MUSINGS FROM BEHIND-THE-METER: A 20TH CENTURY MODEL FOR A 21ST CENTURY WORLD?

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Synopsis: At the altar of cost causation and cost allocation lies a century old debate concerning the term "demand charges." The primary question posed by this article is whether demand charges (i.e., the predominant rate design mechanism used to allocate the fixed costs of the transmission system) will prove sustainable and resilient in the face of the many new challenges affecting the electric transmission system. While it's true that most of these mechanisms have already survived and overcome decades of operational and institutional challenges, it is increasingly unclear whether these century-old rate design mechanisms will be able to sustain themselves for the next wave of transition facing the industry.

The proper calibration of demand charges is largely a question of rate design. At its core, rate design describes the way in which a utility recovers the costs of providing a service. There is a certain ebb and flow – an art and science – to ratemaking. Almost universally, the rate charged to a customer should be a reflection of the actual, steel-in-the-ground costs of providing that service along with a reasonable rate of return. That's the science – there is an ascertainable amount of costs incurred to provide the service. The art, however, of rate design is a far more nuanced way of allocating those real costs to different customer groups. Much like an artist blends colors together to negotiate a new color, rate design often blends competing interests and objectives together to develop a rate that serves as a compromise among the negotiated interests. Demand charges are no exception.

In the case of electric transmission, the issue with assigning costs to customers is that the transmission system is far more complex than producing one product and selling that one product; the same machinery is used to provide a variety of different services to a diverse population of customers. Adding a layer of complexity to an already complex problem, the industry is trending towards a far more interactive and engaged demand-side of the supply-demand balancing equation. It is quite likely that this new dynamic will require inventive forms of rate regulation. Is a rate design sourced in the late 1800s nimble or sturdy enough to adapt to the realities of 21st century electric systems? Probably not. Even though we currently lack great answers to these questions, we are not without tools to guide us through

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this thought process. This article seeks to determine whether there are any breadcrumbs or, better yet, a map and compass that might guide us through the transition.

I. INTRODUCTION

While my inclination is to dive head-first into what a demand charge is and the methods for deriving one, it would feel foolish to do so without first setting the stage for the next decade or two worth of changes coming to the industry.[1]

None of this will come as a surprise to anyone even remotely invested in the industry, but we are, yet again, at the crossroads – or intersection – of a major moment in the evolution of policy and technology. And while this industry is no stranger to existential crossroads (the past century of electric regulation represents a so-called "fast-changing regulatory world"[2] marked by regulatory dynamism),[3] this new set of changes will forever transform the way that transmission customers[4] engage and interface with their utility.[5] In fact, this particular crossroads represents one of the largest changes to electric service – an exercise not merely dressed in hypotheticals and buzzy industry jargon.[6]

1. It's worth acknowledging that, as it relates to the provision of electric service, the context and backdrop for this Article is an industry premised on infrastructure that also happens to be an underlying element of the economy. *See* Hon. Richard D. Cudahy, *Retail Wheeling: Is This Revolution Necessary?*, 25 ENERGY L.J. 351, 353 (1994).

2. Paul B. Mohler, *Experiments at the FERC – In Search of a Hypothesis*, 19 ENERGY L.J. 281, 305 (1998).

3. Hon. Curt L. Hebert, Jr., *The Quest for an Inventive Utility Regulatory Agenda*, 19 ENERGY L.J. 1, 3 (1998).

4. Throughout this article, the term "customer" is intended to apply to transmission customers, such as Network Customers or Load-Serving Entities. Customer, unless specifically identified, is not intended to apply to retail customers, even if much of this thought exercise could apply to retail and distribution grid concepts.

5. The idea of a new wave of resources (such as energy efficiency and qualifying facilities) upending existing paradigms is nothing new. *See, e.g.*, Michael D. Hornstein & J.S. Gebhart Stoermer, *The Energy Policy Act of 2005: PURPA Reform, The Amendments and Their Implications,* 27 ENERGY L.J. 25, 26 (2006).

6. We are in the midst of another significant moment in the industry – words often uttered, but *this* time, it feels real. For a rather complete and insightful tallying of events surrounding the energy transition, *see* Rich Glick & Matthew Christiansen, *FERC and Climate Change*, 40 ENERGY L.J. 1, 10-11, 19-20 (2019). In their

Public policy in the year 2023 is trending towards low- or no-carbon generation solutions.[7] The so-called "energy transition" is at our doorsteps, if not already with two feet in the door. And while most of these ambitious objectives (especially the carbon-eliminating kind) are decades away from realization and achievement, this evolution would represent an even more significant revision to the industry than how open access transformed the electric industry and the ways in which the transmission system was used.[8]

The changes contemplated by the so-called "energy transition" are fairly expansive in nature and include, but are not limited to: (1) advances in offshore

article, they describe the rapid series of events that have occurred in recent years, ranging from customers becoming more sophisticated to an electrification of everything. They even hinted at the idea of flattening or shifting peaks based on the prevalence of electric storage resources.

7. *See* Ari Peskoe, *Easing Jurisdictional Tensions by Integrating Public Policy in Wholesale Electricity Markets*, 38 ENERGY L.J. 1 (2017) (discussing public policy issues involving zero-emission and carbon-pricing issues).

8. In just the past two decades, the infrastructure of electric service has transformed from one that was rooted almost entirely in the use of fossil fueled resources to a far more diverse resource mix. This resource mix is as diverse as ever, with just a sampling of those resources including coal, natural gas steam, natural gas combustion turbine, oil steam, oil combustion turbine, nuclear, solar, wind, hydro, storage, and demand response. *See, e.g., PJM's Evolving Resource Mix and System Reliability*, PJM 3, 9 (Mar. 30, 2017), https://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx.

wind;[9] (2) newer metering technologies and strategies;[10] (3) an increased prevalence and penetration of solar PV;[11] (4) an increasing electrification of just about everything;[12] and (5) electric vehicles.[13] It's . . . *a lot*.[14]

More fundamentally relevant to the issues presented in this article, it is the concept and notion of demand-side resources (such as behind the meter storage, electric vehicles, and solar PV) transforming the way the transmission system is used[15] and, as a consequence, the rates associated with that changed usage.[16] In

9. For example, it's not a question of if offshore wind will make its grand appearance but rather when (and how). The federal government has outlined a path for nearly 30 gigawatts of offshore wind installations by the year 2030. *See, e.g.*, *Energy Secretary Granholm Announces Ambitious New 30GW Offshore Wind Deployment Target by 2030*, DEPT. OF ENERGY 1 (Mar. 29, 2021), https://www.energy.gov/articles/energy-secretary-granholm-announces-ambitious-new-30gw-offshore-wind-deployment-target; *see also, e.g.*, *PJM Interconnection*, 179 FERC ¶ 61,024 at P 3 (2022). One of the stickier issues is who pays for the projects – including the transmission build-out. In PJM, at least, New Jersey has elected to pursue a hard-wired approach under the tariff to building out and funding the build-out.

10. Elin Swanson Katz & Tim Schneider, *The Increasingly Complex Role of the Utility Consumer Advocate*, 41 ENERGY L.J. 1, 4 (May 4, 2020).

11. One example of this is the recent proliferation of solar (i.e., 107 gigawatts of nameplate solar), with another 25 worth of gigawatts in various interconnection queues. *See* Ryan Kennedy, *Over 25 GW of solar is actively being constructed in the U.S.*, PV MAG. USA 1-2 (Feb. 17, 2023), https://pv-magazine-usa.com/2023/02/17/over-25-gw-of-solar-is-actively-being-constructed-in-the-u-s/; *see also* Paul Ciampoli, *U.S. Microgrid Market Develops at Rapid Pace, With Capacity Reaching 10 GW in Q3 of 2022*, AM. PUB. POWER ASS'N (Feb. 14, 2023), https://www.publicpower.org/periodical/article/us-microgrid-market-develops-rapid-pace-with-capacity-reaching-10-gw-q3-2022.

12. The idea of "electrifying everything" has become a short-hand name referring to the idea of transitioning appliances or technology that rely on fuel to electricity (e.g., transitioning natural gas furnaces to electric heat pumps; *see generally, e.g.*, Nathan Reck, *Electric Vehicles, Infrastructure Electrification and the Urban-Rural Divide*, 23 SMU SCI. & TECH. L. REV. 77 (2020).

13. Although these resources reside on the distribution side of the system and would historically have been considered more apt for managing demand on the distribution system, the Commission's issuance of Order No. 2222 will foster and enable an even greater degree of participation among what's called "DER Aggregators." Distributed energy resources (DERs) are resources that seek to participate in either the retail or wholesale market (or, potentially, both) – aggregators pool those resources, which include storage, solar PV systems, and electric vehicles, together. *See, e.g., FERC Order No. 2222: Fact Sheet*, FERC 1-2 (Sep. 17, 2020), https://ferc.gov/media/ferc-order-no-2222-fact-sheet); *see also* James M. Van Nostrand, *Quantifying Resilience Value Distributed Energy Resources*, 35 J. LAND USE & ENV'T L. 15, 16-18 (2019) (For a discussion of the relative value offered by distributed energy resources and a glimpse of potential uses with respect to the ideas of resilience and grid hardening).

14. In addition to the introduction of new technologies (i.e., the changing resource mix), the proportions of those resources have changed dramatically and rapidly – for example, in just a ten-year period, coal fell by 52%, whereas the generation sourced from renewables (such as wind, utility-scale solar, and hydropower) increased by 72%. *See* Lauren Bauer et al., *Ten economic facts about electricity and the clean energy transition*, BROOKINGS 1 (Apr. 27,2023), https://www.brookings.edu/articles/ten-economic-facts-about-electricity-and-the-clean-energy-transition; *see also, e.g., Renewable generation surpassed coal and nuclear in the U.S. electric power sector in 2022*, EIA 1 (Mar. 27, 2023), https://www.eia.gov/todayinenergy/detail.php?id=55960.

15. System, for the purposes of this discussion, is specific to the bulk electric transmission system. To be sure, there are more dramatic impacts that may occur on the distribution system, but the lack of harmony between the wholesale grid and the retail grid enables this discussion to speak exclusively to impacts on the bulk electric transmission system. *See, e.g., Ch. 3: Demand-Side Resources*, DEPT. OF ENERGY 10 (Dec. 9, 2008), https://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/Chapter_3_-_Demand-Side_Resources_12-9-08.pdf.

16. In some ways, the present debates regarding a customer's ability to utilize its own generation resembles the debates at the inception of the industry; *see* Tapan Munroe, *Electric Utility Competition: Lessons from*

many ways, this category of resources and technologies is going to present the most challenges.[17] Even though behind-the-meter technology is not necessarily a new topic, what is new is the variety and volume that exponentially complicates the existing dynamic.[18] For customers, it could very well represent the best thing since sliced bread (though tough questions persist, such as how much bread to make and how big to make those slices). More effectively than in the past, behind-the-meter generation is poised to be one of the biggest "game-changers" as affecting not only load shapes and usage patterns, but introducing an opportunity for a bi-directional[19] exchange of energy.[20]

This sea change is not accidental, however. In the driver's seat of this particular rocket ship, the Federal Energy Regulatory Commission (Commission) has overseen wholesale market rules that are adapting and adjusting at a significant pace. For example, the Commission has overseen a changing of the guard from rules that were once designed to meet the needs of a thermal, fully dispatchable, and synchronous system to a "hybrid" system featuring far more diversity of resources than the rate designs of today envisioned or contemplated. Not only does the Commission have a strong backhand (i.e., the majority of the agency's actions are reactions to the filings it receives), the Commission also has a powerful serve – taking careful, deliberate, and proactive steps in its journey of promoting and ensuring efficient access and pricing under the tariff (i.e., smashing down barriers). In the name of removing the barriers imposed on different technologies and resource types,[21] the Commission has been no passive bystander to progress and

Others, 12 J. ENERGY & DEV. 203, 204 (1987) (citing "[h]istorically, competition is not new to utilities. Competition for industrial loads from self-generation was present at the turn of this century."); *see also Ch. 3: Demand-Side Resources*, *supra* note 15, at 13.

17. The investment decisions, particularly with renewables, is, at best, complicated. *See, e.g.*, Harvey L. Reiter, *America's Energy Future: So Who Are the Good Guys?,* FORTNIGHTLY MAG. 3 (Oct. 16, 2013), https://www.fortnightly.com/fortnightly/2013/10/america's-energy-future-so-who-are-good-guys.

18. *See, e.g.*, David E. Dismukes, *Current Trends and Issues Reforming State-Level Solar Net Energy Metering Policies*, 8 LSU J. ENERGY L. & RES. 419, 423 (Sept. 22, 2020).

19. This is also referred to as the so-called "prosumer." *See, e.g.*, Burcin Unel et. al., *Advancing Energy Policy*, 28 N.Y.U. ENVTL. L.J. 17, 19 (2020) (holding that "[i]ncreasing deployment of these resources disrupts both the traditional electric grid, which has been relying on one-directional power flow from large, centralized generators to end-users, and traditional utility regulation, which has been designed around a core assumption that only utilities could provide certain electric services.").

20. There is a plentiful bounty of literature on the potential impact that solar and storage can have on the electric industry. The literature reveals that there is an indeterminate impact of solar and storage being more prevalent and integrated than they are today. *See, e.g.*, Dismukes, *supra* note 18, at 419-20; s*ee also, e.g.*, Jon Wellinghoff & David L. Morenoff, *Recognizing the Importance of Demand Response: The Second Half of the Wholesale Electric Market Equation*, 28 ENERGY L.J. 389, 393 (2007). At the risk of overgeneralizing the matter, the demand side of the energy balancing equation was pretty darn inelastic in the past decade or so. That dynamic is set to change, and quickly. For example, while solar generation might peak earlier in the day – sooner than the system's evening peak – storage could have the effect of either broadening or blunting the peak; *see also, e.g.*, Nick Schlag & Zach Ming, *Practical Considerations for Application of Effective Load Carrying Capability*, ENERGY + ENV'T ECON. 7 (Aug. 7, 2020), https://www.pjm.com/-/media/committees-groups/task-forces/ccstf/2020/20200807/20200807-item-04-e3-allocating-elccmw-from-portfolio-to-classes.ashx.

21. Glick & Christiansen, *supra* note 6, at 15 (citing, for example, "[e]liminating barriers to competition and unduly discriminatory market rules has been a cornerstone of the Commission's implementation of the FPA.").

instead, has proactively issued a variety of rulemakings that acknowledge and reflect the reality of advanced technologies and their capabilities (a representative example including Order Nos. 745,[22] 755,[23] 841,[24] and 2222).[25] These orders, in particular, enable resources on the distribution side[26] of the equation to participate competitively in wholesale markets.[27] The Commission's rulemakings not only laid the foundation for a more dynamic experience between utilities and customers, but it has directly enabled it.[28] To be sure, there is an appreciable lag to many of the momentous rulemakings the Commission has issued in recent years, as it takes years for an industry, especially one as capital intensive as the electric industry, to adjust and adapt.[29] Even so, we have already seen meaningful, and in some cases exponential, distributed energy resources (DER) penetration.[30] The open, yet to be answered, question is how these changes will interact with the existing methods for allocating the demand costs of the transmission system. We are only at the beginning of understanding how these new resources will affect the fragile ecosystem and balancing of network transmission costs, though, as we cover later – the breadcrumbs reveal a path whereby the existing mechanisms are being stress-tested in real-time.

Prior to the moment we find ourselves in, the way that load-serving entities interacted with the transmission system changed slowly, but steadily.[31] The traditional paradigm of electric service has evolved steadily; through a steady drip of

22. *See generally* Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, 134 FERC ¶ 61,187 (2011).

23. *See generally* Order No. 755, *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, 137 FERC ¶ 61,064 (2011).

24. *See generally* Order No. 841, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 162 FERC ¶ 61,127 (2018).

25. *See generally* Order No. 2222, *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 172 FERC ¶ 61,247 (2020).

26. Richard P. Bonnifield & Ronald L. Drewnowski, *Transmission at a Crossroads*, 21 ENERGY L.J. 447, 448 (2000) ("Over a century ago in the United States, electrifying a town meant building a power plant and stringing "distribution" wires on poles. Distribution wires are the 'local streets' of electricity delivery, while transmission wires are the 'highways.'").

27. *See generally* Udi Helman et al., *The Design of US Wholesale Energy and Ancillary Service Auction Markets: Theory and Practice*, *in Competitive Electricity Markets*, JOHN HOPKINS UNIV. (2007), https://hobbsgroup.johnshopkins.edu/docs/papers/Helman%20Hobbs%20Oneill%20edits%20Ch05.pdf.

28. Glick & Chirstiansen, *supra* note 6, at 17 (citing "[o]ver the last 30 years, the Commission has issued a series of orders eliminating barriers that prevented resources from participating fully in wholesale electricity markets.").

29. As a fairly basic indicator that we are not yet at a point of understanding DER deployment and implementation, utilities are suffering from a lack of visibility into the unregistered DERs. *See, e.g.,* David Kathan, *Assessment of Current Demand Response and DER Data Collection Tools*, KATHAN ENERGY CONSULTING 2 (June 8, 2023), https://www.energy.gov/sites/default/files/2023-06/Assessment%20of%20Current%20Demand%20Response%20and%20DER%20Data%20Collection%20Tools.pdf.

30. Kelsey Horowitz et al., *An Overview of Distributed Energy Resource (DER) Interconnection: Current Practices and Emerging Solutions*, NREL 1 (Apr. 2019), https://www.nrel.gov/docs/fy19osti/72102.pdf.

31. *See generally*, Jeff Winmill, *Electric Utilities and Distributed Energy Resources – Opportunities and Challenges*, 6 SAN DIEGO J. OF CLIMATE & ENERGY L. 199 (2015); *see also* James M. Van Nostrand, *Quantifying the Resilience Value of Distributed Energy Resources*, 35 W. VA. UNIV. COLL. OF L. 15 (2019).

progress, technological and policy advancements have rendered outdated the previous modes of demand-side management (such as curtailment and interruptible methods of demand management). Currently, and now more than ever, transmission customers are better equipped to manage their contributions using demand response and demand-side resources, as but two examples of demand becoming more elastic.[32] With that deployment comes the agency possessed by network customers to engage with their electric needs more than ever before.

To be clear, some of this is new and some of it is not necessarily new.[33] On the latter, the idea of load flattening is *certainly* not new.[34] In short, load flattening – or flattening demand – assumes a reduction in the difference between the "peaks and troughs" in usage in an attempt to lessen the deviation when compared to average usage.[35] What is new, however, is that more advanced and sophisticated demand-side actors have begun testing and challenging the tried-and-true methods for assigning costs. A few recent accounts reveal just how they did this – we get into that later.

Our problem statement – one that does not appear to have an on-the-shelf solution – is whether the principles and policies of old are enough to shepherd customers, utilities, and regulators alike through the next phase of the industry. Technological innovations can enable a smarter, more precise rate design that marries two important concepts: first, the utility to better understand the future needs of its system and second, customers to better understand its own purchasing decisions.[36] As the circumstances underlying the provision of electric service are changing under our very feet, the shifting sands of time will force the industry to confront this question.[37]

32. Ahmad Faruqui & Robert Earle, *Demand Response and Advanced Metering*, CRA INT'L 24, 27 (2006), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=898201.

33. To be clear, the concept of load-flattening is not new. The present-day issue has more to do with customers having more ability, and flexibility, to flatten their load *particularly* in contrast to certain customers that cannot shift their load. *See*, *e.g.*, Richard D. Cudahy & J. Robert Malko, *Electric Peak-Load Pricing: Madison Gas and Beyond*, 1976 WIS. L. REV. 47, 75 (1976).

34. Distributed generation has long been used in an attempt to offset wholesale electric charges – the previously predominant method mostly involving on-site internal combustion engines or gas turbines; *see, e.g.,* Matthew Christiansen & Ann Jaworski, *The Dark Side of DG: Addressing the Environmental Impacts of Dirty Distributed Generation*, 25 NYU ENV'T L. REV. 1, 4, 7, 10 (2016).

35. *See generally*, J. Neubauer & M. Simpson, *Deployment of Behind-The-Meter Energy Storage for Demand Charge Reduction*, NREL (2015), https://www.nrel.gov/docs/fy15osti/63162.pdf.

36. Travis Kavulla, *Why Is the Smart Grid So Dumb? Missing Incentives in Regulatory Policy for an Active Demand Side in the Electricity Sector*, ENERGY SYS. INTEGRATION GRP. 1, n.3 (2023), https://www.esig.energy/wp-content/uploads/2023/01/Why-Is-the-Smart-Grid-So-Dumb-Missing-Incentives-in-Regulatory-Policy-for-an-Active-Demand-Side-in-the-Electricity-Sector.pdf (citing Statement of Comm'r Robert F. Powelson, Pa. Pub. Util's Comm'n, Implementation of Act 129 of 2008 – Relating to Smart Meter Procurement and Installation (Jun. 18, 2009)).

