuant to the Federal Power Act (FPA), which encompasses sale for resale by generators, conventional integrated public utilities, and power marketers, but not governmentally-owned utilities.[6] The FPA leaves the power to regulate the retail sale of electricity to state PUCs.[7] A retail sale is the final sale of electricity to consumers and thus is the focus of this article. As is the case at the federal level, municipal and cooperative utilities are often exempt from comprehensive PUC regulation,[8] so investor-owned utilities will also be the focus of this discussion. The regulatory authority of state PUCs is derived from state legislation or state constitutions,[9] and thus the precise scope of PUC duties and legal constraints varies by state. Procedurally, PUCs make regulatory decisions within their applicable statutory authority on a utility-specific case-by-case basis (rate cases) and through integrated resource planning and development and administration of programs

4. *See generally* Sonal Jessel et al., *Energy, Poverty, and Health in Climate Change: A Comprehensive Review of an Emerging Literature*, FRONTIERS PUB. HEALTH, Dec. 12, 2019; Diana Hernández & Jennifer Laird, *Surviving a Shut-Off: U.S. Households at Greatest Risk of Utility Disconnections and How They Cope*, 66 AM. BEHAV. SCIENTIST 856 (2022).

5. Interviewees included PUC and Department of Public Service staff, a former Administrative Law Judge, public advocate office staff, and energy attorneys at various nonprofit organizations. These interviews were conducted in accordance with procedures approved by the Columbia University Institutional Review Board and will therefore remain anonymous [hereinafter Expert interviews].

6. 16 U.S.C. § 824(b)(1) (2015).

7. *Id*. Some states refer to these regulatory bodies as public service commissions, public regulation commissions, or corporation commissions.

8. Danielle S. Byrnett & Daniel Shea, *Engagement Between Public Utility Commissions and State Legislatures,* NCSL (Oct. 28, 2019), https://www.ncsl.org/energy/engagement-between-public-utility-commissions-and-state-legislatures.

9. Jim Lazar, *Electricity Regulation in the US: A Guide. Second Edition*, REG. ASSISTANCE PROJECT 27 (July 12, 2016), https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-electricity-regulation-US-june-2016.pdf.

through generic proceedings.[10] Substantively, the core historic statutory legal duties of PUCs are relatively uniform nationwide and remain in place: serving customers, ensuring that rates are just, reasonable, and nondiscriminatory, providing safe and reliable service, and preventing undue financial risk in utility financing.[11] In carrying out these duties, PUCs are charged with protecting the "public interest."[12] One growing trend is the passing of state legislation to expand the subject-matter of these duties, by explicitly including consideration of climate change in PUC jurisdiction, for example, and critically, a few states have now done the same for equity.[13]

- In California, the CPUC must consider equity in a number of ways, which will be discussed in further detail below.[14]
- Colorado state law mandates that the PUC adopt rules to consider how to improve equity.[15]
- The Illinois' Climate and Equitable Jobs Act requires that the Commerce Commission conduct a study on low-income discount rates and authorizes the Commission to require utilities to establish low-income discount rates.[16]
- In Maine, state law requires all state agencies to incorporate equity considerations into decision-making, including the PUC.[17]
- In Massachusetts, state law requires the Department of Public Utilities to, in meeting greenhouse gas (GHG) emission reduction goals, prioritize equity, safety, security, reliability, affordability, and GHG emission reductions.[18]
- In New York, the Climate Leadership and Community Protection Act (CLCPA) requires that state agencies direct programmatic resources so that disadvantaged communities receive 35-40% of the benefits of spending on clean energy and energy efficiency programs, projects or investments.[19]
- Oregon state law authorizes the PUC to consider "[d]ifferential energy burdens on low-income customers and other economic, social equity or environmental justice factors that affect affordability for

10. Eric Filipink, *Serving the "Public Interest"- Traditional v. Expansive Public Utility Regulation*, NAT'L REGUL. RSCH. INST. 23 (2009).

11. *Id*. at 12-13.

12. *Id*. at 18.

13. Chandra Farley et al., *Advancing Equity in Utility Regulation*, FUTURE ELEC. UTIL. REGUL. 79 (Nov. 2021), https://live-lbl-eta-publications.pantheonsite.io/sites/default/files/feur_12_-_advancing_equity_in_utility_regulation.pdf.

14. *See infra* Part VII(A).

15. S.B. 21-272, 73rd Gen. Assemb., Reg. Sess. (Colo. 2021).

16. Amend. to S.B. 2408, 102nd Gen. Assemb., Reg. Sess. (Ill. 2021).

17. H.R. 1251, 130th Leg., 1st Reg. Sess. (Me. 2021).

18. H.R. 192nd Gen. Court, Reg. Sess. (Mass. 2021).

19. *See infra* Part VII(A).

certain classes of utility customers" when classifying utility service.[20]
- Washington state law requires the Washington Utilities and Transportation Commission to equitably distribute energy and non-energy benefits of the transition to clean energy.[21]

The passage of such legislation provides legal certainty regarding the scope of authority of PUCs. There are no universal guidelines or metrics to guide these equity-focused approaches, leaving room for interpretation and contestation of these efforts. Given the absence of precise legal definitions of the "public interest" and "just, reasonable, and nondiscriminatory," the contours of these standards have been subject to debate as PUCs confront new regulatory challenges such as widespread energy insecurity and climate change. If a PUC action is challenged in state court as beyond the scope of these duties, the court may strike it down as an illegal exercise of power, but as these duties derive from state statutes, state legislatures have the ultimate authority to change and expound upon these duties.

A. Public Interest

Historically, the courts identified natural monopolies like railroads and utilities as "clothed with the public interest"[22] and thus in need of government regulation to protect consumers. Similarly, the FPA declares that transmission and sale of electricity "for ultimate distribution to the public is affected with a public interest."[23] The meaning of public interest in the utility context as defined in the case law was traditionally limited to controlling the power of monopolistic utility companies to prevent price-gouging and to limit anticompetitive effects through regulation of rates and practices.[24] Today, the legal definition of the public interest is imprecise and evolving.[25] PUCs are increasingly asked to address complicated issues involving conservation, climate change, and energy insecurity absent a statutory definition and thus without legal certainty regarding whether these are within the scope of the public interest duty. The limited case law indicates that despite the evident reluctance to break from traditional practices on the part of PUCs,[26] enabling statutes charging PUCs to serve the public interest could be used to justify actions taken to address energy insecurity and promote energy equity. Moreover, where states have included language around equity, climate change, conservation, and other issues in PUC enabling statutes, PUCs likely have flexibility to take a more expansive approach to the meaning of the public interest.

20. H.B. 2475, 81st Leg. Assemb., Reg. Sess. (Or. 2021).
21. S.B. 5116, 66th Leg., Reg. Sess. (Wash. 2019).
22. Munn v. Ill., 94 U.S. 113, 126 (1876).
23. 15 U.S.C. § 717(a) (2012).
24. Filipink, *supra* note 10, at 40.
25. *Id.* at 3.
26. *Id.*

Absent legislative action to expand the scope of PUC roles, PUC actions that embody the traditional economic-based roles and policy goals are consistently upheld when challenged in court.[27] One key Supreme Court case indicates that PUCs may have broad latitude to go beyond these traditional goals. In *NAACP v. Federal Power Commission*, the Supreme Court held that regulation of discriminatory utility employment practices exceeded FERC's regulatory authority under the FPA and Natural Gas Act (NGA).[28] The Court found that FERC's public interest mandate had to be interpreted within the principal purpose of the NGA and FPA, which was to encourage the orderly development of plentiful supplies of electricity and natural gas at reasonable rates: "Thus, in order to give content and meaning to the words 'public interest' as used in the Power and Gas Acts, it is necessary to look to the purposes for which the Acts were adopted."[29] However, the Court did find FPA authority to consider employment practices to the extent that excessive costs resulted from the practices; for example, back pay recoveries by employees who proved they were discriminatorily denied employment, the costs of lost government contracts terminated due to discrimination, or litigation costs over discrimination claims.[30] Additionally, in coming to this decision, the Court interpreted public interest quite expansively within the confines of the animating statute by indicating FERC's authority to consider "conservation, environmental, and antitrust questions" as subsidiary purposes of the NGA/FPA.[31] Under this precedent, it appears that expansive policy goals are permitted under the public interest principle if tied to the enabling statute's purpose.[32] Thus, a court could in theory find that a narrow PUC enabling statute has the subsidiary purpose of promoting affordability and equity through rate regulation.

In the specific context of PUC ratemaking power, some courts at the state level have similarly allowed for expansive policy goals. In *Southern California Edison Co. v. California Public Utilities Commission*, the California Court of Appeals found that the CPUC had the authority to require electric utilities to collect a ratepayer surcharge to fund renewable energy projects.[33] The court found this authority was encompassed by the CPUC's "vast, inherent power to take any action that is cognate and germane to utility regulation, supervision, and rate setting, unless specifically barred by statute."[34] Along the same lines, in *Public Service Commission of Kentucky v. Commonwealth*, the Kentucky Supreme Court found the PSC had the authority to offer discounted electricity rates in disadvantaged communities and brownfields for the purpose of economic development, despite

27. *Id.*

28. NAACP v. FPC, 425 U.S. 662 (1976).

29. *Id*. at 669.

30. *Id*. at 666-67.

31. *Id*. at n.7. Indeed, many cases have required agencies charged with protection of the public interest to consider antitrust and environmental concerns. *See* Denv. & Rio Grande W. R.R. Co. v. U.S., 387 U.S. 485, 492-493 (1967); Gulf State Utils. v. FPC, 411 U.S. 747, 757-61 (1973); Udall v. Fed. Power Comm'n, 387 U.S. 428, 450 (1967).

32. Farley et al., *supra* note 13, at 79.

33. S. Cal. Edison Co. v. Pub. Utils. Comm'n, 227 Cal.App.4th 172 (2014).

34. *Id*. at 187.

their exclusion from a statutory list of entities eligible for discounted rates.[35] The court found that the prohibition on unreasonable prejudice indicated the legality of *reasonable* prejudice, including the rate discounts in question.[36] In *American Hoechst Corp. v. Department of Public Utilities,* the Massachusetts Supreme Court found authority to permit a utility's implementation of a discounted electricity rate for the elderly poor due to its general jurisdiction over rates.[37] In *Affiliated Construction Trades Foundation v. West Virginia Public Service Commission*, the court found that the PSC had broad authority for "comprehensive consideration" of the public interest and thus had the duty to investigate a power company's methods of financing and workforce composition in constructing a power plant.[38]

In contrast, in *Arkansas Gas Consumers, Inc. v. Arkansas Public Service Commission,* the Supreme Court of Arkansas found that the PSC did not have the authority to develop a program to provide gas service to disconnected families under its statutory ratemaking authority and statutory authorization to protect the public health.[39] The court relied on the fact that the program would be funded through a surcharge on all ratepayers which fell outside the PSC's delegated surcharge authority, which was limited to recovery of costs associated with existing facilities upon request of the utility.[40] The dissenting justices found the opposite to be true, arguing that the disconnection policy easily fit within the PSC's ratemaking authority.[41] In *Process Gas Consumers Group v. Pennsylvania Public Utility Commission,* the Pennsylvania Supreme Court struck down the PUC's industrial surcharge to fund conservation programs because it exceeded the scope of the state law authorizing the PUC to develop an energy conservation program.[42] Note that in July 2024, the Fifth Circuit struck down the use of customer surcharges to fund low-income telecommunications programs (Universal Service Fund) as an unconstitutional tax.[43] The Sixth and Eleventh Circuits upheld the same Fund, meaning the Supreme Court will likely have the last word.[44] If the surcharge structure is found unconstitutional, PUCs may be unable to fund low-income programs in the energy context with customer surcharges without explicit statutory authority.

A number of states have passed legislation providing PUCs with the authority to implement special rates in the public interest for commercial and industrial

35. Pub. Serv. Comm'n of Ky. v. Commonw., 320 S.W.3d 660 (Ky. 2010).

36. *Id*.

37. Am. Hoechst Corp. v. Dep't of Pub. Utils., 399 N.E.2d 1 (Mass. 1980).

38. Affiliated Constr. Trades Found. v. Pub. Serv. Comm'n of W. Va., 565 S.E.2d 778, 789 (W. Va. 2002).

39. Ark. Gas Consumers, Inc. v. Ark. P.U.C., 188 S.W.3d 109 (Ark. 2003).

40. *Id*.

41. *Id*. at 124.

42. Pa. Pub. Util. Comm'n v. Process Gas Consumers Grp*.,* 502 Pa. 545 (1983).

43. Consumers' Rsch. v. FCC, No. 22-60008, 2024 WL 3517592, at *26 (5th Cir. July 24, 2024).

44. *See* Consumers' Rsch. v. FCC, 67 F.4th 773 (6th Cir. 2023), *cert. denied*, No. 23-456, 2024 WL 2883753 (U.S. June 10, 2024); Consumers' Rsch., Cause Based Com., Inc. v. FCC, 88 F.4th 917 (11th Cir. 2023), *cert. denied sub nom*; Consumers' Rsch. v. FCC, No. 23-743, 2024 WL 2883755 (U.S. June 10, 2024).

(C&I) customers due to their contributions to load growth.[45] Even absent such legislation, state courts have appeared amenable to PUC use of general ratemaking authority for this category of special rates. Economic development discounted rates have been authorized without legislation in Arizona,[46] Florida,[47] Kentucky,[48] Michigan,[49] and Oklahoma.[50] Experts have thus proposed using similar economic justifications for low-income rates, arguing that alleviating energy insecurity would lead to load growth.[51] In turn, decreasing energy insecurity would decrease the costs to utilities of managing customer debt and disconnections.[52]

B. Just, Reasonable & Nondiscriminatory

One way in which PUCs must protect the public interest is by ensuring that utility rates are "just and reasonable." Dating back to the Interstate Commerce Act of 1887 and railroad rates, the "just and reasonable" standard traditionally addresses whether the allocation of costs and benefits between public utilities and ratepayers is just and reasonable.[53] This inquiry loosely involves finding a balance in which rates are not "less than compensatory" nor "excessive."[54] However, in the same vein as the public interest principle, "just and reasonable" has no fixed legal definition.[55] In *Federal Power Commission v. Hope Natural Gas*,[56] the Supreme Court established the "end result" approach to judicial review of the rate-making process under which the reviewing court refrains from requiring any rate formula and instead looks to the outcome when assessing whether a rate is "just and reasonable:" "Under the statutory standard of just and reasonable it is the result reached not the method employed that is controlling."[57] While the Supreme Court was considering FERC's rates in this case, state courts have since adopted

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45. Gabriel Chan & Alexandra Klass, *Regulating for Energy Justice*, 97 N.Y.U. L. REV. 1426, 1450 (2022).

46. *In re* UNSE Elec., Inc., No. E-04204A-15-0142, 2016 WL 4467959 (Ariz. Corp. Comm'n Aug. 18, 2016) (order approving revised schedule of rates and charges); *In re* Tucson Elec. Power Co., No. 77856, 2020 WL 8257471, at *97 (Ariz. Corp. Comm'n Dec. 31, 2020) (approving revised schedule of rates and charges).

47. *In re* Duke Energy Fla., LLC, No. 160173-EI, 2016 WL 5869985 (Fla. Pub. Serv. Comm'n Oct. 3, 2016) (order approving economic development and re-development riders).

48. *In re* Louisville Gas & Elec. Co. & Ky. Utils. Co, No. 2011-00103, 2011 WL 3571926, at *1 n.3 (Ky. Pub. Serv. Comm'n Aug. 11, 2011) (order approving EDR tariffs).

49. *In re* DTE Elec. Co. for Approval of Rate Schedule D13 XL High Load Factor Rate, No. U-21163, slip op. at 1 (Mich. Pub. Serv. Comm'n Dec. 22, 2021) (order approving rate schedule).

50. *In re* Okla. Gas & Elec. Co., No. PUD 201400307, 2015 WL 4395296, at *3 (Okla. Corp. Comm'n July 16, 2015) (order approving joint stipulation and settlement agreement).

51. Chan & Klass, *supra* note 45, at 1486-87.

52. *Id*.

53. The standard has occasionally been extended to include allocation between different classes of customers. *Id*. at 1444; Farley et al., *supra* note 13, at 82

54. Farmers Union Cent. Exch., Inc. v. FERC, 734 F.2d 1486, 1502 (D.C. Cir. 1984).

55. *Id*. at 1501.

56. FPC v. Hope Nat. Gas, 320 U.S. 591 (D.C. Cir. 1944).

57. *Id*. at 602.

this highly deferential approach to judicial review of PUC ratemaking.[58] Although the Supreme Court recently overruled a mainstay of administrative law, *Chevron* deference, judicial deference to PUC interpretations of "just and reasonable" will likely survive. In *Loper-Bright*, the Court stated that "the statute's meaning may well be that the agency is authorized to exercise a degree of discretion" and pointed to words such as "reasonable" and "appropriate" as examples of terms that leave agencies with flexibility.[59] PUCs have chosen to employ cost causation principles and cost-of-service regulation in ratemaking by adhering to the goal of charging consumers rates that reflect their marginal cost of service. However, the rigidity of the legal requirement that this approach be utilized rather than an alternative that includes consideration of energy burden[60] depends on the state, both the statutory authority and level of discretion provided by the courts. Some experts posit that the pervasiveness of traditional cost-of-service regulation is the result of an enduring status quo.[61]

Another legal standard within the "just and reasonable" framework is the prohibition of undue discrimination found in most state statutes. While discrimination between classes of customers is generally accepted, different rates for similarly situated customers or charging *the same* rates or offering the same quality of service to customers who are dissimilarly situated, are at risk of being perceived as violating this principle, either by PUCs who choose not to use their general ratemaking authority to set preferential rates of some kind or state courts that have found attempts to do so to exceed their general ratemaking authority. That said, the meaning of undue discrimination varies greatly by state. For example, courts and/or PUCs in Massachusetts,[62] Ohio,[63] Rhode Island,[64] and Utah[65] have found authority to provide distinct rates or discounts for low-income, disabled, or elderly

58. Chan & Klass, *supra* note 45, at 1443; Ari Peskoe, *Unjust, Unreasonable, and Unduly Discriminatory: Electric Utility Rates and the Campaign Against Rooftop Solar*, 11 TEX. J. OIL GAS & ENERGY L. 211, 230 (2016).

59. Loper Bright Enters. v. Raimondo, 144 S. Ct. 2244, 2263 (2024).

60. Lester Baxter, *Electric Policies for Low-income Households,* 26 ENERGY POL'Y 247, 248 (1998).

61. *See* Farley et al., *supra* note 13.

62. Am. Hoechst Corp. v. Dep't of Pub. Util., 399 N.E.2d 1 (Mass. 1980) (upholding authorization of elderly, low-income electric rate).

63. Montgomery Cnty. Bd. of Comm'r v. Pub. Util. Comm'n of Ohio, 503 N.E.2d 167, 171 (Ohio 1986) (finding the percentage of Income Payment Plan (PIPP) was implemented by the PUC without legislative authority and upheld by the Ohio Supreme Court).

64. *In re* Duke Power Co., 26 P.U.R.4th 241 (Aug. 31, 1978) (order approving discount for blind, disabled, or elderly customers).

65. *In re* PacifiCorp, No. 97-035-01, 1999 WL 218118, at *70 (Utah Pub. Serv. Comm'n Mar. 4, 1999) (finding authority to provide low-income lifeline program for electric service); *in re* PacifiCorp., No. 99-035-10, 2000 WL 873337, slip op. at 77 (Utah Pub. Serv. Comm'n May 24, 2000) (requiring implementation of low-income lifeline program for electric service).

consumers while courts and/or PUCs in Alabama,[66] Arkansas,[67] Hawaii,[68] Indiana,[69] New Mexico,[70] and Oregon[71] have refrained from finding authority to implement similar forms of assistance as unduly discriminatory. Despite the uncertainty, at least twenty states offer low-income bill assistance in some capacity that have presumably gone without successful challenge.[72] Additionally, with adoption of time-of-use rates, special rates for new loads, technology-specific rates, and economic development rates, PUCs appear increasingly willing to allow for differentiated rates.[73] The justification for economic development rates, or negotiated discounts for industrial customers who might otherwise leave the utility system, is the theory that losing an industrial customer might leave remaining utility customers worse off—this same reasoning could be used to justify low-income rates in that loss of customers and disconnection costs hurt the system as a whole.[74]

The Supreme Court has placed one constitutional limit on the ratemaking authority of PUCs:

> Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.[75]

In *Federal Power Commission v. Hope Natural Gas Company*, the Supreme Court expounded upon the meaning of a fair return: "return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."[76] Thus, a utility's right to a reasonable opportunity to earn a "fair rate of return" is a legal constraint inherent in all regulatory ratemaking decisions.

The most effective means of clarifying PUC authority to prioritize equity in the ratemaking process under the public interest duty and just and reasonable principle would be the enactment of a bill defining the public interest as explicitly

66. Greater Birmingham Unemployed Comm. v. Ala. Gas Corp., 86 P.U.R.4th 218, 220 (Ala. Pub. Serv. Comm'n Sept. 8, 1987) (rejected authority to set low-income gas rate).

67. Ark. Gas Consumers, Inc. v. Ark. Pub. Serv. Comm'n, 118 S.W.3d 109 (Ark. 2003) (court struck down low-income arrearage forgiveness program).

68. *In re* Haw. Elec. Light Co., 207 P.U.R.4th 117 (Haw. Pub. Utils. Comm'n Feb. 8, 2001) (left low-income rate design to legislature).

69. Citizens Action Coal. v. Pub. Serv. Co., 450 N.E.2d 98 (Ind. Ct. App. 1983) (affirmed P.S.C. decision to refrain from offering a lifeline rate to low-income customers due to lack of authority).

70. Mountain States Legal Found. v. N.M. State Corp. Comm'n, 687 P.2d 92, 94 (N.M. 1984) (court struck down an elderly telephone rate).

71. *In re* Rate Concessions to Poor Persons and Senior Citizens, No. R-23, 1976 WL 419194, at *98 (Or. Pub. Util. Comm'n Jan. 16, 1976) (rejected authority to set low-income and elderly rates; legislature has since provided this authority).

72. *See Low Income Utility Program Working Group Report*, NW ENERGY COAL. 24-35 (Dec. 2018), https://www.oregon.gov/puc/utilities/Documents/LIUPWG-2018-Final-Report.pdf [hereinafter *Low Income Report*].

73. *See infra* Part III(B).

74. Chan & Klass, *supra* note 45, at 1485.

75. Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679, 690 (1923).

76. FPC v. Hope Nat. Gas Co., 320 U.S. 591, 603 (1944).

including considerations of equity by the state legislature.[77] In Washington State's 2019 Clean Energy Transition Act, the legislature included a list of items to be included in the meaning of public interest such as consideration of performance and incentive-based regulation to achieve fair, just, reasonable, and sufficient rates and the equitable distribution of energy benefits and reduction of burdens.[78] In Colorado, Senate Bill 19-236 passed in 2019 directs the PUC to consider specific factors when determining whether a utility's Clean Energy Plan is in the public interest, including the costs to consumers resulting from the plan.[79] On their faces, these statutes are broad enough that they arguably codify pre-existing authority, as discussed above, so more specific language would be more impactful. However, some PUCs are not prioritizing equity despite this arguable authority, so mere codification in vague terms may nonetheless be effective in motivating PUC action. With explicit legislative authority, PUCs would be able to address inequity without fear of litigation over lack of statutory authority.[80] However, even absent state legislative action, PUCs could pass regulations defining public interest in the same manner, acting under the legal authority of animating statutes and the unsettled case law regarding the meaning of public interest in the utility context, or alternatively, in the just and reasonable context. Even without defining public interest explicitly, taking actions that indicate equity is within the scope of PUC authority to consider would also be helpful. For example, according to a National Association of Regulatory Utility Commissioners (NARUC) study in 2021, Alabama, Colorado, Louisiana, Michigan, and Oklahoma mentioned equity in PUC mission statements.[81]

Moreover, due to the unclear law regarding the definition of "just and reasonable," it is arguably within the discretion of PUCs to promote equity under this umbrella duty. If challenged in court, PUCs could put forward a few novel arguments, the success of which is untested to-date. They could argue that if residents cannot afford to be energy secure, this in itself is evidence of unjust and unreasonable rates.[82] Additionally, PUCs could argue that the vast difference in energy burden between low and middle to high-income customers constitutes undue discrimination and thus requires distinct rates to remedy this discrimination. In fact, a UC Berkeley study found that in Baltimore, across all months of the analysis timeframe, the lowest-income households (below $60,000) paid the highest mean and median prices, and the highest-income households (above $80,000) paid the

77. *See* Jessie Ciulla et al., *Purpose: Aligning PUC Mandates with a Clean Energy Future,* RMI (June 2021), https://rmi.org/wp-content/uploads/2021/07/PUC-Clean-Energy-Goals-Report.pdf; *see also* Farley et al., *supra* note 12, at 77.

78. Wash. S.B. 5116.

79. S.B. 19-236, Gen. Assemb., Reg. Sess. (Colo. 2019).

80. *See* Filipink, *supra* note 10, at 6 (finding that risk of litigation decreases when the legislature explicitly delegates authority for expansive commission roles beyond the traditional) (Note that PUCs would still be required to provide a rate of return that is not impermissibly confiscatory and thus could face litigation of that nature).

81. Kiera Zitelman & Jasmine McAdams, *The Role of State Utility Regulators in a Just and Reasonable Energy Transition*, NARUC 13-14 (Sept. 2021), https://perma.cc/7MCF-EUEX.

82. Farley et al., *supra* note 13, at 82.

lowest mean and median prices, and marginal communities faced particularly high prices.[83] Additionally, as technological advances allow for more granular measurements of energy consumption, further delineation of customer classes based on usage, like use of energy for essential versus nonessential purposes, could allow for low-income rates within the traditional cost-of-service framework.[84]

The legal doctrines presented above are often cited as justifications for PUC inaction on issues of equity and energy insecurity, but in practice, there is limited case law considering whether action on these issues would exceed the statutory powers of PUCs. Some of the experts interviewed for this article indicated that it is more likely that PUCs are choosing to be cautious by continuing historic practices.[85] While operating under the status quo and avoiding promotion of equity through rate design protects PUCs from challenges in court, it is quite possible that PUC innovations on the equity front would be upheld as within the bounds of these legal principles, particularly given the tradition of the deferential treatment of PUCs by state courts. The likelihood of successful legal challenge may depend upon the politics of each state.

