Decarbonizing in the Face of Reluctance

Reducing Power Sector Emissions in Baltimore, Maryland

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America's electricity grid is undergoing a massive transition, driven by changing economics as well as the need to rapidly decarbonize in response to climate change. Gone are the days of large baseload generating stations like coal and nuclear plants, replaced by more flexible and modular technologies from solar and wind to combined-cycle natural gas plants and energy storage. Distributed energy resources (DERs) like rooftop solar and batteries are proliferating across the grid, being installed by homeowners seeking lower electricity rates and energy independence. Calls for more flexible demand as well as greater energy efficiency are driving utilities to engage with their customers for the first time, deploying "smart meters" and creating demand response pilot programs. Many states are passing sweeping clean energy policies, providing substantial subsidies to certain technologies like wind, solar, and nuclear in an attempt to lower their state carbon footprints.

At the same time, the electricity grid has increasingly begun to embrace economic competition. The issuance of landmark Orders 888 and 2000 by the Federal Energy Regulatory Commission (FERC) a little over two decades ago has led to the emergence of competitive wholesale electricity markets, coordinated by regional entities known as Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs). With the growth of these markets has come the death of the traditional vertically-integrated electric utility model in many parts of the United States, including Maryland, the focus of this paper. Generation, and transmission to a lesser extent, is now competitively procured. 14 states, including Maryland, have even opened up the retail side to competition, allowing customers to choose from which company they get their electricity supply. Distribution—the actual ownership and operation of the poles and wires getting electricity to customers—remains a tightly regulated monopoly.

It is in this rapidly changing landscape that Maryland's regulators must act, balancing the challenge of having to respond to climate change via deep decarbonization with the need to maintain economic competitiveness. These two issues have recently come to a head in the PJM Interconnection, the RTO to which Maryland belongs, spanning 13 states in the Mid-Atlantic region. Renewable energy generators, receiving subsidies from certain states like New Jersey and Maryland, had been bidding into the capacity market at extremely low prices, putting traditional fossil fuel generators at a disadvantage and lowering their revenues. The extension of price floors to these renewable energy facilities at the behest of fossil fuel generators, however, has limited their revenues from the market and reduced clean energy expansion. Regulators are stuck with the tricky position of how to remain technology-neutral in an age when fossil fuels are feeling the pinch of state policies that finally recognize—and make more expensive—the greenhouse gas (GHG) externalities associated with energy generation.

In this paper, I address not only the challenge facing PJM as they attempt to fix the tensions plaguing their capacity market but the greater difficulties that regulators today are grappling with, from attempting to make demand more responsive to reforming distribution company regulation to embrace a more decentralized grid. To do this, I study the conditions experienced in a representative portion of PJM and my hometown: Baltimore, Maryland. I break this paper into four portions, each addressing a different component of the electricity transportation process: distribution, transmission, generation, and retail. First, I provide a brief overview of the regulatory context of Baltimore, Maryland, and PJM.

Introduction to the Regulatory Context

Baltimore is a medium-sized city of about 600,000 people, located along the Chesapeake Bay in the center of Maryland. A former port and major export hub, the city is now home to employers like Johns Hopkins University & Hospital, several banks, and federal institutions like Social Security.[1] The region has a moderately humid climate, with four seasons and temperatures ranging from 20-30°F in the winter to 90°F+ in the summer. This results in seasonally-variable load curves, with the highest peaks occurring in the summer months (see Figure 1 in Appendix).

Socially, the city is plagued by deep inequalities and the legacy of racial segregation through redlining policies from the 1930s. This has resulted in severe disparities between wealthy, largely white neighborhoods and impoverished, largely black and Latino neighborhoods, with as much as a 20-year gap in life expectancy across zip codes.[2] In the energy context, residents with lower incomes can struggle to pay electricity bills, routinely spending 10% or more of their monthly income (compared to 2.3% of income spent by wealthier residents), in part due to older homes being less well-insulated and having less efficient devices.[3] The COVID-19 pandemic has exacerbated this gap, with a 30% rise in households unable to pay their electricity bills.[4] Energy justice must thus also be of principal concern and importance to regulators working in Baltimore (although these inequities are by no means unique to Baltimore).