37. It is worth acknowledging that the evolutionary arc is a slow but bendy one. Even in the context of retail wheeling, some of the prominent authorities around the moment of open access insisted that the electric power industry maintained enough natural monopoly characteristics to make it uneconomic to effectively unbundle the industry in the pursuit of competition. *See* Cudahy, *supra* note 1, at 358.

Compounding all of this uncertainty is the fact that ratemaking and rate design is *difficult*.[38] That difficulty necessitates a pit stop prior to getting into the meat of the inquiry; we must first set the stage and explain what a rate is and how rates have evolved. Stated differently, we need to figure out where we are and how we got here. We do so next.

II. FUNDAMENTALS OF RATES

The presentation of this policy conundrum begins with its first stop – rate design.[39] Boiled down to its essence, rate design is a sophisticated way of describing how a utility recovers the costs of providing a service.[40] In theory, rate design could be considered an arcane exercise devoted to adding (and subtracting) costs and then invoicing those costs to its customers – *theoretically*, as simple as arithmetic.[41] In reality, rate design is far more difficult and nuanced than simple arithmetic – not only is simple arithmetic not sufficient in such a capital-intensive industry, but rates are often the result of compromises (sometimes messy) made among parties with different, if not competing, interests and incentives.[42] Transmission is no exception, as one piece of equipment can be used to provide multiple

38. Pub. Serv. Comm'n of Ky. v. FERC, 397 F.3d 1004, 1006 (D.C. Cir. 2005) (quoting Time Warner Entm't Co. v. Fed. Commc'n Comm'n, 56 F.3d 151, 163 (D.C. Cir. 1995)) (first citing Ass'n of Oil Pipe Lines v. FERC, 83 F.3d 1424, 1431 (D.C. Cir. 1996); then citing Norwood v. FERC, 962 F.2d 20, 22 (D.C. Cir. 1992)) ("For our part, we have recognized that "agency ratemaking is far from an exact science," and that it involves 'complex industry analyses,' and '[i]ssues of rate design [that] are fairly technical.'"); Time Warner, 56 F.3d at 163 (For these reasons, and because ratemaking 'involves policy determinations in which the agency is acknowledged to have expertise, our review thereof is particularly deferential.").

39. The term "rate design" enjoys many definitions and characterizations. *See*, *e.g.*, David A. Lander, *Public Utility Rate Design: The Cost of Service Method of Pricing*, 19 ST. LOUIS UNIV. L.J. 36, 40-41 (1974) ("The basic principle of law involved in rate design is that the tariffs must be free from undue discrimination against customer classes. Discrimination is lawful as long as it is reasonable, but the standards for measuring reasonableness are vague.").

40. *See, e.g.,* Michael E. Small, *A FERC Electric Rate Primer,* 5 ENERGY L.J. 108 (1984) ("Cost allocation assigns a specific amount of demand, energy, and customer related costs to each customer class. The rates or the unit charges are then determined through a process called 'rate design.' In deriving the demand charge, the estimated billing demand for the class will be divided into the total demand costs assigned to the class. This will result in a $/kW demand charge. In deriving the energy charge, the estimated energy usage or kWh's for the class will be divided into the total energy dollars assigned to the class in order to derive the energy charge in $/kWh. In addition, the allocated customer costs will often be used to derive a customer charge."); *see also* D. Shields, *Rate Design and Building Decarbonization in California: The Essentials*, GRIDWORKS 1 (Sept. 18, 2019), https://gridworks.org/2019/09/rate-design-and-building-decarbonization-in-california-the-essentials/ (for an overview of the terminology related to rate design).

41. Lander, *supra* note 39, at 36-40.

42. *See, e.g.*, Mark C. Christie, *It's Time to Reconsider Single-Clearing Price Mechanisms U.S. Energy Markets*, 44 ENERGY L.J. 1, 4 (2023) (acknowledging a real world full of "conflicting policies and politics.").

services to a diverse universe of customers.[43] This negotiated effort – the proverbial tug-of-war between utilities and customers – is a decades old practice[44] that has, largely speaking, tried to adapt with the times. This adaptation has mostly come in the form of mere variants owing, at least in part, to the fact that the fundamental characteristics of the transmission system have not changed much either.[45]

Even so, efficient rate design sits somewhere in the spectrum between art and science.[46] Almost universally, the rate charged to a customer should be a reflection of the actual, steel-in-the-ground costs of providing that service along with a reasonable rate of return.[47] That's the science – there is a factual amount of costs incurred to provide the service. The art, however, of rate design is a far more nuanced way of allocating those real costs to different customer groups (often melding or fusing together well-established theoretical principles that drive rate design decisions).[48] Much like an artist blends colors together to negotiate a new color, rate design often blends competing interests[49] and objectives together to develop a rate that serves as a compromise among the negotiated interests.[50] As unique as each ratemaking canvas might aspire to be, the science often controls, as the utility has actual infrastructure costs that it needs to recover.

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43. As Alfred Kahn put it, "[w]hen . . . the products are truly joint, in that they can be economically produced only in foxed proportions, neither of them has a genuine, separate incremental cost function, as far as the joint part of their production process is concerned." ALFRED E. KAHN, THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS 79 (MIT Press Books 1988), https://utulsa.summon.serialssolutions.com/#!/search/document?ho=t&include.ft.matches=f&l=en&q=Alfred%20E.%20Kahn,%20The%20Economics%20of%20Regulation:%20Principles%20and%20Institutions&id=FETCHMERGED-utulsa_catalog_b151916552.

44. Valery Yakubovich et al., *Electric Charges: The social construction of rate systems*, 34 THEORY AND SOC'Y 579, 585 (2005).

45. As much as the fundamental characteristics have not changed, the underlying difficulty of calibrating demand charges is part and parcel of a larger issue associated with allocating the costs of jointly-used machinery. This machinery has also been described as, "[w]henever someone turns on her lights, a complex technological and regulatory apparatus allows electricity to flow instantaneously into her home." *See* Joshua C. Macey & Jackson Salovaara, *Rate Regulation Redux*, 168 UNIV. PA. L. REV. 1181, 1194 (2020).

46. Where exactly it falls within the spectrum is a bit of an open question, but it certainly does not reside at either bookend of the extremes; "ratemaking . . . is not a science." *See* Bos. Edison Co. v. FERC, 885 F.2d 962, 969-70 (1st Cir. 1989).

47. Traditionally, costs on a network are allocated "when demand is at its zenith" – or the so-called system peak. The revenue pie is divided among the different customers based on their usage of the system at the time of system peak. *See* Cogeneration Ass'n of Cal. v. FERC, 525 F.3d 1279, 1281 (2008).

48. While this article discusses, at possibly too great a length, the many economic principles and theories underlying rate design, one of the first principles in setting just and reasonable rates is to ensure that, effectively, the regulated rate serves as a substitute for an otherwise competitive product. *See, e.g.*, William R. Hughes & George R. Hall, *Substituting Competition for Regulation*, 11 ENERGY L.J. 243, 244 (1990).

49. *See, e.g.*, J. A. Nordin, *Allocating Demand Costs*, J. LAND & PUB. UTIL. ECON. 163, 163 (1946) ("There are two objectives in allocating an electric power plant's demand costs among its customers. The first is to improve the system consumption pattern, and the second is to do justice among customers.").

50. At the most basic level, these interests are fairly simple in nature – a consumer of a product wants to pay as little as possible whereas a producer of that product wants to sell it for as high of a price as possible. The competing objectives, as they relate to electric transmission, increase exponentially from there. The courts have not only acknowledged the presence of competing objectives, but the complexity requiring the Commission making "on balance" determinations that weigh and balance competing policy goals. *See, e.g.*, Sacramento Mun. Util. Dist. v. FERC, 616 F.3d 520, 541-42 (D.C. Cir. 2010).

While the end-result of ratemaking is a fairly straight-forward one (e.g., the utility "just" needs to recover enough of its costs to do business), the objective function is considerably more complex. A rate must not only provide the utility with sufficient revenues, but must also, for example, send appropriate signals to the customer, fit within accepted regulatory frameworks, and thread the needle between backwards-looking recovery and forward-looking investments.[51] Most rates are a patchwork of quirky compromises reached along the way between utilities and customers, memorialized by regulators – these compromises do not necessarily lend themselves to mathematical precision, but instead, reflect the complexity of negotiating between competing objectives.[52]

Although each rate is an attempt to strike some balance between the respective interests of the utility and customer, rates are also premised on recovering the total cost of providing electric service. Generally, this encompasses two types of costs – variable energy costs and fixed plant costs.[53] The subject of this article rests on how utilities recover the latter category – the fixed costs of the system,[54] which is often used interchangeably with the phrase demand costs, and "has made a nightmare of utility cost analysis."[55]

At the most basic level, modern day rate design in wholesale electric markets appears to be almost entirely premised on the notion of a "thermal" system[56] used to meet demand at its zenith. However, as technologies emerge and evolve, as they are currently,[57] it may not be terribly long before we see a change not just to the thermal nature of the system, but to a fundamentally different way in which

51. Lander, *supra* note 39, at 40.

52. *See generally Sacramento Mun. Util. Dist.*, *supra* note 50.

53. It's worth acknowledging that, as indicated in Bonbright, treating energy costs as an entirely separate cost function suffers from the shortcoming that the costs of producing any amount of energy is not independent of the costs related to a system's capability (demand costs). *See* JAMES C. BONBRIGHT, PRINCIPLES OF PUBLIC UTILITY RATES 349-50 (Colum. Univ. Press 1961), https://www.raponline.org/wp-content/uploads/2016/05/powellgoldstein-bonbright-principlesofpublicutilityrates-1960-10-10.pdf.

54. As a point of clarification, there is a fair degree of controversy surrounding whether there should be a separate charge for demand costs. On the retail side of the meter, many homeowners in the United States, as an example, pay for the fixed costs of the distribution system through a volumetric rate. The subject of this article is focused entirely on wholesale transmission costs and while some of the principles very well may apply to the retail side of the equation, the discussion is narrowly confined to considering the future use and value of demand charges in the wholesale context.

55. BONBRIGHT, *supra* note 53, at 350, n.10. Curiously, Bonbright cited both domestic and international journals as the foundation for that statement, suggesting that, even 70 years after the so-called "discovery" of demand charges, their use was still being debated almost universally.

56. *See, e.g.*, Winmill, *supra* note 31, at 203 ("[T]he electric industry 'gradually converged around gigawatt-scale thermal power plants located far from urban centers."). (The notion of a thermal system, at the risk of providing an overly simplistic worldview, is embedded as the peaking units identified by RTOs and ISOs when they design their demand curve are fossil-fueled generators. This makes sense for a number of reasons, but it exemplifies the "thermal" nature of the system. To the author's knowledge, we have yet to see a different technology (renewable, storage, or otherwise) serve as the reference peaking unit. For example, ISO-NE used a simple-cycle combustion turbine as its peaking unit when it considered its demand curve parameters for its Forward Capacity Auctions). *ISO New England Inc.*, 175 FERC ¶ 61,172 at P 17 (2021).

57. *See, e.g.*, Amandeep Kaur, *Batteries + Storage: Implications Integrating Battery Energy Storage System into Renewable Energy Power Purchase Agreements*, 7 OIL & GAS, NATURAL RES. ENERGY L.J. 911 (2022).

the system is used.[58] As this article aims to address, this changing landscape frustrates an already fragile framework, as the exercise of slicing the fixed-cost pie already presents "theoretical and practical problems"[59] and the frustrations will only continue as the industry slowly transitions.

III. UNDERSTANDING DEMAND COSTS

It is fair to ask how we got here – the answer is pretty surprising, actually. The origin of demand cost allocation goes back to Christmas vacation – no, not the Clark Griswold version of *Christmas Vacation* (that would make this entire exercise a lot less dry) – of 1894. So the story goes, the pricing at issue in this article has origins dating back to a Christmas vacation in 1894, where Samuel Insull (yes, *that* Samuel Insull)[60] and an engineer named Arthur Wright essentially envisioned the concept of having two distinct elements to the provision of electric service – the fixed costs element (i.e., the infrastructure) and the variable costs (i.e., operating costs, fuel costs, and so forth).[61]

The industry struggled in the 1890s with many of the same issues confronting us today.[62] At that time, there were two prominent working theories of pricing: the so-called "Wright" system (e.g., demand charges) and the so-called "Barstow" system (e.g., time-of-use charges). The Wright system emerged as the prevailing rate and one that is embodied and embedded in a wide variety of tariffs today.[63] Although the pricing theories were developed in the late 1800s, it took another

58. *See generally* Richard L. Revesz & Burcin Unel, *Managing the Future of the Electricity Grid: Distributed Generation and Net Metering*, 41 HARV. ENV'T L. REV. 43 (2017).

59. Cities of Batavia v. FERC, 672 F.2d 64, 80 (D.C. Cir. 1982). In its opinion, the court explained that, because each utility is uniquely structured, the Commission has endorsed a flexible approach, as no single method of cost allocation is considered appropriate for all systems. The court acknowledged the difficulty of the task, citing Bonbright in the process.

60. Many credit Insull as being responsible for the electric industry as it is constructed and designed today (including, relevant here, the presence of demand charges). *See, e.g.*, Richard D. Cudahy & William D. Henderson, *From Insull to Enron: Corporate (Re)Regulation after Rise and Fall Two Energy Icons*, 26 ENERGY L.J. 35 (2005); *see generally* Macey & Salovaara, *supra* note 45.

61. Arthur Wright, *Some Principles Underlying the Profitable Sale of Electricity*, 31 PROC. INST. ELEC. ENG'R 155 (1902).

62. Winmill, *supra* note 31, at 203 ("[I]n the 19th and early 20th centuries, most electricity was produced in close proximity to where it was ultimately consumed.").

63. Demand charges are by no means uniform and, rather, come in many shapes, sizes, and varieties. *See, e.g.*, Order on Initial Decision, *Idaho Power Co.*, 126 FERC ¶ 61,044 at P 50 (2009) (citing *Ariz. Pub. Serv. Co.*, 23 FERC ¶ 61,419 at p. 61,931 (1983)), *aff'd* sub nom; Papago Tribal Util. Auth. v. FERC, 773 F.2d 1056 (9th Cir. 1985); *Commonwealth Edison Co.*, 15 FERC ¶ 63,048 (1981), *aff'd* in relevant part, 23 FERC ¶ 61,219, at p. 61,473, n.18 (1983); *Kan. Gas & Elec. Co.*, 28 FERC ¶ 63,004, at p. 65,015 (1984), *aff'd* in relevant part, 31 FERC ¶ 61,012, at p. 61,023 (1985); *Fla. Power & Light Co*., 66 FERC ¶ 61,227, at p. 61,529 (1994); 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*, 61 Fed. Reg. 21,540 (1996) (codified at 18 C.F.R. pts 35, 385); *see also Ind. & Mich. Elec. Co.*, 4 FERC ¶ 63,010 at p. 65,076-77 (1977), *settlement approved*, 4 FERC ¶ 62,007 (1978); *Pub. Serv. Co. of N.M.*, 10 FERC ¶ 63,020, at p. 65,130 (1980), *settlement approved*, 14 FERC ¶ 61,087 (1981)). *See also* Small, *supra* note 40, at 135 ("The allocation of demand costs is a complex and often litigated issue. Issues that are usually litigated include: (1) which coincident peak demand allocation method (1 CP, 3 CP, 4 CP, or 12 CP) should be adopted; (2) whether the numerator and/or denominator (total system demands) in the demand allocator have been properly projected; and (3) whether transmission costs should be rolled-in and allocated on the same basis.").

twenty to thirty years prior to being realized in the United States. Wright's theories were eventually adopted and implemented by an engineer named John Hopkinson – giving rise, as we'll get to later, the idea of a two-part rate.[64] Under his theory, Hopkinson advocated for fixed charges because electricity could not be stored and therefore the utility was required to produce and supply, instantaneously, whenever and whatever the customer demands.[65]

The pricing dilemma then centered on the uncertainty about the efficiency and fairness of specific pricing policies that limited the key actors' ability to rationally choose the optimal scheme.[66] For that reason, early ratemaking methodologies were developed pragmatically rather than theoretically – in 1881, Thomas Edison designed what we'd deem a "contract system," which appears to have been the first-of-its-kind fixed charge per lamp installed.[67] To the author, this looks and feels awfully like the way point-to-point transmission is priced (largely speaking, on a reservation basis).

So the theory goes, central station managers, in the late 1800s, justified pricing schemes with the "rhetoric of economic efficiency" but an after-the-fact analysis revealed that the justifications had little to do with strategic thinking and more to do with actors behaving myopically.[68] Accompanying this theory is a pretty significant strand of research suggesting that pricing is a little less about economic theory and a little more sociological[69] (meaning, in plainer terms, that "money prices are the product of conflicts of interest and compromises").[70]

Our inquiry into demand costs, and thus demand charges, continues on, moving next to a fairly oversimplified explanation of demand costs and how they are allocated.[71] As a practical matter, in order to recover any costs, utilities must have

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64. *See* Michael R. Veall, *Industrial electricity demand and the Hopkinson rate: an application of the extreme value distribution,* 14 BELL J. ECON. 427, 427 (1983) ("The Hopkinson rate consists of an energy charge for total kilowatt hour consumption plus an additional demand charge based on the maximum usage by the plant during any quarter-hour period.").

65. The authors go on to explain that the rationale for demand charges – or at least the idea of a "standby" rate is that service starts as soon as the equipment is ready to operate, not when the actual consumption occurs. Yakubovich, *supra* note 44, at 588 ("Charges for fixed costs . . . were assessed according to 'connected load' – the amount of equipment that the customer had connected.").

66. *Id.* at 585; the authors also argue that "if the Insull circle had not succeeded politically in dominating both trade groups, the industry would have developed in much less homogenous ways." *Id*. at 592.

67. *Id.* at 586.

68. Yakubovich, *supra* note 44, at 581.

69. *Id.* at 583 ("We distinguish between outcomes and institutions. Prices are . . . an 'outcome,' emerging from the aggregation of transactions; what is 'institutional' is not the prices themselves, but the rules, norms, habits, and conventions underlying and supporting them.").

70. MAX WEBER, ECONOMY AND SOCIETY: AN OUTLINE OF INTERPRETATIVE SOCIOLOGY 1 (Univ. of Cal. Press new ed. 1968). The author of that article went on to articulate that prices also result "from power constellations" and that the "price system is a struggle of man against man" with prices being expressions of the struggle.

71. As Bonbright phrased it, the problem with demand charges is "that of imputing joint costs to joint products or by-products, and not merely that of distributing those common but non joint costs which vary more or less continuously with number of consumers or with rates of output. Here, . . . there is no general agreement as to what items or portions of total costs should be included among the demand-related costs, perhaps because cost functions are far too complex to be reflected by the arbitrary, three-way classification of customer, energy, and demand." BONBRIGHT, *supra* note 53, at 350.

on file a tariff that enables the utility to recover those costs.[72] Therefore, rate filings, and by extension the tariffs on file, must feature a method, or mechanism, through which customers are allocated the fixed costs of the system.[73] Based on several decades of literature, coupled with several decades of practice, the predominant means of allocating demand costs steadies itself upon the concept "coincident peak."[74] Coincident peak,[75] simply, reflects a customer's peak as it coincides with the utility's peak – stated slightly differently, what coincident peak tries to do is understand how much of the system a customer is using when the system is demanded the most.[76] The utility uses this information (e.g., what is the peak and who is using the system at the time of system peak) to build out its system. From there, the utility can then allocate the costs of its system to customers on a proportional basis. The utility often will identify a specific period of time when demand for electricity is at its highest (presumably either during the hottest days of the summer, the coldest days of the winter, or some combination of both).

Why is the demand charge so important? The demand charge is critical because it needs to be designed in a way that enables the utility to collect enough revenue to be reimbursed for upgrading and maintaining the system to meet peak demand, whenever that moment comes (i.e., standing ready).[77] Allocating demand costs requires the utility to allocate the cost of infrastructure that is common to

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72. Roughly speaking, Order No. 888 carved into stone the idea that public utilities must have tariffs on file that provide two basic transmission services-network and point-to-point. As part of that effort to memorialize and standardize a minimum suite of rules and practices surrounding transmission service, the Commission also explained that utilities may stray or deviate from this minimum threshold, only so long as the utility can demonstrate that those terms are consistent with or superior to the minimum standard. For a fuller, more in-depth discussion of open access, *see, e.g.*, Cynthia A. Marlette, *FERC Open Access Transmission Rule and Utility Bypass Cases*, 37 NAT. RES. J. 125 (1997).

73. Arguably, the objective function with any pricing methodology should be to induce or mimic what would otherwise look like a competitive outcome. The transmission pricing methods approved by the Commission represent the means of accomplishing the objective function and "translating" transmission costs into transmission charges. *See, e.g.*, Baseem Khan & Ganga Agnihotri, *A Comprehensive Review of Embedded Transmission Pricing Methods Based on Power Flow Tracing Technology*, CHINESE J. ENG'G 1 (2013).