III. RATEMAKING

A. Revenue Requirement

The first step of traditional cost-of-service ratemaking is calculating how much a utility needs to receive from ratepayers to pay for operating expenses and capital investments (rate base) while also making a fair return on investment: this total constitutes a utility's revenue requirement.[86] The revenue requirement formula is thus: rate base x rate of return + operating expenses. The calculation of each of these values can have significant impacts on the bills faced by ratepayers, and as such, the acceptance of the status quo has at times faced criticism for its contribution to energy insecurity broadly.

As allowed return is a function of capital investments in the revenue requirement formula, utilities are incentivized to invest in capital. This phenomenon is called the Averch-Johnson effect and has been the subject of widespread discourse and critique.[87] If an investment does not pan out, utility shareholders will bear the cost if the PUC utilizes the "used and useful" standard which precludes ratepayer responsibility unless costs result in generation of electricity for actual use or other useful outcomes.[88] However, ratepayers will have to pay if the PUC adheres to the prudent investment rule; if the investment was prudent at the time it was made,

83. Jenya Kahn-Lang, *Competing for (In)attention: Price Discrimination in Residential Electricity Markets*, ENERGY INST. AT HAAS 14 (Nov. 2022), https://haas.berkeley.edu/wp-content/uploads/WP333.pdf.

84. *See* discussion *infra* Part III.C.1; Expert interviews, *supra* note 4.

85. Expert interviews, *supra* note 4.

86. Adrienne L. Thompson, *Protecting Low-Income Ratepayers as The Electricity System Evolves*, 37 ENERGY L.J. 265, 282 (2016).

87. Lazar, *supra* note 9, at 86.

88. Jonathan A. Lesser, *The Used and Useful Test: Implications for a Restructured Electric Industry*, 23 ENERGY L.J. 349 (2002).

the cost may be included in revenue requirement as a component of the rate base or an expense, even if the investment did not yield useful services.[89]

Under Supreme Court precedent discussed prior, a utility is entitled to an opportunity to earn a fair rate of return on its rate base commensurate with the risks it faces, rather than the risks of firms operating in competitive markets.[90] However, there is no science to determining the line between fair and unfair; this paired with the inherent imprecision in calculating the cost of equity (perceived publicly as a utility's profit but technically the amount a shareholder must be offered to invest in the utility) has rendered rate of return a controversial element of many rate cases, with experts from each party arguing for different percentages.[91] Economists vary in which calculation model they employ, and PUCs are tasked with determining whether the models and calculations put forth by utilities in rate cases are in fact "fair."[92] The economic sophistication required to determine the rate of return poses questions of information asymmetry between utilities and PUCs, and even more so between utilities and advocates for customers.[93] To combat this asymmetry, some states require utilities to pay for consumer advocates' hiring of expert witnesses.[94]

The average rate of return for electric utilities was 10% in 2023.[95] Rates have historically ranged from 6-16%.[96] Some experts have criticized the industry norm of 10% as being excessive.[97] One recent study observed that over time, the divide between authorized returns on equity and the riskless rate of return, which is the theoretical rate of return of a zero-risk investment, has deepened.[98] According to the study authors, this is a concerning development because "[a]n error or bias of merely one percentage point in the allowed return would imply tens of billions of dollars in additional cost for ratepayers in the form of higher retail power prices."[99] Lowering the rate of return is one method of reducing rates, but one risk of taking this approach is discouraging utilities from investing in much-needed clean energy

89. *Id.*

90. *See generally* Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923).

91. Lazar, *supra* note 9, at 55.

92. *Id.*

93. Expert interviews, *supra* note 4; *see Karl Dunkle Werner and Stephen Jarvis, Rate of Return Regulation Revisited*, ENERGY INST. AT HAAS (Apr. 2024), https://haas.berkeley.edu/wp-content/uploads/WP329.pdf; Ken Costello, *Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives*, NRRI (Apr. 2014), https://pubs.naruc.org/pub/FA86C519-AF31-D926-BE12-2AC7AE0CD8D6.

94. *Sustainable Funding for the Public Utility Commission and the Department of Public Service*, VT. PUB. SERV. DEP'T 4, 24, 29 (Sept. 26, 2018), https://ljfo.vermont.gov/assets/Meetings/Joint-Fiscal-Committee/2018-11-08/aa7a13d868/Sustainable-Funding-for-the-Public-Service-Department-and-the-PUC-_Sept-26-2018_-v4.pdf.

95. Dan Lowrey, *Electric beats gas in exceeding authorized equity returns over past 15 years*, S&P GLOB. (May 25, 2023), https://www.spglobal.com/marketintelligence/en/news-insights/research/electric-beats-gas-in-exceeding-authorized-equity-returns-over-past-15-years.

96. Lazar, *supra* note 9, at 56.

97. David C. Rode & Paul S. Fischbeck, *Regulated Equity Returns: A puzzle*, ENERGY POL'Y, Oct. 2019.

98. *Id.*

99. *Id.*

infrastructure.[100] An alternative method of shrinking the revenue requirement is removing some costs from the formula altogether; Colorado, Connecticut, Maine, and New Hampshire have passed bills prohibiting utilities from recovering costs of lobbying and similar political expenses through rates.[101] While these expenditures are likely not significant enough to make a major impact, some experts have argued that more considerable investments like infrastructure required for the clean energy transition should be paid for by sources other than ratepayers,[102] like revenues from carbon dioxide (CO_2) cap-and-trade schemes or carbon taxes, Electric Vehicle (EV) infrastructure projects, highway clean energy infrastructure projects, and distributed energy resource (DER) projects,[103] surcharges on the largest commercial customers or the wealthiest residential customers,[104] tax revenue,[105] or through other government funds.[106] The feasibility of relying on external sources of funding is highly dependent on the political circumstances in a specific state, but in states such as California where the price of electricity has been shown to far surpass the marginal cost of electricity,[107] the prospect of an innovative solution may be more palatable due to necessity.

An alternative to traditional cost-of-service ratemaking that alters utility incentives is performance-based regulation (PBR). As of 2023, seventeen states and Washington, D.C. had enacted legislation to enable PUC use of PBR.[108] PBR typically uses decoupling, multi-year rate plans (MRP) with incremental rate increases, and performance incentive mechanisms (PIM).[109] Most relevant to equity, PIMs tie revenue to metrics other than cost, thereby replacing consumption and capital investment incentives in the rate formula with other policy goals, such as affordability, sustainability, and energy efficiency.[110] PIMs are most commonly

100. See Ken Costello, *Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives*, NAT'L REGUL. RSCH. INST. (Apr. 2014), https://pubs.naruc.org/pub/FA86C519-AF31-D926-BE12-2AC7AE0CD8D6 (discussing how earning below the authorized rate of return discourages utility investments).

101. *Tracking State Legislation to Get Politics Out of Utility Bills*, ENERGY & POL'Y INST. (Apr. 15, 2024), https://energyandpolicy.org/tracking-states-getting-politics-out-of-utility-bills/.

102. Expert interviews, *supra* note 4.

103. Thompson, *supra* note 86, at 289-290.

104. *Id.*

105. Khan-Lang, *supra* note 83, at 8.

106. Expert interviews, *supra* note 4.

107. Khan-Lang, *supra* note 83, at 6.

108. Daniel Shea, *Performance-Based Regulation: Harmonizing Electric Utility Priorities and State Policy,* NCSL (Apr. 7, 2023), https://www.ncsl.org/energy/performance-based-regulation-harmonizing-electric-utility-priorities-and-state-policy#:~:text=On%20the%20one%20hand%2C%20state,enable%20performance%2Dbased%20regulatory%20approaches.

109. Occasionally, other miscellaneous incentives for underused practices are included. *See id.*

110. Thompson, *supra* note 86, at 301; Lazar, *supra* note 9, at 7; Shea, *supra* note 108, at 13; Herman K. Trabish, *Performance-based regulation: Seeking the new utility business model*, UTILITY DIVE 3 (July 23, 2019), https://www.utilitydive.com/news/performance-based-regulation-seeking-the-new-utility-business-model/557934/.

put in place for energy efficiency, reliability, and clean energy investments while those geared at equity are less common.[111]

According to a 2024 Rocky Mountain Institute (RMI) report, at least six states, Colorado, Hawaii, Illinois, Massachusetts, New Jersey, and New York, and Washington, D.C., have adopted equity PIMs.[112] Hawaii was the first state to require a PBR framework that ties revenue to performance metrics.[113] The PBR framework established pursuant to the Hawaii Ratepayer Protection Act of 2018 and the following PUC stakeholder process includes:

- A Renewable Portfolio Standard (RPS) PIM to incentivize accelerated achievement of RPS goals,
- An Interconnection Approval PIM to incentivize fast interconnection for small-scale solar and storage,
- An AMI Utilization PIM to incentivize utilization of advanced meters,
- A Grid Services PIM to incentivize utilization of DERs for grid services capabilities, and
- For its equity PIM, an LMI Energy Efficiency PIM to incentivize providing energy efficiency opportunities to low income customers.[114]

All of these PIMs include monetary rewards while only the RPS and Interconnection PIMs include monetary penalties.[115] The risk of penalties is one way to ensure the efficacy of PIMs; without a downside risk, PIMs may insulate utilities from cost reduction incentives without adequately motivating them to achieve the policy goals. In Illinois, the legislature passed the Climate and Equitable Jobs Act (CEJA) in 2021, which directs the Illinois Commerce Commission to establish a comprehensive performance-based regulation framework for electric utilities with over 500,000 customers.[116] In this statute, the legislature requires that affordability be considered whenever discussing PIMs and lists affordability of electric delivery as an objective of the performance-based ratemaking framework. Critically, the law requires the Commission to approve at least one metric from each of six categories, including achieving affordable customer delivery service costs and reducing disconnections, reliability and resiliency, peak load reductions using demand response, expanded supplier diversity, timeliness to customer requests for interconnection, and customer service experience.[117]

111. Rachel Gold & Carina Rosenbach, *Transforming the Way We Serve Vulnerable Communities: Performance Incentive Mechanisms and Beyond*, RMI (Apr. 26, 2024), https://rmi.org/transforming-the-way-we-serve-vulnerable-communities-performance-incentive-mechanisms-and-beyond/; Trabish, *supra* note 110, at 3, 5.

112. Gold & Rosenbach, *supra* note 111.

113. Trabish, *supra* note 110, at 9-11.

114. PBR Docket No. 2018-0088, HAWAII PUB. UTILS. COMM'N, (June 1, 2021), https://puc.hawaii.gov/energy/pbr/; *see Performance-Based Regulation: Hawai'I Pioneers a New Energy Regulatory Framework to Accelerate Renewable Energy Innovation and Utility Efficiency*, ULUPONO INITIATIVE 15 (Jan. 2021), https://ulupono.com/media/8d8b904d3490289/pbr-white-paper-final-01-14-21-web.pdf.

115. *Id.*

116. 220 ILL. COMP. STAT. ANN. 5/16-108.18(a)(8) (2021).

117. *Id.*

B. Allocation Between Classes

The intervention opportunities detailed above focus on the revenue requirement stage of ratemaking, but opportunities exist at subsequent phases of the ratemaking process as well. After the revenue requirement is determined, it must be allocated among classes of customers. PUCs define classes of customers and all customers within each class are charged the same rate.[118] Classes are identified based on cost of service, so typically the amount of energy consumption and number of users, with the most common categories being commercial, industrial, and residential customers with sub-categories of commercial and industrial (C&I) based on size or voltage.[119] Some commissions have created classes based on type of technology such as EV charging,[120] agricultural classes, institutional classes for government buildings, or classes for specific usage requirements like street lighting.[121]

Differentiation by rate class is legally permitted as long as it is not undue discrimination, as discussed prior. The economic justification behind rate classes is the minimization of "cross-subsidization," which occurs when one customer effectively subsidizes another by paying more than the costs for which it is responsible.[122] Elimination of cross-subsidization would require a unique rate for each utility customer, which is infeasible, so classes of similarly situated customers are grouped together such that cross-subsidization is minimal enough to avoid undue discrimination. Some experts disagree with the goal of minimizing cross-subsidization and argue that cross-subsidization can be desirable to reach certain policy objectives like energy efficiency.[123] Others point out that cross-subsidization is impossible to avoid and already prevalent, both within and between classes; cost-of-service studies are based on class averages which inherently leads to some subsidization within a class, and new loads often do not contribute to the embedded costs already allocated to existing customers.[124] Additionally, C&I customers nearly universally pay a lower average rate than residential customers,[125] and experts disagree as to whether this is strictly justified by cost of service.[126]

PUCs have recently shown a renewed interest in differentiation between customers in the same class with the goal of more accurately aligning rates with system costs; for example, opt-in and opt-out time-of-use rates allow customers to choose a rate structure where cost is based on time of electricity use, and new customers or users of new technology like EV can sometimes receive discounted

118. Chan & Klass, *supra* note 45, at 1452-53.

119. Thompson, *supra* note 86, at 282; Chan & Klass, *supra* note 45, at 1449.

120. Chan & Klass, *supra* note 45, at 1477.

121. Lazar, *supra* note 9, at 61.

122. Chan & Klass, *supra* note 45, at 1434, 1449.

123. *Id.* at 1451; *see* Troy A. Rule, *Solar Energy, Utilities, and Fairness*, 6 SAN DIEGO J. CLIMATE & ENERGY L. 115, 132 (2015).

124. Chan & Klass, *supra* note 45, at 1451; *see* Rule, *supra* note 123, at 132.

125. *Id.* at 1449; *see generally Electric Power Monthly, Average Price of Electricity to Ultimate Customers*, U.S. ENERGY INFO. ADMIN. (May 2022), https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_5_03.

126. Chan & Klass, *supra* note 45, at 1449; *see* Rule, *supra* note 123, at 132.

rates.[127] Additionally, although mainstream literature does not point to establishment of a low-income customer class as a step in aiding effective equitable rate design, some utilities do this in practice when allocating the funds of discount programs between customers, for example.[128] In a different conceptualization but same end result, California's income-graduated fixed charge applies different fixed charge prices to tiers of customers in the same residential class with one ultimate revenue requirement.[129] Creating a low-income class based on factors like energy burden could allow for easier implementation of special rates, as we see with C&I economic development rates.

The allocation between customer classes is based on cost-of-service studies (COSS) and the methods used are often challenged in rate cases.[130] Upon proposal of a rate design in a rate case, utilities provide a COSS as evidence of alignment between the proposed rates and its costs.[131] Costs are then apportioned based on number of customers, peak demand, and total customer usage.[132] In determining how to weigh these factors, as well as whether to classify costs as demand or usage-related, PUCs have some discretion that could be used to improve or hinder equity.[133]

C. Rate Design

Following allocation between customer classes, parties engage in "rate design": determining how to collect from the ratepayers within each class.[134] Residential rates typically include a fixed monthly service charge in addition to a volumetric charge for each unit of energy used.[135]

1. Rates Based on Energy Usage

The most basic rate design, a flat rate, charges the same rate regardless of usage.[136] Under an inclining block rate structure, energy costs increase with use; typically, upon reaching an identified threshold of energy use, energy becomes more expensive.[137] This structure is effective in reducing energy consumption, a common environmental goal of rate design. However, advocates disagree as to

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127. Chan & Klass, *supra* note 45, at 1453.

128. *See* Robert Hoglund, *Schedule for Electricity Service: Rider S Low Income Program*, CONSOL. EDISON CO. OF N.Y. 255.1 (Mar. 29, 2012), https://lite.coned.com/_external/cerates/documents/elecPSC10/electric-tariff.pdf.

129. *Proposed Decision of ALJ Wang: Decision Addressing Assembly Bill 205 Requirements for Electric Utilities*, CAL. PUB. UTILS. COMM'N (May 9, 2024), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M531/K094/531094134.pdf.

130. Lazar, *supra* note 8, at 61.

131. Ari Peskoe, *Unjust, Unreasonable, and Unduly Discriminatory: Electric Utility Rates and the Campaign Against Rooftop Solar*, 11 TEX. J. OIL GAS & ENERGY L. 211, 230 (2016).

132. *Id*. at 272.

133. *Id.*

134. Thompson, *supra* note 86, at 283.

135. Lazar, *supra* note 9, at 68-69.

136. Thompson, *supra* note 86, at 283.

137. *Id.*

whether inclining block rates benefit low-income consumers. The origins of inclining block rates can be traced to a Public Utility Regulatory Policies Act (PURPA) requirement that PUCs consider "lifeline rates"[138] and the assumption that the first block of electricity would be most affordable and cover the most essential needs.[139] Studies do show that low-income customers tend to use less energy than their wealthier counterparts,[140] but there is a risk that this is due to attempted cost savings rather than lower need. One study found that low-income households were taking undesirable measures to lower their electricity usage and related costs,[141] such as enduring extreme indoor temperatures.[142]

A declining block rate reduces the price when energy usage surpasses a designated level[143] and therefore encourages higher energy consumption. A more novel rate design bases certain charges on customer connection size; because "more customers are served per service connection line" and because "line transformers are sized based on estimated diversified load" with small and multi-family dwellings, the cost of service is higher for larger, single-family homes.[144] Burbank, a municipal utility near Los Angeles, assesses a service size charge based on customer electric panel capacity (typically, apartments have 100-amp service panels, single-family homes have 200-amp panels, and large homes have 400-amp panels).[145] In theory, this structure could lead to a lower rate for low income customers who reside in apartments or small homes. It has also been suggested by one expert that a charge could be made based on type of electricity use– either essential or nonessential.[146] At the time of writing, we are not aware of an example of this in practice, but the Maine PUC has approved a pilot program of rates "tailored to the operational characteristics of ratepayer appliances" to incentivize use of heat pumps.[147] The same tailoring to operational characteristics of specific appliances could aid in designing rates for essential use.

2. Rates Based on Time of Use

Time-of-use (TOU) pricing sets a higher price for consumption during peak times and a lower price for off-peak times.[148] Given that TOU rates have been

138. 16 U.S.C. § 2624(b) (1988).

139. S. COMM. ON AGING, 96TH CONG., ENERGY ASSISTANCE PROGRAMS AND PRICING POLICIES IN THE 50 STATES TO BENEFIT ELDERLY, DISABLED, OR LOW-INCOME HOUSEHOLDS (Comm. Print 1979).

140. Lazar, *supra* note 9, at 70.

141. Hernández, *supra* note 1, at 9.

142. *See* Shucen Cong et al., *Unveiling Hidden Energy Poverty Using the Energy Equity Gap*, NATURE COMMC'NS, May 4, 2022; Miranda Simes et al., *Vigilant Conservation: How Energy Insecure Households Navigate Cumulative and Administrative Burdens*, ENERGY RSCH & SOC. SCI., July 2023.

143. Lazar, *supra* note 9, at 68.

144. Paul Zummo, *Leadership in Rate Design,* PUBLIC POWER 20 (May-June 2019), https://www.publicpower.org/system/files/documents/Leadership-in-Rate-Design.pdf.

145. *Id.*

146. Expert interviews, *supra* note 4.

147. Edward Yim & Sagarika Subramanian, *Equity and Electrification-Drive Rate Policy Options*, AM. COUNS. FOR AN ENERGY-EFFICIENT ECON. 8 (Sept. 2023), https://www.aceee.org/sites/default/files/pdfs/equity_and_electrification-driven_rate_policy_options_-_encrypt.pdf.

148. Lazar, *supra* note 9, at 71.

shown to successfully reduce demand at peak times,[149] they are a desirable model from the environmental perspective. Residential TOU rates are often provided as optional opt-in or opt-out rates while it is more common for C&I customers to have mandatory TOU pricing due to their larger loads.[150] Occasionally seasonal rates offer different prices based on season.[151] Rates that embody dynamic pricing change in response to power market price changes and are almost always optional at the retail level.[152] These include real-time rates, critical period pricing, variable peak pricing, and peak-time rebates.[153] Real-time rates are usually only offered to large C&I customers and include frequent cost changes with limited notice throughout the day based on changes in wholesale market prices.[154] Critical period pricing rates are most often add-ons to TOU rates; rates are set for critical periods in advance and customers are notified, but the rates are typically only implemented when the system is under extreme stress.[155] Variable period pricing involves division of a day into peak, off-peak, and interim periods with varying prices by period, and in at least one period, the price will vary daily based on system conditions.[156] Peak-time rebates give customers discounts for reducing consumption during critical periods rather than raising the price of consumption during that time.[157] While pricing based on time of use has been shown to on average benefit low-income households because of household size and energy intensity of appliances,[158] research shows an information gap– when TOU rates are offered as optional opt-in programs, low-income customers may be missing out on discounts, and when offered as opt-out programs, low-income customers may be unaware of the incentive to adjust use based on time of day.[159] Moreover, wealthier households and homeowners are more able to invest in and benefit from energy efficiency measures[160] and advanced metering infrastructure (AMI) and other smart technologies that aid in reducing energy consumption.[161] Additionally, some low-income customers do not have the flexibility to reduce energy consumption at peak hours[162] and others may benefit from TOU rates through dangerous methods of

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149. *Id.*

150. *Id.*

151. Yim & Subramanian, *supra* note 147, at 13.

152. Lazar, *supra* note 9, at 75.

153. *Id.*

154. *Id.*

155. *Id.*

156. Mina Badtke-Berkow et al., *A Primer on Time-Variant Electricity Pricing*, ENV'T DEF. FUND at ii (2015), https://www.edf.org/sites/default/files/a_primer_on_time-variant_pricing.pdf.

157. *Id.*

158. Jordan Folks & Zac Hathaway, *Assessing Equity in TOU: How Low-Income Customers Fare on Time of Use Rates,* OP. DYNAMICS (2021), https://opiniondynamics.com/wp-content/uploads/2021/06/2020_ACEEE-Summer-Study_Assessing-Equity-How-Low-Income-Customers-Fare-on-TOU_Rates_Folks.pdf.

159. *Id.*

160. Lazar, *supra* note 9, at 71.

161. Herman Trabish, *An emerging push for time-of-use rates sparks new debates about customer and grid impacts*, UTIL. DIVE (Jan. 28, 2019), https://www.utilitydive.com/news/an-emerging-push-for-time-of-use-rates-sparks-new-debates-about-customer-an/545009/.

162. Thompson, *supra* note 86, at 283.

reducing energy consumption.[163] An additional risk posed by TOU rates for low-income customers is the inability to pay abnormally high bills due to peaks in the short-term;[164] for example, annual savings may result due to low usage in winter months but prices during summer months could be cost-prohibitive. This will become an increasingly significant problem as climate change exacerbates extreme weather.

3. Fixed Charges

As previously mentioned, fixed charges are monthly charges that do not vary with customer energy usage and aim to recoup a utility's fixed costs.[165] Without impacting the total revenue requirement, rate design can be used to adjust the proportion of revenue recovered through a volumetric basis versus fixed charges by determining which utility costs should be recovered through each mechanism. Fixed charges can be a tool for equity in that they ensure that customers who use low amounts of energy at peak periods contribute to the fixed costs that they impose on the system. That said, historically low-income customer advocates have opposed increased fixed charges as they are typically regressive, requiring a larger proportion of household income for low-income households.[166] Environmental advocates have also opposed fixed charge increases in the past due to the disincentive to conserve electricity.[167] However, as the grid has become increasingly electrified, the conversation around conservation has become more nuanced, and crucially, as more consumers have invested in DER like rooftop solar, the risk of a disproportionate impact on low-income customers of higher volumetric prices due to lower fixed charges has complicated the equity implications.[168]

In 2022, California was the first state to introduce a novel approach to fixed charges that accounts for impacts on low-income customers: an income-graduated fixed charge.[169] The merits of this model in practice have yet to be seen as implementation by utilities has yet to occur,[170] but groups that had typically opposed increased fixed charges as inequitable and unsustainable in the past have voiced their support for this particular rate design.[171]

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163. Hernández, *supra* note 1, at 6.

164. Folks & Hathaway, *supra* note 158.

165. Thompson*, supra* note 86, at 304.

166. Severin Borenstein et al., *Designing Electricity Rates for an Equitable Energy Transition*, ENERGY INST. AT HAAS (Feb. 2021), https://haas.berkeley.edu/wp-content/uploads/WP333.pdf.

167. Chan & Klass, *supra* note 45, at 1480.

168. Borenstein et al., *supra* note 166, at 7.

169. *See infra* Part VII(B); A.B. NO. 205, at 95 (2022).

170. *Demand Flexibility Rulemaking (R.22-07-005)*, CAL. PUB. UTILS. COMM'N, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-flexibility-rulemaking (last visited Oct. 15, 2024).

171. Jeff St. John, *Income-based electric bills: the Newest Utility Fight in California*, CANARY MEDIA (May 9, 2023), https://www.canarymedia.com/articles/energy-equity/income-based-electric-bills-the-newest-utility-fight-in-california; *Flat Rate Resources*, THE PUB. ADVOCATES OFFICE (Jan. 18, 2024), https://www.publicadvocates.cpuc.ca.gov/press-room/reports-and-analyses/income-graduated-fixed-charge-qa

4. Renewable Energy Rates

With the rapid increase in generation of renewable energy, rate designs unique to renewable energy have subsequently developed. Some utilities allow customers to choose to source all or some of their energy from renewable sources by opting into green rates.[172] Net-metering allows customers who generate their own electricity via DER like rooftop solar to pay only for the electricity delivered by the utility minus the power returned to the grid by the consumer's generation, net consumption at the retail rate.[173] Similar to net-metering, value of solar tariffs compensate onsite generators using a predetermined rate determined by the PUC or utility to reflect the costs and benefits of solar generation to the overall system rather than using the retail rate.[174] A newer development in renewable energy rates is the design of technology-specific rates. A 2022 Lawrence Berkeley National Laboratory study identified 217 electric vehicle (EV) rates in thirty-seven states and Washington, D.C.,[175] and in 2022, the Maine PUC approved a pilot for two heat pump-based rates.[176]

The equity of renewable energy rates often depends on access to DER or specific technologies. Barriers to entry include the up-front costs of installation or temporarily increased energy bills, lack of autonomy over utilization of renewable energy due to renting rather than owning. Low-income customers must be made aware of renewable energy rate opportunities through engagement and education, and barriers to entry must be addressed. Although renewable energy programs are beyond the scope of this article, initiatives like community solar programs are essential to ensuring an equitable green transition.[177]

IV. PROTECTIONS INDEPENDENT FROM RATE DESIGN

A. Bill Assistance Programs

Occasionally referred to as low-income rate designs, bill discounts based on income are generally applied to the entire bill, rather than at the revenue requirement or rate design stages, and can thus be seen as distinct from, but complementary to, equitable rate designs. Given that these discounts are not built into the rate itself, eligible customers must apply for these programs unless there is auto-enrollment. Eligibility for low-income programs is determined through various methods, the selection of which can have a significant impact on the efficacy of a

172. *Utility Green Tariffs*, WORLD RES. INST., https://www.wri.org/initiatives/utility-green-tariffs (last visited Oct. 15, 2024).