74. In an order from 2013, the Commission explained that it "typically allocates demand costs using a [coincident peak] method, through which demand costs are allocated based on each customer class's load at the time of (or coincident with) the system peak load." *Sw. Pub. Serv. Co.,* 144 FERC ¶ 61,133 at P 2 (2013).

75. Under a coincident peak construct, the utility will determine the hour of the year that system-wide usage was at the highest level. From there, the utility will measure each customer's relative usage of the system at that same time (i.e., the *coincident* peak) to determine the customer's contribution to the total system peak compared to other customers. This contribution serves as the basis for the demand charges. The Commission has also defined coincident peak as "the customer's usage of the transmission system at the time of the transmission provider's maximum (i.e., 'peak') demand, while a transmission customer's 'usage' is its scheduled demands. Coincident peak demands are calculated monthly, and their average over the course of a 12-month period is known as the transmission customer's '12 coincident peak demands.'" See *Idaho Power Co.,* 137 FERC ¶ 61,235 at P 7, n.14 (2011).

76. The Commission has a long history of approving the use of coincident peak as a demand allocator. Even rarer, however, are the instances in which the Commission did not rely on coincident peak to determine a demand charge. *See, e.g.*, *Houlton v. Me. Pub. Serv. Co.,* 62 FERC ¶ 63,023, at p. 65,092 (1993).

77. *See, e.g*, KAHN, *supra* note 43, at 95 ("[T]he demand or capacity charge – is a charge for the utility's readiness to serve, on demand. This readiness to serve is made possible by the installation of capacity: the demand charge, therefore, distributes the costs of providing the capacity—the fixed, capital costs—on the basis of the respective causal responsibilities of various buyers for them.").

multiple customers, customers, and uses.[78] Though this method comes with certain warts, as we will discuss, this rate design is battle-tested, has withstood the test of time, and is often scrutinized yet almost always sustained.[79]

Though demand charges were largely a feature of requirements contracts, they are not just a vestige of the past but instead a centerpiece of modern-day tariffs. In fact, demand charges are as common in the United States as baseball and fireworks in July.[80] Not only are they prominently featured in the tariffs of vertically integrated utilities, but they're also featured in RTO/ISO tariffs – for example, both the PJM and ISO-New England tariffs utilize coincident peak to allocate transmission costs within their regions.[81] In PJM, each transmission owner is given its "slice of the pie" and then the utility allocates that pie within its service territory. All of the transmission owners utilize the coincident peak method, with the only variance being the number of peaks used.[82] Though slightly different in New England, as the transmission owners have separate rates for "Regional" versus "Local" transmission service, the costs of the regional system are allocated using the coincident peak demand allocator.[83]

While some of these issues feel new and shiny, it's not clear that the crossroads the industry finds itself is necessarily unchartered territory. In the years leading up to Order No. 888,[84] utilities, regulators, and customers alike were confronted with the challenge of identifying new pricing paradigms as the industry was evolving from the vertically integrated "bundled product" utility model to a functionally unbundled one. The question seems less a matter of whether we will need to adapt, but instead, how and when.

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78. BONBRIGHT, *supra* note 53, at 350 (citing "[h]ere, as with the other two categories of cost, there is no general agreement as to what items or portions of total costs should be included among the demand-related costs, perhaps because cost functions are far too complex to be reflected by the arbitrary, three-way classification of customer, energy, and demand."); *see also id.* at 354 (citing "[b]ut what, then, makes capacity cost allocation or apportionment such a highly controversial problem? The answer lies in the fact that capacity costs, instead of being ordinary overhead costs, common to different kinds of amounts of service, are *joint* costs-the costs of producing services which are joint products when they are rendered at different periods of time.").

79. The Commission has expressed its general policy as allocating "demand costs on the basis of peak responsibility as is demonstrated by the overwhelming majority of decided cases." *See, e.g.*, 62 FERC ¶ 63,023, at 65,092.

80. *See, e.g.*, *Idaho Power Co*., 137 FERC ¶ 61,235 (2011); *Entergy Ark., Inc.,* 171 FERC ¶ 61,037 (2020); *S. Co. Services, Inc*., 129 FERC ¶ 61,253 (2009); *Pac. Gas and Elec. Co.*, 113 FERC ¶ 61,084 (2005); *New England Power Co.,* 52 FERC ¶ 61, 090 (1990); *Cleco Power,* 139 FERC ¶ 61,166 (2012); *N. States Power Co.,* 143 FERC ¶ 61,220 (2013); *see also* Small *supra* note 40, at 135.

81. It is worth acknowledging that, in PJM as an example, the tariff allocates generation capacity costs, as well, on the basis of five coincidental peaks in order to calculate the Peak Load Contributions (PLC) and Network Service Peak Load (NSPL). *See, e.g.*, *PJM Manual 27: Open Access Transmission of Tariff Accounting*, PJM 29 (2023), https://www.pjm.com/-/media/documents/manuals/m27-redline.ashx.

82. *See, e.g.*, *eTariff – Tariff Browser*, FERC, https://etariff.ferc.gov/TariffBrowser.aspx?tid=1731 (last visited Nov. 1, 2023) (The Attachment M-2s are used to allocate demand costs within the respective transmission owner zones).

83. *See, e.g.*, ISO-New England's Internal Market Monitor, *Spring 2020 Quarterly Markets Report*, ISO-NE 17 (Aug. 17, 2020), https://www.iso-ne.com/static-assets/documents/2020/07/2020-spring-quarterly-markets-report.pdf.

84. *See generally* Order No. 888, *supra* note 63.

IV. ECONOMIC THEORY, AS IT APPLIES TO DEMAND CHARGES

From a theoretical perspective, there are three dominant, classical methods of pricing—marginal cost, incremental cost, and embedded cost. Marginal cost studies look at the cost of building a new utility system[85] and are more difficult to determine than incremental cost and embedded cost, both of which are methods anchored by the costs of the existing system.[86] Whereas embedded cost is essentially a "slice of the system," incremental cost represents what it would take to build onto the existing system to accommodate the new service. Because of their simplicity and relative efficiency, incremental costs and embedded costs are two dominant methods for cost allocation.[87]

As it relates to demand costs, as we touched on briefly, the idea of coincident peak allocation has origins that date back to the so-called "Hopkinson-type" rate schedule (with a specific emphasis on the provision of a two-part rate).[88] The first part of the rate consists of the energy charge (e.g., the variable costs of providing the service).[89] The second part of the rate, the subject of this Article, is the demand charge that seeks to recover the fixed capacity costs of the system.[90] While the variable costs – being driven mostly by fuel costs – are easier to calculate and identify, a customer's use of the system, and the system's capacity, is not as easily calculated or determined.

Notwithstanding the difficulty of the task, nearly every earnest inquiry into pricing starts with the question of how to align prices with the costs being charged.[91] Although it is not necessarily the industry standard, the use of marginal cost pricing has long been considered the preferred approach. Considered a bedrock principle by the prominent authorities on the matter, using marginal costs as a gravitational anchor gives the utility the appropriate investment decisions and the customer the appropriate usage decisions.[92] The argument for marginal costs

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85. Jim Lazar, *Dividing the Pie: Cost Allocation, the First Step in the Rate Design Process*, REGUL. ASSISTANCE PROJECT A-2 (2015), https://www.raponline.org/wp-content/uploads/2016/05/appendix-a-smart-rate-design-2015-aug-31.pdf.

86. The Commission has long touted the benefits of incremental cost pricing, acknowledging that "customers must face prices that reflect their supplier's incremental costs in order for them to make efficient investment decisions and efficient choices when seeking alternative supply sources." *Norwood*, *supra* note 38, at 23.

87. The Commission has a historical preference for the use of embedded, rolled-in costs. *See, e.g.*, *S. Co. Sers., Inc.*, 116 FERC ¶ 61,247 at P 17 (2006) ("Rolled-in pricing is appropriate when the relevant facilities are integrated into the transmission network. This pricing is appropriate because it spreads the cost of network facilities across the entire network; as part of the network, the added facilities benefit all users of the network and thus their costs should be shared among all users of the network. In contrast, rolling in facilities not integrated with the network inappropriately forces all users to subsidize facilities that benefit only one user.").

88. *See, e.g.*, Alfred Lewis, *Two-Part Tariff*, 8 ECONOMICA 249, 251 (1941).

89. *See, e.g.*, KAHN, *supra* note 43, at 65 (defining marginal costs as "producing one more unit; it can equally be envisioned as the cost that would be saved by producing one less unit.").

90. Nordin, *supra* note 49, at 164 ("Capacity is to be understood as fixed equipment used in production, and it is to be measured in terms of the number of KW of demand that can be satisfied.").

91. There is, of course, a give-and-take between the notion that prices should align with costs, but also that prices align with competitive forces. *See, e.g.*, Harvey L. Reiter, *Competition between Public and Private Distributors in a Restructured Power Industry*, 19 ENERGY L.J. 333, 338 (1998).

92. For example, one of the leading authorities argued that "marginal cost must play a major and even a dominant role in the elaboration of any scheme of rates or prices that seriously pretends to have as a major motive the efficient utilization of available resources and facilities." William Vickrey, *Some Implications of Marginal*

is fairly well-known at this point.[93] That said, the theoretically pristine model – or idea – of marginal cost pricing may not easily translate to a highly capital-intensive industry like the electric industry.[94] For starters, marginal cost pricing may be difficult to apply because, given the totality of the fixed expenditures, the marginal cost of a kilowatt of electricity can be less than the average cost, which could lead to losses.[95] It's also entirely possible that long-run marginal cost pricing could result in something resembling monopoly pricing[96] – hence what amounts to a cap at embedded cost. That dynamic could very well be why marginal cost pricing feels more mythical – a unicorn of sorts – than realistic and practical.

As desirable as marginal cost pricing may be, two related items on the menu – embedded cost pricing and load-ratio pricing – are the most frequently ordered.[97] While load-ratio pricing can take many forms, embedded cost pricing takes more of a historical approach to developing rate design. Embedded cost pricing, broadly speaking, is a little more in line with the idea that the utility has sunk costs that it has incurred as part of trying to provide service at some point in the future. With respect to demand allocation, the answer is almost always a reflection of slicing and dicing historical, embedded costs among the different users of the system. Although these costs are essentially sunk, it is these (slowly depreciating) investments that the utility must be reimbursed for in order to continue providing service. To a large extent, these costs were incurred to provide service for years, and even decades, into the future. However, the price signal being sent – a price signal that focuses on past investments – does not necessarily align well with either future customer uses (or usage) and the investments necessary to serve those customers. Is this necessarily indicative of a problem? No, not necessarily – this speaks directly to the concept of how ratemaking is part science, part art and the difficulty of allocating costs in such a capital-intensive industry.

Cost Pricing for Public Utilities, 45 AM. ECON. ASS'N, 605, 605 (1955), *reprinted in* JAMES C. BONBRIGHT ET AL., *supra* note 53, at ch. 17.

93. *Electric Utility Cost Allocation Manual*, NARUC 147 (1992), https://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD (citing "Major reason for allocating costs using marginal cost principles is to promote economic efficiency and societal welfare by simulating the pricing structure and resulting resource allocation of a competitive market.").

94. As a related point, theory alone does not control. The court remanded a matter back to the Commission for reconsideration because, in the court's view, the Commission relied too narrowly on the theory of marginal cost pricing. The court found that the "mere invocation" of the theory was an insufficient substitute for substantial evidence and reasoned explanations, particularly where the theory had been "severely compromised by the revenue constraint." Elec. Consumers Res. Council v. FERC, 747 F.2d 1511, 1513-17 (D.C. Cir. 1984).

95. STEPHEN BROWN AND DAVID SIBLEY, THE THEORY OF PUBLIC UTILITY PRICING 34-37 (Cambridge Univ. Press 1986); *see also*, Severin Borenstein, *The Economics of Fixed Recovery by Utilities.*, 29 ELEC. J. 5 (2016) (citing "[e]conomics provides policymakers guidance when they must depart from efficient pricing (equal to societal marginal cost) to cover an electric utility profit shortfall.").

96. Economic theory suggests that a monopolistic firm will maximize profits by aligning marginal revenue and marginal costs. *See, e.g.*, Herbert Hovenkamp, *Antitrust's Protected Classes*, 88 MICH. L. REV. 1, 3 (1989) (standing, roughly speaking, for the proposition that, in perfect competition, a firm will set price equal to marginal cost, but in the context of a monopoly, the firm will find the point at which marginal cost equals marginal revenue). *See also* James I. Serota, *Monopoly Pricing in Time Shortage*, 33 LOY. U. CHI. L. J. 791, 795 (2002).

97. Load-ratio pricing refers to the idea that customers of the transmission system pay on the basis of the ratio of its load to the transmission provider's entire load on its system. *See, e.g.*, Fla. Mun. Power Agency v FERC, 315 F.3d 362 (D.C. Cir. 2003).

At its core, these two concepts represent the sturdy, fundamental pillars of electric pricing. Moreover, these two concepts effectively embody the objective underlying peak pricing (i.e., how to allocate the embedded costs of the system to each of the users of the system on a proportional basis). Under "peak pricing," the peak price is levied on a customer's entire consumption during a specific moment in time (again, the concept of a load ratio share).[98] The "peanut butter and jelly" of assigning capacity costs – or demand costs – is on the basis of coincident peaks.[99] Under a coincident peak pricing approach, demand costs are allocated based on the customer's usage of the utility's system during the coincident peak (or, as is the case in many instances, *peaks*).[100] One of the more common methods is known as the "12-CP" coincident peak.[101] Under this method, demand costs are allocated by taking the hour of highest total usage (the coincident peak) during each of the preceding twelve months, determining the percentage of peak usage drawn by each customer class during each of the twelve months, and averaging the resulting percentages for each customer class.[102]

The emphasis on good rate design is one that seeks to balance, offset, or optimize the different incentives at issue. Inherent in any rate design choice will be decisions on how to balance competing objectives and incentives among the utility and its customers.[103] Using the 1-CP methodology as an example, for a moment, we can quickly identify the push and pull involved with this particular rate design. While the 1-CP methodology makes sense, rationally, for the utility to base its rates (i.e., a rate based on the highest, coincident usage on its system), that methodology only provides a meaningful incentive shave load during the peak moment.[104] And while that peak-shaving is desirable from a reliability perspective, peak-shaving does not occur in a vacuum.[105] When the Commission accepted Do-

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98. *Id.*

99. *See* Small*, supra* note 40, at 135 (citing "Demand costs are generally allocated in proportion to a customer's load coincident with the system peak load."). The author goes on to explain that the Commission does not necessarily have a set policy, but instead relies on a host of factors that, collectively, attempt to account for a full range of the utility's operating realities.

100. *Id.*

101. *See, e.g.,* Order No. 888 at 21,599 (citing "We are reaffirming the use of a twelve monthly coincident peak (12 CP) allocation method because we believe the majority of utilities plan their systems to meet their twelve monthly peaks.").

102. Second Taxing Dist. Of Norwalk v. FERC, 683 F.2d 477, 480 (D.C. Cir. 1982).

103. There is, at the heart of the matter, an issue of competing incentives that is pretty difficult to balance. *See, e.g.*, Joel B. Eisen, *Demand Response's Three Generations: Market Pathways and Challenges in the Modern Electric Grid*, 18 N.C. J. OF L. & TECH. 351, 358 (2017) ("There is no organic demand for using less electricity. Progress to more demand-side participation . . . can be derailed by those adversely affected by incentives for demand response.").

104. Under a 1-CP method, the incentive to shave or manage load is muffled – if not lost altogether – during all other hours of the year.

105. Though we get into a full menu of ideas later, it was at this point in drafting that the author wondered whether, in an attempt to align the different incentives, there should be a "standard" demand charge based on average usage throughout a year, with a "plus or minus" penalty or bonus for either shaving load or exceeding your baseline average. *See, e.g.*, Nordin, *supra* note 49, at 163-64 ("[T]he influence of the schedule should be directed toward inducing customers to move consumption from the station peaks to the station troughs. Therefore, hourly demand cost rates should vary directly with the amount of the hourly demand.").

minion's proposal to move from a 1-CP method to a 12-CP method, the Commission was forced to address concerns that the proposal reduced the customer's incentive, and ability, to peak shave.[106] The proposal was effectively being wedged between two competing policy objectives – the first, to promote efficient use of the system and the second, to promote fair and just pricing (so that one party is not subsidizing another).[107] The Commission navigated this dispute by finding that the load reductions at issue were "discretionary" as the load being shaved was not controllable by PJM and thus the utility had no way of avoiding costs (meaning that Dominion must build out its system to serve the customer's entire load, not its load net of any discretionary peak shaving).[108] This is an important theme that will come up again, soon, when we discuss how behind-the-meter generation has affected the demand charge dynamic.

V. Open Access & Pricing Around the Time of Order No. 888

Any discussion of transmission would be incomplete without a proper acknowledgement of Order No. 888, open access,[109] and the idea that you cannot modify transmission service without considering modifying the pricing associated with that service.[110] We start there – the pricing bit – first because there is a unique set of orders that continues to serve as the guardrails for subsequent pricing proposals.

Prior to the Commission's issuance of Order No. 888, the Commission was confronted with requests to resolve the tension between old and new.[111] The old way of pricing service – the bundled and vertically integrated kind – was not terribly compatible with the demand for new uses of the system (i.e., new incremental demands for either network or point-to-point transmission service). In a series of orders that changed the landscape of what pricing means under the open access

106. *PJM Interconnection et al.*, 172 FERC ¶ 61,054 at PP 42-43 (2020).

107. The concept of cross-subsidization is also referred to as a "rate tilt" – both of which aspire to explain when a customer's charge is out of alignment. *See, e.g.*, *Norwood*, *supra* note 38, at 25.

108. 172 FERC ¶ 61,054, at PP 65-68.

109. Open access was "designed to create a level playing field for new market-entrants who could piggyback on previously created infrastructure at competitive rates. These reforms, known as electricity deregulation or restructuring, promised consumers a true choice in their electricity provide and with it a new era of electricity competition." *See* Joseph P. Tomain, *Electricity and Ideology,* 7 J. ENERGY L. & POL'Y 315 (1986).

110. Order No. 888 has been referred to as the "single largest step" to introduce greater competition into wholesale markets. *See* Gregory N. Basheda et al., *FERC, Stranded Cost Recovery, and Municipalization*, 19 ENERGY L.J. 351, 351-52 (1998).

111. *See, e.g.*, Joshua Z. Rokach, *Transmission Pricing Under the Federal Power Act: Applying a Market Screen*, 14 ENERGY L. J. 95, 101-02 (1993) [hereinafter *Transmission Pricing Under FPA*].

paradigm,[112] the Commission set the stage for how the Commission would evaluate future pricing proposals.[113] These three orders, all issued prior to the Commission's landmark Order No. 888 ruling, would enable the Commission to proceed fearlessly with the "barrier-smashing" concept of open access.[114]

The first – *Northeast Utilities Service Company* – is where the Commission established three central principles in evaluating the justness and reasonableness of different pricing mechanisms.[115] These principles[116] are to: (1) hold native load customers harmless, (2) provide the lowest reasonable cost-based price to third-party firm transmission customers, and (3) prevent the collection of monopoly rents by transmission owners and promote efficient transmission decisions.[117]

Around the time same, the Commission issued another order that established yet another key principle that would soon become weaved into the fabric of modern-day pricing policy. This order – involving Pennsylvania Electric Company ("Penelec")[118] – established the "or" pricing policy, which has come to be understood that a utility can choose to charge one type of rate (e.g., embedded cost) or another (e.g., incremental cost), but not both. To put a little more color on the canvas, this order drastically changed the way we think about transmission pricing. The origin of the initial filing goes back to 1991 when Penelec entered into an agreement with a customer, Penntech Papers, Inc ("Penntech").[119] The agreement provided that Penntech would pay a rate that featured three core elements: 1) the embedded cost rate; 2) an "increased energy cost component" rate designed to compensate native load for lost savings, or opportunity cost; and 3) administrative

112. *See Ne. Utils. Serv. Co. (Re: Public Service Company of New Hampshire)*, 58 FERC ¶ 61,070 (1992), *reh'g denied*, 59 FERC ¶ 61,042 (1992), Order Granting Motion to Vacate and Dismissing Request For Reh'g, 59 FERC ¶ 61,089 (1992), *aff'd in part and remanded in part sub nom*; Ne. Utils. Serv. Co. v. FERC, 993 F.2d 937 (1st Cir. 1993), *order on remand*, 66 FERC ¶ 61,332 (1994), *reh'g denied*, 68 FERC ¶ 61,041 (1994) (1st Cir. Sept. 6, 1994); *Mass. Elec. Co.*, 58 FERC ¶ 61,278 (1992), *reh'g denied* and pricing policy clarified, 60 FERC ¶ 61,034 (1992), *reh'g denied*, 60 FERC ¶ 61,244 (1992), affirmed sub nom, Pa. Elec. Co. v. FERC, 11 F.3d 207 (D.C. Cir. 1993).

113. In Order No. 888, the Commission did not up-end, or even really touch for that matter, pricing for transmission service. As a practical matter, the Commission did not declare a singular just and reasonable approach to pricing in Order No. 888. Instead, the Commission acknowledged that such unbundling could not be implemented in a vacuum without understanding the impact that unbundling would have on pricing. Specifically, the Commission emphasized that the many "non-price" terms and conditions related to functional bundling could not be modified independent of pricing and cost recovery considerations. *See* Order No. 888, *supra* note 63, at 291.

114. Marlette, *supra* note 72, at 125.

115. Just and reasonable is defined under Federal Power Act (FPA) of 2018 at 16 U.S.C. § 824d(a) (2023); *see also* 16 U.S.C. § 824e(a) (2023); *see also*, Matthew R. Christiansen & Joshua C. Macey, *Long Live the Federal Power Act's Bright Line*, 134 HARV. L. REV. 1360, 1368, 1389, 1400 (2021).

116. "A principle is induced from a line of specific reasoned decisions and, once identified, becomes the major premise from which a conclusion may be deduced in the cause at hand." RUGGERO J. ALDISERT, LOGIC FOR LAWYERS: A GUIDE TO CLEAR LEGAL THINKING 33 (3rd ed. 1989).

117. These principles are fairly consistent with what it means to regulate a firm holding a natural monopoly. *See* STEPHEN G. BREYER, REGULATION AND ITS REFORM 15 (1982) ("[T]he most traditional and persistent rationale for government regulation of a firm's prices and profits is the existence of a 'natural monopoly.'").

118. *Pa. Elec. Co.*, 58 FERC ¶ 61,278 (1992), *reh'g denied* and pricing policy clarified, 60 FERC ¶ 61,034 (1992), *reh'g denied*, 60 FERC ¶ 61,244 (1992), *affirmed* sub nom; Pa. Elec. Co. v. FERC, 11 F.3d 207 (D.C. Cir. 1993).

119. *Pa. Elec. Co.*, 11 F.3d at 208.

and other costs.[120] While the customer was willing to pay the "and" rate at the time the parties executed the agreement, the Commission essentially rejected the agreement and expressly prohibited "and" pricing through this order (and ever since, of course). Relevant to the issues presented in this Article, this order represents the Commission's attempt of "right-sizing" pricing to costs.

Finally, the third musketeer, though possibly the mightiest of this batch of seminal orders is: *AEP*.[121] In *AEP*, the Commission established a "golden rule" of transmission access and transmission pricing, an articulation of a standard that would effectively become what's known as the "open access" requirement.[122] If anything, the "golden rule" established in *AEP* kicked down the door to open access, with the policy ossifying, officially, in Order No. 888.[123] It was in this case that the Commission was required to address whether access was considered open or not – in doing so, the Commission stated that an "open access tariff that is not unduly discriminatory or anticompetitive should offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's uses of its system."[124] In slightly less jargony terms, the "golden rule" means treating others as you would treat yourself (with such treatment serving as a binding, forcing mechanism for what might be considered a permissible pricing mechanism).[125] This concept of comparability, attended by the "golden rule" metaphor, bleeds directly into pricing, as a utility should charge itself in a manner that is comparable, if not the same, with what it would charge others.[126]

Building on the momentum of these three orders, the Commission decided to weave them together as the working, going-forward theories of transmission pricing, and announced the broad framework in the so-called "Transmission Pricing Policy Statement."[127] In essence, the policy statement codified all of the things the Commission was saying, but put them in one central location as a guidepost

120. *Id.* at 208-09.

121. *Am. Elec. Power Serv. Corp*., 67 FERC 61,168 (1994) ("*AEP*").

122. *Id.*

123. Harvey Reiter, *The Contrasting Policies of the FCC and FERC Regarding Importance of Open Transmission Networks in Downstream Competitive Markets.*, 57 FED. COMM. L.J. 243, 257 (2005).

124. *Am. Elec. Power Serv. Corp*., 67 FERC 61,168 (1994).

125. One of the issues of comparability includes a requirement that a utility must provide all services it can provide – not just the ones it provides itself. WILBUR C. EARLY, COMPETITION IN THE ELECTRIC INDUSTRY: EMERGING ISSUES, OPPORTUNITIES, AND RISKS FOR FACILITY OPERATORS (Nat'l Academies Press 1996).

126. The Commission further articulated this standard in a case that established the relationship between the price and quality of service (and establishing, in particular, the idea that a higher level of service costs more and therefore demands a higher rate). This concept was borne through the precedent established in *Fla. Mun. Power Agency v. Fla. Power & Light Co*., 67 FERC ¶ 61,167, at p. 61,482 (1994). As the author understands it, the fundamental elements of the golden rule include, first, the idea that cost must be allocated between customers in a consistent way – meaning that cost responsibility should be fairly equalized. Second, that when the utility uses its own transmission system to make off-system sales, it should do so at a price that it would otherwise charge third parties for that same service. Again, the theme of "right-sizing."

127. *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, Policy Statement,* FERC Stats. & Regs. ¶ 31,005 (1994), *clarified,* 71 FERC ¶ 61,195 (1995) [hereafter referred to as *Pricing Policy Statement*]; *see* 18 C.F.R. § 2.22(1994).

for the future pricing proposals.[128] The ideas the Commission shared back in 1994 sound awfully like the language we hear and use today – namely, the idea that, with the revenue requirement as a backstop, the Commission can approve a mechanism that allocates costs among customers in a manner commensurate with the costs they cause to be incurred.[129] That "roughly commensurate" standard is complemented by the notion that there is no single preferred or favored ratemaking method – a working legal standard that has been in effect for decades, well before any of these notable pricing orders.[130] This policy statement has not been updated in over 30 years, a testament first to the durability of the pricing mechanisms, but also a signal that – *maybe* – pricing mechanisms are due to be revisited to assess their continued durability at a time when the industry is undergoing another wave of significant change.

Pricing really followed everything else the Commission was thinking and doing at the time of Order No. 888 and open access. Open access, simply stated, fundamentally and forever changed the way customers interfaced with utilities and the ways in which those customers utilized the utility's system. Whereas customers were previously "bundled" entirely, the unbundling of transmission from generation forced the industry to develop new methods for pricing transmission usage. New rate designs were needed then to accommodate that transition (i.e., how do you price incremental transmission transactions). The Commission acknowledged as much in Order No. 888, when it espoused the need for innovative pricing that would need to keep pace to match the corresponding evolution of transmission service.[131] We find ourselves at a similar crossroads yet again, though the streets have changed and the lamp posts are solar powered.[132]

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128. *See* 18 C.F.R. § 2.22. In addition to the principles established in *Penelec, Northeast,* and *AEP*, the Commission grounded transmission pricing by clarifying that there exists an upper-bound on any pricing mechanism – the binding properties of the revenue requirement. The revenue requirement, roughly speaking, represents the total cost of service. Typically, the revenue requirement is developed based on a particular test year, often a 12-month period that is most representative of the actual costs of providing service. A cost-of-service study would assist in not only developing the requirement but then, more relevantly, understanding and determining how to design a rate that can recover the costs of providing service under the tariff. This one is a little bit more straight-forward than the first: the price for transmission should be based on the costs of providing that service (as a means of not recovering more than your costs).

129. FPC v. Hope Nat. Gas Co., 320 U.S. 591, 601 (1944). *Hope* still represents a certain flexibility in ratemaking practices in an attempt to allow an equitable exchange of value. *See also* James J. Hoecker, *Used and Useful: Autopsy of a Ratemaking Policy*, 8 ENERGY L.J. 303, 321, 324 (1987).

130. *See, e.g., Duquense Light Co. v. Barasch*, 488 U.S. 299, 316 (1989). Summing the parts together, it appears that the revenue requirement backstop continues to function as a means of preserving the regulatory compact and balancing act that customers pay a just and reasonable price and utility retains its ability to be appropriately and adequately compensated.

131. Order No. 888-A, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 62 Fed. Reg. 12,274, at p. 12,320 (1997) (to be codified at 18 C.F.R. part 35).

132. The need for innovation is probably stronger today than it was in the mid-90s. *See, e.g.*, Eisen*, supra* note 103, at 358 (holding that "Progress has always depended upon the presence of visionary state and federal regulators who see the need for innovation.").

That "pretty similar" crossroads the Commission found itself in 1994 constituted the push and pull between old and new.[133] Even though transmission was, and continues to be, considered a natural monopoly,[134] the gravitational pull of competition moved the industry towards open and competitive wholesale power markets.

How does this all relate to demand charges? For starters, the idea of demand charges is very much embodied in the *pro forma* tariff – the baseline or minimum standard for terms and conditions related to transmission service – adopted by the Commission.[135] The Commission, through Order No. 888, required that public utilities have on file a tariff that features network and point-to-point transmission services that third parties, as well as the utilities themselves, would take under the tariff.[136] The *pro forma* tariff offers two primary types of transmission service – network and point-to-point.[137] Under the network model, a customer's entire needs are served by the transmission provider.[138] Network service is the more flexible of the two services,[139] as the customer pays for what it uses of the system (load, often coincident, will determine the ultimate price for network service). In

133. It is certainly debatable regarding the "pace of play" with respect to regulatory innovation and evolution. In certain ways, the changes feel glacial, while in other ways, the pace feels rapid. *See* Joseph T. Kelliher & Maria Farinella, *The Changing Landscape of Federal Energy Law*, 61 ADMIN L. REV. 611, 612 (2009).

134. *See* Sidharth Sinha, *Introducing Competition in the Power Sector: Open Access and Cross Subsidies*, 40 ECON. AND POL. WEEKLY 631, 631 (2005).

135. *Preventing Undue Discrimination and Preference in Transmission Service*, 123 FERC ¶ 61,299 at P 173.

136. Using ISO-NE and its tariff as an example, "Regional Network Service" is considered the network transmission product. The customer pays a monthly transmission rate that features geographical attributes (in that the monthly transmission rate is based on the load of the local network. The local network, in this example, is considered the transmission facilities of the transmission owner in that particular zone or area. ISO-NE takes these revenues and allocates them among the transmission owners under Schedule 9 of its tariff. Under that section of the tariff, the rate for Regional Network Service is developed by combining the revenue requirements of the individual transmission owners' revenue requirements. *See, e.g.,* EARLY, *supra* note 125, at 10.

137. *Id*. at 10. A brief review of different tariffs reveals that these constructs are largely enshrined in the tariffs of different RTOs and ISOs, though in different ways. *See also Sw. Power Pool,* 149 FERC ¶ 61,113 (2014); *ISO New England Inc*., 178 FERC ¶ 61,086 (2022); *Midcontinent Indep. Sys. Operator, Inc.,* 180 FERC ¶ 61,141 (2022); and *California Independent System Operator Corp.,* 111 FERC ¶ 61,337 (2005).

138. The transmission customer is able to utilize the transmission provider's systems to serve all of its needs (through the process of designating network load and network resources). The Commission defined network service as permitting "a transmission customer to integrate and economically dispatch its resources to serve its load in a manner comparable to the way that the transmission provider uses the transmission system to integrate its generating resources to serve its native load. Because network service is load based, it is reasonable to allocate costs on the basis of load for purposes of pricing network service. This method is familiar to all utilities, is based on readily available data, and will quickly advance the industry on the path to nondiscrimination." Order No. 888-A, *supra* note 131, at 296.

139. *See* Fla. Mun. Power Agency v. FERC, 411 F.3d 287 (D.C. Cir. 2005) (first citing "[n]etwork service permits a utility company using another utility's transmission system to fully integrate load [*i.e.,* the aggregate demand for service on the system at any given time,] and resources on an instantaneous basis in a manner similar to the transmission owner's integration of its own load and resources.") (then citing "We recognized in TAPS that 'network service, as the Commission defined it, means that network customers can call upon the transmission provider to supply not just some, but all of their load at any given moment, when for instance they experience blackouts or brownouts.'"). *See also* Transmission Access Pol'y Study Grp. v. FERC, 225 F.3d 667, 724-25 (D.C. Cir. 2000), *aff'd sub nom.* New York v. FERC, 535 U.S. 1, (2002).

other words, pricing for network service is based on a tried-and-true basis of load-ratio pricing.[140]

As is most relevant to the issues raised here, the Commission outlined in Order No. 888 its policy on whether, and how, a customer could use its own resources to offset its peak demand.[141] More specifically, in Order No. 888, the Commission found that the definition of Network Load would not allow a customer to leverage behind-the-meter resources to lower its peak demand.[142] The Commission went on to re-affirm this policy in Order No. 890, but explained that it would review deviations, or exceptions, to this policy on a case-by-case basis.[143]

Meanwhile, point-to-point transmission service is the less-flexible of the two products, but by far, the most predictable. This approach is based on the contract-path model of transmission service.[144] Contract path pricing is a remarkably efficient method for pricing transmission as, for pricing purposes, the rate for a "contract path" is premised on the costs of providing service along the path – customers pay for service from designated points of receipt to designated points of delivery.[145] A customer must reserve a certain amount of capacity to be used and the price it pays is based entirely on the reservation and not the actual load.[146] Thus,

140. Under load ratio pricing, the costs of the transmission system are allocated on the basis of the ratio of the network customer's load to the transmission provider's entire load on its transmission system. *See* 315 F.3d 362, *supra* note 97, at 363.

141. Order No. 888, *supra* note 63, at 21,599.

142. The Commission reinforced these findings further through Order No. 888-A when it found that the definition of network load in the *pro forma* OATT does not allow for the use of BTM generation to lower a network customer's coincident peak demand. It provided for the exception whereby BTM generation could be excluded. *See* Order No. 888-A, *supra* note 131, at 12,320 (citing "[c]ustomers that elect to do so . . . must seek alternative transmission service for any such load that has not been designated as network load for network service. This option is also available to customers with load served by 'behind the meter' generation that seek to eliminate the load from their network load ratio calculation.").

143. Order No. 890, *Preventing Undue Discrimination & Preference in Transmission Service*, 118 FERC ¶ 61,119 at P 1,619 (2007) ("The Commission is not persuaded to require transmission providers to allow netting of behind the meter generation against transmission service charges to the extent customers do not rely on the transmission system to meet their energy needs. Commenters in this proceeding have not provided any different arguments that were not fully considered and addressed in Order No. 888, *et al*. The existing *pro forma* OATT already permits transmission customers to exclude the entirety of a discrete load from network service and serve such load with the customer's behind the meter generation and through any needed point-to-point transmission service, thereby reducing the network customer's load ratio share. Therefore, the Commission's existing policy already provides customers with the opportunity to reduce network service costs to the extent a customer is not relying on the transmission system to meet its energy needs. As the Commission concluded in Order No. 888-A, transmission customers ultimately must evaluate the financial advantages and risks and choose to use either network integration or firm point-to-point transmission service to serve load. We believe it is most appropriate to continue to review alternative transmission provider proposals for behind the meter generation treatment on a case-by-case basis, as the Commission did in the PJM proceeding cited by the commenters.").

144. For a more detailed history of contract path pricing and its alternatives, *see* Michael A. Cannella et al., *Beyond Contract Path: A Realistic Approach to Transmission Pricing*, 9 ELEC. J. 26 (1996); *see also* William W. Hogan, *Path Dependent Transmission Access*, HARV. UNIV. (2006), https://hepg.hks.harvard.edu/files/hepg/files/hogan_oatt_060906.pdf.

145. *See, e.g.,* Transmission Access Pol'y Study Grp. v. FERC, 225 F.3 667, 725 n.12 (D.C. Cir. 2000).

146. For example, assume there are two customers, one network and another point-to-point. The network customer will pay a charge based on its actual load during the coincident peak moment (say, 30 MW, even if its load is otherwise higher during the non-coincident peak moments). The point-to-point transmission customer

point-to-point transmission customers pay for the fixed costs of the transmission system based on its reservations unlike network customers that pay fixed costs on the basis of its actual usage (e.g., coincident peak load). However, as has been well documented, power flows do not necessarily respect contractual boundaries[147] making contract path pricing a decent-at-best proxy for the actual costs of the facilities used to accommodate a transmission service request. In contrast, "[n]etwork service allows more flexibility by allowing a transmission customer to use the entire transmission network to provide generation service for specified resources and specified loads without having to pay multiple charges for each resource-load pairing."[148]

Although the Commission did not prescribe a universal method for pricing, the Commission did the next best thing which was to outline two clear paths – the first path, which included a reaffirmation that most utilities plan their systems to meet twelve monthly peaks, therefore reinforcing the continued use of the "12-CP" method for allocating network system costs.[149] Alongside that endorsement came the second path (in the form of an invitation) that utilities were free to file another method so long as the utility could draw a connection to its transmission system planning.[150] This serves as the foundation for the section to follow.

VI. THE SUSTAINABILITY OF UTILIZING PEAK PRICING

A ratemaking method is arguably successful in so far as it is able to align what it charges a customer with the actual costs that the customer causes (or at least does so on a reasonably consistent basis).[151] The coincident peak method is, if nothing else, a battle-tested method for allocating the demand-related costs of the system. The battles reveal that the coincident peak method is not without challenges – not just from the perspective of new challenges (the premise of this Article), but from a basic design standpoint (the decision points inherent in designing a reasonably good demand charge). The existing design challenges are fairly well known and include, for example, the inherent variability of usage, ever-changing

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will always pay for, and receive, the full amount of its reservation, regardless of whether it uses or needs the entire reservation.

147. In reality, power flows are rarely confined to a designated contract path. Rather, power flows over multiple parallel paths that may be owned by several utilities that are not on the contract path. The actual power flow is controlled by the laws of physics which cause power being transmitted from one utility to another to travel along multiple parallel paths. This parallel path flow is sometimes called "loop flow." *See Ind. Mich. Power Co. & Ohio Power Co.*, 64 FERC ¶ 61,184, at p. 62,545 (1993).

148. Order No. 888, *supra* note 63, at 21,547 n.65.

149. *Id.* at 21,599.

150. *Id.* The Commission also spoke to rate discounts, explaining that discounts could be justified on the basis that the discount is offered on the same unconstrained path to any customer that wants to take advantage of the discount. Order Nos. 888 and 888-A provided an express pathway towards providing discounts on transmission service. It did so, of course, under precise conditions. *See* Order No. 888-A, *supra* note 131, at 12,332.

151. To be sure, and as is a major theme of this article, ratemaking – and by extension, rates – is a fabric weaved together by multiple threads in an attempt to capture and balance the different interests. One possible means of weaving together a new rate is through settlement. The idea of settlement can be formal or informal, with competition from other utilities potentially driving rate concessions for customers. *See generally* Nordin, *supra* note 49.

weather patterns (along with more extreme weather events) and its ability to navigate new technologies. We touch on these issues briefly.

Regarding the natural and inherent variability, peaks, as a baseline, and a customer's coincident peak, will naturally fluctuate.[152] This certain unpredictability represents one of the difficulties faced by the utility in designing a coincident peak method that appropriately captures how the system peaks and how its customers use the system during that peak (i.e., the difficulty of hitting a moving target).[153] Predicting customer behavior is a challenge for the utility because, while the rate design signals an incentive for customers to shave their peak load, it is not an event the utility can rely upon with exact precision. Adding a layer of complexity is that most (if not all) coincident peak methods on file, by design, are backwards looking[154] and may not prove to be a good proxy for usage in the future.[155]

Regarding new technologies and new uses, this is the space that has grabbed our attention. Although energy efficiency is hardly the most representative example, let's use it as one for the sake of discussion (particularly, in the context of the question as to the compatibility of the coincident peak method with energy efficiency measures).[156] The principle question posed here asks whether coincident peak pricing is able to provide or sustain the appropriate incentives for customers to employ behind-the-meter constructs, which would include energy efficiency measures.[157] A simplified version of this analysis yields a scenario whereby energy efficiency fails to capture its intended effect. For example, customers that invest in energy-efficiency measures may not yield the desired benefits of their investments; even if they may be successful in lowering non-coincident peak demand, coincident peak demand may still be proportionally high enough to yield

152. As Alfred Kahn put it, "[i]n the real world, costs and demands are constantly changing over time." KAHN, *supra* note 43, at 103.

153. Traditionally speaking, what this looks like is a utility identifying the number of peaks its system has (often choosing between 1, 3, 5, or 12, though any proposed number must be backed and supported by actual evidence demonstrating how the system peaks).

154. There are, of course, forward-looking formula rates that attempt to project costs one year into the future (a concept borrowing heavily on the Commission's Part I and Part II cost-of-service regulations). Even so, the vast majority of the costs at issue are sunk and historical.