173. Lazar, *supra* note 9, at 138.

174. *Id.* at 79-80.

175. Peter Cappers et al., *Snapshot of EV-Specific Rate Designs Among U.S. Investor-Owned Electric Utilities*, LAWRENCE BERKELEY NAT'L LAB. (April 2023), https://eta-publications.lbl.gov/sites/default/files/ev_rate_snapshot_report-final-20230424.pdf

176. Yim & Subramanian, *supra* note 147, at 12.

177. For an in-depth discussion on solar programs and low-income customers, *see* Priya Patel, *Energy Equity: A Framework for Evaluating Solar Programs Targeting Low-Income Communities*, 43 ENERGY L. J. 299 (2002).

program in addressing energy insecurity. Measures include household income[178] (via percentage of Federal Poverty Level or state median income, energy burden, or a set number),[179] eligibility for Low Income Energy Assistance Program (LIHEAP) assistance,[180] eligibility for other state or federal public assistance programs,[181] enrollment in other utility assistance programs,[182] and evidence of vulnerable or disabled household members.[183] While any form of bill assistance is positive from an equity perspective, compared to a structural change to the rate-making process or rate designs implemented on a more permanent basis, bill assistance could be considered a band-aid approach to energy insecurity.[184] In short, bill assistance programs will only be effective as long as electricity rates are unaffordable, and they are depend on accurate identification of needy customers, securing a steady funding source, and ongoing political support.

1. Straight Bill and Tiered Discounts

Straight discount programs reduce the bills of customers who qualify as low-income by one single percentage regardless of energy burden level. The California Alternative Rate for Energy (CARE) program discounts the electricity bills of low-income customers by 30-35% and natural gas bills by 20%.[185] Examples of straight discount programs can also be found in Alabama, Arizona, Georgia, Illinois, Kansas, Kentucky, Maine, Maryland, Massachusetts, and Rhode Island.[186] Tiered discount programs offer different percentage discounts depending on income level.[187] Consumption-based discounts, in effect, a hybrid between inclining block rates and tiered discounts, decrease as energy usage increases.[188]

2. Percentage of Income Payment Plan (PIPP)

Under PIPPs, an affordable energy burden is established based on a percentage of household income and the burden is then calculated based on the annual household income of customers. Energy costs that surpass the resulting threshold

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178. *PIPP Plus*, OHIO PUB. UTIL. COMM'N, https://puco.ohio.gov/utilities/gas/resources/pipp-plus (last visited Oct. 15, 2024).

179. Lee Hansen, *Utility Rate Discounts for Low-Income Customers in Other States*, OFF. OF LEGIS. RSCH., https://www.cga.ct.gov/2018/rpt/pdf/2018-R-0051.pdf

180. *Energy Affordability Program*, N.Y. DEPT. OF PUB. SERV., https://dps.ny.gov/energy-affordability-program (last visited Oct. 15, 2024).

181. *Id.*

182. Hansen, *supra* note 179.

183. *Id.*

184. Robert Walton, *The energy system is 'inherently racist,' advocates say. How are utilities responding to calls for greater equity?*, UTIL DIVE (Oct. 26, 2022), https://www.utilitydive.com/news/energy-system-inherently-racist-utilities-responding-equity-ej-justice40/634203/.

185. *CARE/FERA Program*, CAL. PUB. UTILS. COMM'N, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/care-fera-program

186. Thompson, *supra* note 86, at 276.

187. *Id.* at 277.

188. *Id.* at 278.

are funded by ratepayers or state or federal LIHEAP funds.[189] Examples of early PIPPs can be found in Illinois, Ohio, and Pennsylvania.[190]

3. LIHEAP

The Low Income Energy Assistance Program (LIHEAP) is a federal assistance program that provides block grants derived from annual Health and Human Services (HHS) appropriations to states and tribes upon application.[191] Grantees then administer the funding through their own energy assistance programs; each state at least in part funds a low-income energy assistance program through LIHEAP.[192] LIHEAP has been criticized for underutilization[193] and underfunding.[194]

State bill assistance programs often mirror LIHEAP; funded by both LIHEAP and ratepayers, they are often administered through bill credits or other one-time payments. Other bill assistance programs focus on the form of billing and are offered by utilities themselves; prepaid metering programs allow customers to use only energy they have paid for in advance,[195] budget billing spreads energy costs evenly over a twelve-month period to avoid price spikes associated with temperature or other demand factors,[196] and arrearage management plans allow for gradual debt forgiveness when customers adhere to certain payment plans.[197] Forgiveness of customer debt through arrearage programs takes various forms based on state or utility, but the two primary models are a one-time forgiveness of full or partial debt and gradual forgiveness of customer debt after a number of timely payments.[198]

B. Other Protections

Other vital low-income assistance programs that exist outside of the rate design framework, and are therefore not the focus of this paper, include disconnection protections and funding assistance for weatherization and energy efficiency programs. Most states have disconnection moratoriums derived from the state

189. *Id.*

190. Thompson, *supra* note 86, at 277.

191. Andrea Nishi et al., *Energy Insecurity Mitigation: The Low Income Home Energy Assistance Program and Other Low-Income Relief Programs in the US*, CTR. ON GLOB. ENERGY POL'Y (Nov. 15, 2023), https://www.energypolicy.columbia.edu/publications/energy-insecurity-mitigation-the-low-income-home-energy-assistance-program-and-other-low-income-relief-programs-in-the-us/#LIHEAP.

192. *Id.*

193. Thompson, *supra* note 86, at 272; *see also* Nishi et al., *supra* note 191, at 19.

194. Thompson, *supra* note 86, at 286.

195. *Bridging the Gaps on Prepaid Utility Service*, U.S. DEP'T OF ENERGY (Sept. 2015), https://www.energy.gov/oe/articles/bridging-gaps-prepaid-utility-service#:~:text=Prepaid%20utility%20service—which%20allows,area%20where%20these%20changes%20converge.&text=Prepay%20is%20an%20alternative%20payment,balance%20as%20it%20is%20used.

196. *Budget Billing*, NYSEG, https://www.nyseg.com/w/budget-billing (last visited Oct. 15, 2024).

197. Charlie Harak, *Helping Low-Income Utility Customers Manage Overdue Bills through Arrearage Management Programs (AMP)*, NCLC (Sept. 2013), https://www.nclc.org/wp-content/uploads/2022/09/amp_report_final_sept13.pdf

198. Farley et al., *supra* note 13, at 31.

legislature or PUC, based on season, weather conditions, life-threatening medical conditions and COVID-19 emergency policies.[199] While protections against severe cold are generally comprehensive, the same cannot be said for protections for severe heat.[200] States also require varying levels of communication from utilities before disconnecting customers.[201]

Similar to LIHEAP's structure, through its congressional appropriations-funded Weatherization Assistance Program (WAP), the federal government distributes grant funding to the states to administer for weatherization in the homes of low-income customers.[202] Additionally, many states offer complementary low-income energy efficiency programs. Energy efficiency is a key avenue to addressing equity outside of the constraints of rate design as energy efficient technologies and retrofits are often cost prohibitive, preventing low-income customers from benefiting from the lower electricity bills that would result from lower energy usage due to increased energy efficiency.[203]

VI. PROCEDURAL JUSTICE

Equity is not only implicated by the substance of the ratemaking process and rate designs, but also in the access, or lack thereof, to the process. Given that decisions made in formal proceedings are based on the record of evidence developed in the proceeding itself, facilitating participation is critical to ensuring all perspectives are considered.[204] To this end, states have implemented a variety of measures to improve public access to utility proceedings.

A. State Efforts to Combat Information and Resource Asymmetry

To address the inherent disparity in resources between large utility companies and those who represent consumers, most states have created offices with the mission of representing the public in PUC proceedings: consumer advocates. Although consumer advocates represent all residential consumers, they are a critical voice for bill affordability and other interventions that help low-income consumers specifically.[205] As of 2021, forty-four states and the District of Columbia had consumer advocate offices either as independent state agencies, state attorneys general

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199. Chan & Klass, *supra* note 45, at 1454; *see Disconnect Policies*, LIHEAP CLEARINGHOUSE, https://liheapch.acf.hhs.gov/Disconnect/disconnect.htm (last updated July 2024) (disconnection policies by state).

200. Chan & Klass, *supra* note 45, at 1454; *see* Matthew Flaherty et al., *Electric Utility Disconnection Policy and Vulnerable Populations*, 33 ELEC. J., 10, 1, 4 (Dec. 2020).

201. Chan & Klass, *supra* note 45, at 1454.

202. Thompson, *supra* note 86, at 278.

203. *See* Tony G. Reames, *A community-based approach to low-income residential energy efficiency participation barriers*, 21 INT'L J. OF JUST. & SUSTAINABILITY 1449, 1455 (2015).

204. Jacob Becker et al., *Regulatory Process Design for Decarbonization, Equity, and Innovation*, RMI 20 (July 2022), https://rmi.org/wp-content/uploads/dlm_uploads/2022/07/regulatory_process_design_for_decarbonization_equity_and_innovation.pdf.

205. Some consumer advocates even represent non-residential customers, but this is less common. *See* Michael Murphy & Francine Sevel, *The Role of Utility Consumer Advocates in a Restructured Regulatory Environment*, NAT'L REG. RSCH. INST. (Sept. 2004), https://pubs.naruc.org/pub/FA8626E1-0000-871D-4660-18F3E7238C8A.

divisions, nonprofits, or positions in the legislature.[206] Consumer advocates (CAs) are established by state statute excluding a few nonprofit CAs, with the statutory directive generally being to represent consumers and to operate independently from the PUC.[207] The enabling legislation will also define the scope of the CA's legal right to participate in PUC proceedings.[208] Some states have more than one consumer advocate, such as a state agency or division within the Attorney General's office in addition to a nonprofit.[209] Funding sources vary by state, and include state budgets, utilities, intervenor compensation, member dues, and philanthropic funding.[210] Persistent underfunding is an often cited barrier to efficacy of consumer advocates, in addition to the broad mandate of representation of all customers, rather than just low-income customers.[211] Nonetheless, consumer advocates have been highly effective in making rates more equitable and play an essential role in bridging the gap between PUCs and their low-income customers.[212]

Some states have also created advisory boards and other governmental bodies with the purpose of addressing procedural justice. For example, New York launched the Energy Affordability Policy Working Group consisting of representatives from state government, utilities, and other interest stakeholders pursuant to a 2021 PSC order,[213] and California created the Low Income Oversight Board (LIOB) with Senate Bill 2 from the Second Extraordinary Session (SBX2 2).[214] The LIOB advises the CPUC on low-income customer issues and serves as a liaison to low-income ratepayers for the CPUC. It consists of representatives of low-income consumers, state government, utilities, and private weatherization companies.[215] In Massachusetts, the Energy Efficiency Advisory Council (EEAC) established an equity working group to include the environmental justice perspective in future energy efficiency rulemakings.[216] FERC's establishment of an Office of Public Participation (OPP) in 2021 indicates a growing trend of facilitating public participation in utility proceedings.[217] In addition to designating specific bodies

206. Jake Duncan & Julia Eagles, *Public Utilities Commissions and Consumer Advocates: Protecting the Public Interest*, NAT'L COUNCIL ON ELEC. POL'Y 2 (Dec. 2021), https://pubs.naruc.org/pub/21475F72-1866-DAAC-99FB-1E3EE0593D06.

207. *Id.* at 2-3.

208. *Id.*

209. *Id.*

210. Duncan & Eagles, *supra* note 206, at 2.

211. *Id.* at 3, 6; *see* Elin Swanson Katz & Tim Schneider, *The Increasingly Complex Role Of The Utility Consumer Advocate*, 41 ENERGY L. J. 1, 2-3 (2020).

212. *See* Katz & Schneider, *supra* note 211, at 3.

213. *See generally Arrears Report*, N.Y. DEP'T OF PUB. SERV.: ENERGY AFFORDABILITY POL'Y WORKING GRP. (May 20, 2022), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={C94E6142-5E56-469E-B85F-77B636C2D583}.

214. *Low Income Oversight Board, State of California*, CAL. PUB. UTILS. COMM'N, https://liob.cpuc.ca.gov/ (last visited Oct. 15, 2024).

215. *Id.*; S.B. 2, 2001 Leg., Reg. Sess. (Cal. 2001).

216. Becker et al., *supra* note 204, at 19.

217. *See generally Office of Public Participation*, FERC, https://www.ferc.gov/OPP (last updated Sept. 5, 2024).

to consider issues of affordability and equity, some PUCs have initiated generic proceedings with the specific purpose of considering issues of affordability.[218]

To support consumer advocacy efforts from intervenors, including but not limited to consumer advocates offices, some states have implemented intervenor compensation programs. These programs are funded by utilities themselves and thus ratepayers[219] and compensate non-utility stakeholders like nonprofits representing low-income consumers, typically as reimbursement after the proceedings have closed.[220] As of 2021, sixteen states had authorized these programs through legislation, but only California, Idaho, Michigan, Minnesota, Oregon, and Wisconsin were actively utilizing them.[221] Accessibility of these programs can vary with different eligibility requirements, funding amounts, and application processes depending on the state.[222] Some states allow consumer advocates to apply for compensation while others require intervenors to be utility customers; eligibility criteria typically include a showing of financial hardship and lack of prior adequate representation.[223]

Another disparity exists in information access between utility and nonutility representatives. Utilities often have the advantage of sole access to their modeling assumptions, data, and methodologies.[224] Additionally, utilities have the advantage of more funding to dedicate to experts, and experts are necessary for the effective utilization of data and analysis before the PUC. The path of least resistance thus becomes to accept utility characterizations as conclusive.[225] In New Mexico and Oregon, PUCs have required that intervenors be given free access to utility modeling software in an attempt to combat this problem.[226] In California, utilities must share their spreadsheets of assumptions as attachments to Integrated Resource Plans (IRPs) and the code of the publicly available IRP modeling software, RESOLVE, along with the assumptions, are published on the CPUC's website.[227] A 2019 NARUC resolution is indicative of the information access problem when it comes to various categories of data that speak to energy insecurity:

> states should consider requiring utilities to (1) collect monthly data that tracks uncollectibles, number of payment arrangements, number of payment arrangement defaults, number of revised payment arrangements, disconnections, reconnections, duration and frequency of disconnections, and other relevant data points; (2) make the data publicly available on a monthly basis, delineated by general residential customers and those receiving low-income assistance; and (3) file the data with State public utility commissions to be published on the public utility commission's website so that

218. *See supra* Part VII(B).

219. *State Approaches to Intervenor Compensation*, NARUC 13 (Dec. 2021), https://pubs.naruc.org/pub/B0D6B1D8-1866-DAAC-99FB-0923FA35ED1E; Becker et al., *supra* note 204.

220. *State Approaches to Intervenor Compensation*, *supra* note 216, at 22.

221. Chan & Klass, *supra* note 45, at 1501 (citing *State Approaches to Intervenor Compensation*, *supra* note 219, at 14–21).

222. Becker et al., *supra* note 204, at 16.

223. *State Approaches to Intervenor Compensation*, *supra* note 219, at 12.

224. Becker et al., *supra* note 204, at 22.

225. *See id*.

226. *Id*. at 23.

227. *Id*. at 24.

> policy makers might have access to sufficient, objective and granular data for forming public policy aimed at protecting the public health, safety and welfare.[228]

B. State Efforts to Improve Accessibility

Consumers may face obstacles in accessing energy assistance programs and PUC proceedings. Although some energy assistance programs provide for auto-enrollment, this is not always the case. Consumers may be unaware of the programs for which they qualify or unable to navigate the application process. Underutilization of energy assistance is an often-cited barrier to widespread energy security, and auto-enrollment as well as more effective outreach to low-income consumers are important tools to continue using alongside more structural changes to the ratemaking process. PUC dockets are notoriously difficult to navigate with many even lacking a keyword search function.[229] PUCs like the California PUC, New York PSC, Arkansas PSC, Illinois Commerce Commission, and Oregon PUC have established more accessible websites for featured proceedings.[230] Other methods of improving procedural justice in PUC proceedings include providing more translation options and increased flexibility in modes and times for attendance.[231]

C. Other Influences

It is important to acknowledge that influences that ultimately shape the outcomes of rate cases and generic proceedings are not always visible in the standard procedure discussed. Rate design reform often originates with consumer advocates who successfully persuade the legislature to direct PUC action or less commonly, advocates who persuade PUCs to take action.[232] PUC commissioners are appointed in 40 states while they are elected in the remaining ten,[233] and the corresponding political dynamics may impact how willing PUCs are to stray from the status quo.[234] On paper, rulemaking proceedings present an opportunity to focus solely on specific issues of equity and affordability, making them a better forum for these considerations than rate cases. But the political will of PUCs and the executive branch can impact the efficacy of advocacy in proceedings. Some of the experts consulted for this article cited experiences of being told questions of

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228. *2019 Annual Meeting and Education Conference: Final Resolutions*, NARUC 3 (Nov. 19, 2019), https://pubs.naruc.org/pub/5B694F5B-D52A-A964-2EF3-8C734C18FC89.

229. Becker et al., *supra* note 204, at 16.

230. *Id.*; *see generally Proceedings and Rulemaking*, CAL. PUB. UTILS. COMM'N, https://www.cpuc.ca.gov/proceedings-and-rulemaking (last visited Oct. 15, 2024); *Notable Cases and Matters*, N.Y DEP'T OF PUB. SERV., https://dps.ny.gov/notable-cases-and-matters (last visited Oct. 15, 2024).

231. Becker et al., *supra* note 204, at 21.

232. Expert interviews, *supra* note 4.

233. *See Public Service Commissioner (state executive office)*, BALLOTPEDIA, https://ballotpedia.org/Public_Service_Commissioner_(state_executive_office)#:~:text=In%20all%2050%20states%2C%20the,appointed%20in%20the%20other%2040 (last visited Oct. 15, 2024).

234. Expert interviews, *supra* note 4.

equitable rate design are outside the scope of both rate cases and generic proceedings, thus being left with no forum to discuss the issue.[235] Additionally, as generic proceedings lack the concrete deadlines and self-executing binding impact of rate cases, absent legislative direction, the success of generic proceedings is largely dependent on the political will of the PUC. Although some utilities have shown genuine interest in aiding in addressing energy insecurity, ultimately, the best interest of the shareholders will be prioritized, and utilities push these interests with a large lobbying presence.[236] Many states have passed legislation to preclude treatment of lobbying costs as operating expenses to be paid for by ratepayers,[237] but the disparity between utility and customer advocate lobbying resources remains.

VII. NEW YORK AND CALIFORNIA

What follows is a snapshot of California and New York, two states that are largely considered to be at the forefront of integrating equity considerations into the work of PUCs but nonetheless boast high energy insecurity statistics. Operating based on the definition of energy insecurity as the inability to meet household energy needs, nearly 30% of New York City residents were found to be energy insecure in 2022,[238] and approximately 25% of Californians were found to be impacted by energy insecurity before COVID-19 exacerbated affordability issues.[239] Moreover, a 2023 CSR report shows that the median low-income energy burden in the Mid Atlantic is 9.4%, and on the west coast, is 6.8%,[240] both above 6%, which is defined as a "high" energy burden.[241]

A. Governing Laws

The enabling statutes of the New York PSC (NY PSC) and California PUC (CPUC) both generally provide for the standard PUC legal duties: ensuring safe and adequate service, just and reasonable charges, and prohibiting unjust discrimination, and unreasonable preference.[242] The California Public Utilities Code, enacted by the state legislature, includes explicit equity language in a number of provisions. In section 382, "Funding programs provided to low-income electricity customers; assessment of needs of low-income ratepayers," subsection B includes

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235. Expert interviews, *supra* note 4.

236. Hernández, *supra* note 1, at 9.

237. Akielly Hu, *8 states move to ban utilities from using customer money for lobbying*, GRIST (Feb. 21, 2024), https://grist.org/politics/8-states-move-to-ban-utilities-from-using-customer-money-for-lobbying/.

238. *See* Eva Laura Siegel et al., *Energy Insecurity Indicators Associated With Increased Odds Of Respiratory, Mental Health, And Cardiovascular Conditions*, 43 HOUS. & HEALTH 260 (Feb. 2024), https://www.healthaffairs.org/doi/full/10.1377/hlthaff.2023.01052.

239. *Living Without Power: Health Impacts of Utility Shutoffs in California*, UTIL. REFORM NETWORK 5 (2018), https://static1.squarespace.com/static/63c1c8c8e9c7381c93194 52b/t/64d6ba-dac0a93c195c86c626/1691794164104/2018_TURN_Shut+Off+Report_FINAL.pdf.

240. *Electric Utility Disconnections*, CONG. RSCH. SERV. (Jan. 31, 2023), https://crsreports.congress.gov/product/pdf/R/R47417.

241. *National and Regional Energy Burdens*, AM. COUNCIL FOR AN ENERGY-EFFICIENT ECON. (2020), https://www.aceee.org/sites/default/files/pdfs/ACEEE-01%20Energy%20Burden%20-%20National.pdf.

242. *See* N.Y. Pub. Serv. Law § 65 (Consol. 2024); CA. PUB. UTIL. CODE § 451 (2023).

the phrases "recognizing that electricity is a basic necessity, and that all residents of the state should be able to afford essential electricity and gas supplies" before requiring that the commission "shall ensure that low-income ratepayers are not jeopardized or overburdened by monthly energy expenditures" and explicitly authorizing the CPUC to reduce energy expenditures "through the establishment of different rates for low-income ratepayers, different levels of rate assistance, and energy efficiency programs."[243] Subsection F later specifies that "the commission shall allocate funds necessary to meet the low-income objectives in this section."[244] Section 739(d)(2) states that the CPUC shall observe "the principle that electricity and gas services are necessities, for which a low affordable rate is desirable" while ensuring that rates recover a just and reasonable amount of revenue.[245] In section 739.9, which governs adoption of fixed charges, the CPUC is required to "ensure that any approved charges . . . Are set at levels that do not overburden low-income customers."[246] In 2022, the California legislature amended this section to introduce the income-graduated fixed charge, which will be discussed in further detail below. The CPUC is also required to "[e]nsure that the energy burden of low-income electricity and gas customers is reduced" in conjunction with the LIOB.[247] In enacting California's low-income assistance program, CARE, the intent of the Legislature explicitly included "that the commission ensure CARE program participants receive affordable electrical and gas service that does not impose an unfair economic burden on those participants."[248]

The New York Public Service Law does not include similar equity-based language, but on July 18, 2019, New York passed the Climate Leadership and Community Protection Act (CLCPA). The CLCPA requires that disadvantaged communities receive no less than 35% of the overall benefits of spending on clean energy and energy efficiency programs, that agency decisions not disproportionately burden disadvantaged communities, and that reductions of greenhouse gas emissions and co-pollutants be prioritized in disadvantaged communities, and these requirements apply to all state agencies, including the PSC.[249] Specific to the PSC, the CLCPA requires the PSC to "design [renewable energy] programs in a manner to provide substantial benefits for disadvantaged communities . . . including low to moderate income consumers, at a reasonable cost while ensuring safe and reliable electric service."[250] Additionally, the PSC is assigned specific duties related to energy storage, solar deployment, and most relevant to this report, the allocation of ratepayer funds for clean energy; the provision provides that the PSC must direct NYSERDA and utilities "to develop and report metrics for energy

243. CAL. PUB. UTIL. CODE § 382(b).
244. *Id.*
245. *Id.* § 739(d)(2).
246. *Id.* § 739.9(e).
247. CAL. PUB. UTIL. CODE § 382.1.
248. *Id.* § 739.1(g).
249. S. 6599, 2019-20 Leg., Reg. Sess. § 75-0117 (N.Y. 2019).
250. N.Y. PUB. SERV. LAW § 66-p(7) (2020).

savings and clean energy market penetration in the low and moderate income market and in disadvantaged communities."[251] To fulfill these duties, the PSC initiated a proceeding entitled *In the Matter of Assessing Implementation of and Compliance with the Requirements and Targets of the Climate Leadership and Community Protection Act* that is ongoing at the time of writing this article.[252] Even more explicit about equity in the utility context than the CLCPA, the proposed New York Home Energy Affordable Transition (HEAT) Act would give explicit statutory authority to the PSC to pursue climate justice and would require the initiation of a proceeding on climate justice, including a specific inquiry into ratemaking strategies.[253]

B. Notable Approaches to Rate Design and Affordability Programs

In 2022, California became the first state to establish an income-based fixed charge by state statute. With AB 205, the California legislature amended the fixed charges section of the Public Utility Code to require that the CPUC authorize a fixed charge, which "shall be established on an income-graduated basis with no fewer than three income thresholds so that a low-income ratepayer in each baseline territory would realize a lower average monthly bill without making any changes in usage," by July 1, 2024.[254] Income-graduated was defined as "low-income customers pay a smaller fixed charge than high-income customers."[255] The bill also removed the cap on the amount of chargeable fixed charges by utilities.[256] On January 30, 2024, the California Assembly introduced AB 1999 to cap the potential fixed charge at $10 a month.[257] As of the writing of this article, AB 1999 remains in committees, but its introduction highlights the polarizing nature of an income-based fixed charge. The CPUC approved a plan on May 9, 2024,[258] under which high-income households will pay a fixed charge of $24.15 while households enrolled in CARE will pay $6 a month, and those enrolled in FERA or who live in affordable housing restricted to residents with incomes at or below 80 percent of Area Median Income will pay $12 a month.[259] This plan will reduce volumetric prices by 5 to 7 cents per kilowatt-hour.[260] Before approving this plan, the CPUC

251. *Id.*

252. Order on Implementation of the Climate Leadership and Community Protection Act, N.Y. PUB. SERV. COMM'N (2022).

253. S.B. 2016-A, 2023 Leg., Reg. Sess. (N.Y. 2023).

254. CAL. PUB. UTIL. CODE § 739.9(e)(1)(F).

255. *Id.*

256. A.B. 205, 2022-23 Leg., Reg. Sess. (Cal. 2022).

257. A.B. 1999, 2023-24 Leg., Reg. Sess. (Cal. 2024).

258. *CPUC Approves A New Billing Structure That Will Cut Residential Electricity Prices And Accelerate Electrification*, CAL. PUB. UTILS. COMM'N (May 9, 2024), https://www.cpuc.ca.gov/news-and-updates/all-news/cut-residential-electricity-prices.