155. KAHN, *supra* note 43, at 109 (citing "[m]ost of the time and energy expended in regulatory proceedings is taken up with recomputing aggregate company revenue requirements, with a view toward adjusting the general rate level to changes in total costs. There is no question of economic principle about the necessity for these efforts: ideally, prices should reflect marginal cost at the time of the sale – not at some time in the past.").

156. To be clear, energy efficiency continues to suffer from its own inefficiencies, which obscure the analysis just a smidge. Even though energy efficiency is "a bit like motherhood and apple pie" – things that are considered ostensibly good – the features and flaws of the design and implementation of those programs have led to mixed results. *See, e.g.*, Heather Payne, *Electrifying Efficiency*, 40 STAN. ENVTL. L.J. 57 (2021).

157. Potentially complicating our discussion of incentives is the role that subsidies (e.g., tax incentives) play. This article takes no position on the impact that subsidies will have on this dynamic, though plenty of articles have attempted to do so. *See, e.g.*, David B. Raskin, *The Regulatory Challenge of Distributed Generation*, 4 HARV. BUS. L. REV. ONLINE 38 (2013).

little reduction in their demand charges.[158] Stated slightly differently, their contribution to (and investment in) lowering their usage during non-coincident peak moments may not guarantee any reduction in their coincident peak demand charges.

Those are not the only design challenges with relying on coincident peak. One issue – maybe even a blind spot – of the coincident peak method is that it is merely a snapshot. It is a single moment in time that may not be fully representative of how the customer uses the system throughout a calendar year. Therefore, the concept of a snapshot introduces a potential flaw of the coincident peak method, which is its inability to mitigate (or account for) the difference between a customer's usage during the peak moment and that customer's usage during the other moments.[159] One possible construction of this argument is that the coincident peak method focuses solely at one moment at the expense of, essentially, all other moments. This issue is not merely theoretical, as we will soon explore, but rather a practical implication of a utility's choice to use one moment, or a few moments, to serve as representative of a customer's demand of the system. This is where administrative efficiency clashes with mathematical precision.

For the sake of example let's assume that a utility has: (1) a peak load of 100 MW; (2) four customers; and (3) a "1-CP" tariff. During the 1-CP moment, the four customers use the system as follows, on a relative basis: customer one demands 25%, customer two demands 20%, customer three demands 5%, and customer four demands 50%. However, during the non-coincident peak moments, the same four customers use the system, on a relative basis as follows: customer one demands 30%, customer two demands 25%, customer three demands 20%, and customer four demands 25%.[160] While this scenario is for illustrative purposes, it demonstrates the possibility that one customer could curtail its usage significantly below the amount that it otherwise would use (arguably, in a manner that is not representative of its usage during the remaining 8,759 hours of the year).[161] In a vacuum, that curtailment and conservation is meaningful and valuable to the system, but for the purposes of allocating demand costs, the end result is that customer three pays significantly less than it otherwise should and, because of the proportional nature of the coincident peak allocation, the remaining customers pay a larger share. These cost shifts speak to the potential for issues with (relying solely on) peak-load pricing – utilities are taking into consideration investment during non-coincident peak moments (i.e., building out a system to account for solar that typically peaks hours well before the transmission system peaks later

158. This holds true if you subscribe to the belief that peaks are becoming more extreme (or that we're trending towards setting new and higher peak demands).

159. It's entirely possible that, when you look at how Kahn referred to demand charges, it seemed to be assumed that demand was far more inelastic than it is today – and, certainly, than it will be a decade from now). For example, most of Kahn's arguments regarding demand charges focused on the discrepancy between average cost pricing and marginal cost pricing. In particular, Kahn took issue with the "[M]ajor discrepancy between the economist's prescription for optimal pricing and the traditional and still generally followed approach of public utility regulation." KAHN, *supra* note 43, at 88-89.

160. The issues presented here become magnified when certain customers have a greater ability to reduce their consumption and others don't. One possible argument is that the coincident peak method assumes that customers are similar in their elasticity of their demand.

161. Meaning, for planning purposes, the utility cannot ignore demands during non-coincident peak periods.

in the day). Indeed, there is some recent literature indicating that, at least on the distribution side, peak costs may not necessarily be the primary driver of infrastructure costs.[162]

While the above example is theoretical, the following example is not and points to the limitations and future pressure points that may emerge between the existing coincident peak methods and the new uses of the system, including behind-the-meter generation (with the hypothesis being tested that the coincident peak method is only as valuable as its ability to properly and genuinely allocate costs among customers in a way that is representative of how those customers use the system across the duration of a calendar year).

In 2017, Virginia Electric and Power Company (otherwise known as Dominion) filed proposed changes – a new average demand calculation – that would effectively establish a backstop to its then-current coincident peak methodology.[163] The problem presented by Dominion was that, under the then-existing method, certain customers would be able to forecast the annual peak and intentionally reduce their load to avoid certain charges. Dominion's method at the time relied on what's known as a "1-CP" method – effectively a single snapshot, the one highest peak hour across all hours of the year.[164] As Dominion argued, the proposed backstop would reduce a transmission customer's incentive to avoid consumption during the system peak because, as a result of that avoided consumption, costs will begin shifting disproportionally to other customers.[165] The argument presented by Dominion, and the one illustrated in the example using the four transmission customers above, is that, under the current paradigm, discretionary load reduction can have the effect of shifting costs onto other customers. Dominion's argument was that the then-existing method was sending the wrong incentives.

Arguably, that's true, but it is a design choice and reflective of the fact that one rate design cannot wholly fulfill the incentives and desires of both the utility and the customer.[166] Therefore, we have not just an incentives issues but also one involving mechanics and mitigation.[167] One viewpoint is that reducing consumption at the time of system peak is a good thing, but the failure of the 1-CP method is that it is unable to protect or shield other customers from bearing a disproportionate amount of costs (effectively picking up the tab for the customer, or customers, that successfully reduced their load at the time of system peak, as the utility cannot avoid building its system to meet demand during non-coincident

162. In one strand of research – though narrowed to the field of distribution system capacity – one study revealed that only 10% of a utility's capital investments in the distribution system went towards system capacity. *See* Noah Rauschkolb, et al., *Estimating electricity distribution costs using historical data*, 73 UTILS. POL'Y (2021).

163. *PJM Interconnection, Inc. et al,* 162 FERC ¶ 61,136 at P 1 (2018).

164. *Id.* at PP 1-2.

165. *Id.* at PP 1, 4.

166. As alluded to previously, policy is often a series of messy compromises cobbled together – while there may be a mathematically optimal and elegant solution to these problems, any policy decision must balance several competing objectives.

167. As relevant to this article, I use the term "mitigation" to mean the ability of the mechanism to protect against unnecessary or undue harm or preference to the particular users of that mechanism. *See, e.g.*, Nordin, *supra* note 49, at 164 (holding that "[i]n assessing charges for demand costs, justice among customers must be thought of in terms of the fairness of hourly charges.").

moments). This issue is significantly more acute when you consider the fact that not all customers are created equal, with some being able to shift their load (or more easily, at least[168]) and others being unable to shift it whatsoever.[169]

In order to address this concern, Dominion proposed to incorporate an average demand calculation to its existing coincident peak methodology – in essence, a minimum charge for access to the transmission system.[170] Under the proposal, Dominion would calculate each customers' average demand by dividing its total hourly load during the relevant twelve-month period. Under the proposal, Dominion would effectively use the higher of its average demand or the customers' coincident peak demand when it came time to determine demand charges.[171] This served as Dominion's attempt to build in a mechanism that could mitigate the cost-shifting in a way that accounted for and reflected its customers usage during all periods – not just peak periods.[172] As Dominion described it, a transmission customer could have load on the transmission system in all hours besides the one coincident peak hour and yet not pay any network system charges.[173] And, according to Dominion, even though the transmission customer reduced its demand at the time of the coincident peak, that reduction does not mean Dominion can avoid building its system to meet this customer's needs (i.e. as Dominion must continue serving that load in the remaining 8,759 hours).[174]

168. Ethan Howland, *Data centers, EVs drive PJM's long-term load growth forecast, but it expects some utilities to see declines*, UTIL. DIVE (Jan. 4, 2022), https://www.utilitydive.com/news/data-centers-evs-drive-pjm-load-growth-forecast-capacity-market/616584/.

169. At the risk of undermining my own statement, it would seem that the very existence of customers being able to shift their load at the time of system peak means that the customers needing the system the most at the time of system peak should pay the most. The task of apportioning joint costs on a jointly-used system is not simple, especially when a utility must plan and build its system to meet a customer's needs at all hours – not just the coincident peak. Even to Kahn this analysis wasn't terribly straight-forward. As he put it, "the economic principle here is absolutely clear: if the same type of capacity serves all users, capacity costs as such should be levied only on utilization at the peak." Immediately after making that statement, however, Kahn acknowledged that while "the principle is clear . . . it is more complicated than might appear." KAHN, *supra* note 43, at 89. What isn't clear is whether the methods for allocating demand costs made certain assumptions about the elasticity of demand that may not hold true in today's environment.

170. 162 FERC ¶ 61,136, at P 1, 4 (citing "[s]pecifically, Dominion's proposed changes incorporate a new average demand calculation that would serve as a backstop to the current annual coincident peak demand methodology in order to reduce a transmission customer's incentive to avoid consumption during the system peak, and thereby shift transmission costs to other transmission customers."). The Commission did not accept the proposal, but it is discussed here to illustrate the challenges with properly calibrating demand charges.

171. A literature review reveals the relative use and benefits of an average demand. *See, e.g.*, Carolyn Brancato, *New Approaches to Current Problems in Electric Utility Rate Design*, COLUM. J. ENVTL. L. 1989, at 40.

172. 162 FERC ¶ 61,136, at P 4 (citing "Dominion states that, absent its proposal, a transmission customer could have load on the transmission system in all hours (including those hours during which emergency conditions are occurring) besides the coincident peak, yet pay no Network Service charge.").

173. *Id.*

174. *Id.*

The cost-shifting issue is a serious one,[175] and likely to be stressed further with the progression of demand-side tools that will soon be cheaper and more accessible.[176] If load reductions are causing or enabling cost-shifting in a way that disrupts the delicate cost causation ecosystem that exists among different network customers, then it seems entirely possible that the rate design provides neither the appropriate incentives nor the appropriate cost-shifting mitigation.[177] Stated differently, if one customer is able to avoid costs in a way that causes a different customer to pay a higher share than their proportional use, it is entirely possible that such a cost-shift could violate the Commission's cost causation policy.[178]

While this case presented the Commission with an opportunity to speak to the different competing objectives – and possible infirmities – with the coincident peak method, it did not need to speak to those issues. Ultimately, the Commission determined that it was not able to accept Dominion's proposal – not because of an issue with the merits, but rather that Dominion had not fully supported its proposed approach.[179] The Commission acknowledged that Dominion relied solely on a hypothetical scenario – a bug of the existing pricing paradigm[180] – without evidence that any customer had, or was likely to, cause costs to be shifted. The Commission declared that it could not determine something to be just and reasonable, in this regard, given the lack of evidence.[181] It was near the end of the determination, however, that the Commission gave a breadcrumb as to how it would look at the use of a customer's average demand – the Commission explained that it was

175. In Order No. 888-A, the Commission spoke directly to this concern – the idea of cross-subsidization – and the concern that "any cost responsibility evaded by a network customer in this manner would be borne by the remaining network customers and native load." Order No. 888-A, *supra* note 131, at 248.

176. *See, e.g.*, *Spring 2020 Quarterly Markets Report*, *supra* note 83, § 3.2.3. In that report, the Internal Market Monitor raised concerns that certain "[n]etwork customers [we]re avoiding paying their share of the costs of the transmission network." In addition, the Internal Market Monitor observed that "unreported" behind-the-meter generation was leading to a higher network transmission service rate for all network customers. In particular, the report argued that "with the significant growth in small scale distributed generation in New England, notably photovoltaic and energy storage devices, the wider and future impact of the proposed change should be considered from the perspective of equitable cost allocation and impacts on wholesale markets. For instance, consideration should be given to any adverse impacts on bulk system reliability and market efficiency of potentially large amounts of non-centrally dispatchable and unpriced generation choosing to be behind-the-meter (given the proposed transmission savings to the associated load) when otherwise they might participate in the wholesale market based on a demonstrated equitable allocation of transmission costs." *See Comments of the Internal Market Monitor on the Proposal to Exclude Behind-the-Meter Generation from Transmission Cost Allocation*, FERC Docket No. ER21-2337-000 (July 22, 2021).

177. We have, at the heart of this thing, an incentives problem. *See* Kavulla, *supra* note 36, at 19.

178. *See, e.g.*, *Occidental Chemical Corp. v. PJM Interconnection et al.*, 102 FERC ¶ 61,275 at P 14 (2003). ("Access charges for use of PJM's transmission system should be allocated to network customers based on a network customer's actual use of PJM's system, consistent with the principle of cost causation.").

179. *Id.* at P 18.

180. A bug, in part, because going-forward rates should reflect going-forward costs. *See, e.g.*, KAHN, *supra* note 43, at 63-86. Instead, the coincident peak mechanism charges customers on a prospective basis based primarily on historical load – load that may or may not be representative of the future.

181. 162 FERC ¶ 61,136, at P 25 (citing "[t]he Commission cannot determine the justness and reasonableness of Dominion's proposal given the lack of evidence to support the existence of the problem and the solution to the potential problem.").

unsure, at best, of how average demand would align with how transmission customers pay for their use of the system.[182] The linkage between how a utility plans its system and the ultimate billing is the strongest thread we have.

The concerns associated with cost-shifting are not new, either. In Order No. 888, the Commission spoke to concerns regarding the potential for cost-shifting among Network Customers (and to be precise, cost-shifts driven by load reductions).[183] As relevant to cost-shifts, the Commission emphasized the idea that any cost responsibility evaded by one customer would necessarily mean that another customer would need to assume that cost responsibility, in addition to its own.[184] We are only at the beginning of understanding these interactions, but behind-the-meter generation may prove a successful challenger to the coincident peak method, if it is successful in prompting the concerns raised by the Commission (i.e., evading and/or shifting cost responsibility). Relevant to that answer is the degree to which a customer's behind-the-meter generation enables the utility to avoid incurring costs to serve that customer. We turn next to a few cases that provoked those questions.

VII. LESSONS FROM BEHIND-THE-METER, A CASE STUDY OF SORTS

The idea of behind-the-meter generation is not necessarily new,[185] but its use is set to become nearly ubiquitous.[186] The problem statement posed here, however, is the compatibility of the current coincident peak method with the increased use of behind-the-meter generation. There are a few cases that inform our thinking on this, or at least begin the process for thinking about this issue more holistically. These cases speak more to confirming the problem statement's existence, as opposed to presenting ready-made solutions.

182. *Id.*

183. *See* Order No. 888, *supra* note 63, *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at p. 30,259-60, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997) [hereinafter Order No. 888-B], *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998) [hereinafter Order No. 888-C], *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*. New York v. FERC, 535 U.S. 1 (2002) ("For example, if at the time of the monthly system peak the FMPA member city generates more than 40 MW (or takes short-term firm transmission service (or a combination of the two), it may be able to lower its monthly coincident peak load for network billing purposes, and thereby reducing if not eliminating its load-ratio cost responsibility for network service. Because network and native load customers bear any residual system costs on a load-ratio basis, any cost responsibility evaded by a network customer in this manner would be borne by the remaining network customers and native load.").

184. Order No. 888, *supra* note 63, at 491-92.

185. In fact, what we'd called behind-the-meter generation today largely looks like the "self-generation" from an "isolated plant" that was previously the dominant source of electricity at the turn of the 20th century. John L. Neufeld, *Price Discrimination and the Adoption of the Electricity Demand Charge*, 47 J. ECON. HIST. 693, 693–709 (1987). That article also went on to argue that "[m]any, if not all, of the electricity pricing structures, which continue to be used and considered today were explored then, and lively exchanges occurred between advocates of demand-charge rate structures and advocates of time-of-day structures."

186. There is, to be sure, a direct relationship between assets *behind-the-meter* and the concept of net-metering, though this Article does not explore that relationship. Net-metering, in short, is a retail billing mechanism that treats excess output from a behind-the-meter asset as a credit against a homeowner's consumption of electricity. *See, e.g.*, Order No. 2003-A, *Standardization of Generator Interconnection Agreements and Procedures,* FERC Stats. & Regs. ¶ 31,160, 68 Fed. Reg. 69,599 at P 744 (2004) (codified at C.F.R. pt. 35).

In 2004, PJM filed, and the Commission accepted, a proposal that would allow market participants to net their behind-the-meter generation against load (at the same electrical location) for the purposes of calculating demand charges in PJM.[187] There were two critical components to that proposal – the first being that the generation needed to be at the same electrical location as load and second, that PJM needed to have the ability to require the generation to run in the event of a capacity shortage.[188] Several municipal entities raised issues with the proposal because they could not take advantage of the netting rules as a result of having several load points – PJM argued, in response that those uses would not qualify, as that particular behind-the-meter generation configuration would make use of the transmission system.[189] In accepting the 2004 filing, the Commission required several status reports – the Commission would eventually use those status reports to initiate a section 206 proceeding[190] that ultimately resulted in a settlement.[191] The final resting spot for this issue involved tariff language that permitted netting, but so long as the behind-the-meter generation does not use the transmission system.[192]

Picking up again on the theme of reliance on the transmission system, the Commission also explored this issue in a dispute between Amtrak and PPL.[193] Amtrak sought to utilize and leverage the power from one of its resources – a hydro resource – as a means of netting out its network transmission charges.[194] The Commission rejected this request, however, finding instead that Amtrak's request cuts against the very nature of network service.[195] Amtrak insisted that, on the basis of cost causation, it should only pay for transmission costs when the facility (which happened to be behind-the-meter) failed to provide enough power to meet Amtrak's demand.[196]

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187. *PJM Interconnection*, 107 FERC ¶ 61,113 at P 8 (2004) (citing "[f]inally, PJM emphasizes that the intent of its proposal is to limit the netting of behind the meter generation to only entities that directly serve load by generating resources that are located at the same site or "single electrical location.").

188. As a point of emphasis, the Commission emphasized the idea of a "qualified" resource. *See id.* at P 29 (citing "[a]s proposed, PJM's market rules will provide a benefit to qualifying behind the meter generation that contributes to network load reductions by allocating a fairer share of transmission system and other operating costs.").

189. *Id.* at P 30 (citing "[f]or instance, unlike industrial generators, the municipal generators have failed to show that their generation does not make use of the transmission system, such that they should be relieved of paying the applicable charges.").

190. *PJM Interconnection,* 112 FERC ¶ 61,034 at P 17 (2005) (citing concerns that "PJM has not satisfactorily shown that BTM generation that is connected to load through a distribution system should be excluded from the netting program.").

191. *PJM Interconnection*, 113 FERC ¶ 61,279 at P 4 (2005) (citing that the "settlement provides an opportunity for generators connected to a distribution system to qualify for the BTMG netting provisions.").

192. *Id.*

193. *Nat'l R.R. Passenger Corp. v. PPL Elec. Utils. Corp.,* 171 FERC ¶ 61,237 at P 1 (2020), *reh'g*, 173 FERC ¶ 61,043 at P 1 (2020).

194. 171 FERC ¶ 61,237, at P 2.

195. 173 FERC ¶ 61,043*,* at n.34 (citing "[t]o the extent Amtrak believes it is not relying on PPL to meet its transmission needs, it should modify the type of transmission service it uses.").

196. *Id.* at P 9.

In response to these arguments, the Commission explained that Amtrak's service was not reservation based (i.e., point-to-point transmission), but instead network based[197] – meaning that Amtrak could "'call upon the transmission provider to supply not just some, but all of their load at any given moment, when for instance they experience blackouts or brownouts.'"[198] Under this dynamic, the Commission found that the bargain struck under network service is that a customer can call upon the system to meet all of its load at any given moment – making network service something of an "all or nothing" proposition.[199]

This issue appeared again in the context of behind-the-meter generation in ISO-NE.[200] The issue presented there was a little less narrow and a little more holistic. The question, primarily, was how to treat behind-the-meter generation when the Transmission Owner goes to determine the peak load (and peak load responsibility).[201] The Commission was left with a fairly difficult task – squaring away the treatment of these newer technologies with these bread-and-butter transmission products.[202] Ultimately, the answer came down to old-school open access fundamentals.[203] The Commission's answer in this proceeding also hinged on a distinction with a significant difference – specifically, the idea that not all behind-the-meter generation resources are created equally.[204] Even though there was a significant amount of installed behind-the-meter generation, not all of it was es-

197. *Id.* at P 12 (citing "[w]hat Amtrak seeks to do is carve out from network service charges the power supplied by Safe Harbor. Such an outcome is impermissible under the PJM Tariff and inconsistent with the nature of NITS.").