259. CAL. PUB. UTIL. COMM'N, PROPOSED DECISION OF ALJ WANG, DECISION ADDRESSING ASSEMBLY BILL 205 REQUIREMENTS FOR ELECTRIC UTILITY (2024).

260. *CPUC Approves A New Billing Structure That Will Cut Residential Electricity Prices And Accelerate Electrification*, *supra* note 258.

rejected a utility-proposed plan that would have had the highest-income customers paying a fixed charge of $128 and five income-based tiers.[261]

California's low-income discount program, the California Alternate Rates for Energy (CARE) was established in section 739.1 of the Public Utilities Code. This section requires the PUC to "ensure that low-income ratepayers are not jeopardized or overburdened by monthly energy expenditures" and "that the level of the discount for low-income electricity and gas ratepayers correctly reflects the level of need" as determined by a low-income needs assessment outlined in section 382(d).[262] The CARE discount must be between 30 and 35% of the revenues that would have been produced for the same billed usage by non-CARE customers for utilities with 100,000+ customers and 20% with those with fewer than 100,000 customers.[263] The CPUC is required to examine methods to improve enrollment and participation in CARE and to ensure that customers who are eligible for public assistance programs in California are enrolled in the CARE program.[264] To aid in accessibility, the regulation requires utilities to use a single application form for CARE and other commission-approved programs.[265] CARE is funded by a ratepayer surcharge.[266] In addition to CARE, families whose household income exceeds that of the CARE allowances (250% of Federal Poverty Guidelines rather than the 200% required by CARE) can receive an 18% electric bill discount through the Family Electric Rate Assistance Program (FERA).[267] FERA is limited to California's three largest electric utilities, Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison.[268] To aid in accessibility, the CPUC is required to ensure that utilities use a single application form for all commission-approved assistance programs.[269]

Independent from CARE and FERA, the CPUC initiated a more comprehensive affordability rulemaking on July 12, 2018.[270] Phase 1 established an affordability framework by establishing a definition of affordability, identifying the residential essential service level for electric, natural gas, water, and communications services, and in turn, adopting metrics to assess the services' affordability: the Affordability Ratio, Hours-at-Minimum-Wage, and SocioEconomic Vulnerability

261. Ahmad Faruqui, *How will the income-graduated fixed charges (IGFC) proposed by California's investor-owned utilities affect customer bills?*, ENERGY CENTRAL (Apr. 17, 2023), https://energycentral.com/c/um/how-will-income-graduated-fixed-charges-igfc-proposed-california%E2%80%99s-investor-owned.

262. CAL. PUB. UTIL. CODE § 739.1(b).

263. *Id.* § 739.1(c).

264. *Id.* § 739.1(e).

265. *Id.* § 739.1(f)(2).

266. *California Alternate Rates for Energy (CARE)*, CAL. PUB. UTILS. COMM'N, https://www.cpuc.ca.gov/consumer-support/financial-assistance-savings-and-discounts/california-alternate-rates-for-energy (last visited Oct. 23, 2024).

267. CAL. PUB. UTIL. CODE § 739.12.

268. *Id.*

269. *Id.* § 739.1(f)(2).

270. *Affordability Rulemaking*, CAL. PUB. UTILS. COMM'N, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/affordability (last visited Oct. 15, 2024).

Index.[271] The concluding order of this phase also directed the CPUC staff to publish an Annual Affordability Report.[272] Phase 2 determined how the affordability metrics will be implemented into CPUC efforts.[273] Adopted recommendations in the Implementation Staff Proposal of particular relevance include that the responsibility to scope and request accompanying affordability analysis be clarified as being within the purview of individual proceedings, that the affordability metrics be introduced in the first large electric IOU GRC Phase 2 proceeding, that affordability metrics be included by utilities in all applications that seek to increase revenues by at least one percent, and that for proceedings that do not trigger the one percent threshold, the implementation of the affordability metrics in rate design and revenue allocation be tested in the first Phase 2 proceeding.[274] Phase 3 is scheduled to conclude on December 31, 2024,[275] and aims to consider strategies to mitigate future energy rate increases.[276] As part of this phase, the CPUC held public town hall-style listening sessions and asked for feedback regarding how to best vet affordability issues to be considered in a future workshop.[277] The CPUC also has an ongoing disconnections proceeding that began in 2018 with the goal of reducing electric and gas utility disconnections and improving reconnection processes.[278]

In 2015, the New York PSC initiated a proceeding to examine the low-income programs offered by the major electric and gas utilities in New York with the cited primary purposes of standardizing utility low-income programs to reflect best practices, streamlining the regulatory process, and ensuring consistency with the PSC's statutory and policy objectives.[279] In 2016, the PSC adopted a statewide Energy Affordability Program (EAP) pursuant to an examination and resulting report by the PSC's staff.[280] The EAP sets a target energy burden of 6% of household income.[281] Through this proceeding, the PSC required New York utilities to implement a default tiered discount presented by the PSC or an equally protective

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271. *Id.*

272. Decision Adopting Metrics and Methodologies for Assessing the Relative Affordability of Utility Service, Decision 20-07-032, at 74 (Cal. Pub. Util. Comm'n July 22, 2020) (Rulemaking 18-07-006).

273. *Affordability Rulemaking, supra* note 266.

274. Decision Implementing the Affordability Metrics, Decision 22-08-023, at 46-47, 58, 61 (Cal. Pub. Util. Comm'n Aug. 4, 2022) (Rulemaking 18-07-006).

275. Order Extending Statutory Deadline, Decision 23-12-026, at 1 (Cal. Pub. Util. Comm'n Dec. 20, 2023) (Rulemaking 18-07-006).

276. Assigned Commissioner's Ruling Amending Ruling of May 20, 2022 and Further Updating Proceeding Schedule for Phase 3 of Proceeding, at 1 (Cal. Pub. Util. Comm'n June 9, 2022) (Rulemaking 18-07-006).

277. *Id.*

278. Administrative Law Judge's Ruling Requiring Data From Respondent Utilities, (Cal. Pub. Util. Comm'n July 12, 2018) (Rulemaking 18-07-005).

279. Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility, Case 14-M-0565 (Cal. Pub. Util. Comm'n Jan. 9, 2015) (Instituting Order).

280. *Energy Affordability Program*, N.Y. DEP'T OF PUB SERV., https://dps.ny.gov/energy-affordability-program (last visited Oct. 15, 2024).

281. *Id.*

rate discount in their rate cases.[282] Utilities have since done so.[283] The PSC also established identification and enrollment requirements and mandated automatic enrollment in budget billing by utilities through this proceeding.[284] Households that receive assistance from a number of public assistance programs are eligible, including but not limited to the Home Energy Assistance Program (HEAP), the Supplemental Nutrition Assistance Program (SNAP), Medicaid, and Supplemental Security Income (SSI).[285] Some utilities provide for automatic enrollment in the EAP if a consumer receives benefits from a government assistance program.[286] EAP's mode of cost recovery is determined in rate cases on a case-by-case basis, but according to the PSC, the costs must be borne by all classes of customers.[287] Most recently, the PSC approved a one-time credit for eight million customers in February 2024.[288] In contrast to California's codification of CARE in the Public Utilities Code, EAP exists only as a function of NY PSC orders. The proposed NY HEAT Act would change that by codifying the goal of 6% in state law.[289]

C. *Procedural Justice*

Both New York and California have state agency and nonprofit consumer advocates as well as bodies that are specifically dedicated to low-income issues. The California Low-Income Oversight Board (LIOB) advises the commission on low-income customer issues and serves as a liaison for the commission to low-income ratepayers and representatives. The provided duties of the board are to monitor and evaluate implementation of programs provided to low-income customers, to aid in the development and analysis low-income customer need assessments, to encourage collaboration between state and utility programs "to maximize the leverage of state and federal energy efficiency funds" for low-income customers, to provide reports to the Legislature as requested, to assist in streamlining the application and enrollment process of low-income programs, and to "encourage the usage of the network of community service providers" for low-income energy efficiency programs.[290] As mentioned prior, the CPUC is required to work in conjunction with the LIOB to increase participation in low-income programs

282. Order Adopting Low Income Program Modifications and Directing Utility Filings 3-4 (N.Y. Pub. Serv. Comm'n May 20, 2016).

283. *Financial Assistance Programs*, CONSOL. EDISON CO. OF N.Y., https://www.coned.com/en/accounts-billing/payment-plans-assistance/help-paying-your-bill (last visited Oct. 15, 2024).

284. *Id.*

285. *Id.*

286. *Id.*; *see Energy Affordability Program*, NAT'L GRID, https://www.nationalgridus.com/Upstate-NY-Home/Monthly-Bill-Credits/Energy-Affordability-Program (last visited Oct. 15, 2024).

287. Order Adopting Low Income Program Modifications and Directing Utility Filings, *supra* note 282, at 4

288. *Governor Hochul Announces $200 Million in Utility Bill Relief for 8 Million New Yorkers*, N.Y. STATE (Feb. 15, 2024), https://www.governor.ny.gov/news/governor-hochul-announces-200-million-utility-bill-relief-8-million-new-yorkers.

289. S. 2016-A, 2023-2024 Leg. Reg. Sess. § 2 (2023).

290. CAL. PUB. UTIL. CODE § 382.1(a)(6).

with interested parties and community-based organizations, to provide technical support to the LIOB, critically, to "[*e*]*nsure that the energy burden of low-income customers is reduced*," and to provide formal notice of LIOB meetings.[291] Pursuant to Assembly Bill 205, the LIOB must periodically aid the CPUC in conducting an assessment of the needs of low-income ratepayers as well as an evaluation of low-income, weatherization, and energy efficiency program implementation measured by energy expenditures, hardship, language needs, and economic burdens.[292] California also has a group designed to ensure that CPUC and California Energy Commission (CEC) clean energy programs and policies benefit disadvantaged communities: the Disadvantaged Communities Advisory Group (DACAG).[293] DACAG was created by the Clean Energy and Pollution Reduction Act of 2015, SB 350.[294]

In New York, the Energy Affordability Policy Working Group was established by order in 2021 as part of the low income proceeding with the cited purpose of cooperation and coordination among the utilities, the Office of Temporary and Disability Assistance, Department of Public Service Staff (Staff), and other stakeholders.[295] The working group consists of state agencies, utilities, nonprofits, community groups, and municipal governments and has been convened to discuss improvement of the EAP and produce recommendations for the PSC.[296]

California and New York differ when it comes to intervenor compensation. According to a 2021 study by NARUC, California's intervenor compensation program is the most comprehensive in the country, paying the most in awards and issuing the most decisions.[297] The compensation program covers three categories of customers: category one customers are utility customers, category two are authorized representatives of utility customers, and category three are organization representatives who have received authorization to represent the interests of residential customers or small commercial customers via organization by-laws or articles of incorporation.[298] Compensation occurs after the completion of the proceeding upon the filing of a NOI and claim by the intervenor; categories one and two must prove undue hardship without compensation, and category three custom-

291. *Id.* § 382.1(e)(3).

292. *Id.* § 382(d).

293. *See generally Disadvantaged Communities Advisory Group*, CAL. PUB. UTILS. COMM'N, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/disadvantaged-communities/disadvantaged-communities-advisory-group (last visited Oct. 15, 2024).

294. *Id.*

295. Order Adopting Energy Affordability Policy Modifications and Directing Utility Filings 51 (N.Y. Pub. Serv. Comm'n Aug. 12, 2021).

296. New York State Energy Bill Credit Report, N.Y. DEP'T OF PUB. SERV.: ENERGY AFFORDABILITY POL'Y WORKING GRP. 2 (Nov. 21, 2023).

297. *State Approaches to Intervenor Compensation*, *supra* note 219, at 14.

298. *Id.*

ers must prove that the costs of effective participation outweigh the economic interests of their members.[299] Despite the overall success of this program, the administering CPUC ALJ Division has a backlog of claims.[300] In contrast to California, New York does not offer intervenor compensation, but a proposed New York law would have "permit[ted] groups of individuals or not-for-profit organizations that represent residential or small business customers to apply for reimbursement of its costs for reasonable advocate's fees, reasonable expert witness fees, and other reasonable costs in a proceeding before the Public Service Commission (PSC)."[301] The bill passed both the Assembly and Senate but was vetoed by Governor Hochul in November 2023.[302]

D. *Other Interventions*

Two remaining miscellaneous actions that impact rate equity are implementation of equity-based PIMs and prevention of recovery of utility political costs from ratepayers. New York's Reforming Energy Vision (REV) Proceeding[303] is exploring comprehensive implementation of PBR, including PIMs, decoupling, multiyear rate plans, and shared savings mechanisms.[304] According to RMI's new Emergent PIMs Database, New York electric utilities and Orange & Rockland and National Grid have implemented PIMs designed to incentivize use of energy efficiency measures to assist low-income customer savings and Central Hudson Gas & Electric has implemented a PIM designed to incentivize low-income customer savings more broadly.[305] In a separate article, RMI highlighted that New York utilities have also utilized PIMs to reduce residential service disconnections, uncollectible expenses, and customer arrears.[306] The RMI database does not report any PIMs in California that can be categorized under the emergent topics of "affordability" or "equity."[307] California does utilize PIMs based on energy efficiency[308] and self-generation using distributed energy resources[309] but does not

299. *Id.*

300. *Id.*

301. S.B. S405, 2023-2024 Leg., Reg. Sess. (N.Y. 2023).

302. *Id.*

303. *See* Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Matter No. 14-00581, N.Y. DEP'T OF PUB. SERV., https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101 (last visited Oct. 15, 2024).

304. Dan Cross-Call et al., *Navigating Utility Business Model Reform: A Practical Guide to Regulatory Design*, RMI (Nov. 2018), https://rmi.org/wp-content/uploads/2018/10/RMI_Navigating_Utility_Business_Model_Reform_2018-1.pdf.

305. *See PIMs Database: Emergent Performance Mechanisms across the United States*, RMI, https://pims.rmi.org/ (last visited Oct. 15, 2024).

306. *See* Gold & Rosenbach, *supra* note 111.

307. *Id.*

308. *See Energy Efficiency Shareholder Incentive Mechanism*, CAL. PUB. UTILS. COMM'N, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/energy-efficiency-shareholder-incentive-mechanism (last visited Oct. 15, 2024).

309. *Self-Generation Incentive Program (SGIP)*, CAL. PUB. UTILS. COMM'N, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/self-generation-incentive-program (last visited Oct. 15, 2024).

currently have an equivalent to New York's REV proceeding. Both New York[310] and California[311] introduced bills to preclude recovery of utility lobbying costs through rates; New York's remains in Senate committees at the time of writing while California's failed a Senate committee vote in April 2024.

VIII. CONCLUSION

Energy insecurity in the United States is a formidable problem. Solving it will require the collaborative efforts of legislators, regulators, and advocates. A number of state PUCs have made progress in addressing energy insecurity by incorporating equity considerations into their regulatory schemes. Some have relied on new statutory authority, but others have relied on broadly worded enabling statutes under which they operate.

California and New York PUCs have in particular made commendable moves towards increasing equity. Both legislatures have taken action to provide PUC authority on equity; California with language in the Public Utilities Code and New York with the CLCPA. Both have initiated affordability proceedings and have robust state bill assistance programs. Both have shown a willingness to push the boundaries when it comes to traditional cost-of-service ratemaking, with California's Income-Graduated Fixed Charge and New York's Reforming Energy Vision (REV) Proceeding.[312] Both have taken measures to improve procedural justice that set them apart from many states. Other states should look to and try to replicate their success.

State legislatures should consider enacting legislation that (1) expands PUC authority to endorse explicit consideration of equity in ratemaking and in the rate case forum, (2) requires PUCs to implement specific equitable rate designs, (3) forms specific bodies and proceedings to establish a dedicated forum for consideration of equity in the ratemaking context, (4) makes structural changes by using performance-based regulation to alter utility incentives or by determining which costs may be excluded from the rate formula, (5) funds intervenor programs and Consumer Advocate Offices, and (6) requires public access to utility modeling assumptions, data, and methodologies. Even absent new state legislation, PUCs should interpret existing authority broadly considering the historical deference provided to PUC actions and pursue many of these same actions independently.[313] PUCs should also pursue measures outside of the formal regulatory context, including, but not limited to, instituting auto-enrollment, improving educational outreach, implementing more user-friendly PUC websites and dockets, providing translation options, and increasing flexibility in modes and times of PUC proceedings.

When it comes to rate design, there is no objectively most equitable model. While inclining block rates generally benefit low-income customers as they use

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310. S.B. 7637, 2023-2024 Leg., Reg. Sess. (N.Y. 2023).

311. S.B. 938, 2023-2024 Leg., Reg. Sess. (Cal. 2023).

312. However, the former is explicitly an equity-based rate design while the latter has so far excluded equitable rate design considerations.

313. Excluding performance-based ratemaking, which likely does require statutory authorization.

less electricity, affordability of the lowest tier is critical to avoid undesirable energy saving measures by customers. Additionally, more granular use-based rates based on appliance or building type may present an opportunity for innovative rate design to benefit low-income customers. While time-of-use rates can be inequitable due to information asymmetry, outreach and education efforts can allow for low-income customers to take advantage of these rates as a cost-saving measure. Historically advocates have understood fixed charges to disproportionately harm low-income customers, but novel approaches like the income-graduated fixed charge can make increasing fixed charges a more equitable measure. Finally, the equitability of renewable energy rates often turns on consumer access to distributed energy resources like rooftop solar. The potential for either equitable or inequitable outcomes depending on technical implementation of each mainstream rate design underlines the importance of explicit consideration of equity in, and improved accessibility to, the ratemaking process.

Even with the improvements documented in this article, energy insecurity persists. An estimated 25% of California families are impacted by energy insecurity,[314] and approximately 1 million New Yorkers faced energy poverty between 2015 and 2019 according to the most recent U.S. census data.[315] State efforts must continue with the ultimate goal of a more transformational paradigm-shift within the ratemaking process: equity should be an explicit consideration in all rate cases and effective participation in the ratemaking process should be made feasible for all. The equity measures considered in this article depend in part on state-specific political amenability. Less common interventions may face significant political opposition from utilities and regulators, but identification of these opportunities is an essential first step. Advocates and regulators should prioritize equity in ratemaking just as economic efficiency and energy efficiency have been in the past. This article provides a number of possible avenues to get started.

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314. *Energy Insecurity and Health: Reducing and Avoiding Disconnections*, ALAMEDA CNTY. DEP'T OF PUB. HEALTH (Dec. 2018), https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_website/content/utilities_and_industries/energy/energy_programs/electric_rates/alameda-county-department-of-public-health-brief.pdf.

315. Jonathan A. Lesser, *Energy Poverty in New York: The Adverse Impacts of the State's Green Power Mandates*, MANHATTAN INST. (June 30, 2022), https://manhattan.institute/article/energy-poverty-in-new-york.

CHEAPER, FASTER, BETTER: HOW WE'LL WIN THE CLIMATE WAR

By Tom Steyer
Reviewed by Kenneth A. Barry[*]

I. INTRODUCTION

Readers of a political bent may recall Tom Steyer as a longshot candidate for president in the 2020 Democratic primaries. His backstory was striking: though a political newcomer, he was a seasoned hedge fund billionaire who now aspired to duel with climate change from the highest platform he could ascend. Steyer's foray into politics did not go very far – flanked, as he was, by other more plausible candidates waving banners almost as green. With thoughts of high office now set aside, the quixotic California capitalist has reappeared atop a new platform with the publication of *Cheaper, Faster, Better: How We'll Win the Climate War* (2024) ("*Cheaper, Faster, Better*").

The book is an amalgam of genres. Strands of memoir are woven around a core of initiatives proposed to address global warming and its impacts. The text also bristles with attacks on the perceived foes of renewable energy. Steyer first sketches his career transition from plutocrat to politician to full-time climate activist (or, to use his preferred label, "climate person") in the opening pages of the 240-page volume. Also introduced at the outset is his avowed mission to recruit readers to the ranks of "climate people." While his conscripts may not have the luxury of devoting themselves exclusively to the campaign, the author maintains that every citizen could – and *should* – redirect a significant portion of time and energy to the twin causes of curbing greenhouse gas emissions and spurring renewable energy development and deployment.

While you may not be able to tell a book by its cover, the outside jacket of *Cheaper, Faster, Better* offers some strong hints. First, the primary title reflects Steyer's conviction that a broad spectrum of engineering and agricultural innovations points to a better energy future – not just cleaner, but with lower costs and fewer other drawbacks. Second, the subtitle's reference to a "climate war" strikes a resonant note: that the determination and sacrifice of Steyer's parents' generation, victorious as it was in World War II, must be matched in scale and scope to defeat the threat of climate change. Third, the front cover hoists the battle flag of legendary activist Bill McKibben – author of *The End of Nature* (1989) – who hails Steyer's book as "a triumph." Pusillanimous, the book is not.

Across the enemy lines, so to speak, is the array of fossil fuel companies. Both Steyer's ideas and rhetoric treat this industry as the *bete noir* of the planet's current predicament. It is therefore understandable that those who regard oil and gas companies as relatively constructive and responsible corporate citizens may

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blanch at portions of *Cheaper, Faster, Better*. However, Steyer's partisanship aside, the book should hold the interest of many readers, given its breezy but cogent conversational style,[1] its anecdotal strolls down the author's memory lane, and its sprinkling of short but engrossing profiles of little-known entrepreneurs – *i.e.,* "climate people" – engaged in out-of-the-box efforts to solve tough industrial or agricultural challenges in a decarbonizing manner.

The easygoing, storytelling style of *Cheaper, Better, Faster* may not go down so well with readers who insist on verification for factual assertions. Although the book brims with the latter, there are no footnotes and only occasional references to independent sources. In this regard, it is more akin to a lecture series, where the audience has vouchsafed its trust in the speaker's candor. Readers with extensive backgrounds in energy policy and practices as well as novices might prefer that such assertions were anchored in footnotes they could peruse and evaluate independently, in lieu of Steyer's "trust-me-I-know-whereof-I speak" air. This reviewer soon came to view Steyer as a deeply committed advocate-evangelist, not a dispassionate analyst evaluating competing claims on the causes, consequences, and cures for climate change.

II. STEYER'S ENVIRONMENTAL ODYSSEY

Steyer is not the first high-profile billionaire to step forward with a book testifying to growing climate change concerns or – having compiled a fortune – to seek out investments in companies with innovative technologies to reduce greenhouse gas emissions. In 2021, Microsoft co-founder Bill Gates published *How to Avoid a Climate Disaster.*[2] Gates's book was a comprehensive and pragmatic study of the current state of play in various sectors of the economy, zeroing in on major sources that could ameliorate their emissions via either incremental improvements or major breakthroughs. One of the book's hallmarks was quantifying the "green premium" – a measure, across various products (electricity, vehicles, steel, cement, *etc*.), of whether the tradeoff of higher costs to achieve lower emissions is currently manageable or needs to be reduced for competitive viability in the market.[3]

Like Gates, Steyer turned to environmentally mindful investing and advocacy relatively late in life. He recalls how on a family visit to Alaska in 2006, he was astonished by the altered appearance of a once-snowy glacial valley he had admired twenty-five years earlier. Here are his stark conclusions upon beholding that denuded valley:

> First, climate change was real – and happening much faster than most of us imagined at the time. Second, climate change would affect us all: economies, governments, businesses, societies. *This will cause famines,* I thought. *This will cause wars.* The

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1. In an "acknowledgement" section towards the end, the author concedes that it takes a village, crediting "many people who contributed to the writing, editing, and publishing of this book." TOM STEYER, CHEAPER, FASTER, BETTER: HOW WE'LL WIN THE CLIMATE WAR 239 (2024).

2. *See* Kenneth A. Barry, *How to Avoid a Climate Disaster*, 42 ENERGY L.J. 249 (2021).

3. *Id.*

> third thing I realized was perhaps the most important, although it was less a realization than a deep, immediate conviction: We can and must solve it.[4]

This passage, brief as it is, reveals the entire DNA of Steyer's book. Climate change is unquestionably happening before our eyes at an alarming pace, he asserts, and apocalyptic things will happen if societies don't acknowledge the threat and take prompt and decisive action to reverse its course.

The rest of the story, as broadcaster Paul Harvey might have said, is that Steyer, in 2013, quit his day job as founder of a successful hedge fund and became a fulltime warrior in the trenches of climate change.[5] His new enterprise, Galvanize Climate Solutions, is focused on investing in companies that he believes can contribute to solving emissions challenges. He also notes that he donates larger sums than anyone else to "Democratic campaigns and causes."[6] And, much like Bill Gates, he became a self-directed student of climate change and potential solutions, attesting: "I've now spent more than fifteen years immersed in the science, politics, finance, and technology behind the fight to protect our planet, and ourselves, from climate change."[7]

Student though he is, Steyer refuses to engage in the debate over whether climate change is both serious and imminent:

> One thing I won't spend much time on is debating whether climate change is real. That debate is settled. . . . No wonder that even the oil companies admit global temperatures are rising and that extreme weather is becoming more common.[8]

That "the debate is over" stance, though nearly universal among environmental advocates and supportive policymakers, necessarily glides past the question of *how much* global warming may be occurring due to natural swings in the long-term planetary climate and how much, in turn, can be attributed to human-caused greenhouse gas emissions. Steyer also consistently falls in line with the prevailing thesis among climate change activists that the more severe prognostications of future weather impacts are mainstream enough and should be taken seriously. He recalls with fondness how, back in 2010, he recruited an esteemed Republican and fellow Californian, George Shultz, to join him in publicly opposing a state ballot initiative launched by the oil and gas industry to rescind certain climate change initiatives passed by the legislature. Shultz regarded his support of Steyer's position as analogous to fire insurance or a business hedge, reasoning that "If your business has a 20 percent chance of bankruptcy, you'd have to deal with it, even though there's an 80 percent chance everything would be fine."[9] Steyer rounds off the anecdote with his own handicapping: "The odds of global catastrophe [if we act too slowly] aren't 20 percent, they're probably more like 99 percent."[10]

4. STEYER, *supra* note 1, at 2.
5. *Id.* at 3.
6. *Id.* The author states this amount exceeds a quarter of a billion dollars.
7. *Id.*
8. STEYER, *supra* note 1, at 5.
9. *Id.* at 24.
10. *Id.* at 25.