198. *See Fla. Mun. Power*, 411 F.3d at 289. (The Commission made this statement, relying on precedent established in this case). The Commission also explained that "Amtrak's cost causation arguments similarly fail because the assessment of NITS is not based on actual use over a particular transmission path, but rather based on the network customer's right to use the entire system." 173 FERC ¶ 61,043, at P 14.

199. *Fla. Mun. Power*, 411 F.3d at 289.

200. 178 FERC ¶ 61,086, at P 49 (citing "[w]e find that the proposed revisions, which exclude from the Monthly RNL load served by unregistered behind-the-meter generation, along with the portion of the output of a Generator Asset that serves load located behind the same retail customer meter as the Generator Asset, reasonably reflect each Network Customer's usage of the transmission system and assigns the cost of providing Regional Network Service accordingly.").

201. *Id.* at PP 1, 4-5.

202. *Id.* at P 56.

203. *Id.* at P 51 (citing, in response to whether the proposal was consistent with the policy articulated in Order No. 888, "[h]ere, such an approach is just and reasonable because each Network Customer's net load is a reasonable approximation of its use of the transmission system: unregistered behind-the-meter generation reduces the Network Customer's load that must be served from the transmission system.").

204. The distinction made in the filing revolved around the idea of "registered" versus "unregistered" behind-the-meter generation. 178 FERC ¶ 61,086, at PP 1, 51, n.78 (citing "*see* 107 FERC ¶ 61,113, at PP 1, 28 (accepting proposal to allow market participants to net operating behind-the-meter generation against load at the same electrical location for the purposes of calculating a variety of applicable PJM charges, including transmission service charges, because the proposal appropriately allocated operating costs of the transmission system, among other reasons); *see also Occidental Chemical Corp. v. PJM Interconnection*, 102 FERC ¶ 61,275 at P 14 (rejecting PJM's proposal to add back curtailed load for purposes of calculating network charges, finding that while PJM's consideration of curtailed loads may be one of many factors that is appropriate to consider for transmission planning purposes, its inclusion as an allocation factor for network charges was not justified.").

sentially registered as a resource with ISO-NE (and thus not available to be committed or dispatched in a reliably predictive manner).[205] Therefore, in this case, the Commission put a bit of a finer point on its stance on utilizing behind-the-meter generation to offset a customer's coincident peak load.[206]

VIII. THE WAY FORWARD & POTENTIAL MODIFICATIONS TO THE COINCIDENT PEAK METHOD

This Article takes the position that demand charges – as they are predominantly comprised today – are not enshrined in wholesale tariffs because they are necessarily the *best* at what they do.[207] Instead, they seem to exist because of their ability to accommodate a compromise of competing interests. The case law outlined above indicates that maybe the compromise is being renegotiated in real-time. If history is to yield any clues, it is that the solution that bridges the competing interests together will likely be a fact- and case-specific solution.[208]

As we embark on a search for a potential solution, we are not at a complete loss for tools; we have an adequate compass and map. First, the compass, our north star: we have a statutory framework and second, a map consisting of several decades worth of case law that may help guide, and inform the way we look at these issues in the future.

First, the compass. We have the framework under section 205 of the Federal Power Act ("section 205") as the ultimate guidepost,[209] as any proposal will need

205. 178 FERC ¶ 61,086, at P 54 (citing "[w]e find that behind-the-meter Generator Assets and unregistered behind-the-meter generators are not similarly situated for the purposes of the inquiry at hand, namely the Monthly RNL calculation and corresponding charges for Regional Network Service, which is the focus of the proposed Tariff revisions.").

206. *Id.* at P 55 (citing "[a]s a result, we find that unregistered behind-the-meter generation is not similarly situated to Generator Assets for purposes of calculating the Monthly RNL; the electricity that a Generator Asset produces to serve load is metered as Filing Parties explain with robust telemetering equipment or revenue grade metering, while the electricity that an unregistered behind-the-meter generation produces is not.").

207. The doubt presented here is not new and dates back several decades, if not to the origin story of demand charges. In particular, the two quintessential "Godfathers" of regulatory policy – Kahn and Bonbright – have cast doubt on demand charges, with Alfred Kahn deeming them "illogical." *See, e.g.*, KAHN, *supra* note 43, at 96; *see also*, Borenstein, *supra* note 95, at 10 (citing "[i]t is unclear why demand charges still exist. Charging customers for their peak usage during a billing period has been supported as an approximation to a customer's demand during system peak periods, but it was never a very good approximation, as the customer's peak may not be coincident with the system peak. Furthermore, the single highest consumption hour of the billing period is not the only, and may not even be the primary, determinant of the customer's overall contribution to the need for generation, transmission, and distribution capacity.").

208. *See, e.g.*, 172 FERC ¶ 61,054, at P 72 (citing "[a]s to the fact that other PJM transmission owners utilize the 5-CP method, the Commission explained in the Coincident Peak Order that this is irrelevant for purposes of our determination here. Order No. 888 allows transmission providers to adopt a different allocation method than the 1-CP, and the fact that other transmission providers have justified the 5-CP does not detract from the fact that Dominion has demonstrated that the 12-CP method reflects Dominion's planning to accommodate the unique features of its transmission system. For example, Dominion explained how the increase in high-load data centers affects load even during shoulder months and is more conducive to utilizing monthly coincident peaks for cost allocation.").

209. Under § 205 of the Federal Power Act, rates "for or in connection with transmission or sale of electricity subject to the jurisdiction of the Commission . . . shall be just and reasonable." *See* Joshua Z. Rokach, *FERC's Jurisdiction under Section 205 of the Federal Power Act*, 15 ENERGY L.J. 83, 99 (1994).

to be proven just and reasonable.[210] As is relevant to the pricing of demand costs, there are really two main ideas that guide our thinking. The first is that there is no single theory of ratemaking meaning, for our purposes, that there is no one way to slice and dice costs and allocate those to customers.[211] Particularly illuminating for our purposes is what the court said in *Duquense*.[212] There, the Court said that the "designation of a single theory of ratemaking as a constitutional requirement would unnecessarily foreclose alternatives which could benefit both consumers and investors."[213] The second idea is, as a result of the first, that the utility must carry its burden, prior to the Commission determining that a particular rate is just and reasonable,[214] to demonstrate that its proposed allocation is just and reasonable.[215]

The immediate question then becomes what is possible, or even permissible, under the existing statutory framework (i.e., the map). That's where the case law becomes singularly relevant.[216] At our fingertips exists several decades worth of Commission precedent on how to allocate demand costs and the appropriate rate design that enables the Commission to approve a rate as being just and reasonable.[217] A reading of that precedent reveals that there really is no one way to allocate demand charges. While that statement is true – a fact-of-life acknowledged by both the Commission and courts[218] – it is nevertheless somewhat *odd* to the author. In the age of fairly advanced metering, a customer's demand of the system – at all hours and moments – is known and yet the appropriate method for allocating costs to that customer is seemingly a little bit art and a little bit science. In

210. Christiansen & Macey, *supra* note 115, at 1368.

211. *Pricing Policy Statement*, *supra* note 127, at 9 (citing "[w]hile many of the comments expressed dissatisfaction with the Commission's current pricing policy, the comments indicated no consensus for any one alternative pricing method.").

212. Duquense Light Co. v. Barasch, 488 U.S. 299, 316 (1989) ("The designation of a single theory of ratemaking as a constitutional requirement would unnecessarily foreclose alternatives which could benefit both consumers and investors.").

213. *Id.*

214. *See, e.g.,* Advanced Energy Mgmt. All. v. FERC, 860 F.3d 656, 662 (D.C. Cir. 2017) ("When acting on a public utility's rate filing under section 205, the Commission undertakes an essentially passive and reactive role and restricts itself to evaluating the confined proposal.").

215. Fed. Power Comm'n v. Hope Nat. Gas Co., 320 U.S. 591, 602 (1944).

216. The answer to that question in the context of rate design seems to vary. *See Norwood*, *supra* note 38, at 22 ("Issues of rate design are fairly technical and, insofar as they are not technical, involve policy judgments that lie at the core of the regulatory mission.").

217. This process begins, truly, with functionalization – the process by which the utility separates costs among the production, transmission, distribution, and customer service functions. From there, the utility classifies costs as being either fixed or variable costs. The final step in the process is to allocate the functionalized and classified costs among customers causing those costs. As it relates to the issues presented in this article, the transmission revenue requirement enables the utility to allocate a proportional share of costs to individual customers using, in almost every case, coincident peaks (typically a number of peaks based on the load and peaking profile of the utility). *See, e.g., Guide to the Class Cost of Service Study (CCOSS)*, XCEL ENERGY 2, 5, 7, https://puc.sd.gov/commission/dockets/electric/2014/EL14-058/volume2/jpg1schedule2.pdf (last visited Oct. 19, 2023).

218. The courts have previously found that a utility is required only to demonstrate and establish that its proposed rate design is reasonable – not, necessarily, that it is better than any or all alternatives. *See, e.g.,* City of Bethany v. FERC, 727 F.2d 1131, 1136 (D.C. Cir. 1984); *see also*, Batavia, v. FERC, 672 F.2d 64, 84 (D.C. Cir. 1982) ("[B]illing design need only be reasonable, not theoretically perfect.").

other words, why, when advanced metering exists, do we still rely on rough approximations instead?[219] It is *this* squishy, fungible thing that we intend to explore fully.

One of the possible reasons for this is the relative "squishiness" of what "benefits" really means, how to define those benefits,[220] and as a result, how to charge a customer for their receipt of those benefits.[221] While metered demand is a known quantity, the benefits that a customer draws from the grid are not precisely measurable and thus, a decent proxy is utilizing coincident peak to gauge how much a customer demands, and therefore benefits, from the grid. Although the utility plans its system to meet its peak, it also plans a system to provide reliability for all 7,658 hours of the year. As reasonable as any method might be, they remain proxies and approximations of the benefits derived by the customer. While there is no one method that the Commission has accepted to the exclusion of others,[222] in order to understand how future proposals would be considered,[223] we will need to rely on the compass and map we have as the only tools to guide us through the moment.

The compass and map illuminate the presence of neither a singular destination nor a singular path. Instead, the compass and map reveal that the Commission has a preference for "right-sizing," meaning a demand allocation method rooted in choosing a number of coincident peaks consistent with how the utility peaks (with the determinative factor being how many peaks does the utility have across a 12-month period).[224] The Commission has utilized a variety of tests for arriving at that determination (sometimes, for example, looking at the extent to which peak demands in non-peak months exceed the peak demands in the alleged peak

219. The simple answer is that section 205 does not demand exact precision. *See, e.g.*, *Transmission Pricing Under FPA*, *supra* note 111, at 99.

220. For example, not all kWh are created equal.

221. In other words, cost allocation does not need to be perfect. *See* Ill. Com. Comm'n v. FERC, 576 F.3d 470, 477 (7th Cir. 2009) ("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."); s*ee also* Midwest ISO Transmission Owners v. FERC, 373 F.3d 1361, 1368 (D.C. Cir. 2004) ("We have never required a ratemaking agency to allocate costs with exacting precision.").

222. *See, e.g.*, *Delmarva Power & Light Co.*, 17 FERC ¶ 63,044 (1981).

223. Relatively recent filings show the existing paradigm being stress-tested, as evidenced by Florida Power and Light's (FPL) proposed Variable Energy Resource Wheeling Transmission Service. Under FPL's proposal, FPL introduced the idea of modifying the point-to-point transmission pricing paradigm – where pricing is determined based on reservation – to consider usage to determine pricing for a product typically priced based on a reservation basis. As is a prominent theme of this article, real-world solutions will likely dominate the textbook solutions, and this filing was no exception, as it represented an effort between a utility and potential customers to meld existing tariff offerings to meet the needs and demands of current-day electric systems.

224. In most cases, the Commission has accepted a few flavors and varieties – mostly surrounding 1-CP, 3-CP, 4-CP, 5-CP, and, most frequently, 12 CP. Under a 1-CP method, the allocator for a particular wholesale class will be developed by dividing the wholesale class's CP for the peak month by the total company system peak. Similarly, for any other alternative, the numerator would consist of the average of the wholesale class's coincident peaks for each of the peak months, while the denominator would consist of the average of the total system peaks for each of the peak months. *See*, *e.g., PJM Interconnection*, 169 FERC ¶ 61,041 at PP 1-8 (2019).

months).[225] The case law is rich with litigation[226] – a testament to the difficulty of tailoring the right answer. What does all of this mean? One version of this story – the potential takeaway – is that, while a few methods (such as embedded cost pricing) have predominantly been used by utilities, no one pricing mechanism is perfect and without its shortcomings – a mechanism that features administrative efficiency may not be the most accurate.[227]

In its policy statement, the Commission spoke directly to the most basic task inherent in rate design: solving the tension between a rate that is precise and a rate that is simple to administer and understand.[228] Inherently, this is the threshold decision point involved in any allocation method – administrative simplicity versus accuracy. Around the time of Order No. 888, the tension revolved around the debate between the simpler, traditional methods (such as contract path pricing and postage stamp pricing) with newer methods that produced more accurate signals at the expense of more complexity (such as distance-sensitive and flow-based rates). The Commission never chose a path,[229] instead yielding to an approach enabling flexibility – a natural posture given the (1) trade-offs between more precise price signals and administratively efficient and simple methods and (2) the permissiveness of the just and reasonable standard.[230]

As a global matter, while the Commission has outlined parameters for designing rates, it has also articulated that, once a particular method is established for a particular company, those methods persist short of a supervening change in circumstances or Commission policy.[231] In the case of Dominion, the Commission very clearly rejected a proposal in the name of "you can't file something for the

225. *See, e.g.*, *Sw. Pub. Serv. Co*., 18 FERC ¶ 63,007, at p. 65,034 (1988) (monthly peak in any non-peaking month exceeded the monthly peak in peak month only once and 3 CP adopted).

226. Inherent in any potential filing is a balancing of the costs and benefits of potential litigation, possibly one of the reasons "progress" with respect to new rates has been relatively slow. *See, e.g.,* Stephen C. Pearson, *Innovations in FERC Hearing Procedures*, 41 ENERGY L.J. 23, 24-25 (2020).

227. In one case, a utility switched from a 12-CP methodology to a 3-CP methodology. City of Bethany v. FERC, 727 F.2d 1131, 1135 (D.C. Cir. 1984).

228. *Pricing Policy Statement*, *supra* note 127, at 13-14 (citing "[T]he Commission believes that improving price signals is an important goal, but recognizes that trade-offs between improved price signals and simplicity are inevitable. On one hand, transmission service is typically a small component of the total cost of electric service and, therefore, arguably does not merit overly complex pricing methods. On the other hand, in many cases transmission capacity is a scarce and valuable resource, and its pricing can send signals that promote the efficient siting of generation facilities and efficient decisions as to the dispatch of generation. . . . We therefore must balance the sometimes competing goals of better price signals and simplicity when evaluating any new pricing methodologies.").

229. Prior to the issuance of Order No. 888, the predominant method of transmission pricing was one that boasted both simplicity and administrative efficiency – essentially a single price for using the transmission system (e.g., a postage stamp pricing). *See, e.g*., 64 FERC ¶ 61,184, at 62,545.

230. There is, of course, the possibility of incorporating non-price factors, so long as they are justified. *See* Farmers Union Cent. Exch. v. FERC, 734 F.2d 1486, 1501 (D.C. Cir. 1984); Consumers Union v. FPC, 510 F.2d 656, 660 (D.C. Cir. 1974) (stating that "[r]eliance on non-cost factors has been endorsed by the courts primarily in recognition of the need to stimulate new supplies.").

231. The Commission explained its policy on this in two orders. *See, e.g.*, *La. Power & Light Co.*, 14 FERC ¶ 61,075, at p. 61,128 (1981) and *Sw. Pub. Serv. Co.*, 144 FERC ¶ 61,133 at P 45 (2013).

sake of filing it."[232] There, the Commission rejected a proposal because it deemed it to be hypothetical.[233] Merely pointing to a hypothetical scenario is not enough to clear the necessary threshold.[234] Stated slightly differently, though the just and reasonable standard features a certain degree of flexibility,[235] that flexibility is not unbounded.

Even in the face of advanced metering and improvements in metering technology, the coincident peak method has withstood the test of time – and there are good reasons for that.[236] As a threshold matter, as far as just and reasonable methods for allocating demand costs are concerned, the use of coincident peak pricing is still the predominant method, as it represents "an eminently sensible" solution.[237] The burden on the Commission, when confronted with these rate design questions, is not to find the most mathematically optimal solution[238] – just and reasonable is not a standard that necessarily lends itself to mathematical precision.[239] In the context of transmission ratemaking, the Commission's goal in approving a proposed demand cost allocation method is that it reasonably aligns

232. In another instance, the courts remanded and vacated a proceeding because it was deemed unreasonable to base demand charges on unsupported estimates of coincident peak demand. *See* Villages of Chatham & Riverton v. FERC, 662 F.2d 23, 29-31 (D.C. Cir. 1981).

233. 162 FERC ¶ 61,136, at P 25. It's worth acknowledging that, despite being in a context different than transmission pricing, the Commission has considered market rules solely in the context and framework of economic theory. *See* S.C. Pub. Serv. Auth. v. FERC, 762 F.3d 41, 65 (D.C. Cir. 2014) ("Agencies do not need to conduct experiments in order to rely on the prediction that an unsupported stone will fall.") (quoting Assoc. Gas Distribs. v. FERC, 824 F.2d 981, 1008 (D.C. Cir. 1987)). That said, it is not clear whether that deference applies to transmission rate cases.

234. For example, the Commission considers the utility's transmission planning as a means of connecting the dots between cost causation and cost causation. *See, e.g.*, Order No. 888-A, *supra* note 131, at 235 (citing "Accordingly, utilities are free to propose in a section 205 filing an alternative to the use of the 12-month rolling average (e.g., annual system peak) in the load ratio share calculation, subject to demonstrating that such alternative is consistent with the utility's transmission system planning and would not result in overcollection of the utility's revenue requirement.").

235. The basic premise of the Commission's flexibility in evaluating transmission pricing proposals is that comparable access to efficiently priced transmission services is critical to the continued development of competitive wholesale markets. *See, e.g.*, *Am. Elec. Power Serv. Corp.*, 44 FERC ¶ 61,206, at p. 61,749 (1988). The circumstance the Commission found itself in 1994 is not terribly different than the one it finds itself in now – new uses of the electric system brought along with it new rate structures and new rate policies.

236. A few strands of literature argue that modern day demand charge allocation has its roots in price discrimination. *See, e.g.,* John L. Neufeld, *Price Discrimination and the Adoption of the Electricity Demand Charge*, 47 J. OF ECON. HIST. 693, 694 (1987). This Article takes no position on the matter, as some literature reveals that the primary actors debating the different cost allocation methods may not have fully understood the issues at hand. *See* Yakubovich, *supra* note 44, at 579-80.

237. Union Elec. Co. v. FERC, 890 F.2d 1193, 1198 (D.C. Cir. 1989) (citing that costs "are assessed to the peak-period users because it is peak demand that determines how much a utility will invest in capacity.").

238. To that end, the Commission enjoys a certain degree of deference. *See, e.g.,* Petal Gas Storage v. FERC, 496 F.3d 695, 698 (D.C. Cir. 2007) (acknowledging that the Commission is afforded substantial deference in the field of ratemaking).

239. In the market rule context, the Commission does not necessarily require a cost-benefit analysis. *See, e.g., Sw. Power Pool,* 173 FERC ¶ 61,267 at n.52 (2020) ("WEIS Order") (citing "*PJM Interconnection,* 151 FERC ¶ 61,208 at P 49 (2015) ('[T]he Commission does not generally require the mathematical specificity of a cost-benefit analysis to support a market rule change.'), *order on reh'g*, 155 FERC ¶ 61,157 at P 30 (2016) ('[W]hile the Commission is required to consider all relevant factors and make a "common-sense assessment"

costs and benefits.[240] Furthermore, under the just and reasonable standard, the utility does not need to disprove other options – it only needs to make the necessary showing under section 205 (i.e., the idea that you can't file something just for the sake of filing it.).[241]

If mathematical precision is not a prerequisite, the question then becomes "what exactly is the problem to be solved here?" As a threshold matter, the principal question to be addressed is whether the demand allocator is doing its job.[242]

The answer to that question depends on the degree to which the ultimate charges align with usage (alignment arguably being the engine and rudder for maneuvering cost causation questions).[243] Demand allocators are, at best, an approximation of the demand that the customer has on a particular system.[244] Thus, inherent in the design is both a feature and a flaw – the value is merely a proxy. Recent cases seem to suggest that at least one issue raised with the coincident peak method is a potential asymmetry in the measurement of the demand (i.e., billing)

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that the costs that will be incurred are consistent with the ratepayers' overall needs and interests, the Commission's finding need not be accompanied by a quantitative cost-benefit analysis.'), *aff'd sub nom. Advanced Energy Mgmt. All. v. FERC*, 860 F.3d 656, 660-61 (D.C. Cir. 2017); *see also Sw. Power Pool, Inc.,* 141 FERC ¶ 61,048 at P 57 (2012) ('[W]e note that our approval of the Integrated Marketplace proposal is not based on any specific cost-benefit amount. A cost-benefit analysis is largely a tool for stakeholders to evaluate different market designs and to determine their interest in moving forward with a market proposal.')."

240. In short, just and reasonable demands a linear connection between an allocator and cost causation. *See* Ill. Com. Comm'n v. FERC, 756 F.3d 556, 561 (7th Cir. 2014).

241. *See, e.g., Sw. Power Pool*, 158 FERC ¶ 61,063 at n.16 (2017) (citing City of Bethany v. FERC, 727 F.2d 1131 (D.C. Cir. 1981) ("FERC has interpreted its authority to review rates under the FPA as limited to an inquiry into whether the rates proposed by a utility are reasonable — and not to extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs"), *cert denied*, 469 U.S. 917 (1984)); OXY USA v. FERC, 64 F.3d 679, 692 (D.C. Cir. 1995) ("[T]he Commission may approve the methodology proposed in the settlement agreement if it is 'just and reasonable'; it need not be the only reasonable methodology or even the most accurate."); *see also* 44 FERC ¶ 61,206, at 61,749 ("The Commission's task is to determine whether AEP's proposal is just and reasonable. It is not required to find that the proposal is the 'best', or 'superior' to all others, in order to adopt it. Since AEP has shown that its method is just and reasonable, it is entitled to use it.").

242. As the author understands demand charges, they were largely a means of approximating the impact that a particular customer has on the system. The current structural feature of the electric industry is that the demand side of the equation is unable to respond nimbly over short- and medium-term horizons. There are a few reasons for this, but one prevalent issue is arguably the lack of visibility that end-use customers have on the prices they pay. *See, e.g*., Robert E. Gramlich, *The Role of Energy Regulation Addressing Generation Market Power*, 1 ENV'T & ENERGY L. & POL'Y J. 55 (2006).

243. 172 FERC ¶ 61,054, at n.80 ("We note that Dominion's proposed Tariff modification need not be superior to the 1-CP method, as long as it is just and reasonable, in other words, aligns with Dominion's approach to transmission planning."). *See, e.g.* OXY USA, 64 F.3d 679 (holding that, as long as the Commission finds a methodology to be just and reasonable, that methodology "need not be the only reasonable methodology or even the most accurate one.").

244. Kahn spoke directly to the complexity associated with this particular conundrum of identifying a separate charge for the fixed costs of the system ("When instead the products are truly joint, in that they can be economically produced only in fixed proportions, neither of them has a genuine, separate incremental cost function, as far as the joint part of their production process is concerned."). KAHN, *supra* note 43, at 79.

versus the *actual* impact that the customer causes on the system.[245] This "asymmetry" is not necessarily a new issue but embodies the tension resting between precision and simplicity.

The issue of asymmetry is not merely an academic exercise, either -- the potential for asymmetry presents challenges for the utility in not only aligning the two (i.e., the appropriate demand measurement versus a customer's actual impact on the system), but also doing so in a way that preserves that alignment across its customers (and, ultimately, billing).[246] Related to concerns of asymmetry,[247] another issue is that most existing allocation methods do not seem to insulate one customer's actions from another. As exemplified in *Dominion*, a customer choosing to reduce its load for economic reasons created cost-shifts for others.[248] Stated slightly differently, the asymmetry issue is that certain customers might evade, or escape, billing for demand costs they caused.[249]

At the risk of being a broken record, assume for the sake of example a utility that utilizes a single coincident peak to allocate demand costs, meaning that the charge will be based on a single hour out of 8,760 hours in a calendar year. One customer's usage during that one hour, and thus demand charge, may not align terribly well with the costs that the utility has incurred to serve that customer throughout the course of the year.[250] Even in the context of a 12-CP allocator – if a utility utilizes twelve coincident peaks, the demand charge could be based on a

245. 172 FERC ¶ 61,054, at P 6 (citing "Dominion explained that customers have actively reduced demand of their own volition during the 1-CP to shift Transmission Service charges to other customers; Dominion further asserted that this 12-CP method would discourage cost-shifting among Network Customers."). Dominion explained that it observed this in response to rising network service charges. *See id.* at PP 6-7 ("Dominion added that the incentive for this type of cost-shifting behavior has risen over the past decade as Network Integration Transmission Service charges have increased to recover Dominion's significant transmission system investments.").

246. There is, outside of the RTO/ISO context, a different wrinkle to this problem that involves the potential asymmetry between unbundled customers taking service under the utility's *pro forma* tariff and pre-Order No. 888 bundled customers that do not take service under the utility's *pro forma* tariff. *See, e.g.,* John S. Moot, *Whither Order No. 888?*, 26 ENERGY L.J. 327, 336 (2005).

247. The disparity – or asymmetry – between competitive users of the system and captive users of the system has the potential to produce cost savings for the competitive users but cost increases to the captive customers. Tomain, *supra* note 109, at 328.

248. Reducing load on the basis of economic reasons is not necessarily the same thing as demand response. For example, in PJM, certain demand response providers can qualify as Curtailment Service Providers. The demand is registered with PJM and the demand reductions are verified by PJM – making this a tool that PJM can use in not only managing issues in real-time, but also a factor it can plan on having when it conducts its planning. *See PJM Interconnection,* 155 FERC ¶ 61,004 at P 2 (2016) (For more on Curtailment Service Providers).

249. The Commission's ultimate concern, dating back to Order No. 888, has been the scenario whereby one network customer could reduce its coincident peak – for the purposes of network billing – in a manner that would force remaining network customers to essentially absorb the evaded cost responsibility. One possible construction of this argument is that shifting your demand at the peak moments does not mean you are foisting costs onto someone else – the thrust of their argument being that usage at peak is representative of what the customer demands of the utility at the peak moments. That argument may ignore, however, that capacity during the remaining moments is not without cost. That argument may also ignore the idea that utilities are increasingly shifting investment to non-coincident peak moments. A rate design focused only on a peak moment may ignore those benefits and investments altogether. *See generally*, Order No. 888-A, *supra* note 131.

250. For example, because of the manner in which solar peaks earlier in the day, renewable penetration is requiring systems to specifically make investments during off-peak periods.

single hour out of the 720 hours in a month, or just twelve events within the 8,760 hours. Again, each customer is charged for its use during these coincident peak moments, but that single snapshot is not necessarily representative of the ways in which the customer either uses the system or causes costs to be incurred.[251] The problem to be solved, at least initially by the utility, is lining up the rate to be charged with the costs the utility incurs on behalf of the customer.[252]

It is unlikely, in the author's opinion, that the Commission will declare one method superior to another. That's just not how this works.[253] That said, however, demand charges seem imperfect.[254] Demand charges are blunt instruments used to allocate the costs of a diverse and complex system. These charges – which seek to aggregate the costs of a fairly large system and network of sub-components – do not necessarily offer a localized or terribly persistent or fulsome price signal. For example, it is pretty unlikely that each customer impacts the system in the same way and yet, for the purposes of allocating costs of the system, customers are charged a rate that presumes each customer impacts the system on a similar $/kWh basis (i.e., the push and pull of administrative efficiency versus mathematical precision). Moreover, demand charges may place a disproportionate emphasis on peak moments, rendering fairly meaningless – for the purposes of pricing and incentive signaling – the other moments of the year. Demand charges – as predominantly constructed – seem to lack a certain chorus that allows all of the elements to sing in harmony.[255] If anything, the success of the coincident peak method is its relative efficiency (and simplicity) in aligning the costs and benefits of the service,[256] even if not on an exact basis, but preserving "some resemblance" between costs and benefits (in other words, most of the chorus is singing together,

251. Imagine, for a moment, a rate design that permits a Network Customer to charge its storage resources hours before a coincident peak moment only to then use those resources to lower its billing responsibility during the coincident peak moment. While it's true, yes, that the network customer did indeed use less of the system during the peak moment, that usage may not necessarily be representative of the customer's demand of the system.

252. Suedeen G. Kelly et al., *The Subdelegation Doctrine and the Application of Reference Prices Mitigating Market Power*, 26 ENERGY L.J. 297, 299 (2005).

253. Rate design, especially, enjoys a certain degree of deference as it is a careful and deliberate balance of competing interests and objectives. *See, e.g.,* Brancato, *supra* note 171, at 99 (citing "[c]ommissions may have to balance a desire to achieve, on the one hand, a precise correlation between users and the incremental costs for which they are responsible and, on the other, a relative stability of rates. Obviously, a utility tariff can not be changed so frequently that customers are unable to make intelligent purchasing decisions. Such an approach would undermine the entire effort to change rate structures, which is predicated on the belief that consumers will make efficient choices when charged for the costs they actually impose on the system. If these efficient choices are made, the need to build new plants at a greatly increasing cost per unit, dictated by growing use at the peak, will be tempered.").

254. The premise of more precise demand charges is by no means new. Munroe, *supra* note 16, at 214 (citing "[t]here is the need as well for a critical assessment of regulatory changes particularly with reference to pricing flexibility, developing interruptible and curtailable rates to retain customers at risk, and eventually developing continuous load-factor pricing.").

255. The playbook is largely written for real-time pricing, but to date, there is little appetite to move in that direction. *See* Kavulla, *supra* note 36, at 20 (citing "[i]n general, a time-of-use rate with a critical peak price add-on is a reasonable compromise to face customers with both routine contours of price differentials, including demand-related portion of transmission and distribution investments that can be allocated to peak periods (the time-of-use rate) and with events representative of unusually stark scarcity conditions (critical peak price).").

256. Midwest ISO Transmission Owners v. FERC, 373 F.3d 1361, 1364 (D.C. Cir. 2004).

though not necessarily in harmony). What's also challenging is separating signal from noise – were demand charges designed for demand that was only inelastic?

Most recently, the Commission has accepted proposals that seek to better align charges that reflect changes to the operational realities of the utilities – this appears to be the path we are heading down.[257] This path is very much one the Commission cleared when it articulated its policy back in Order No. 888 that utilities are obviously free under section 205 to propose and file methods that reflect their transmission planning.[258] The Courts have upheld this flexible approach, mostly with affirmations that there is no one way to do this and certainly no off-the-shelf solution.[259] That flexibility is more of a reflection of how difficult the task is, as opposed to an outright blessing to proceed with any and all methods.[260]

So, then, what roughly falls under the umbrella of flexibility? Most of the methods in circulation today represent modern variants of the coincident peak methodology for demand allocation, each with its own pros and cons. For the sake of discussion, this Article does touch on a few of these methods.[261] These methods include, but are not necessarily limited to using: (1) average demand; (2) solely non-peak usage; (3) both coincident and non-coincident peak demand; (4) increasing the number of hours considered; and (5) the use of a ratchet. We also touch on other novel concepts as well.

The first alternative is the average demand methodology, where the demand allocation is based on the average demand over a period of time (maybe even over the course of the entire year). If you buy the argument that the utility is planning for all hours, not just a handful of peak hours, then maybe it does make sense to design a rate that takes into account all hours of the year, even if on an average basis.[262] As imperfect as it is, average cost pricing is attended by benefits that cannot be ignored: a certain ease of understanding and predictability for both utility and customer. Even though the Commission rejected Dominion's proposal to use a customer's average demand across the year as a backstop, it did so because

257. The Commission did ultimately express an openness and willingness to Dominion moving from a 1-CP method to a 12-CP method. Even though moving from one coincident peak method to another doesn't seem overly significant on its face, accepting the proposal signaled the Commission's interest in considering a variety of different factors (instead of utilizing something resembling a "one-sized fits-all" approach). This contrast is fairly stark when considering the procedural history involving the use and setting of coincident peaks in Dominion. *See PJM Interconnection, & Va. Elec. and Power Co.*, 109 FERC ¶ 61,012 at PP 45-46 (2004).

258. *See generally* Order No. 888, *supra* note 63. This is, quite possibly, the most nutritionally dense bread crumb that we have – so long as a utility can express a linear relationship between planning and cost allocation, the method will likely be OK.

259. "There is no necessary relationship between a particular method of demand allocation and a particular method of demand billing." Batavia v. FERC, 672 F.2d 64, 83 (D.C. Cir. 1982).

260. To be sure, apart from structural changes, there are other "low-hanging fruit" type items that might work towards "right-sizing" costs and charges. One such fruit is addressing issues with load forecasts and forecasting peak demand. This Article doesn't attempt to tackle this issue, but others have. *See, e.g.*, Todd Aagaard & Andrew N. Kleit, *Too Much Is Never Enough: Constructing Electricity Capacity Market Demand*, 43 ENERGY L.J. 79, 88 (2022).

261. The review of possible alternatives is limited, purposefully, as this section could easily become the equivalent of letting a thousand flowers bloom (and the associated risk of letting the garden become overrun). There are nearly endless variants and possibilities.

262. KAHN, *supra* note 43, 95-96, 101-03.

Dominion was unable to support its proposal.[263] That lack of support stemmed from Dominion's own admission that its concerns over cost shifts were still hypothetical in nature.[264]

It is not entirely clear from the Commission's order whether there would have been a flaw with Dominion's proposal.[265] Would the backstop have been viable? Or would that have been the fatal flaw rendering the proposal unjust and unreasonable, overall, when some customers are allocated costs using their peak demand while others are allocated costs using their average demand. Would Dominion have had more success had they only proposed to use an average demand?[266] It's not clear. On one hand, it is true that the average demand concept continues to afford the customer control, even if on a muted basis (i.e., a rate based on usage is a good thing, even if that usage is averaged out over the course of a certain length of time, leaving the customer with some agency over its billing). On the other side of that coin, a potential issue with the use of average demand is that it blunts the only lever a customer has in affecting, or driving, ultimate billing. In other words, while the rate is based on a customer's average demand, the customer's ability to impact its rates are considerably less than under a coincident peak paradigm.

There may also be lessons to learn from a recent Pacific Gas & Electric ("PG&E") case, where the utility proposed a rate for its stand-by customers – in essence, charging a unique rate to its stand-by customers.[267] In determining the rate, PG&E developed what it phrased a "probabilistic" method.[268] Under the method, rates were based on the percentage of "contract demand" that the standby class would likely use rather than usage at the time of system peak.[269] This, of course, represented a deviation from the coincident peak method that relies on

263. 162 FERC ¶ 61,136, at P 25 (citing "[t]raditionally, public utility transmission providers have relied on the demand of its transmission customers at its system's coincident peak to determine each customer's network transmission service charges. A public utility transmission provider may adopt a different approach, but it must adequately support it. Here, Dominion has failed to do so. Dominion relies on a hypothetical situation under which a transmission customer could reduce its load at Dominion's coincident peak to avoid Network Service charges, shifting costs to other transmission customers; however, Dominion has not provided any evidence that such cost shifts have actually occurred or are likely to occur.").

264. The D.C. Circuit recently spoke to the potential for a customer using batteries to "reduce its apparent demand to zero during system peak, eliminating [the customer's] responsibility for its pro rata share of [the utility's] fixed costs." The D.C. Circuit invited the utility to return to the Commission for relief should the customer's deployment of batteries result in a confiscatory outcome. Duke Energy Progress, LLC v. FERC, 23 F.4th 1008, 12 (D.C. Cir. 2022).

265. *See Old Dominion Elec. Coop*., 172 FERC ¶ 61,161 at PP 1, 7 (2020) (accepting modification from a 12-CP methodology to an average hourly demand allocator for one of three components of the demand rate).

266. It is the author's view that the ultimately accepted 12-CP proposal best represented and approximated the average demand that each customer causes. While not perfect, it nevertheless better represented the customer's usage throughout the year. That said, it's not clear the issues *really* went away (instead, the move from 1-CP to 12-CP blunted the issue but did not resolve it directly).

267. Cogeneration Ass'n of Cal. v. FERC, 525 F.3d 1279, 1281 (D.C. Cir. 2008) (citing "Under this method, rates are based on the percentage of 'contract demand' the standby class is likely to use, rather than usage at the time of system peak. Contract demand is the maximum amount of electricity a standby customer can draw under the terms of its contract.").

268. *Id.*

269. *Id.*

shares each customer uses of the system when demand is at its "zenith" (and, notably, historical usage). The question for us is one of applicability to the scenarios applied here – the contract demand concept is interesting, as it represented a case where the Commission permitted a utility to charge a rate (based on expected usage) for a unique type of customer.[270] Network service is not based on a reservation (that's a role and construct for point-to-point transmission service) and the applicability of that sort of rate construct to the premise of network service seems tenuous at best. The question, for the sake of a complete thought process, is nevertheless an interesting one: does a model that puts the burden on the customer of making an appropriate reservation make sense (with, of course, the appropriate push-and-pull levers of incentives and penalties for meeting or exceeding the reservation, respectively)?

Another alternative is utilizing a blend between coincident peak and non-coincident peak data, which would try and capture both the peak moments *and* the non-peak impact that a customer has on a system.[271] This method can be more accurate than the average demand methodology, but it still has the potential to underestimate costs (if, for example, more weight is given to the non-peak hours than the peak hours). Ultimately, the choice of methodology depends on the specific circumstances and goals of the allocation process.[272] The use of non-coincident peak factors is not terribly controversial despite the Commission's clear preference for utilizing coincident peak information to derive demand charges. The question of whether or not to utilize non-coincident peak factors is not necessarily a policy question, but rather one to be addressed on the merits – are non-coincident peak factors affecting the incurrence of capacity costs? The Commission has spoken to this and has expressly allowed utilities to consider factors beyond coincident peak.[273]

The Commission's order in this case provides more than a map and a compass – the Commission expressly acknowledged several factors that will prove relevant and salient in the years to come. First, the Commission acknowledged the appropriateness of considering factors beyond just system peak as it relates to allocating demand charges.[274] Second, the Commission acknowledged the concern – the

270. *Id* at 1282.

271. *Cogeneration Ass'n of Cal.,* 525 F.3d at 1286.

272. This is why, for example, this article takes the position that solutions will need to be fact- and case-specific (i.e., to manage the unique interaction between utility and customer). This is in line with the Commission's long-settled history favoring settlements. *See, e.g.,* Mary Ann Walker, *Settlement Practice at the FERC: Boom or Bane*, 7 ENERGY L.J. 343, 344 (1986).

273. 172 FERC ¶ 61,054, at PP 32-33. As explained elsewhere in this article, the Commission accepted Dominion's proposal as a method for resolving the tension created by load reductions that skewed the actual usage of, and dependency on, the transmission system. *See also* Small, *supra* note 40 at 135 (explaining that the Commission may also evaluate factors such as "[t]he full range of a company's operating realities including, in addition to system demand, scheduled maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales.").

274. 169 FERC ¶ 61,041, at P 54 (citing "[h]ere, we find that Dominion's proposed 12-CP methodology aligns with how Dominion conducts transmission system planning. Dominion has shown that, in the past five years, its transmission planning has changed to factor-in additional load periods because it is experiencing both winter and summer peaks, a changing capacity mix, growth of distributed energy resources, growth in renewables, and replacement of aging transmission infrastructure.").

concern stemming from Order No. 888 – that load reductions during coincident peak moments do not represent a customer's actual usage or need of the system.[275] In that regard, the argument is that demand was "artificially lowered" solely for the purpose of billing. Third, the Commission acknowledged that utilities are planning their systems to meet a wider variety of concerns and issues beyond just peak usage – and thus aligning planning that accounts for things beyond peak and the ultimate rate charged.[276] The task inherent in determining whether any particular method is just and reasonable will be determining the nexus between a customer's own operations and load profile along with whether the demand charges align with those parameters.[277]

Critically, as useful as different demand-side management tools are, their ability to affect or reduce demand charges is limited by their ability to offset investments that the utility must make on behalf of the customer.[278] The utility, of course, has an obligation to serve. The thrust of the question posed here is whether that "offset" means the customer is essentially responsible when the lights go out.[279] The very fact- and case-specific negotiation will center upon questions such as how much of the customer's load is the utility required to serve – all, none, some?

A related concept is thinking about whether to simply increase the number of hours of demand used – going well above twelve to consider a different number of hours (enabling the utility and customer to identify the most representative number of hours – be it twenty, fifty, one-hundred, or whatever the case might be). This idea is something of a blend – a shift away from coincident peak, solely, of course, and trending somewhere between non-coincident peak information and average demand. This would be more in line with utilizing non-coincident peak factors, but moving away from the idea that coincident peak can only be some number between one and twelve – and instead, a reflection that there are a variety

275. *Id.* at P 60 (citing "[w]hile we recognize system benefits may result from voluntary load reductions, the record in this proceeding demonstrates that voluntary load reductions during the 1-CP events are obscuring the level of transmission system usage by Dominion's customers. As detailed in the examples offered by Dominion, certain wholesale customers are voluntarily reducing demand during the 1-CP events and returning to normal levels of demand during off-peak times. This can result in Dominion not having an accurate depiction of transmission usage with which to plan the transmission system in a manner that ensures all demand can be reliably served.").