However, there has been pushback against the more dire forecasts from some credible scientists in the field who've felt impelled to write books about their reservations concerning the so-called "consensus." Prominent among these dissenters is Steven E. Koonin, whose 2021 book, *Unsettled: What Climate Science Tells Us, What it Doesn't, and Why it Matters,* went into great detail on the necessity for further debate on the scientific evidence underlying the rate and severity of global warming,[11] as well as Judith Curry's 2023 book, *Climate Uncertainty and Risk: Rethinking our Response,* another deeply reflective analysis of what we know and what is legitimately regarded as uncertain or unknown regarding climate and the models attempting to project future trends.[12]

In fairness, Steyer himself does not claim to be a scientist, and parrying the arguments of these more skeptical authors doesn't necessarily fall to him. Nonetheless, readers should be aware that opinion in the scientific community is not quite as monolithic as *Cheaper, Faster, Better* would have it.

III. DENOUNCING THE FOSSIL FUEL COMPANIES

In their public utterances, U.S.-based oil and gas companies often suggest they are part of the *solution* to climate change. Rather than denying the challenges posed by the issue, they portray themselves as well-positioned to develop new, less carbon-intensive sources of energy as well as continue to furnish the nation's (and much of the free world's) energy needs with comparatively cleaner fossil fuel production versus that coming from certain foreign sources. This makes some business sense – why *wouldn't* these companies want to be players in new, cost-effective energy sources if they're going to happen anyway? – but Steyer will have none of it. The book paints them as incorrigible dissemblers and obstacles to a cleaner energy future.

There isn't much gray area in this aspect of *Cheaper, Faster, Better.* In one chapter that implores policymakers to "Do the Obvious Thing,"[13] Steyer draws a hypothetical comparison between "Industry A" and "Industry B." While the former is experiencing waves of innovation and "experiencing explosive growth," he posits, the latter "is doing basically the same thing it's done for the past century."[14] Among other points of comparison, he states, is that Industry B "relies on trillions of dollars in annual government subsidies to remain competitive" and "is causing enormous amounts of human suffering."[15] Industry B, he reveals at the end, is (unsurprisingly) the producer of fossil fuels. The absoluteness of this comparison is typical of the book's jeremiad against oil and gas firms. One might ask: are the "trillions of dollars in subsidies" from just the U.S., or globally? How much of the "subsidies" arguably are business tax deductions, permitted for companies of

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11. *See* Kenneth A. Barry, *Unsettled: What Climate Science Tells Us What it Doesn't and Why it Matters*, 43 ENERGY L.J. 237 (2022).

12. *See* Kenneth A. Barry, *Climate Uncertainty and Risk: Rethinking Our Response*, 45 ENERGY L.J. 111 (2024).

13. STEYER, *supra* note 1, at 13-31.

14. *Id.* at 13.

15. *Id.* at 14.

many sorts, rather than outright governmental largesse?[16] Should the "human suffering" (presumably the result of global warming) be counterweighed against the many advancements in human welfare and safety that fossil fuels have enabled since they displaced more unwieldy forms of energy (or as natural gas/LNG have partially displaced coal, a higher emitter of greenhouse gases)?[17]

A bit later, Steyer acknowledges that, at least in the past century, fossil fuels "allowed us to do incredible things."[18] But the tables have turned, the author contends:

> Right now, the thermometer is rising across the globe. . . . [T]he global warming caused by burning fossil fuels is devastating the planet and threatening all the progress fossil fuels once helped us achieve.[19]

The ensuing passage submits that, even though it's "impossible" to predict the "exact weather" ten years from now, in "broad strokes" the future is "pretty easy to predict" and that future is bleak. What follows is a parade of ecological horribles worthy of a fire-and-brimstone Sunday sermon depicting the eternal punishments of hell.[20] Summing up, Steyer avers:

> Climate change is the most dangerous global threat facing humanity right now. And that's not a controversial statement, or at least it shouldn't be. It's like saying two plus two is four.[21]

Boring in still further on the oil and gas industry, this chapter boils down fossil fuel's "story" to a short list of hopes and fallbacks, *i.e.*;

- The earth will self-regulate;
- Carbon capture technology will be economical enough to remove the emissions we discharge;
- If those two hypotheses don't "work out," we'll be able to geoengineer our way out of the crisis.[22]

Steyer finds each of these "stories" unlikely, even if they can't be completely refuted (because nothing about the future is completely certain).[23] In short, it would be foolhardy to rely on them, he counsels, and potentially be stuck in an irreversible planetary crisis if they don't "work out." Still further on, the book dives into the history of the whale oil industry and its political allies in the mid-19th century, who insisted it would remain dominant even if petroleum was creeping into its

16. Much later in the book, Steyer inveighs against the oil depletion allowance specifically. *Id.* at 187-88. The oil depletion allowance has long been controversial. It's often justified, as Steyer explains, as an incentive to encourage risk-taking in drilling. But it's also been rationalized as an equivalent to taking depreciation in tax accounting on a "wasting asset" (mineral reserves), and depletion applies to many other extractive industries. Moreover, the oil depletion allowance is reserved for independent oil and gas companies, not the big integrated majors. These finer points aren't raised by Steyer.

17. The multiple benefits of fossil fuels to mankind are touted in Alex Epstein's 2022 book, *Fossil Future,* a treatise as enthusiastic (and as one-sided) about oil, gas, and coal as Steyer's book is dour. *See* Kenneth A. Barry, *Fossil Future*, 44 ENERGY L.J. 301 (2023).

18. STEYER, *supra* note 1, at 18.

19. *Id.*

20. *Id.* at 19.

21. *Id.* at 21.

22. STEYER, *supra* note 1, at 23.

23. *Id.*

territory. Drawing a parallel, Steyer contends that oil and gas today is likewise a fading industry caught in a web of denial. In one of his edgier epigrams, the author remarks:

> In fact, I'd argue that the oil and gas industry is in a much worse place today than the whaling industry was back then. Why? . . . Whaling killed the whales. Oil and gas are killing us.[24]

Yet, despite the blinding clarity of it all, Steyer worries that the wheels of public policy aren't turning with the necessary urgency:

> . . . [I]f you look at the numbers right now, that change isn't happening fast enough. Powerful forces in business and politics are pushing back to keep the status quo in place for as long as possible. The technology to bring cheaper, cleaner, more reliable energy to everyone is improving rapidly. It's already here in many cases, but not yet in all of them. And the political will to act isn't materializing nearly as fast as we need it to.[25]

Steyer still isn't through raking the fossil fuel industry over the coals. Employing a common vulgarity throughout the next chapter ("Sharpen Your Bull**** Detector"), the author attacks the industry as a shrewd and persistent purveyor of damaging disinformation. "Oil and gas," he inveighs, is "quite possibly the most politically powerful industry on earth. We're facing what might just be the largest, most well-funded bull**** machine in human history. And the fate of humanity depends on whether we fall for it."[26]

The author catalogs some cases-in-point. For example, he undercuts the notion that natural gas is a cleaner "bridge fuel" to a future when societies can switch entirely to renewable energy. While it's quite true, he continues, that natural gas burns much cleaner than coal "in the lab," out in the real world, he submits, the propensity of natural gas to escape closed systems and "send methane into the atmosphere" can, "without a whole lot of leakage make natural gas even dirtier than coal."[27] And, he questions, while the U.S. and some other wealthier nations may be able to develop technologies capable of finding and plugging leaks, "what about the other 80 percent of the world?"[28]

In a similar vein, Steyer dresses down the oil and gas industry as exemplars of deception, taking advantage of credulous pigeons like some less scrupulous practitioners in the investment industry he left behind. In a concluding passage, Steyer allows that, although not everything a fossil fuel company says is "guaranteed to be a lie," neither do their spokespeople "deserve to be trusted implicitly," because they "have lied through their teeth for decades" and have "been making suckers out of us for way too long. . . ."[29]

The industry's goal isn't even to win the argument, the author supposes, but merely to preserve the status quo while its participants and their executives make

24. *Id.* at 29.
25. *Id.* at 31.
26. STEYER, *supra* note 1, at 40.
27. *Id.* at 41-42.
28. *Id.* at 42.
29. *Id.* at 49.

"tens of billions in new profits" and "tens of millions in salaries," respectively.[30] Manifestly, then, a central thrust of *Cheaper, Faster, Better* is that the conventional energy sector has sold its soul – and sold out the planet – for corporate and personal gain. As previously noted, that's a tough line of argument for those readers more sympathetic to the hydrocarbon industry to swallow whole.

IV. FOUNDATIONS FOR ACROSS-THE-BOARD DECARBONIZATION

In a chapter entitled "Know What to Know,"[31] Steyer gets down to some brass tacks. He offers short synopses of opportunities in five sectors to cut their emissions: electric generation, transportation, manufacturing, agriculture, and buildings. These are quick-hitters, more suitable for a beginner than an advanced student of decarbonization. For example, under "transportation," Steyer simply notes that electric cars, trucks, buses, and charging networks are the way to go – but that shipping (*i.e.,* by larger trucks or boats) as well as aircraft are a greater challenge, as current battery technology isn't up to the task. New battery technologies or alternative fuel sources (he mentions green hydrogen as the most promising of the latter) will be necessary to "move down the technology cost curve."[32]

Steyer follows up these synopses with a more extended discussion of carbon sequestration. This field of technological development has been, for some time, controversial in the environmental community because, first, it offers a permission structure for burning more fossil fuels and, second, it's inherently suspect because it's being promoted by fossil fuel companies. The book straddles the line, however, suggesting that "sequestration can certainly be part of the solution," but cautioning that "anyone who says that sequestration can get us to net zero . . . is either wildly ignorant, naïve, or lying."[33]

V. THE IMMORALITY OF PRESERVING THE STATUS QUO

I have already tried to convey how impassioned the book is in castigating the oil and gas industry for its purported callousness in the face of the climate catastrophes Steyer envisions. Presumably, a strategic goal is to stir outrage in the minds of prospective "climate people." However, the extent of the opprobrium is so remarkable that it's worth underscoring. In a chapter called "Stop Rooting for the End of the World,"[34] the author chastises the elites who lead the oil and gas industry, implying that they are at best morally numb to what they are accomplishing in their lives.

Digging into his own biography, Steyer recounts that his father was a young Navy prosecutor in the Holocaust trials at Nuremberg following WWII. The lesson he draws is that the misdeeds of the Nazi regime were enabled not just by "comic-book villains or deranged megalomaniacs" but also regular people self-

30. STEYER, *supra* note 1, at 50.
31. *Id*. at 55-70.
32. *Id*. at 65.
33. *Id.* at 69.
34. STEYER, *supra* note 1, at 73-87.

justifying their actions as "inevitable, or good, or necessary."[35] His analogy to the fossil fuel industry is that its enablers tend to justify their roles as necessary because modern civilization needs oil and gas. He scolds them for misspending their talents in a dead-end industry when they could be making good money in the vanguard of the green energy revolution. Steyer acknowledges that the professionals at the helm of the fossil fuel industry could be excused in 1980 or 1990, as they may have been "genuinely unaware" of the "terrible side effects of burning fossil fuels."[36] But such a posture is inexcusable today; in the author's scathing words: "You're living a perfectly normal life. Yet you owe your wealth and social position to your willingness to knowingly inflict misery on millions, if not billions, of human beings."[37]

The chapter even wags a finger at Warren Buffett. Steyer bows to the Oracle of Omaha as "the best investor in history." However, Buffet's Berkshire Hathaway conglomerate has invested billions in oil and gas – an implied prediction that there'll be a substantial market in fossil fuels for a long time to come.[38] Steyer concludes that while Buffett is "a good man," he happens to "think and hope that Warren is wrong."[39]

Some pages later, Steyer lectures large environmental organizations for being "too incremental" in opposing climate change. His rap against these groups, with their "conservation" roots, is they are wont to "let the perfect be the enemy of the good."[40] The context is that they opposed a bill that would have expedited the permitting of gas pipelines and, more importantly, that of clean energy projects. The problem these groups have – one that Steyer thinks they should get over – is that clean energy projects (such as new mountaintop wind turbines or solar farms on undeveloped land) can have environmental tradeoffs, such as habitat disruption.[41]

VI. NO NEED TO PROP UP RENEWABLES?

In a chapter curiously named "Kindness Doesn't Scale,"[42] Steyer argues that it's wrongheaded (and unnecessary) to talk about a "green premium" and how much caring consumers should be willing to pay up to be served with cleaner, renewable energy. Flipping the concept on its head, he first assures readers that he remains a "proud and committed capitalist"[43] and then asserts that *economic self-interest* (the lubricant of capitalism) should drive customers to prefer renewable power as well as devices that run on electricity.

In arriving at that conclusion, Steyer states that natural gas won out over coal in the marketplace and, in turn, "what natural gas did to coal, renewable energy

35. *Id*. at 78.
36. *Id*. at 78-79.
37. *Id*. at 79.
38. STEYER, *supra* note 1, at 81.
39. *Id*.
40. *Id*. at 97.
41. *Id*.
42. STEYER, *supra* note 1, at 159-74.
43. *Id.* at 160.

can do to oil and gas."[44] By way of illustration, he contends that "in many places, the cheapest form of electricity is now solar or wind" and "[m]any of the cheapest, best vehicles are electric, too" (not counting the "massive taxpayer subsidies that the oil and gas industry receives").[45] A bit later, he augments this narrative with the observation that "[r]ooftop solar isn't just cleaner than traditional power, it's far cheaper."[46]

This is one of the more noticeable places where the author's advocacy side seems to take precedence. Readers may question whether the EV business in the United States, led by Tesla, offers "many of the cheapest" vehicles, as well as whether customer uptake, even though spurred by governmental incentives, is showing acceleration. Looking to Europe for comparisons, readers may take note of a recent opinion piece in the *Washington Post* by an Anglo-German historian, Katja Hoyer, describing "the slow death of German industry, coupled with high energy prices and uncontrolled migration," that's fueling the rise of the far right. Her September 9, 2024, article, *Volkswagen's Woes and Germany's Decline*, focuses on how the country's pro-EV policies forced Volkswagen to "direct its investment and creative energy towards electric vehicles, a market that has fallen short of expectations."[47]

As for the assertion that rooftop solar energy offers homeowners far less expensive energy than conventional system power, while solar has indeed become low-cost per kwh of output, there's the need for grid backup to intermittent power to consider. Can home batteries completely cover the gaps? Are people willing to decouple from the grid, or will they pay extra for its reliability, and if so, how much? Isn't utility-scale solar (complemented by dispatchable resources) more cost-effective than home rooftop anyway? These are critical questions elided by Steyer's sunny outlook. Further, when the author represents that solar "is now 33 percent cheaper than natural gas,"[48] shouldn't he, for context, mention that China – no stranger itself to industrial policy and subsidies – has set about to dominate the market for solar panels and has, so far, achieved its goals?[49]

Steyer also conjectures that the "gap in price is almost certain to keep growing," because that's what happens with newer technologies.[50] In contrast, he adds, "[t]he price of oil shoots up every time the cartel that includes Russia, Saudi Arabia, Iran and other petrostates decides to artificially cut supply. Meanwhile, solar

44. *Id*. at 167.

45. *Id*.

46. STEYER, *supra* note 1, at 171.

47. Katja Hoyer, *Volkswagen's Woes and Germany's Decline,* WASH. POST: OPS. (Sept. 6, 2024, 8:00 AM), https://www.washingtonpost.com/opinions/2024/09/06/volkswagen-factory-germany-populism-merkel/.

48. STEYER, *supra* note 1, at 171.

49. *See* DANIEL YERGIN, THE NEW MAP: ENERGY, CLIMATE, AND THE CLASH OF NATIONS (2020) (reviewed at Kenneth A. Barry, *The New Map: Energy, Climate, and the Clash of Nations*, 41 ENERGY L.J. 375 (2020)). Yergin writes: "What catapulted solar into the mainstream was the marriage of Germany's environmental politics with Chinese manufacturing prowess. . . . Adding in Chinese companies that manufacture in other countries, brings the total share [of China's solar panel dominance] up to almost 80 percent. . . . When It comes to solar wafers out of which the cells are produced, China's share is even greater – almost 95 percent." *Id*. at 395-97.

50. STEYER, *supra* note 1, at 171.

just keeps getting cheaper."[51] It's true that the cartel hasn't gone away; but its clout has been diminished considerably by U.S. and other Western Hemisphere production growth, and the cartel currently seems concerned primarily with price stabilization and maintaining as much market share as it can manage.[52]

VI. CONCLUSION

There is much more one could say about *Cheaper, Faster, Smarter* as it weaves its way between autobiography, profiles in innovation, and exhortations to get involved in the "climate war." What to make of this investment tycoon turned climate action radical?

Steyer takes on multiple guises. He can assume the mantle of personal coach urging his recruits to think outside the box or resist the pressures of conformity. He can be like a prophet raging in the wilderness or a modern-day Cassandra, warning of the calamities to come, whether or not heeded by the power brokers – only to reemerge as a self-styled climate optimist[53] proclaiming that the "clean energy revolution hasn't just begun – it's become unstoppable."[54]

Though the author's homilies and digressions drawn from lifelong experience are many, he always manages to bring them back to his primary theme of driving action on climate change. There are more than a few passages where informed readers may raise an eyebrow. For example, when Steyer rebukes Texas Senator Ted Cruz for not only airily dismissing the climate change issue but also suggesting that "carbon pollution was 'good for plant life,'"[55] he might have qualified this riposte by acknowledging that there is a vital carbon dioxide/oxygen exchange and that more plant growth reduces atmospheric CO2. That's why there's such a fuss over the shrinkage of the Brazilian rain forests, or why tree planting may be rewarded with carbon offsets.

Or take the author's riff on "environmental justice," where he decries that "poor people in disadvantaged neighborhoods are . . . breathing toxic air from refineries. They're drinking toxic water from fracking."[56] One's reaction may be: sure, environmental controls may not be perfect, but we do have rigorous laws and regulations applicable to refineries and an EPA in the hands of Democratic leadership for three out of the last four administrations. Furthermore, the notion that properly supervised fracking pollutes groundwater has long been debunked. In this light, such pokes at U.S. refineries and fracking seem like the kinds of broadsides you find in fundraising letters from advocacy groups, not a book scrupulously examining the state of play in environmental regulation of energy production.

51. *Id.* at 171-72.

52. It also seems worth noting that oil – whatever its volatility – is no longer a major fuel in U.S. electricity production.

53. STEYER, *supra* note 1, at 227.

54. *Id.*

55. *Id.* at 117.

56. *Id.* at 105.

At its essence, *Cheaper, Faster, Better* is Cook's tour[57] through the landscape of encouraging developments in renewable energy and decarbonization, coupled with a tenacious assault on what the author views as a stranglehold the fossil fuel industry has on modern civilization. As noted, Steyer believes the former will win out over the latter, but not without a struggle. The book also sounds a few environmental ethicist overtones, brooding over how the conventional energy industry is violating Mother Earth:

> There's also the broader question of our relationship to the natural world. The fossil fuel companies don't just represent an industry. They represent a mindset focused on extraction—that the only way to enjoy the benefits of the modern world is to destroy the natural one. This idea, that plundering is an unavoidable part of life, is a recipe for tragedy and disaster. It's also clearly unsustainable.[58]

A book like *Cheaper, Faster, Better* speaks to two audiences. On the one hand, Steyer is preaching to the choir of likeminded activists. On the other, he's reaching out to new converts. I hesitate to be overly critical of such advocacy literature – a popular genre – simply because getting a complete and balanced picture involves exploring other books or media.[59] It's apparent that a "climate person" like Tom Steyer is guided by Senator Goldwater's famous credo (slightly modified): *moderation in defense of the planet is no virtue.* And one must give him his due; Steyer has surely paid for his platform.

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57. *Cook's tour,* MERRIAM-WEBSTER, https://www.merriam-webster.com/dictionary/Cook%27s%20tour (last visited Oct. 2, 2024).

58. STEYER, *supra* note 1, at 237-238. This inspired passage near the close of the book avoids mentioning that the major "clean energy" technologies of today – wind and solar power or EVs, for example – also depend on extractive industries for their manufacture.

59. An excellent starting point would be Dan Yergin's *The New Map: Energy, Climate, and the Clash of Nations* (2020).

PROTECTING THE "DOMINANT" INTEREST: THE APPLICATION OF LAPSE STATUTES IN MINERAL RIGHTS DISPUTES

Brandon Berry

I. INTRODUCTION

The oil and gas industry has a widespread economic impact on the United States ("U.S.") economy.[1] The birth of this heavily regulated sector occurred in 1859 near Titusville, Pennsylvania, with the nation's "first commercially successful oil well."[2] Since the establishment of that first well, crude oil has become arguably the most used and essential commodity used by Americans to "fuel vehicles, heat homes, and power businesses."[3] Crude oil's surging importance led

1. AM. PETROL. INST., IMPACTS OF THE OIL AND NATURAL GAS INDUSTRY ON THE US ECONOMY IN 2021, at ES-2 (Apr. 2023), https://www.api.org/-/media/files/policy/american-energy/pwc/2023/api-pwc-economic-impact-report-2023.

2. Ross H. Pifer, *Drake Meets Marcellus: A Review of Pennsylvania Case Law Upon the Sesquicentennial of the U.S. Oil and Gas Industry*, 6 TEX. J. OIL GAS & ENERGY L. 47, 48 (2010-11).

3. Alyssa W. Kovach, *Fracking Wars: Severance Tax, the Solution that Makes Sense*, 32 TEMP. J. SCI. TECH. & ENV'T L. 317 (2013); *see Oil Industry*, HIST., https://www.history.com/topics/industrial-revolution/oil-

to safety and antitrust concerns, and as a result, the passage of a host of federal and state regulations aimed at protecting consumers and the economy.[4] While the U.S. traditionally relied heavily on imports to meet these needs, technological advances, such as fracking, have caused the U.S. to surpass Saudi Arabia and Russia, becoming the world's leader in oil and gas production.[5]

The production of crude oil and natural gas has historically been left to the states.[6] Consequently, many state legislatures have enacted laws to conserve production and ensure efficient operations.[7] However, these regulations have resulted in various disputes, as demonstrated in the recent *P.D. Miller Farms* case in 2023.[8] This case centers around Georgia's mineral lapse statute that authorizes owners of surface property rights to strip title from corresponding mineral rights owners in severed estates.[9] Although the District Court granted the mineral owner's motion for summary judgment, the Eleventh Circuit found issues of material fact and reversed this decision.[10] While the appellate court reversed on procedural grounds, the substance of *P.D. Miller Farms* raises an important issue regarding property interests in surface versus mineral rights and highlights that state legislatures could alter their lapse statutes to safeguard severed estates from future disputes over mineral rights.[11]

This case note will include a discussion of the interests in real property and the various rights accompanying them as they relate to *P.D. Miller Farms, LLC v. BASF Catalysts, LLC*.[12] Moreover, it will break down the various ways to acquire these interests, such as through severance, adverse possession, and lapse statutes.[13] Specifically, this case note will analyze the Georgia mineral lapse statute at issue

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industry (last updated Mar. 27, 2023) ("Increasing sales of gasoline first for automobiles and then for airplanes in the early 1900s came as oil discoveries across the U.S. mounted.").

4. *See* Ronan Graham & Ilias Atigui, *A strong focus on oil security will be critical throughout the clean energy transition*, INT'L ENERGY AGENCY (Mar. 11, 2024), https://www.iea.org/commentaries/a-strong-focus-on-oil-security-will-be-critical-throughout-the-clean-energy-transition ("Much has changed in the global energy landscape since the IEA was founded 50 years ago, but the security of oil supply remains a pressing concern for governments across the globe. An enduring focus on oil security is a consequence of the continued need for oil to fuel cars, trucks, ships and aircraft, as well as to produce the petrochemicals necessary to manufacture countless everyday items").

5. Tara K. Righetti et al., *The New Oil & Gas Governance*, 130 YALE L.J. FORUM 51 (2020); *see* Jeffry Bartash, *Fracking revolution that's made the U.S. the top global oil producer is boosting the economy — and keeping emissions down*, MKT. WATCH (Mar. 22, 2019), https://www.marketwatch.com/story/fracking-revolution-thats-made-the-us-the-top-global-oil-producer-is-boosting-the-economy-and-curbing-emissions-too-2019-03-22/ ("The most influential example is the rise of fracking — extracting oil and natural gas from rock formations under the continental U.S. that had long been considered inaccessible").

6. Righetti, *supra* note 5, at 76.

7. *Id.* at 52-54.

8. P.D. Miller Farms, LLC v. BASF Catalysts, LLC, No. 22-11375, 2023 WL 106828 (11th Cir. Jan. 5, 2023).

9. *Id.* at *7.

10. *Id.* at *11.

11. *See infra* pp. 11-12.

12. *See generally P.D. Miller Farms*, 2023 WL 106828; *see also* discussion *infra* Section II.A.

13. *See* discussion *infra* Section II.A.

in this case and explore ways to reduce potential disputes stemming from its rigid enforcement.[14]

II. BACKGROUND

A. The History of Severance of Rights to Oil and Gas

In general, landowners can have one of six possessory estates: fee simple absolute, fee simple determinable, fee simple subject to condition subsequent, life estate, fee tail, and lease.[15] However, in analyzing the issues arising from *P.D. Miller Farms*, this note will focus solely on leases and fee simple absolute estates.[16] A lease is classified as a "non-freehold estate"[17] because a leaseholder does not own the estate outright but rather obtains rights to use the estate for a defined period in exchange for consideration.[18] On the other hand, a fee simple absolute is considered a "freehold estate,"[19] and such landowners are entitled to all rights of ownership with the "unlimited power of disposition in perpetuity without condition or limitation."[20] Among these "bundle of rights" are the right to enter, use, exclude others, derive income, alienate, and transfer or destroy property rights.[21] Further, fee simple owners can sever the rights of ownership underneath their land, allowing them "to create various types of mineral interests in other persons."[22] Traditionally, this severance is done through the use of mineral leases.

A mineral lease is a contract that gives a mineral lessee the "right to explore for and produce" oil, gas, or any other mineral provided in the agreement.[23] Before severance, the minerals below are considered a part of the surface estate.[24] However, after severance, the surface and mineral estates become separate entities.[25] For example, an owner may choose to convey the property's surface alone while reserving the "remaining minerals" that lie below it, and vice versa.[26] Although it

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14. *See* GA. CODE ANN. § 44-5-168(a) (2024).

15. Chad J. Pomeroy, *A Theoretical Case for Standardized Vesting Documents*, 38 OHIO N. U. L. REV. 957, 976 (2012).

16. *Id.*

17. *See* Luke Meier, *Drafting a Texas Oil and Gas Lease to Ensure Enforceability of a Consent-to-assign Clause: How to Make an Oil and Gas 'Lease' a Lease*, 51 TEX. TECH L. REV. 169, 179 (2019).

18. *Lease*, BLACK'S LAW DICTIONARY (12th ed. 2024).

19. Meier, *supra* note 17, at 178.

20. Hoke v. O'Bryen, 281 S.W.3d 457, 460 (Tex. App. 2007) (citing Walker v. Foss, 930 S.W.2d 701, 706 (Tex. App. 1996).

21. Kamaile A.N. Turčan, *U.S. Prop. Law: A Revised View*, 45 WM. & MARY ENV'T. L. & POL'Y REV. 319, 323-24 (2021).

22. 1A NANCY SAINT-PAUL, SUMMERS OIL AND GAS § 8:1 (3d ed.), Westlaw (database updated Oct. 2024).

23. 17 RICHARD A. LORD, WILLISTON ON CONTRACTS § 50:57 (4th ed.), Westlaw (database updated May 2024).

24. W. R. Habeeb, Annotation, *Acquisition of title to mines or minerals by adverse possession*, 35 A.L.R. Fed. 2d 124 § 1 (1954).

25. Faith United Methodist Church & Cemetery of Terra Alta v. Morgan, 745 S.E.2d 461, 468 (W. Va. 2013).

26. *Id.* (citing Carlos B. Masterson, *Adverse Possession and the Severed Mineral Estate*, 25 TEX. L. REV. 139, 141 (1946)).

depends on the expressed intent of the conveyance, mineral estates are often limited to the hydrocarbons below the surface.[27] Courts have held that a general conveyance or reservation does not include minerals that can only be extracted by "destroying the surface of the land," such as sand, gravel, and limestone.[28]

The severance of these estates often leads to disputes over who is entitled to the mineral rights. The general rule is that the mineral owner holds the dominant interest, while the surface owner has the servient estate.[29] For example, if a landowner leases the property's mineral rights, the mineral lessee is permitted to use as much of the surface "as is reasonably necessary to produce and remove the minerals."[30] In other words, the lessee's interest is dominant because they may enter and "use any part of the surface of the leasehold necessary to conduct his operations."[31] Conversely, the lessor's surface estate is servient because they are prohibited from interfering with these rights.[32] Consequently, in addition to the right to enter the premises for drilling purposes, mineral owners have the "right to execute oil and gas and mineral leases," as well as to receive "bonuses, rentals, and royalties."[33]

B. Adverse Possession and Georgia's Mineral Lapse Statute

1. Introduction to Adverse Possession

As an alternative to acquiring property through deeds and other conveyances, property can be obtained through adverse possession.[34] The concept of adverse possession dates back to England in 1275.[35] This ancient doctrine arises when someone in possession of another's property acquires valid title by meeting the applicable common law, statutory, and duration requirements.[36] Traditionally, common law requires that the possession must be hostile, exclusive, open and notorious, and under claim of title or right.[37] In addition, each of these elements must be both simultaneous and continuous for the entirety of the statutory period's

27. JOHN S. LOWE ET AL., CASES AND MATERIALS ON OIL AND GAS LAW 26 (West ed., 7th ed. 2018).

28. Payne v. Hoover, Inc., 486 So.2d 426, 428 (Ala. 1986); *but see id.* (quoting Heinatz v. Allen, 217 S.W.2d 994, 997 (Tex. 1949)) ("[S]ubstances such as sand, gravel and limestone are not minerals within the ordinary and natural meaning of the word unless they are rare and exceptional in character or possess a peculiar property giving them special value, as for example sand that is valuable for making glass and limestone of such quality that it may profitably be manufactured into cement.").

29. Getty Oil Co. v. Jones, 470 S.W.2d 618, 621 (Tex. 1971).

30. *Id.*

31. Douglas H. Gross, Annotation, *What constitutes reasonably necessary use of the surface of the leasehold by a mineral owner, lessee, or driller under an oil and gas lease or drilling contract*, 53 A.L.R. Fed. 3d 16 § 3(b) (1973).

32. *Id.*

33. Clayton Williams Energy, Inc. v. BMT O & G TX, L.P., 473 S.W.3d 341, 353 (Tex. App. 2015) (citing Marrs & Smith P'ship v. D.K. Boyd Oil & Gas Co., 223 S.W.3d 1, 14 (Tex. App. 2005)).

34. *See* Stevie Swanson, *Sitting on Your Rights*, 12 FLA. COASTAL L. REV. 305, 309 (2011).

35. *Id.* at 308.

36. 142 AM. JUR. 3D *Proof of Facts* 349, § 1 (database updated Nov. 2024) [hereinafter *Acquisition of Title to Property*].

37. *Id.*

duration.[38] However, these requirements vary by jurisdiction. For example, while Georgia and Oklahoma share the same five elements, they differ in the required length of the continuous statutory period.[39]

Regarding the first requirement, "hostile" possession merely means that the adverse possessor does not have "permission to be on the land."[40] Second, "exclusive" possession requires that the adverse possessor is the sole occupier of the land.[41] At a minimum, this exclusiveness requirement "only precludes shared possession with the record owner."[42] Next, "open and notorious" simply means that the possession of the land is evident to others.[43] To meet this standard, an adverse possessor can merely use the land the way the true owner would use land.[44] Lastly, for the possession to be under claim of title, the adverse possessor must have the intent to assert and claim ownership over the property.[45]

2. The Adverse Possession of Mineral Rights

As mentioned above, jurisdictions vary regarding what can be adversely possessed. This jurisdictional variation is especially apparent as it pertains to mineral rights. Some states maintain that simply failing to "use" the minerals or an adverse possessor's mere "possession" of the surface interest does not automatically terminate its severance from the surface estate.[46] In Texas, for instance, an adverse possessor must take steps beyond possession and use of the surface to acquire title to a severed estate.[47] Texas requires the adverse possessor to take control over the minerals in a way that notifies the true owner, such as by "actual drilling," "continuous drilling," or "taking of the oil and gas."[48] In other words, the adverse possessor must take "actual possession of the minerals below the surface by drilling" and continue to produce "them for the statutory-described period."[49] Thus, such control of the minerals must be actual and visible rather than occasional or temporary.[50]

Conversely, the law in other states holds that nonuse of the mineral interest for a certain period of time will cause the mineral owner's interest to "lapse" and

38. *Id.* § 3.

39. *Compare* GA. CODE ANN. § 44-5-163 (2024) (Georgia requires possession of real property "for a period of 20 years" when no written evidence of title is involved), *with* OKLA. STAT. tit. 12, § 93(4) (2024) (Oklahoma requires an individual to occupy the real property for at least "fifteen (15) years").

40. *Acquisition of Title to Property*, *supra* note 36, § 10.

41. *Id.* § 9.

42. *Id.*

43. *Id.* § 12.

44. *Acquisition of Title to Property*, *supra* note 36, § 12.

45. *Id.* § 13.

46. 58 C.J.S. *Mines and Minerals* § 241, Westlaw (database updated May 2024) [hereinafter *Effect of nonuse of mineral rights*].

47. PRACTICAL LAW OIL & GAS, ADVERSE POSSESSION OF THE MINERAL ESTATE IN TEXAS, West Practical Law, W-026-6184 (last visited Nov. 8, 2024).

48. *Id.*

49. Verde Mins., LLC v. Burlington Res. Oil & Gas Co. et al., 360 F.Supp.3d 600, 621 (Tex. D. Ct. 2019) (quoting Sarandos v. Blanton, 25 S.W.3d 811, 815 (Tex. App. 2000).

50. *Id.* at 622.

revert to the surface owner.[51] Instead of relying on a typical adverse possession prerequisite of taking sufficient control of the minerals, these lapse statutes merely require a showing that the actions or inactions of a fee simple owner bar their right to ownership.[52] Consequently, these statutes make it less burdensome for the adverse possessor to take ownership interest in mineral rights.[53] While some state statutes require the surface owner to give notice of the lapse to the mineral interest owner, giving them the option to preserve their "interest by filing a statement of claim," other states, such as Georgia, do not.[54] In Georgia, surface owners are merely required to show they have a "deed to the property in issue, that the mineral rights have been severed," and that the requirements of Georgia's mineral lapse statute have been met.[55] Under this statute, the adverse possessor must show that the mineral rights owner "neither worked nor attempted to work the mineral rights nor paid any taxes due on them for a period of seven years since the date of the conveyance."[56] This working requirement is satisfied when the possessor initiates an "operation to explore for, use, produce, or extract minerals in the land."[57]

C. Procedural Aspects of Adverse Possession

1. Jurisdiction

The first issue a Georgia court must address when reviewing a claim of adverse possession is whether it has jurisdiction to hear the claim.[58] There are three types of jurisdiction that a court must consider: personal jurisdiction, subject-matter jurisdiction, and venue.[59] Personal jurisdiction requires the court to have power over the defendant.[60] In other words, personal jurisdiction circumscribes a court's "authority to bind the litigants to the judgment it renders."[61] Thus, the personal jurisdictional authority of Georgia courts extends "to all persons while within its limits."[62] Generally, it requires a showing of sufficient "minimum contact" between the defendant and the court.[63] Specifically, this requirement is met when the defendant's contacts "with the State are so continuous and systematic as to render them essentially at home in the forum."[64]

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51. *Effect of nonuse of mineral rights*, *supra* note 46, § 241.
52. Mixon v. One Newco, Inc., 863 F.2d 846, 848 (11th Cir. 1989).
53. *Id.*
54. *Effect of nonuse of mineral rights*, *supra* note 46, § 241.
55. *Mixon*, 863 F.2d at 848.
56. § 44-5-168(a).
57. Fisch v. Randall Mill Corp., 426 S.E.2d 883, 885 (1993)
58. Susan Gilles & Angela Upchurch, *Finding a "Home" for Unincorporated Entities Post-Daimler Ag v. Bauman*, 20 NEV. L. J. 693, 695 (2020).
59. *Id.*
60. *Id.* at 697.
61. *Id.*
62. GA. CODE ANN. § 50-2-21(a) (2024).
63. Gilles & Upchurch, *supra* note 59, at 697-98.
64. *Id.* at 698 (citing Goodyear Dunlop Tires Operations, S.A. v. Brown, 564 U.S. 915, 919 (2011)).

Subject-matter jurisdiction requires the court to have the "power to hear the specific kind of claim."[65] Traditionally, state courts are governed by general jurisdiction, meaning that they can hear all cases that are not required to be heard in federal courts.[66] For example, Superior Courts in Georgia are courts of general jurisdiction, giving them "authority to exercise original, exclusive, or concurrent jurisdiction over all causes both civil and criminal, granted to them by the Constitution and laws."[67] Conversely, federal courts have limited subject-matter jurisdiction.[68] Although there are two ways to establish subject-matter jurisdiction in federal courts, this analysis is limited to the one relevant to this article: diversity jurisdiction.[69] Diversity jurisdiction allows a case to be heard in federal court if action is "between diverse citizens when the amount in controversy exceeds \$75,000."[70] In other words, the parties to the case must reside in different states, and the dispute must involve an amount exceeding \$75,000.[71]

Lastly, Georgia's third jurisdictional requirement is whether the chosen forum is the proper venue for the case.[72] Georgia's Constitution provides that cases of equity must "be tried in the county where a defendant resides against whom substantial relief is sought."[73] This requirement is a low burden that merely requires all defendants to be residents of the same state, with at least one being a resident of the judicial district where the case is brought.[74] Accordingly, if the parties to the case and the chosen forum meet these requirements, the court has the authority to hear the case.

2. Declaratory Judgment Actions

Declaratory judgments are an extremely common tool litigants use in the initial stages of a case to seek out a court's direction.[75] This section will introduce the three relevant declaratory actions discussed in this note: complaint for declaratory judgment, answer and counterclaim for declaratory judgment, and summary judgment in declaratory judgment actions.

65. *Id.*

66. *Id.* at 696.

67. Schuehler v. Pait, 238 S.E.2d 65, 67 (Ga. 1977).

68. *See* JOANNA R. LAMPE, CONG. RSCH. SERV., WHERE A SUIT CAN PROCEED: COURT SELECTION AND FORUM SHOPPING 2, https://crsreports.congress.gov/product/pdf/LSB/LSB10856 (last updated Mar. 21, 2024) ("Federal courts can generally hear cases only if authorized to do so by the Constitution and a federal statute.").

69. Gilles & Upchurch, *supra* note 59, at 696 (citing 28 U.S.C. § 1332(a) (2018)).

70. *Id.*

71. *Id.*

72. *Id.*

73. G.C. CONST. art. VI, § 2, para. 3.

74. Gilles & Upchurch, *supra* note 59, at 697*; but see* 28 U.S.C. 1391(b) (2024) (In federal cases, venue is governed by 28 UCS 1391, which provides that "civil actions may be brought in: (1) a judicial district in which any defendant resides, if all defendants are residents of the State in which the district is located; (2)a judicial district in which a substantial part of the events or omissions giving rise to the claim occurred, or a substantial part of property that is the subject of the action is situated; or (3) if there is no district in which an action may otherwise be brought as provided in this section, any judicial district in which any defendant is subject to the court's personal jurisdiction with respect to such action.").

75. Neal F. Weinrich, *Declaratory Judgment Actions: When are they Appropriate?* (Dec. 2016), https://www.bfvlaw.com/wp-content/uploads/2016/12/Weinrich-Declaratory-Judgment-Actions.pdf.

Generally, courts only grant a complaint for declaratory judgment "when it will terminate the controversy giving rise to the proceeding."[76] In other words, the litigant's complaint must allege facts demonstrating substantive legal issues entitling them to declaratory relief.[77] Specifically, Georgia courts have held that such relief "applies where a legal judgment is sought that would control or direct future action, and it requires the presence in the declaratory action of a party with an interest in the controversy adverse to that of the petitioner."[78]

Subsequently, a defendant may file an answer and counterclaim for declaratory judgment of its own. In response to the complaint, the defendant may deny or admit to the allegations.[79] If the defendant chooses the former, it has the burden of providing an alternative recitation of the disputed facts and any affirmative defenses that may apply.[80] Alternatively, if the defendant chooses to admit to the matters within the complaint, it may file an admission stipulating the alleged facts.[81] However, simply failing to answer would constitute an admission to the allegations.[82]

In addition to the defendant's answer, he may file a counterclaim against the plaintiff. Generally, courts allow a declaratory judgment counterclaim "when it has greater ramifications than the original suit."[83] For example, this action would be appropriate if there were issues beyond what the plaintiff alleged.[84]

Lastly, at any time, either litigant may file a motion for summary judgment. A party is entitled to summary judgment if the movant can show "that there is no genuine dispute as to any material fact and the movant is entitled to judgment as a matter of law."[85] However, even if the nonmovant fails to present such evidence, the court may nonetheless deny the motion or grant a continuance to allow the nonmovant to obtain additional discovery.[86] Courts exercise this provision "where it would be unjust to grant summary judgment without allowing the opposing party an opportunity to present his opposing evidence."[87]

76. FED. R. CIV. P. 57 advisory comm. notes (1937).

77. 26 C.J.S. *Declaratory Judgments* § 148, Westlaw (database updated May 2024) [hereinafter *Declaratory Judgments*].

78. Lapolla Indus, Inc. v. Hess, 750 S.E.2d 467, 470 (Ga. Ct. App. 2013).

79. *Declaratory Judgments*, *supra* note 78, § 149.

80. *Id.*

81. *Id.*

82. *Id.*

83. *Declaratory Judgments*, *supra* note 78, § 150.

84. *Id.* § 150.

85. FED. R. CIV. P. 56(a).

86. FED. R. CIV. P. 56(d)(1)–(2).

87. Jean F. Rydstrom, Annotation, *Sufficiency of showing, under Rule 56(f) of Fed. Rules of Civ. Proc., of inability to present by affidavit facts justifying opposition to motion for summary judgment*, 47 A.L.R. Fed. 206 § 2(a) (1980).

III. ANALYSIS

A. Factual Background and Procedural History

1. The Parties and the Issue

P.D. Miller Farms concerns a dispute between a Georgia surface owner and a mineral-rights owner over who possessed the valid title of a land's mineral rights.[88] Initially, W. B. Miller purchased the surface rights to the 600-acre Georgia property in 1943, while the Floridin Company reserved its mineral rights.[89] Today, the surface rights have remained in the Miller Family and are now held by the plaintiff, P.D. Miller Farms, LLC ("Miller").[90] After a series of conveyances, the property's mineral rights are now owned by the defendant, BASF Catalysts, LLC ("BASF").[91]

This dispute arose in November 2020, when BASF entered the property with the intention of exploring its minerals.[92] However, upon entering the property, BASF personnel discovered newly planted pine trees, prompting BASF to meet with Miller's owner.[93] During the meeting, Miller disputed BASF's mineral rights ownership and successfully requested BASF to leave the property.[94]

2. Procedural History

Following this incident, Miller filed a declaratory judgment action in the Superior Court of Decatur County, Georgia, alleging that BASF's rights to the property's minerals had lapsed.[95] Miller argued that it acquired the mineral rights through adverse possession under section 44-5-168(a) of the Georgia Code.[96] Subsequently, BASF successfully removed the case to the "Middle District of Georgia after demonstrating that the district court had diversity jurisdiction over this action as BASF is domiciled in New Jersey."[97] There, BASF answered the complaint and filed its own counterclaim for declaratory judgment on the grounds that: "(1) BASF's mineral rights on the property are valid; and (2) BASF has the right to exercise its mineral rights . . . without the interference of P.D. Miller Farms."[98]

BASF then moved for summary judgment, presenting evidence that it allegedly complied with the lapse statute by working the minerals and paying taxes on them in 2019.[99] Regarding the working requirement, BASF presented affidavits

88. *P.D. Miller Farms*, 2023 WL 106828, at *2.

89. *Id.*

90. *Id.*

91. *Id.*

92. *P.D. Miller Farms*, 2023 WL 106828, at *2.

93. *Id.* at *2-3.

94. *Id.* at *3.

95. *Id.*

96. *P.D. Miller Farms*, 2023 WL 106828, at *3; *see* § 44-5-168(a).

97. *P.D. Miller Farms*, 2023 WL 106828, at *3; *see id.* at *1 n.1 ("[W]e granted BASF's motion to supplement the record to establish that it is a citizen of Delaware and New Jersey. Because P.D. Miller Farms is a citizen of Georgia, we concluded that the parties are diverse.").

98. *Id.*

99. *Id.* at *3-4.

and other supporting documents from its employees.[100] For example, a mining supervisor, Randolph Jenkins, said he planned to have BASF's drilling contractor work on the property.[101] Jenkins also noted that BASF "would have" entered and marked hole locations on the property and speculated that "there appeared to be a large deposit of valuable minerals on the Miller tract."[102] Additionally, BASF relied on an affidavit from a mining engineer, Nathalie LeGare, who alleged that "she contacted the survey company to locate the hole locations" for Logan Drilling USA to drill.[103] In support, she provided "a survey plot identifying the hole locations" and invoices from BASF's drilling company that led her to believe it drilled holes and obtained core samples from the property.[104] Such invoices indicated that BASF had intermittently worked the property from June 21 to July 11, 2019.[105] Moreover, LeGare added that following the alleged hole drilling on July 11, BASF made further plans to explore the Miller property.[106] Lastly, as for the tax payment claim, BASF presented evidence that it paid taxes on the mineral rights nearly "every year since 1998."[107] However, both parties agree that this evidence "did not correspond to the mineral rights on the Miller property" because of a clerical error.[108]

In response to BASF's "working" evidence, Miller provided an affidavit from its owner, stating that neither he nor any of his employees had "seen, observed, heard of, nor seen signs of anyone working, or attempting to work, the mineral rights" despite being on the farm "virtually every day."[109] Additionally, he stated that contrary to BASF's affidavits, "none of my trees, roads, ditches, pasture indicate that equipment and personnel were ever on the property."[110] Concerning the tax payment issue, Miller presented an affidavit from the county's Tax Commissioner, John Mark Harrell.[111] Harrell stated that there is no evidence of BASF "being invoiced for, or paying, any taxes for the mineral interests."[112] In addition, Miller submitted an affidavit of the county's Chief Appraiser, Amy Rathel, who stated that while BASF did pay taxes on the mineral rights of a particular property, such payment was for a "different nearby piece of property owned in fee simple by BASF."[113]

Despite the contradictory evidence presented by each party, the district court "granted BASF's motion for summary judgment."[114] It found that BASF provided

100. *P.D. Miller Farms*, 2023 WL 106828, at *4.
101. *Id.*
102. *Id.*
103. *Id.*
104. *P.D. Miller Farms*, 2023 WL 106828, at *4.
105. *Id.*
106. *Id.* at *5.
107. *Id.*
108. *P.D. Miller Farms*, 2023 WL 106828, at *5.
109. *Id.*
110. *Id.*
111. *Id.* at *6.
112. *P.D. Miller Farms*, 2023 WL 106828, at *6.
113. *Id.*
114. *Id.*

"unrefuted evidence that it worked its mineral rights to a sufficient degree to retain those rights" under the mineral lapse statute.[115] However, the court failed to address the issue of whether BASF "paid taxes on the mineral rights during the statutory period."[116] Nonetheless, the court "granted BASF's motion for summary judgment" as it found "no genuine issue of material fact" remained.[117]

Miller then appealed to the Eleventh Circuit Court of Appeals to dispute the finding that BASF "worked" the mineral rights.[118] On appeal, the court reversed the district court's order, finding that BASF failed to meet its burden to show that "there was no genuine question that it either worked or attempted to work the mineral rights or paid taxes on those mineral rights."[119] It found that although BASF's argument that it drilled four holes on the Miller property would meet the statutory requirement, BASF failed to show that its invoices for work performed "correspond[ed] to holes drilled on the Miller property."[120] Further, the court noted that Miller's affidavits created issues regarding BASF's payment of taxes on the Miller property's mineral rights.[121]

B. The Eleventh Circuit Properly Concluded that the District Court Erred in Granting BASF's Motion for Summary Judgment.

The circuit court correctly found issues of material fact as to BASF's "working" of the minerals and tax payments. Considering how courts have held that merely conducting genealogical research and taking rock samples does not satisfy the working requirement on its own, the Circuit Court reasonably concluded that BASF's inconsistent and contradictory affidavits were unpersuasive.[122] Although much of Miller's opposing evidence relies on personal testimony, it does not create grounds to strike the affidavits because "an affidavit by a person who was directly involved" amounts to "personal knowledge and is sufficient to warrant denial of a summary-judgment motion."[123]

C. GA. CODE ANN. § 44-5-168 Should Incorporate a Notice Requirement

Georgia's mineral lapse statute sets out to promote the "use of the state's mineral resources and the collection of taxes" and deter "holders of mineral rights who neither use nor pay taxes upon them" from sitting on their rights.[124] However, since the law is a lapse statute, it does not "require the surface owner to assert any acts of dominion over the surface estate or the minerals below."[125] Consequently,

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115. *Id.*
116. *P.D. Miller Farms*, 2023 WL 106828, at *7.
117. *Id.* at *6.
118. *Id.* at *8.
119. *Id.* at *11.
120. *P.D. Miller Farms*, 2023 WL 106828, at *9-10.
121. *P.D. Miller Farms*, 2023 WL 106828, at *11.
122. *See, e.g., Fisch*, 426 S.E.2d at 886 ("The owner of a mineral interest must do more than conduct genealogical research and pick up rock samples to meet the statutory requirement of working or attempting to work the mineral rights.").
123. 6B CHRISTINE M. G. DAVIS ET AL., CARMODY-WAIT § 39:128 (2d ed. 2019).
124. *Fisch*, 426 S.E.2d at 885 (citing Hayes v. Howell, 308 S.E.2d 170, 175 (1983)).
125. *Mixon*, 863 F.2d at 848.

mineral owners can unknowingly lose their interests with no recourse.[126] While the U.S. Supreme Court has held that mineral lapse statutes lacking a notice requirement do not violate due process rights,[127] some states have nonetheless mandated this requirement.[128]

For example, Ohio's Dormant Mineral Act ("DMA") requires surface owners to give mineral owners notice and opportunity to preserve their interest before the estate can lapse.[129] After receiving the surface owner's notice of intent to declare the interest abandoned, the mineral owner may exercise its preservation rights by timely filing an affidavit within sixty days of such notice.[130] In its affidavit, the mineral owner must provide a description of its interest with any recording information supporting the claim and a declaration of its intent to retain the rights.[131]

However, suppose the mineral owner fails to file this affidavit in a timely manner. In that case, the surface owner may quiet title in the minerals by showing that it attempted to notify the mineral owner and that the mineral owner did not preserve their interest.[132] DMA requires surface owners to "exercise reasonable diligence to identify" and serve notice by mail to "all holders of the severed mineral interest."[133] If this reasonable attempt does not reveal the mineral owners, "the surface owner may provide notice by publication."[134] In other words, when notice cannot be mailed, publication is sufficient to meet the DMA's notice requirement.[135] Considering the uncertainty associated with the number and ownership of severed mineral interests in any particular estate, this publication exception is needed as "a surface owner can never be certain that he has identified every successor and assignee of every holder who appears in the public record."[136]

Similarly, the Kansas Mineral Lapse Act follows a procedure where these competing interests are equitably balanced by providing that the mineral interest will not lapse "until the surface owner gives notice of the lapse and the mineral interest owner fails to respond" within sixty days.[137] Under this Act, surface owners may file such notice only if the mineral owner failed "to take any affirmative steps to maintain" their interest for over twenty years.[138] The Act requires the "surface owner to make reasonable efforts to identify and contact the owners of

126. *Id.*

127. *See* Texaco, Inc. v. Short, 454 U.S. 516, 536, 540 (1982) (finding that the Dormant Mineral Interest Act did not violate the Fourteenth Amendment because the "Due Process Clause does not require a defendant to notify a potential plaintiff that a statute of limitations is about to run" where the Act "furthers a legitimate statutory purpose" of encouraging multiple ownership and use of mineral interests).

128. *See, e.g.,* OHIO REV. CODE ANN. § 5301.56(C) (West 2014); KAN. STAT. ANN. § 55-1604(b) (West 2024).