276. *Id.* at P 55 (citing "Dominion points to the growth of distributed generation in creating operational challenges, such as backflow occurring onto the transmission system during light load periods, which requires transmission upgrades. Additionally, Dominion notes that data center growth has a high load factor, which influences year-round monthly peaks, and that renewable generation resources are being sited in areas further away from heavy load centers, covering a broader geographic area with multiple points of interconnection.").

277. *Id.* at P 55.

278. The threshold question, at least in the author's opinion, is the degree to which the utility is obligated – literally, standing ready – to ensure that it has adequate transmission service to fulfill the needs of the network customer, particularly when, or if, the behind-the-meter generation is unavailable or cannot be called upon. These questions seem like the very fact-specific questions that need to be tailored between utilities and customers.

279. Cudahy, *supra* note 1, at 357 (citing "one of the merits of territorial electrical franchise has been their function of defining who is responsible in a particular place for the adequacy, reliability, reliability, and quality of the electric supply.").

of meaningful hours. Although this wouldn't move the rate design closer to something resembling "marginal costs," it would nevertheless seem to move towards a better measurement of usage, and this reliance, on the transmission system.[280]

Another fairly prevalent method is what is referred to as the "ratchet."[281] Concerns and issues with the viability and sustainability of coincident peak pricing are not new – in fact, you could argue, these issues are quite "arcane" and have been debated thoroughly for decades.[282] Ratchets have been one mechanism for navigating the debate. A ratchet, simply, is a way to essentially create a "minimum" threshold for billing.[283] At the risk of oversimplifying the strategy employed by this rate mechanism, the so-called "ratchet" tool is a way for the utility to create more rate stability year to year. The Commission has accepted this approach in different contexts but has expressed a general reluctance to employ the ratchet, generally.[284] Because the coincident peak method invites a certain amount of volatility in that usage can change drastically depending on a variety of circumstances, utilities have attempted to utilize the "ratchet" method as a means to mitigate the volatility.[285] However, the Commission has expressed a generalized reluctance towards the use of a ratchet as, in one circumstance, the ratchet could even enable some customers to subsidize others.[286]

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280. An efficient rate design will lead to customer behavior that optimizes system costs. *See* Mark Lebel & Frederick Weston, *Demand Charges: What Are They Good For? An Examination in Cost Causation*, REGUL. ASSISTANCE PROJECT 7 (Nov. 2020), https://www.raponline.org/wp-content/uploads/2020/11/rap-lebel-weston-sandoval-demand-charges-what-are-they-good-for-2020-november.pdf.

281. One purpose of a ratchet is to encourage conservation at time of system peak. *See, e.g.,* Carolyn Brancato, *supra* note 171, 86 (citing "[a] demand ratchet is a form of rate design whereby customers are billed throughout the year on the basis of their maximum annual demand or their maximum demands during the peak capacity season. A customer pays a rate for his maximum peak demand and then is charged a monthly demand rate which is a fixed percentage of his annual or seasonal peak demand. If the original peak is exceeded, that new peak becomes the basis for charging the customer."). *See also* Small, *supra* note 40, at 137 ("A ratchet imposes minimum payment obligations on utility customers. Two determinative factors in deciding whether a ratchet should be allowed are whether the customer is a full requirements customer, and whether the demand costs are allocated on a 12 CP basis.").

282. Kan. Gas & Elec. Co. v. FERC, 758 F.2d 713, 714 (D.C. Cir. 1985).

283. Reasonable minds can debate whether or not a ratchet is similar in nature to the so-called "minimum bill." A minimum bill is essentially a bargain between utilities and customers whereby, even if the customer consumes no energy, the customer will nevertheless compensate the utility with a minimum amount of revenue for "standing ready" to serve. *See generally* Jim Lazar, *Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches to Recovering Basic Distribution Costs*, REGUL. ASSISTANCE PROJECT (Nov. 2014), https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-electricutilityresidentialcustomer-chargesminimumbills-2014-nov.pdf.

284. *See Conn. Light & Power Co*., 14 FERC ¶ 61,139, at pp. 2-3 (1981), *aff'd sub nom.* Second Taxing Dist. of City of Norwalk v. FERC*,* 683 F.2d 477, 487-88 (D.C. Cir. 1982); *Union Elec. Co.*, 12 FERC ¶ 61,239, at p. 61,586 (1980).

285. The logic being that ratchets "more fairly charge customers for their share of the company's generation and distribution costs and tend to reduce customers' demand fluctuations." Given that the ratemaking incentive works towards "average" demand, this theory appears to have been undone by caselaw seemingly demonstrating that ratchets reduce the incentive customers previously had to manage or reduce their demand at the time of system peak. *See* Brancato, *supra* note 171, at 86.

286. *Cent. Ill. Light Co.,* 10 FERC ¶ 61,248, at p. 13 (1980) (citing "it follows that those low-usage members of the wholesale class affected by operation of the ratchet during a given month will in effect be subsidizing those class members with recorded floors above the 'ratcheted' level.").

To be sure, there are also nutritionally dense breadcrumbs to feast upon that do not involve coincident peak methods, at least not exclusively.[287] In one case, the Commission accepted a rate design that featured an "initial block" and a "tail block" – effectively, a blending of embedded costs and marginal costs within the same rate.[288] The initial block represented 80% of the average system costs (roughly speaking, the embedded costs). For demand (and energy use) beyond the 80% the remaining 20% tail block was designed to represent the estimated long-run marginal costs for future capacity and energy.

In another case, we have the NYISO model. There, the transmission service and pricing model does not rely on coincident peak methods for allocating the demand costs of the transmission system.[289] Significantly, the NYISO tariff does not necessarily abide by the concepts of point-to-point or network services.[290] Parties taking service under the New York Independent System Operator (NYISO) tariff are billed based on actual energy withdrawals to service load (including, for example, the cost of congestion to serve that load).[291] As opposed to a demand charge, NYISO's framework seemingly factors in not only the fixed costs of the system,[292] but also the marginal costs (e.g., congestion) of administering and providing transmission service.[293] To be clear, these are separate charges.[294] Although NYISO did, at one point, attempt to remove network service from its tariff, the Commission rejected that on the basis that, even if customers did not "avail themselves" of network service, the service should still be available.[295] This model

287. In the author's opinion, right-sizing demand charges mirrors the theory of right-sizing the capacity contributions of different generating technologies (otherwise known as the Effective Load Carrying Capability). *See PJM Interconnection,* 183 FERC ¶ 61,009 at PP 29 (2023) (citing "[t]hus, we find that PJM's proposal to strengthen the ability of its ELCC model – the objective of which is to estimate the reliability contribution of resources in a future Delivery Year based on forecasted system conditions – to account for deliverability is just and reasonable.").

288. *See generally Norwood*, *supra* note 38.

289. In one context, NYISO described its model as less dealing with physical reservations and more of a Commission-approved "financial reservation" model (without the physical features, such as transmission service requests). *See N.Y. Indep. Sys. Operator, Inc*., 123 FERC ¶ 61,134 (2008).

290. In fact, initially, the NYISO framework did not offer the option for firm point-to-point transmission service. *See Cent. Hudson Gas & Elec. Corp., et al.*, 86 FERC ¶ 61,062, at p. 8 (1999) (citing "[t]here is no notion of firm service at a fixed price under the tariff.").

291. *Id.* at 6-7.

292. *Id.* at 31 (citing "the Transmission Service Change is an hourly rate that recovers the embedded fixed costs of the transmission system. It is assessed on the basis of hourly metered loads for deliveries within the ISO's control area.").

293. *Id.* at 34 (citing "[t]he second rate component is the Transmission Use Charge which recovers any congestion costs associated with the transaction and marginal losses.").

294. 86 FERC ¶ 61,062, at P 31 (citing "[t]here are three components to the transmission charge included in the New York ISO Tariff. They are as follows: (1) the Transmission Service Charge; (2) the Transmission Use Charge; and (3) the NYPA Transmission Adjustment Charge.").

295. *See N.Y. Indep. Sys. Operator, Inc.,* 131 FERC ¶ 61,074 at P 14 (2007) (citing "*See New England Power Pool*, 83 FERC ¶ 61,045, at p. 61,231 n.30 (1998) (requiring NEPOOL to reinstate point-to-point service as an option for transmission service; 'the choice must be the customer's to make, not the transmission provider's to dictate.'").

relies less on a "snapshot" in time and more on the cost of the service at the time the service is being provided.[296]

Finally, it wasn't all that long ago that performance-based ratemaking was considered viable – these programs presented the theoretical framework for leveraging rewards and penalties as a means of aligning incentives, efficient investment decisions, and adequate reliability.[297]

IX. CONCLUSION

The coincident peak load allocation method remains the bread-and-butter of allocating demand costs associated with the transmission system.[298] Its place in the history books of ratemaking methodologies renders it, and affords it, reasonable deference (even if, for example, other methods could be justifiably reasonable so long as they're supported).[299] The importance of getting pricing right – particularly for peak moments and moments of scarcity – is possibly more acute than ever. For example, while coincident peak methodologies are accustomed to wrestling with the normal variability that attends fluctuating weather patterns, those weather patterns seem to be getting more extreme by the year.[300]

The so-called energy transition has yielded serious questions about the future of the industry.[301] Ideas and issues are as bountiful as the offerings at your local buffet – the overburdened plate includes issues running the gamut of the electrification of everything, renewable portfolio standards, cap-and-trade programs, distributed energy generation, state policies, methods for solving resource adequacy, and a massive transmission build-out.[302] And while all of those issues deserve

296. Intertwined with the transmission service paradigm in NYISO is that transmission works in tandem with the "locational-based marginal pricing" (otherwise, what we refer to as locational marginal pricing) and a financial instrument to manage congestion costs, called "transmission constraint contracts." *See* 86 FERC ¶ 61,062, at PP 3-4.

297. *See, e.g.,* Richard P. Bonnifield & Ronald L. Drewnowski, *Transmission at a Crossroads*, 21 ENERGY L.J. 447 (2000) (For a fuller discussion of performance-based rates).

298. *See, e.g.*, 169 FERC ¶ 61,041, at P 53 ("Traditionally, public utility transmission providers have relied on the demand of its transmission customers at its system's coincident peak to determine each customer's network transmission service charges.").

299. *See* Order No. 888, *supra* note 63, at 31,736 (cross-referenced at 75 FERC ¶ 61,080), *order on reh'g*, Order No. 888-A, *supra* note 131 (cross-referenced at 78 FERC ¶ 61,220), *order on reh'g*, Order No. 888-B, *supra* note 183, *order on reh'g*, Order No. 888-C, *supra* note 183, *aff'd in relevant part sub nom.* Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom.* New York v. FERC, 535 U.S. 1 (2002) ("Because network service is load based, it is reasonable to allocate costs on the basis of load for purposes of pricing network service. . . . [W]e recognize that alternative allocation proposals may have merit. . . . [T]hey will be evaluated on a case-by-case basis and decided on their merits.").

300. Maximilian Auffhammer et al., *Climate change is projected to have severe impacts on the frequency and intensity of peak electricity demand across the United States,* 114 PROC. NAT'L ACAD. SCI. 1 (2017).

301. By now, we know that we're converting, even if slowly, to a low carbon "energy economy," but this conversion will not be cheap. The primary question posed by this article has to do with the cost of transmission and wondering whether the existing levers and mechanisms are in alignment and producing the right signals for both investment and usage. *See, e.g.,* Harvey Reiter, *Removing Unconstitutional Barriers to out-of-State and Foreign Competition from State Renewable Portfolio Standards: Why the Dormant Commerce Clause Provides Important Protection for Consumers and Environmentalists*, 36 ENERGY L.J. 45, 45 (2015).

302. One construction of this statement is that "improving technologies alone is insufficient, and policy support has been indispensable to demand response's success, as is the case for other distributed energy resources.

serious consideration, this Article does not seek to overwhelm the plate even further. In fact, the Article only considers what might happen to modern day rate design and ratemaking in the face of these significant changes – something of a forgotten yet fundamental element underlying so many of the moving parts on the surface. The system is changing, so should the cost allocation for transmission?

To be sure, there is nothing fundamentally defective about the way that transmission is currently priced or allocated.[303] In fact, the rules of ratemaking haven't changed much.[304] This article does not attempt to ascribe value to the different methods. The contribution of this Article is neither a diagnosis nor prognosis. The entire point of this article is to pause, momentarily, to consider these issues and what the road ahead *might* look like. Is the coincident peak method the most efficient method? No – no pricing method is perfect in its ability to harmonize the universe of competing interests, incentives, and objectives.[305] It is also unlikely for there to be a uniform approach or unanimous consensus on any of these issues. In fact, it is unrealistic to expect as much.[306] And so, in that regard, this Article does not attempt to answer the question of whether a resolution, or solution, even exists. As unsatisfying as that is, the underlying fundamentals of this particular policy dilemma could very well change in short order. Modern day technological advancements are advancing rapidly and will only serve to animate (or frustrate) further policy debates about how the system is being used and how to apportion the costs with that usage. As just one example shows, storage being considered and used as a transmission asset would seemingly render the very hypothesis being explored and tested in this text unambiguous: demand charges were designed for a system that no longer exists.

As much time as we spend thinking about the right resource mix and how much that mix will, or should, cost,[307] it seems equally important to get the cost of delivery right, too.[308] For now, while modifying existing rate designs seems to be

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Working out the rules for participation has required considerable tinkering and iteration, and the path of progress has hardly been straight." Eisen, *supra* note 103, at 351.

303. *See, e.g.*, Me. v. FERC, 854 F.3d 9, 23 (D.C. Cir. 2017) ("Statutory reasonableness allows a 'substantial spread' of potentially reasonable rates."). In fact, the Commission once acknowledged the "complexity of estimating marginal cost on the transmission grid" and "encourage[d] experimentation in this area." *Pricing Policy Statement*, *supra* note 127, at 11.

304. *See, e.g.*, JAMES C. BONBRIGHT, *Principles of Public Utility* Rates, POWELL GOLDSTEIN LLP 31 (1961), https://www.raponline.org/wp-content/uploads/2016/05/powellgoldstein-bonbright-principlesofpublicutilityrates-1960-10-10.pdf (citing "[i]nstead, the merits of alternative rules of ratemaking are to be judged solely by reference to their functional efficiency in getting the work of the world accomplished – in attracting capital to public utility enterprises, in supplying incentives to high-grade management, in controlling the demand for the service, etc.").

305. Harmonizing costs and pricing are matters that "have been with us for a long time and they are to some degree indeterminate" and pose a "perennial dilemma." *See* Cudahy, *supra* note 1, at 359.

306. *See, e.g.*, Craig Glazer et al., *The Future of Centrally Organized Wholesale Electricity Markets*, FUTURE ELEC. UTIL. REGUL. 47 (2017), https://eta-publications.lbl.gov/sites/default/files/lbnl-1007226.pdf (arguing that the "electric utility industry speaks with a unanimous voice on very few questions.").

307. Harvey L. Reiter, *When Is Renewable Not Renewable: Constitutionality State Laws Denying New Large Canadian Hydroelectric Projects Treatment as Renewable Res.*, 5 HARV. BUS. L. REV. ONLINE 76, 76 (2015).

308. Patrick J. McCormick II. & Sean B. Cunningham, *Requirements "Just and Reasonable" Standard: Legal Bases for Reform Elec. Transmission Rates*, 21 ENERGY L.J. 389, 389 (2000) (citing "The widening gap

the more straight-forward path to addressing the issues presented in this article, these modifications would likely represent mere variants to an outdated model. Is it worth exploring novel ideas and concepts to tackle the novel issues of the future?[309] Maybe – the Commission is no stranger to innovation and competition – but for now, the majority of our focus rests on the mantle of the ideas that have come before (with a specific focus on identifying whether there's continued utility and value in some of these other methods).[310]

Indeed, it is possible there's space for a more innovative solution. In fact, there is no exact rulebook suggesting transitions are without turbulence. Case in point, there was a time and place when the Commission considered an alternative to network and point-to-point transmission service products.[311] The Commission ultimately terminated the rulemaking – given the passage of time and developments within the industry – but the premise of the proposed rulemaking is still a good one and represents the idea that the Commission can identify solutions that "right-size" a solution to a particular problem.

What was true around the time of open access remains true today: flexibility is paramount.[312] As the Commission did then, it will have to do now: identify a path forward, merging and weaving together both old and new. In the years leading up to Order No. 888 and the Commission's Transmission Pricing Policy Statement, the Commission developed its policy – a foundation laid piece by piece,

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between transmission capacity and growing demands on the system threatens to make transmission function as more of a "bottleneck" than a "pipeline" for increasingly competitive markets in electricity. . . . Transmission rate reform, to encourage new investment in transmission infrastructure, is an essential ingredient in the remedy for the "transmission investment gap.").

309. The Commission is no stranger to exploring and adopting, when appropriate, innovative approaches to pricing problems. *See, e.g*., Heidi Werntz, *Let's Make Deal: Negotiated Rates for Merch. Transmission*, 28 PACE ENVTL. L. REV. 421, 451 (2011); *see also,* Jon Wellinghoff et al., *Facilitating Hydrokinetic Energy Development through Regulatory Innovation*, 29 ENERGY L.J. 397 (2008).

310. As ambitious as this article desires to be, new information, dialogue, and caselaw may render the Article's contents obsolete, as our understanding of the issues will evolve naturally over time, sometimes rapidly. There is, inherently, no right or wrong answer. Furthermore, no statement in this Article should be interpreted as a criticism of any particular theory, argument, policy, or case – the purpose of this Article is to seek understanding, serve as a decent custodian of history and caselaw, and attempt to think holistically about pricing.

311. In 1996, the Commission issued a Notice of Proposed Rulemaking aimed at understanding whether having two products – each with their own unique terms and conditions – was the best vehicle for accomplishing open access. *See* Notice of Proposed Rulemaking, *Capacity Reservation Open Access Transmission Tariffs*, FERC Stats. & Regs. ¶ 32,519, 61 Fed. Reg. 21,847, 21,848 (1996) (to be codified at 18 C.F.R. pt. 35). We also know that the Commission does not view these things in a vacuum (in that, for example, modifications to transmission service are not viewed in isolation from modifications to transmission rates); *see* Order No. 888-A, *supra* note 131, at 240 (citing "any modifications to the non-price terms and conditions established in the pro forma tariff must be fully supported by the utility and the appropriateness of such proposed changes will be evaluated by the Commission for consistency with the proposed rates or rate methodologies.").

312. *See generally* 61 Fed. Reg. 21,847. In 1996, the Commission issued a Notice of Proposed Rulemaking aimed at understanding whether having two products – each with their own unique terms and conditions – was the best vehicle for accomplishing open access. *See* Order No. 888-A, *supra* note 131, at 240 (citing "[A]ny modifications to the non-price terms and conditions established in the pro forma tariff must be fully supported by the utility and the appropriateness of such proposed changes will be evaluated by the Commission for consistency with the proposed rates or rate methodologies."). We also know that the Commission does not view these things in a vacuum (in that, for example, modifications to transmission service are not viewed in isolation from modifications to transmission rates).

brick by brick – through case law. It is not clear that the Commission has issued any "brick" yet that would represent the foundation of a solution for the problems articulated in this article.

Possibly, more principally than the narrow issues raised in this Article, is the need for harmony between retail markets and wholesale markets[313] – as outlined by Commissioner Christie, the price signals sent to load are muted,[314] as their electric bills include non-by-passable charges, for example.[315] More often than not, there is the faintest of eye contact between the two, let alone a handshake indicating some form of agreement or unity between the two related, but separate elements of electric delivery.[316] Possibly a story for the next article.

313. Severin Borenstein & James Bushnell, *Do Two Electricity Pricing Wrongs Make a Right? Cost Recovery, Externalities, and Efficiency,* 14 AM. ECON. J.: ECON. POL'Y 80, 100 (2022). Not only that, but retail pricing also continues to suffer from a number of distortions – most notably, the idea that retail prices do not fluctuate with the momentary fluctuations of supply and demand. The authors of that article make persuasive arguments – pulling on several strands of literature – that there are several pervasive distortions with respect to retail pricing and that, critically, markets with multiple distortions may not be necessarily improved by addressing one distortion in insolation.

314. *See, e.g*, Serota, *supra* note 96, at 792 (citing "[r]atepayers are not responsive to price signals because these users are not charged real time marginal prices.").

315. Christie, *supra* note 42, at 19.

316. *See, e.g.,* Ashley Brown & Susan Kaplan, *Retail and Wholesale Transmission Pricing: A Troublesome Divergence?* HARV. ELEC. POL'Y GRP. 5 (1999); *see also, Michael* Giberson & Lynne Kiesling, *The Need for Electricity Retail Market Reforms*, 40 REGUL. 34 (2017).