129. Gerrity v. Chervenak, 166 N.E.3d 1230, 1234 (Ohio 2020).

130. *Id.*

131. § 5301.56(C)(a), (c).

132. *Gerrity*, 166 N.E.3d at 1234.

133. *Id.*

134. *Id.* at 1242.

135. *Id.* at 1236.

136. *Gerrity*, 166 N.E.3d at 1236.

137. Scully v. Overall, 840 P.2d 1211, 1214 (Kan. Ct. App. 1992) (quoting David E. Pierce, *July 1 is Deadline for Filing Claims to Preserve "Unused Mineral Interests,"* 25 CIRCUIT RIDER 6 (1986)).

138. *Id.* at 1211.

the lapsed interest."[139] As an alternative to providing proof of "actual knowledge that the mineral interest had lapsed," notice by publication will also suffice under the Act.[140]

Georgia *should* implement a similar notice requirement to avoid ownership uncertainty and better preserve the equity interest as the legislatures did in Ohio and Kansas.[141] Modeling this new notice requirement after these laws would provide Georgia mineral owners an opportunity to protect their interests.[142] Further, a notice requirement is unlikely to impact the statute's purpose of preventing mineral owners from sitting on their rights because the mineral owner would likely be unable to satisfy the current stringent working requirements before the sixty-day window closed.[143] In other words, while adding this notice requirement to the existing work and tax obligations may create a complex and time-consuming procedure, it would still help achieve the legislative goal by ensuring that only those who meet these requirements can retain their mineral interests.[144] Lastly, it must also be noted that Georgia's seven-year lapse period is thirteen years shorter than both the Ohio and Kansas statutes.[145] Thus, regardless of the preceding reasons, mandating a notice procedure with an opportunity for the mineral owner to preserve is justified because of the statute's abridged lapse duration.

D. Future Implications

1. How would these modifications impact the present case?

If Georgia modeled its statute after Ohio's DMA, BASF would receive notice and have an opportunity to preserve its mineral interest by timely filing an affidavit within sixty days of receiving Miller's notice of abandonment.[146] Consequently, this additional procedure would moderate Georgia's harsh lapse statute, allowing mineral owners to act and retain their rights.[147]

Assuming Georgia instituted a notice requirement with retroactive effect, Miller could likely argue that it provided BASF with proper notice when it met with BASF, disputed its ownership of the rights, and requested that it leave the premises.[148] Consequently, if the court found that Miller's ousting amounted to proper notice, then BASF's interest would be deemed abandoned because it failed to timely file an affidavit to preserve its interest.[149] Nonetheless, these ramifications are merely speculative, given that Georgia's legislature has yet to implement such a requirement.

139. *Id.* at 1214 (quoting Pierce, *supra* note 138, at 9).
140. *Id.* at 1213 (quoting § 55-1604(b)).
141. *See Gerrity*, 166 N.E.3d at 1241; *see also Skully*, 840 P.2d at 1214.
142. *Scully*, 840 P.2d at 1214.
143. *See Gerrity*, 166 N.E.3d at 1234.
144. *Id.*; *see* § 44-5-168(a).
145. *See Gerrity*, 166 N.E.3d at 1234; *see also Skully* 840 P.2d at 1212.
146. *Gerrity*, 166 N.E.3d at 1234.
147. *Id.*
148. *P.D. Miller Farms*, 2023 WL 106828, at *3.
149. *Id.*

2. What would be the future of mineral rights litigation if Georgia refused this modification?

Although Georgia is not bound by law to include a notice provision in its lapse statute, adopting a notice requirement would reduce mineral rights disputes and make any future disputes easier to adjudicate. These benefits could persuade the state legislature to consider amending Georgia's mineral lapse statute.[150] However, even if Georgia makes this change, the benefits would be limited to Georgia and matters resolved under Georgia law.[151] Therefore, it is unlikely that a case involving this modification would reach the U.S. Supreme Court. Instead, cases interpreting a revised Georgia lapse statute would be limited to the Georgia Supreme Court or as persuasive authority in jurisdictions with similar statutes.

Assuming Georgia refuses to add a notice provision to its lapse statute, mineral rights litigation would likely continue to arise, as it has in other states that lack notice provisions.[152] Unlike in Georgia, however, most of these statutes have lapse periods of twenty years.[153] Consequently, due to Georgia's short seven-year lapse period, disputes over mineral rights will likely continue to be prevalent among dominant and servient interests.

IV. CONCLUSION

In *P.D. Miller Farms*, the Eleventh Circuit reversed and remanded the District Court's opinion for failing to recognize an issue of material fact.[154] Despite the fact that appellate courts are reluctant to overturn decisions of fact, the contradictory evidence presented by each party suggested that substantial questions of fact remain as to whether BASF properly worked the minerals, complying with the mineral lapse statute.[155] Accordingly, the circuit court properly relied on sufficient evidence to remand the lower court's grant of summary judgment.

These procedural issues aside, the substance of *P.D. Miller Farms* shows the complications and difficulties arising from Georgia's mineral lapse statute and its lack of a notice requirement. Following the *P.D. Miller Farms* opinion, Georgia should consider making legislative modifications to its statute as it could insulate severed estates from future mineral rights disputes. As demonstrated in the Ohio and Kansas statutes, lapse statutes become more equitable and easily resolved by

150. *Gerrity*, 166 N.E.3d at 1241.

151. *See* § 44-5-168(a).

152. *See generally* Lakeland Area Prop. Owners Ass'n v. Oneida Cnty., 957 N.W.2d 605 (Wis. Ct. App. 2021); Westervelt v. Woodcock, 15 N.E.3d 75 (Ind. Ct. App. 2014).

153. *See, e.g.,* WIS. STAT. ANN. § 706.057(3)(a) (West 2024) ("[A]n interest in minerals lapses if the interest in minerals was not used during the previous 20 years."); IND. CODE ANN. §§ 32-23-10-2 (West 2024) ("An interest in coal, oil and gas, and other minerals, if unused for a period of twenty (20) years, is extinguished and the ownership reverts to the owner of the interest out of which the interest in coal, oil and gas, and other minerals was carved."); MICH. COMP. LAWS ANN. § 554.291(1) (West 2024) ("Any interest in oil or gas in any land owned by any person other than the owner of the surface . . . shall . . . be deemed abandoned, unless the owner" undertakes a certain event within twenty years, such as the "transfer of record of that interest," "issuance of a drilling permit," "actual production or withdrawal . . . or the use of that interest in oil or gas in underground gas storage operations . . . .").

154. *P.D. Miller Farms*, 2023 WL 106828, at *4.

155. *Id.*

incorporating a notice requirement with an opportunity to preserve their mineral interests. Although mineral owners are the dominant interest, it is nonetheless in the best interest of the oil and gas industry that they have the option to preserve their rights.

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WOTUS V. SCOTUS: THE IMPLICATIONS OF *SACKETT* ON INTERSTATE ENERGY INFRASTRUCTURE AND THE ENVIRONMENT

Devyn Saylor

I. INTRODUCTION

On May 25, 2023, the United States Supreme Court clarified lingering ambiguities in the definition of "waters of the United States."[1] The Supreme Court further clarified the authority of the United States Army Corps of Engineers ("Corps") and the Environmental Protection Agency ("EPA") to regulate wetlands under the Clean Water Act ("CWA").[2] The difficulties associated with interpreting "waters of the United States" directly result from the absence of a definition in the CWA.[3] In *Sackett v. EPA*, the Court concluded that the Corps and EPA have jurisdiction over adjacent wetlands only if the body of water adjacent to the wetland falls under the definition of "waters of the United States" and the wetland has a "continuous surface connection with that water."[4]

1. Sackett v. EPA, 143 S. Ct. 1322 (2023).

2. *Id*.

3. Stephen P. Mulligan, CONG. RSCH SERV., R44585, EVOLUTION OF THE MEANING OF "WATERS OF THE UNITED STATES" IN THE CLEAN WATER ACT 1 (2019), https://sgp.fas.org/crs/misc/R44585.pdf.

4. *Sackett II*, 143 S. Ct. 1322.

In 2004, Michael and Chantell Sackett purchased a small plot of land near Priest Lake, Idaho and began backfilling the land in preparation to build a family home.[5] Shortly after, the EPA informed the Sacketts that their land contained federally protected wetlands, and they were in violation of the CWA due to the backfilling work.[6] This kickstarted an intense legal battle that spanned almost two decades and resulted in a landmark decision with major implications for both the environment and energy industry.[7]

This case note contains a background discussion of the history of federal water pollution legislation, the varying interpretations of "waters of the United States" since the CWA's inception, and the characteristics and benefits of wetlands.[8] Additionally, this case note will examine both times the Sacketts have challenged the EPA in front of the Supreme Court. The facts, the procedural history, the main issues addressed by the Court, and the Court's conclusions and reasoning will be analyzed.[9] Furthermore, this case note will address the future implications of the Court's decision for both the environment and energy industry.[10]

II. BACKGROUND

A. Federal Water Pollution Legislation

While the Clean Water Act of 1972 ("CWA") is commonly referred to as the United States' most successful environmental legislation, it was not the first.[11] The Rivers and Harbors Appropriations Act of 1899 ("RHA") first attempted to protect water on a federal level.[12] In essence, the RHA made it unlawful for any person or corporation to discharge pollutants into the "navigable waters of the United States."[13] Additionally, the RHA criminalized the discharge of pollutants into tributaries of the "navigable waters of the United States."[14] Moreover, criminalization resulted if discharged pollutants onto the banks of waterways could be washed into the waterway through floods, storms, or high tides.[15]

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5. *Id.* at 1331.

6. *Id.*

7. Sackett v. EPA, 566 U.S. 120 (2012); *Sackett II*, 143 S. Ct. 1322.

8. Mulligan, *supra* note 3; Claudia Copeland, CONG. RSCH SERV., RL30030, CLEAN WATER ACT: A SUMMARY OF THE LAW 1 (2019), https://sgp.fas.org/crs/misc/RL30030.pdf; *Why Are Wetlands Important?*, NAT'L PARK SERV. (May 5, 2016), https://www.nps.gov/subjects/wetlands/why.htm.

9. *Sackett I*, 566 U.S. 120; *Sackett II*, 143 S. Ct. 1322.

10. *Streamlining Energy Infrastructure Permitting*, AM. PUB. ASS'N (June 2023), https://www.publicpower.org/system/files/documents/70%202023%20PMC%20Issue%20Briefs_PPPermitti%20Reform_FINAL.pdf; Miranda Wilson, *Does Sackett Clip EPA's Wings on Permits, Water Rules?*, E&E News: GREENWIRE (Jan 19. 2024), https://www.eenews.net/articles/does-sackett-clip-epas-wings-on-permits-water-rules/.

11. Richard Lazarus, *Judicial Destruction of the Clean Water Act: Sackett v. EPA*, U. CHI. L. REV. ONLINE (Aug. 11, 2023), https://lawreview.uchicago.edu/judicial-destruction-clean-water-act-sackett-v-epa.

12. Andrew Franz, *Crimes Against Water: The Rivers and Harbors Act of 1899*, 23 TUL. ENV'T L.J. 255 (2010).

13. 33 U.S.C. § 407 (1899).

14. *Id.*

15. *Id.*

Sections 9 and 10 of the RHA granted the Secretary of the Army the authority to regulate the discharge of pollutants into "navigable waters."[16] The phrase "navigable waters of the United States" referred only to waters that were "navigable-in-fact."[17] However, the legislation ultimately failed at addressing water pollution due to the RHA's primary focus to prevent the dumping of materials that impede navigation.[18]

In order to address water pollution, Congress passed the Federal Water Pollution Control Act of 1948 ("the FWPCA").[19] The FWPCA laid the framework for future water pollution legislation, granted the rights and responsibilities in water pollution control to the states, and encouraged interstate cooperation.[20] The FWPCA criminalized the pollution of "interstate waters" and defined the phrase as "all rivers, lakes, and other waters that flow across, or form a part of, State boundaries."[21] Pollution that travelled through tributaries to reach interstate waters fell within the scope of the FWPCA.[22]

While the FWPCA was a monumental step to combat water pollution, the FWPCA faced numerous restrictions and limitations.[23] For instance, pollution was only subject to the Act's penalties if the pollution caused an injury to the "health or welfare of persons" in a different state than the one in which the pollution originated.[24] Additionally, polluters had several opportunities to avoid legal action.[25] The FWPCA granted the Surgeon General the authority to issue formal notice, recommend measures to diminish the pollution, and establish a reasonable timeline for compliance if a polluter was found to have polluted interstate waters in a manner that harmed the health and welfare of people in another state.[26] The Surgeon General was also required to give notice to the agency that controlled water pollution in the state in which the pollution originated.[27] If a polluter did not comply with the Surgeon General's recommendations within the established timeline, the Surgeon General could issue a second notice to the polluter and state agency and recommend the state agency pursue legal action to abate the pollution.[28] If the polluter did not take action to abate the pollution and the state agency did not file suit within a reasonable time after the second notice, the Federal Security Administrator had the authority to appoint a board to review the evidence and recommend "reasonable and equitable" measures to abate the pollution.[29] If the polluter did

16. 33 U.S.C. §§ 401, 403 (1899).

17. The Daniel Ball, 77 U.S. 557, 563 (1870).

18. Franz, *supra* note 12, at 24.

19. Frank J. Barry, *The Evolution of the Enforcement Provisions of the Federal Water Pollution Control Act: A Study of the Difficulty in Developing Effective Legislation*, 68 MICH. L. REV. 1103, 1104 (1970).

20. *Id.*

21. *Id*.

22. *Id*. at 1104.

23. Barry, *supra* note 19, at 1105.

24. *Id*.

25. *Id*.

26. *Id.*

27. Barry, *supra* note 19, at 1106.

28. *Id*.

29. *Id*. at 1105-06.

not comply with these recommendations within a reasonable time, the Attorney General was permitted to sue the polluter on behalf of the United States.[30] In general, the FWPCA can best be characterized as a failure;[31] not a single lawsuit was filed under the FWPCA's authority, and the limitations and restrictions did not deter pollution.[32]

Although Congress amended the FWPCA numerous times between 1948 and 1972, the amendments did not further the FWPCA's success as a pollution deterrent.[33] Finally in the 1960s, the demand for water protection and pollution control gained national support.[34] This rise in support can be credited to major environmental disasters, including the Cuyahoga River fires.[35] The Cuyahoga River fires were a series of three fires on the Cuyahoga River near downtown Cleveland.[36] Backed by national support, Congress significantly amended the FWCPA,[37] and the comprehensive amendments became colloquially known as the Clean Water Act of 1972 ("CWA").[38]

The CWA was approved with overwhelming bipartisan support.[39] The CWA passed through the Senate unanimously and the House of Representatives with a 366 to 11 vote.[40]

The CWA is the principal law governing water pollution in the United States.[41] Its objective is to "prevent, reduce, and eliminate pollution" in order to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters."[42] The CWA initially had two primary goals: eliminate the discharge of pollutants by 1985 and achieve "fishable" and "swimmable" water quality by 1983.[43] To achieve these goals, the CWA prohibits the unauthorized discharge of pollutants into "navigable waters" through the National Permit Discharge Elimination System ("NPDES") permit program.[44] The CWA vaguely defines "navigable waters" as "waters of the United States, including the territorial seas."[45] Under the CWA, the Environmental Protection Agency ("EPA") and the

30. *Id*.
31. Barry, *supra* note 19, at 1106.
32. *Id*. at 1107.
33. *History of the Clean Water Act*, TUL. UNIV. L. SCH. (June 15, 2021), https://online.law.tulane.edu/blog/clean-water-act-history.
34. *Id*.
35. *Id*.
36. *Id*.
37. *History of the Clean Water Act*, *supra* note 33.
38. *Id*.
39. Lazarus, *supra* note 11.
40. *Id*.
41. *Id*.
42. Clean Water Act of 1972 § 101, 33 U.S.C. § 1251.
43. *Id*. § 101(a)(1)-(2).
44. *Id*. § 402.
45. Clean Water Act § 502(7).

U.S. Army Corps of Engineers ("Corps") jointly have the authority to enforce violations and the responsibility to interpret "waters of the United States," a phrase that is not explicitly defined in the CWA's statutory text.[46]

B. Establishing the Clean Water Act's Jurisdictional Reach

Since the CWA's inception, all three branches of government have struggled to clearly establish the CWA's jurisdictional reach and interpret the meaning of "waters of the United States."[47] The ambiguities associated with "waters of the United States" are a direct consequence of the CWA not defining the phrase.[48] In the over fifty years since Congress enacted the CWA, the interpretation of "waters of the United States" has greatly evolved.[49] Pursuant to section 404 of the CWA, the Corps and EPA have the administrative responsibility to define the phrase through agency guidance and regulations.[50]

In 1973, the EPA first attempted to establish the scope of its jurisdictional power under the CWA when implementing the NPDES permit program.[51] The EPA's initial definition of jurisdictional waters was broad and extended its jurisdiction to include "all navigable waters of the United States."[52] The EPA's definition further extended to tributaries of navigable waters of the United States and certain interstate waters.[53] The Corps' initial definition was vastly different than the EPA's.[54] The Corps believed that its jurisdiction was constitutionally limited to waters it previously had the authority to regulate.[55] Therefore, the Corps limited its definition of "navigable waters" to "waters of the United States" subject to the "ebb and flow of the tides" and waters used for the "purposes of interstate or foreign commerce."[56] This definition lasted less than one year after the United States District Court for the District of Columbia issued a ruling in *Natural Resources Defense Council v. Callaway*.[57]

C. "Waters of the United States" & The Inclusion of Wetlands

In *Natural Resources Defense Council*, the United States District Court for the District of Columbia ruled that the Corps' definition was too narrow and inconsistent with the CWA.[58] In response to this ruling, the Corps issued an interim final rule which expanded its interpretation of "waters of the United States" to

46. Clean Water Act § 404.
47. Mulligan, *supra* note 3, at 1.
48. *Id.*
49. *Id.* at 3.
50. *Id.* at 3.
51. Mulligan, *supra* note 3, at 3.
52. *National Pollutant Discharge Elimination System*, 38 Fed. Reg. 13,528, 13,529 (May 22, 1973).
53. *Id*.
54. *Permits for Activities in Navigable Waters or Ocean Waters*, 39 Fed. Reg. 12,115, 12,119 (Apr. 3, 1974).
55. *Id*.
56. *Id*.
57. Nat. Res. Def. Council, Inc. v. Callaway, 392 F. Supp. 685 (D.D.C. 1975).
58. *Id*.

include "wetlands, mudflats, swamps, marshes, and shallows" that are "contiguous or adjacent to other navigable waters" and "artificially created channels and canals used for recreational or other navigational purposes that are connected to other navigable waters."[59] In 1977, the Corps updated its interpretation of "waters of the United States" through regulations to include all waters that could affect interstate commerce.[60]

By 1982, the EPA and the Corps had come to an agreement on an interpretation of "waters of the United States."[61] Both agencies defined the phrase to include "all waters which are currently used, were used in the past, or may be susceptible to use in interstate or foreign commerce."[62] If the potential for an interstate affect existed, the CWA's jurisdiction under this 1982 interpretation extended to "intrastate lakes, rivers, streams, mudflats, sandflats, wetlands, sloughs, prairie potholes, wet meadows, playa lakes, or natural ponds."[63] Additionally, the agencies expanded the CWA's applicability to "adjacent" wetlands by defining "adjacent" to mean "bordering, contiguous, or neighboring."[64] Furthermore, the EPA and Corps declared that "adjacent wetlands" include wetlands that are separated from traditionally covered waters by "manmade dikes or barriers, natural river berms, beach dunes and the like."[65]

Five years later, the Supreme Court reviewed a challenge to the Corps' interpretation of "waters of the United States."[66] In *United States v. Riverside Bayview Homes, Inc*., the Supreme Court reviewed the Corps' assertion that the CWA had jurisdiction over wetlands that "actually abutted on a navigable waterway."[67] Concerned that wetlands could not be deemed "traditional notions of 'waters,'" the Court deferred to the Corps because "the transition from water to solid ground is not necessarily or typically an abrupt one."[68] In response, the Corps and EPA expanded their interpretations of "waters of the United States."[69] In 1986, the agencies issued the Migratory Bird Rule, which extended CWA jurisdiction to all waters and wetlands that are used or may be used by migratory birds or endangered species.[70] Under the Migratory Bird Rule, the CWA had jurisdiction over nearly all waters.[71]

59. Proposed Policy, Practice and Procedure, *Permits for Activities in Navigable Waters or Ocean Waters*, 40 Fed. Reg. 19,766 (proposed May 6, 1975).

60. Final Rule*, Regulatory Programs of the Corps of Engineers*, 42 Fed. Reg. 37,122 (July 19, 1977).

61. 40 C.F.R. § 122.3 (1981); 33 C.F.R. § 323.2 (1983).

62. *Id*.

63. *Id.*

64. *Id*.

65. 40 C.F.R. § 122.3 (1981); 33 C.F.R. § 323.2 (1983).

66. United States v. Riverside Bayview Homes, Inc., 729 F.2d 391 (6th Cir. 1984).

67. *Id.*

68. *Id*. *See* Chevron U.S.A., Inc. v. Natural Res. Def. Council, Inc. 467 U.S. 837 (1984).

69. Final Rule, *Final Rule for Regulatory Programs of the Corps of Engineers*, 51 Fed. Reg. 41,206, 41,217 (Nov. 13, 1986).

70. *Id*.

71. *Id*.

The Supreme Court reviewed another challenge to the Corps' interpretation of "waters of the United States" in 2001.[72] In *Solid Waste Agency of Northern Cook County v. U.S. Army Corps of Engineers* ("SWANCC"), the Court invalidated the Migratory Bird Rule and held that the CWA does not "extend to ponds that are not adjacent to open water."[73] The Court concluded that the CWA did not grant the Corps the authority to regulate wetlands isolated from navigable waters.[74] Furthermore, the Court held that the CWA's jurisdiction only extends to non-navigable waters with a "significant nexus" to navigable waters.[75] In response, the agencies ordered their field agents to make decisions on a case-by-case basis.[76]

The Supreme Court granted certiorari in *Rapanos v. United States* after the Sixth Circuit Court of Appeals held that the CWA had jurisdiction over wetlands near drains that emptied into navigable waters more than eleven miles away.[77] While the Supreme Court vacated the Sixth Circuit's decision, a majority was unable to come to an agreement on a proper standard for future disputes over the CWA's jurisdictional reach.[78] Instead of issuing a majority opinion, the Court developed two competing standards for evaluating jurisdiction under the CWA.[79] The four-justice plurality led by Justice Scalia concluded that "waters of the United States" refers only to "relatively permanent, standing, or continuously flowing bodies of water."[80] Wetlands are only included in this interpretation of "waters of the United States" if they have a "continuous surface connection" to other "waters of the United States."[81] However, Justice Kennedy's concurrence concluded that CWA jurisdiction only extends to waters with a "significant nexus" to navigable waters.[82] Under Justice Kennedy's interpretation, wetlands satisfy the "significant nexus" test and fall under CWA jurisdiction if "the wetlands, either alone or in combination with similarly situated lands in the region, significantly affect the chemical, physical, and biological integrity of a traditionally navigable waterbody."[83]

In an effort to clarify the jurisdictional boundaries of the CWA, the Corps and EPA issued the Clean Water Rule ("CWR") in 2015.[84] The CWR separates water into three categories: (1) waters that are categorically "waters of the United States"; (2) waters that may be considered "waters of the United States" on a case-

72. Solid Waste Agency of N. Cook Cnty. v. U.S. Army Corps of Eng'rs, 531 U.S. 159 (2001).

73. *Id.*

74. *Id.*

75. *Id*.

76. Joint Memorandum from Gary S. Guzy, General Counsel, U.S. Envtl. Prot. Agency, and Robert M. Andersen, Chief Counsel, U.S. Army Corps of Eng'rs on Supreme Court Rule Concerning CWA Jurisdiction Over Isolated Waters (Jan. 19, 2001), https://www.environment.fhwa.dot.gov/ecosystems/laws_swepacoe.asp.

77. Rapanos v. United States, 547 U.S. 715 (2006).

78. *Id.*

79. *Id.*

80. *Id.*

81. *Rapanos*, 547 U.S. 715.

82. *Id.*

83. *Id.*

84. Final Rule, *Clean Water Rule: Definition of "Waters of the United States"*, 80 Fed. Reg. 37,054 (June 29, 2015).

by-case basis if there is a significant nexus with other waters that fall under CWA jurisdiction; and (3) waters that are not "waters of the United States."[85] The CWR was highly controversial, widely unpopular, and the subject of numerous legal challenges.[86] In an attempt to block the CWR from implementation, both chambers of Congress passed a resolution of disapproval calling the rule an overregulation.[87] Over half of the states and fifty-three non-state plaintiffs filed suit challenging the CWR's legality.[88] The parties opposing the CWR argued that the rule overextended the EPA and Corps' statutory and constitutional authority.[89] Additionally, the opposition parties argued that the CWR violated the Administrative Procedures Act because the final rule was not a logical outgrowth of the proposed rule, regulated parties were not given a meaningful opportunity to comment, and the agencies did not consider or respond to significant comments.[90]

In the early days of the Trump Administration, President Trump issued Executive Order 13,778, which instructed the EPA and the Corps to rescind the CWR and clarify the definition of "waters of the United States."[91] The agencies approached this task with a two-step solution.[92] First, the agencies needed to rescind the CWR in its entirety.[93] Second, the agencies needed to redefine "waters of the United States."[94] Ultimately, the EPA and the Corps published the Navigable Waters Protection Rule ("NWPR").[95] Under the NWPR, "waters of the United States" included traditional navigable waters, tributaries, lakes, and adjacent wetlands.[96] The NWPR significantly reduced the number of wetlands that fell within the CWA's jurisdictional reach by clarifying the definition of "adjacent wetlands."[97] "Adjacent wetlands" were defined as wetlands that "abut covered waters, are flooded by those waters, or are separated from those waters by features like berms or barriers."[98]

Under the Biden Administration, the EPA and the Corps issued a new interpretation of "waters of the United States."[99] This new interpretation essentially

85. *Id.* at 37,073-95.

86. Mulligan, *supra* note 3, at 25-26.

87. S.J. Res. 22, 114th Cong. (2016).

88. *See* Ohio v. U.S. Army Corps of Eng'rs, 803 F.3d 804 (6th Cir. 2015).

89. Texas v. EPA, 389 F.Supp. 3d 497 (S.D. Tex. 2019).

90. *Id.* at 503.

91. Executive Order 13778, *Restoring the Rule of Law, Federalism and Economic Growth by Reviewing the "Waters of the United States" Rule*, 82 Fed. Reg. 12,497 (Feb2017).

92. Proposed Rule, *Definition of "Waters of the United States" – Recodification of Pre-Existing Rule*, 82 Fed. Reg. 34,899 (proposed July 27, 2017).

93. *Id.* at 34,901.

94. *Id.* at 34,906.

95. Final Rule, *The Navigable Waters Protection Rule: Definition of "Waters of the United States"*, 85 Fed. Reg. 22,250 (Apr. 21, 2020).

96. *Id.* at 22,340.

97. Kristine A. Tidgren, *Navigable Waters Protection Rule is Finalized*, IOWA STATE UNIV. CENTR. FOR AGRIC. L. & TAX'N (Feb. 6, 2020), https://www.calt.iastate.edu/blogpost/navigable-waters-protection-rule-finalized.

98. 85 Fed. Reg. 22,250, at 22,340.

99. Final Rule, *Revised Definition of "Waters of the United States"*, 88 Fed. Reg. 3,004 (Jan. 18, 2023).

mirrored the pre-CWR interpretation.[100] Two months after the enactment of the new interpretation, the Supreme Court decided *Sackett v. EPA*.[101]

D. Wetlands

The EPA and Corps jointly define wetlands as "those areas that are inundated or saturated by surface or ground water at a frequency and duration sufficient to support, and that under normal conditions do support, a prevalence of vegetation typically adapted for life in saturated soil conditions."[102] Swamps, marshes, mangroves, billabongs, fens, lagoons, and bogs are all classified as wetlands.[103] Typically, wetlands are a transitional zone between dry land and submerged water bodies.[104] There are more than 290 million acres of wetlands in the United States;[105] however, it is estimated that more than half of the country's wetlands have been destroyed.[106]

Wetlands provide a wide range of beneficial services for people, wildlife, and the environment.[107] For instance, wetlands provide flood protection, combat coastal erosion, and naturally improve water quality and supply.[108] Additionally, wildlife rely on wetlands for survival and protection.[109] Nearly one-third of the country's endangered and threatened animals live exclusively in wetlands.[110] Wetlands are also essential for migratory and breeding bird populations.[111] Breeding birds such as ducks, geese, and hawks raise their nestlings in wetlands.[112] Migratory birds utilize wetlands for feeding, breeding, and nesting.[113] Moreover, wetlands provide a specialized habitat for plant species.[114] Thousands of plant species can only survive in wetland environments.[115] The benefits that wetlands provide to people, wildlife, and the environment are immense, which underscores the need for federal protections.

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100. *Id*.

101. Sackett v. EPA, 143 S. Ct. 1322 (2023).

102. 33 C.F.R. § 328.3(c)(1); 40 C.F.R. § 120.2(c)(1).

103. *Id*.

104. *Id.*

105. *Wetlands Most in Danger After the U.S. Supreme Court's Sackett v. EPA Ruling*, EARTHJUSTICE (June 21, 2023), https://earthjustice.org/feature/sackett-epa-wetlands-supreme-court-map#:~:text=The%20United%20States%20has%20at,loss%20of%20protections%20are%20incalculable.

106. *Why Are Wetlands Important?*, U.S. ENV'T PROT. AGENCY (Mar. 22, 2023), https://www.epa.gov/wetlands/why-are-wetlands-important [hereinafter EPA Wetlands].

107. *Id.*

108. *Why Are Wetlands Important?*, *supra* note 8.

109. *Id*.

110. *Id.*

111. *Id*.

112. *Why Are Wetlands Important?*, *supra* note 8.

113. EPA Wetlands, *supra* note 106.

114. *Id*.

115. *Id*.

III. ANALYSIS

A. The Sacketts and Sackett I

1. The Sacketts

In 2004, Michael and Chantell Sackett purchased a small parcel of land near Priest Lake, Idaho.[116] Shortly after purchasing the property, the Sacketts began backfilling the lot with dirt and rocks in preparation to build a family home.[117] Through a compliance order, the EPA informed the Sacketts that their property contained protected wetlands.[118] Additionally, the Sacketts were informed that their backfilling violated the Clean Water Act ("CWA"), which prohibits the discharge of pollutants into "waters of the United States" without the proper permits.[119] The EPA ordered the Sacketts to immediately stop developing their property and threatened penalties of over $40,000 per day if the Sacketts did not comply.[120]

2. Establishing Jurisdiction Under Rapanos

The EPA used the "significant nexus" standard established in *Rapanos* which interpreted "waters of the United States" to include all waters that "could affect interstate or foreign commerce."[121] Additionally, this interpretation included "wetlands adjacent" to those waters.[122] The EPA's definition of "adjacent" extended past "bordering" and "continuous" and included "neighboring" wetlands.[123] Moreover, the EPA claimed jurisdiction over wetlands "adjacent" to non-navigable waters when the wetlands had a "significant nexus to a traditional navigable water."[124] A "significant nexus" existed when wetlands "significantly affect the chemical, physical, and biological integrity" of a traditional navigable water.[125] When determining whether a "significant nexus" existed, EPA field agents were instructed to look at the wetland alone or in combination with other similarly situated lands, and consider an expansive list of ecological and hydrological factors.[126]

The EPA classified the wetlands on the Sacketts' land as "waters of the United States" because the wetlands are "adjacent" to an unnamed tributary.[127] The wetlands on the Sacketts' property and this tributary were separated by a thirty-foot road.[128] The unnamed tributary feeds into a non-navigable creek, which

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116. Sackett v. EPA, 143 S. Ct. 1322, 1331 (2023).
117. *Id.*
118. *Id.*
119. Clean Water Act §§ 301, 502(12).
120. *Sackett II,* 143 S. Ct. at 1331.
121. *Id.*
122. 40 C.F.R. § 230.3(s)(3), (7) (2008).
123. 40 C.F.R. § 230.3(b).
124. *Sackett II*, 143 S. Ct. at 1331.
125. *Id.*
126. *Id.*
127. *Id.* at 1331.
128. *Sackett II*, 143 S. Ct. at 1331, 1332.

fed into Priest Lake, a traditionally navigable intrastate waterway.[129] The EPA claimed the existence of a "significant nexus" after the agency grouped the Sacketts' wetlands with the nearby Kalispell Bay Fern wetland complex.[130] The EPA concluded the two wetlands were "similarly situated" and "significantly affected" the ecology of Priest Lake;[131] therefore, the Sacketts violated the CWA by illegally dumping dirt and rocks into "the waters of the United States."[132]

3. The Supreme Court's Analysis in Sackett I

In 2008, the Sacketts filed suit challenging the EPA's interpretation of "waters of the United States."[133] This kick-started a lengthy legal battle which saw almost two decades of litigation with the United States Supreme Court granting certiorari twice.[134]

The Sacketts filed suit seeking declarative and injunctive relief and argued that the EPA's compliance order was arbitrary and capricious under the Administrative Procedure Act ("APA").[135] Additionally, the Sacketts argued that the compliance order deprived them of due process in violation of the Fifth Amendment.[136] The United States District Court for the District of Idaho ("District of Idaho") dismissed the Sacketts' case for lack of subject matter jurisdiction.[137] The court reasoned that the EPA's compliance order was not a final agency action;[138] therefore, the court did not have jurisdiction to review the case under the APA.[139] On appeal, the United States Court of Appeals for the Ninth Circuit affirmed the district court's decision holding that the CWA precluded pre-enforcement judicial review of compliance orders.[140] Moreover, the Ninth Circuit concluded that this preclusion did not violate Fifth Amendment due process.[141] The United States Supreme Court granted certiorari to review whether the Sacketts were permitted under the APA to challenge the EPA's compliance order.[142]

The Supreme Court held that the Sacketts were permitted under the APA to challenge the EPA's compliance order.[143] The APA provides judicial review of "final agency action for which there is no other adequate remedy in a court."[144] The court first looked at whether the EPA's compliance order was final agency

129. *Id*. at 1332.
130. *Id*.
131. *Id*.
132. *Sackett II*, 143 S. Ct. at 1332.
133. Sackett v. EPA, 566 U.S. 120, 120 (2012).
134. *Id*; *Sackett II*, 143 S. Ct. 1322.
135. *Sackett I,* 566 U.S. at 122.
136. *Id*.
137. *Id*.
138. *Id*. at 121.
139. *Sackett I*, 566 U.S. at 121.
140. *Id*.
141. *Id*. at 125.
142. *Id*. at 125.
143. *Sackett I*, 566 U.S. at 132.
144. 5 U.S.C.S. § 704 (1966).

action and concluded that the compliance order checks all the boxes of APA finality.[145] The Court reasoned that the compliance order was final agency action because the order contained a detailed list of alleged wrongdoings committed by the Sacketts[146] and provided legal consequences for failure to comply.[147] Additionally, the delivery of the compliance order signals the consummation of the EPA's decision-making.[148] Moreover, the compliance order exposed the Sacketts to double penalties for failure to comply in future enforcement proceedings[149] and severely limited their ability to obtain a permit from the Corps.[150] The Court next looked at whether the Sacketts had no other adequate remedy in a court.[151] The Court noted that a civil action brought by the EPA under the CWA provides judicial review; however, civil action could not be initiated by the Sacketts.[152] Moreover, bringing suit under the APA after the denial of a Corps permit does not constitute an adequate remedy;[153] therefore, the Court found that the Sacketts had no other adequate remedies in a court.[154] On the issue of whether the CWA precluded pre-enforcement judicial review of compliance orders, the Supreme Court concluded that the CWA was not a statute that precluded judicial review under the APA.[155] The Court reasoned that the CWA's statutory scheme does not preclude APA review,[156] and there is no indication that Congress sought to exclude compliance order recipients from initiating the judicial review process.[157] Ultimately, the Supreme Court reversed the Ninth Circuit's judgment and remanded the matter for future proceedings consistent with its opinion.[158]

B. The Supreme Court's Analysis in Sackett II

On remand, the District of Idaho ruled in favor of the EPA and held that the Clean Water Act covers wetlands with a "significant nexus" to traditionally navigable waters.[159] The Ninth Circuit affirmed the district court's decision.[160] In May of 2023, the Supreme Court again granted certiorari.[161]

On review, all nine Supreme Court justices agreed that the EPA did not have the authority to assert jurisdiction over the Sacketts' wetlands because the wetlands do not have a continuous surface connection to any "waters of the United

145. *Sackett I*, 566 U.S. at 131.
146. *Id*.
147. *Id*.
148. *Id*. at 127.
149. *Sackett I*, 566 U.S. at 126.
150. *Id*.
151. *Id*. at 127.
152. *Id*.
153. *Sackett I*, 566 U.S. at 127.
154. *Id*.
155. *Id*.
156. *Id*. at 128.
157. *Sackett I*, 566 U.S. at 128
158. *Id*. at 131.
159. Sackett v. EPA, 143 S. Ct. 1322, 1332 (2023).
160. *Id*.
161. *Id*.

States."[162] The majority opinion discussed the aforementioned history of the CWA and analyzed the statutory text.[163] The Court concluded that the CWA accurately reflects Congress's assumption that certain "adjacent wetlands" are "waters of the United States."[164]

Next, the court addressed how to determine if a wetland is adjacent to traditionally navigable waters.[165] The Court concluded that the *Rapanos* plurality was correct in determining that the CWA's use of "waters" must be interpreted as only "relatively permanent, standing or continuously flowing bodies of water 'forming geographical features' that are described in ordinary parlance as 'streams, oceans, rivers, and lakes.'"[166] The Court reasoned that this was the proper interpretation based on the CWA's deliberate use of the plural term "waters."[167] Additionally, this interpretation best aligns "waters of the United States" and "navigable waters."[168] The Court also concluded that adjacent wetlands are only included in this interpretation if the wetlands satisfy a newly established two-pronged test.[169] To assert jurisdiction over an adjacent wetland under the CWA, the EPA or Corps must *first* establish that the adjacent body of water falls under the definition of "waters of the United States."[170] *Second*, the wetland must have a continuous surface connection with that body of water.[171] A continuous surface connection exists if it is difficult to define the end of the traditionally navigable water and the beginning of the wetland.[172] Essentially, the CWA extends only to wetlands that are practically indistinguishable from a traditionally navigable waterbody.[173] While the Court noted that a surface connection may face temporary interruptions due to low tides or dry spells, these exceptions are limited.[174]

1. Concurrences

Justice Thomas, joined by Justice Gorsuch, agreed with the Court's opinion in full. He utilized his concurring opinion to attack the CWA's other jurisdictional terms: "navigable" and "of the United States."[175] After a lengthy review of the relationship between federal water pollution control and the Commerce Clause, Thomas argued that the "[f]ederal [g]overnment's authority over certain navigable waters is granted and limited by the Commerce Clause."[176] The Commerce Clause grants Congress the authority to "regulate Commerce with foreign Nations, and

162. *Id*. at 1322.
163. *Sackett II*, 143 S. Ct. at 1335.
164. *Id*. at 1340.
165. *Id*. at 1336.
166. *Id*. (quoting Rapanos v. U.S., 547 U.S. 715 (2006)).
167. *Sackett II*, 143 S. Ct. at 1335.
168. *Id*. at 1337.
169. *Id*. at 1339, 1340.
170. *Id*. at 1339.
171. *Sackett II*, 143 S. Ct. at 1341.
172. *Id*.
173. *Id*.
174. *Id*. at 1340.
175. *Sackett II*, 143 S. Ct. at 1344 (Thomas, J., concurring).
176. *Id*. at 1345 (Thomas, J., concurring).

among the several States, and with the Indian Tribes."[177] Moreover, Congress's regulatory authority is limited to ensuring that instruments of commerce can navigate waters that are "channels of interstate commerce."[178] Since wetlands are not channels of interstate commerce, Thomas believes that Congress lacks the authority to regulate wetlands, specifically isolated wetlands.[179] When determining what constitutes "the waters of the United States," Thomas believes that courts must analyze "whether the water is within Congress' traditional authority over the interstate channels of commerce."[180] Relying on this analysis, Thomas concluded that the "Sacketts' land is not a water, much less a water of the United States."[181]

Justice Kavanaugh, joined by Justices Kagan, Sotomayor, and Jackson, agreed with the majority's judgment that the EPA did not have jurisdiction over the Sacketts' wetlands.[182] Kavanaugh also agreed with the Court's decision to reject the "significant nexus" test.[183] However, Kavanaugh disagreed with the newly established two-pronged test to determine when the CWA extends to wetlands.[184] In his opinion, the "continuous surface connection" test restricts the CWA's "coverage of 'adjacent' wetlands to mean only 'adjoining' wetlands."[185] Kavanaugh relied on dictionary definitions, statutory text, court precedent, and a long history of "consistent agency practice" to highlight the distinct meanings of "adjacent" and "adjoining."[186] Under Kavanaugh's interpretation, "adjacent" wetlands include "(i) those wetlands contiguous to or bordering a covered water, and (ii) wetlands separated from a covered water only by a man-made dike or barrier, natural river berm, beach dune, or the like."[187]

Justice Kagan, joined by Justice Sotomayor and Justice Jackson, agreed that the EPA did not have jurisdiction over the Sacketts' wetlands; however, she disagreed with the test adopted by the majority.[188] She argued that the "continuous surface connection" test too narrowly defines "adjacent" and disregards the ordinary meaning of the word.[189] According to Kagan, a wetland should be considered adjacent "not only when it is touching, but also when it is nearby" a covered water.[190] Furthermore, Kagan criticized the majority for acting "as the national decisionmaker on environmental policy."[191]

While Justice Kavanugh and Justice Kagan both took issue with the newly established "continuous surface connection" test and Justice Thomas expressed

177. U.S. CONST. art. I, § 8, cl. 3.
178. *Sackett II*, 143 S. Ct. at 1346 (Thomas, J., concurring).
179. *Id*. at 1357, 58 (Thomas, J., concurring).
180. *Id*. at 1357 (Thomas, J., concurring).
181. *Id* at 1357, 58 (Thomas, J., concurring) (emphasis omitted).
182. *Sackett II*, 143 S. Ct. at 1362 (Kavanaugh, J., concurring).
183. *Id*. (Kavanaugh, J., concurring).
184. *Id*. (Kavanaugh, J., concurring).
185. *Id*. (Kavanaugh, J., concurring).
186. *Sackett II*, 143 S. Ct. at 1363-66 (Kavanaugh, J., concurring).
187. *Id*. at 1369 (Kavanaugh, J., concurring).
188. *Id*. at 1359 (Kagan, J., concurring).
189. *Id*. (Kagan, J., concurring).
190. *Sackett II*, 143 S. Ct. at 1359 (Kagan, J., concurring).
191. *Id*. at 1362 (Kagan, J., concurring).

his desire to limit the CWA's jurisdiction, the *Sackett* decision provides certainty regarding the definition of "waters of the United States" and agency authority under the CWA to regulate wetlands. Since the enactment of the CWA in 1972, courts have failed numerous times to provide this much-needed certainty. Many thought that *Rapanos* would achieve this; however, the Court's decision and subsequent agency action only caused more uncertainty. The *Sackett* decision finally clarified the definition of "waters of the United States" and established a binding test to determine when agencies have authority under the CWA to regulate wetlands. While the "continuous surface connection" test has its critics, the current Supreme Court is unlikely to address the issue again. The test is binding and will be for the foreseeable future.

C. Implications of a Narrower Definition of "Waters of the United States"

Hailed as the most important water-related Supreme Court decision in a generation, the *Sackett* decision has been met with support from the energy industry and opposition from environmentalists.[192] On one hand, the decision significantly limits the authority of the EPA to regulate waterways, specifically wetlands.[193] On the other hand, the decision provides energy industry actors the ability to more confidently plan infrastructure projects and avoid unexpected costs resulting from delays in obtaining permits.[194] Supporters of both sides should be pleased that the decision provided a much-needed clarification of the extent of the CWA's reach.

1. Environmental Concerns

The *Sackett* decision leaves environmentalists with valid concerns regarding wetland protection; however, there is no need to panic.[195] On its face, the adverse impact of the decision on the environment appears significant due to the sheer acreage of wetlands that are no longer federally protected.[196] It is estimated that roughly sixty million acres of wetlands are no longer protected by the CWA.[197] Additionally, twenty-four states are entirely reliant on the CWA for protection of "waters of the United States" within their borders.[198] These states will need to take legislative action if they desire to restore protection of their waters to a pre-*Sackett* level.[199] The other twenty-six states independently protect waters that do not meet the definition of "waters of the United States"; however, the *Sackett* decision has

192. Jeff Turrentine, *What the Supreme Court's Sackett v. EPA Ruling Means for Wetlands and Other Waterways*, NRDC (June 5, 2023), https://www.nrdc.org/stories/what-you-need-know-about-sackett-v-epa.

193. *Id*.

194. *Streamlining Energy Infrastructure Permitting*, *supra* note 10.

195. Wilson, *supra* note 10.

196. Kirti Datla, *What Does Sackett v. EPA Mean for Clean Water?*, EARTHJUSTICE (May 26, 2023), https://earthjustice.org/article/what-does-sackett-v-epa-mean-for-clean-water.

197. *Id*.

198. James M. McElfish, Jr., *What Comes Next for Clean Water? Six Consequences of Sackett v. EPA*, ENV'T L. INST. (May 26, 2023), https://www.eli.org/vibrant-environment-blog/what-comes-next-clean-water-six-consequences-sackett-v-epa.

199. *Id*.

left several states with waters that are not protected by the CWA or a state equivalent.[200] For instance, New York only protects wetlands over 12.4 acres[201] and will need to take legislative action to protect smaller wetlands that are no longer protected under the CWA.[202] The *Sackett* decision provides states with better clarity on which of its waters, specifically wetlands, are considered "waters of the United States" and federally protected under the CWA.[203] Before the Court's decision, there was uncertainty in many states on whether their wetlands were federally protected.[204] The clearer scope of the EPA and Corps' reach under the CWA established by the Court now provide states with the knowledge that certain wetlands are no longer federally protected and allows states to confidently take the necessary legislative actions to ensure protection.[205]

Additionally, the fact that a wetland is no longer federally protected under the CWA does not mean that the wetland is unprotected.[206] The decision will not result in a race of energy industry actors, or others, to damage wetlands that are no longer considered "waters of the United States."[207] The CWA is one of many hurdles that energy industry actors must overcome to construct energy infrastructure.[208] The National Environmental Policy Act of 1969 ("NEPA") and the Endangered Species Act ("ESA") are two examples of federal legislation that protect the environment.[209] NEPA requires the federal agency exercising jurisdiction over a proposed infrastructure project to take into consideration the environmental impact of the project.[210] The ESA prohibits proposed projects from harming threatened or endangered species or their critical habitats.[211] If a project crosses a wetland that is not protected, the project likely will be halted if the environmental impact is significant or construction would harm threatened or endangered species.[212] As a result of NEPA and the ESA, energy industry actors must strive to minimize their environmental impact to obtain the necessary permits for their infrastructure projects.[213]

2. Energy Industry Clarity

Energy infrastructure projects, specifically interstate pipeline construction and maintenance, are heavily regulated, and energy industry actors must obtain

200. *Id*.

201. N.Y. Env't Conserv. L. § 24-0105 (2008).

202. McElfish, Jr., *supra* note 198.

203. Brief for the Am. Petroleum Inst., et al. as Amicus Curiae, p. 5, Sackett v. EPA, 143 S. Ct. 1322 (2023).

204. *Id*.

205. *Id*.

206. Wilson, *supra* note 10.

207. *Id*.

208. William E. Bauer, *Pipeline Regulatory and Environmental Permits*, *in* PIPELINE PLANNING AND CONSTRUCTION FIELD MANUEL 57, 60 (2011).

209. *Id* at 60, 61.

210. *Id.*

211. *Id.* at 61.

212. Bauer, *supra* note 208, at 61.

213. *Id*.

several permits before the project can begin.[214] Obtaining the required permits is a long and expensive process.[215] The *Sackett* decision provided energy industry actors with better clarity to confidently plan and predict permit applications, which will speed up project timelines and allow industry actors to avoid unexpected costs that result from delays in permit approval.[216]

If a planned oil or natural gas pipeline crosses a waterway, an energy industry actor must obtain Corps permits before construction can commence.[217] Industry actors can either obtain a Nationwide Permit 12 ("NWP 12") or individual CWA section 404 permits for each water crossing.[218] The latter option is significantly more regulated, costly, and time consuming.[219] It can take up to 300 days to process an individual permit application.[220] Industry actors must obtain a water certification from each state and tribal government the project impacts.[221] Industry actors can obtain an NWP 12 for oil and natural gas pipeline projects that are "similar in nature" and only have minimal adverse environmental effects.[222] An NWP 12 application can be processed in as little as forty-five days.[223]

If every water crossing in an oil or natural gas pipeline project involves "waters of the United States," an energy industry actor can apply for an NWP 12.[224] If the project involves "waters of the United States" and waters not federally protected under the CWA, the industry actor must obtain individual permits for each water crossing.[225] This distinction is crucial when establishing a timeline for an oil or natural gas infrastructure project and avoiding unexpected costs caused by delayed permits.[226] The *Sackett* decision provides energy industry actors with a clearer definition of "waters of the United States."[227] The clearer definition is likely to result in Corps field offices issuing more consistent decisions regarding the scope of the CWA's authority.[228] Decisions on whether wetlands were considered "waters of the United States" and federally protected under the CWA used

214. Akriti Bhargava & Hannah Oakes Dobie, *Interstate Natural Gas Pipeline Permitting Process*, HARV. L. SCH.: ENV'T & ENERGY L. PROGRAM (June 8, 2023), https://eelp.law.harvard.edu/interstate-natural-gas-pipeline-permitting-process/.

215. *Id*.

216. *Id.*

217. *Id*.

218. Bhargava & Oakes Dobie, *supra* note 214.

219. Andrew J. Turner & Brian R. Levey, *Army Corps Finalizes Nationwide Permit Renewal for Expedited Clean Water Act Permitting*, HUNTON ANDREWS KURTH: THE NICKEL REP. (Jan. 7, 2022), https://www.huntonnickelreportblog.com/2022/01/army-corps-finalizes-nationwide-permit-renewal-for-expedited-clean-water-act-permitting/.

220. *Id*.

221. Turner & Levey, *supra* note 219.

222. Final Rulemaking, *Reissuance and Modification of Nationwide Permits*, 88 Fed. Reg. 73,522 (2021).

223. Turner & Levey, *supra* note 219.

224. Sierra Club v. U.S. Army Corps of Eng'rs, 803 F.3d 31, 38-40 (2015).

225. *Id*.

226. Brief for the Am. Expl. & Mining Ass'n, et al. as Amicus Curiae, p. 11, Sackett v. EPA, 143 S. Ct. 1322 (2023).

227. *Id*.

228. Bauer, *supra* note 208.

to vary greatly between field offices.[229] After *Rapanos*, if a pipeline crossed two similarly situated wetlands, it was likely that one field office would assert jurisdiction over the wetland in its territory, and the other would not.[230] When industry actors were forced to navigate the ambiguous interpretations of "waters of the United States," they faced significant uncertainty that impeded their ability to move forward with projects.[231] The *Sackett* decision allows energy industry actors to confidently predict which permits they are required to obtain and establish an accurate timeline.[232] The decision will not necessarily lead to reduction in the overall construction costs of necessary energy infrastructure; however, the decision will significantly reduce unexpected costs resulting in construction delays due to permitting issues.[233]

IV. CONCLUSION

The *Sackett* decision provides much needed clarity on the scope of the CWA, specifically the meaning of "waters of the United States." This clarity is important for both the environment and energy industry. Having a better understanding of the meaning of "waters of the United States" will allow states the opportunity to take legislative action to ensure its waters that are not federally protected under the CWA are protected at the state level. The Court's clarification of "waters of the United States" is important for the energy industry because it allows industry actors to confidently plan and predict the outcomes and timelines of permit applications required for the interstate construction and maintenance of oil and gas pipelines. Allowing energy industry actors the opportunity to plan ahead will lead to significant reductions in unexpected costs resulting from construction delays due to permitting issues.

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229. *Id.*

230. *Id.*

231. Brief for the Am. Expl. & Mining Ass'n, et al. as Amicus Curiae, p. 11, Sackett v. EPA, 143 S. Ct. 1322 (2023).

232. *Id.*

233. *Id.*

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