Baltimore Gas & Electric (BGE) is Baltimore's primary distribution utility (see Figure 2 in Appendix for map of service area), possessing sole ownership of all power lines and equipment. They are an investor-owned utility (IOU) servicing 1.3 million customers[5] and have been granted domain over their territory of service by the Maryland Public Service Commission (PSC), which oversees all utilities in the state. BGE is a subsidiary of Exelon Corporation, which has separate subsidiaries owning generation, including Constellation Energy (a major owner of

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[1] "Major Employers," *Live Baltimore*, accessed February 10, 2021, https://livebaltimore.com/discover-baltimore/major-employers/

[2] "20-Year Gap in Life Expectancy Between Richer, Poorer Areas of Baltimore," CBS Baltimore, July 6, 2017, https://baltimore.cbslocal.com/2017/07/06/life-expectancy-baltimore/

[3] Julian Spector, "Where America's Poor Pay the Most for Electricity," Bloomberg CityLab, April 14, 2016, https://www.bloomberg.com/news/articles/2016-04-14/the-u-s-cities-where-electricity-costs-more-for-low-income-households

[4] Colin Campbell, "'A Tsunami Waiting to Happen': Lawmakers, advocates say Maryland needs to fix help line for utility bill assistance," *Baltimore Sun*, October 29, 2020, https://www.baltimoresun.com/coronavirus/bs-md-utility-assistance-20201029-yksinsiaqbglxkzqlln4c6frei-story.html

[5] "Regional Demographics," BGE, accessed February 18, 2021, https://www.bge.com/DoingBusinessWithUs/Pages/RegionalDemographics.aspx

generating stations in Maryland, including a large nuclear plant and several coal plants).[6] This separation of generation and distribution was required by law when Maryland deregulated its electricity sector in 1999 with the passage of the Electric Customer Choice and Competition Act, opening up both generation and retail to competition while leaving distribution as a regulated monopoly.[7] Now, customers have the ability to choose their supplier, although BGE is required by law to maintain a Standard Offer Service (SOS) default.

Maryland is fairly progressive when it comes to supporting renewable energy. The state has a Renewable Portfolio Standard (RPS) committing to 50% renewables by 2030, including 14.5% from solar and 1,200 MW from offshore wind.[8] In terms of their actual generation profile, the state produces 42.3% of its energy from nuclear, 39.4% from natural gas, 9.4% from coal (this has fallen rapidly in recent years due to several coal plant closures), and 12.3% from renewables including solar, wind, and hydroelectric (see Figure 3 in Appendix).[9] The state imports about 35% of its electricity supply,[10] including 75% of its renewable energy.[11] The commercial sector is the largest consumer at 48% of total electricity, with the residential sector comprising 45% and the industrial sector at 7% (lower than other more industrialized states).[12]

On a more regional scale, Maryland is part of the Eastern Interconnection and participates in the PJM Interconnection, a Regional Transmission Organization (RTO) comprised of 13 states (see Figure 4 in Appendix) and regulated by the Federal Energy Regulatory Commission (FERC). Maryland is also a member of the Regional Greenhouse Gas Initiative (RGGI), an 11-state cap-and-trade market for greenhouse gases (GHGs).

Distribution Sector

The Maryland PSC uses a cost-of-service remuneration procedure for distribution utilities, whereby the utility is allowed to recover all of its costs deemed "prudent," plus a reasonable rate of return. The amount the utility receives, called its revenue requirement (RR), is calculated using the following formula: $RR = r(RB) + E + D + T$, where $r$is the rate of return (i.e., weighted average cost of capital, including long-term and short-term debt as well as common equity and preferred stock), $RB$is the rate base (investment in the form of capital expenditures minus depreciation), $E$is the operating expenses (including O&M, administrative, insurance),$D$is depreciation and amortization, and $T$is the taxes. The revenue requirement is

[6] "A Diverse Portfolio with Clean Energy at its Center," Exelon, accessed February 18, 2021, https://www.exeloncorp.com/companies/exelon-generation
[7] "Regulatory Activities—Electricity," Maryland Office of People's Counsel, accessed April 24, 2021, http://opc.maryland.gov/Regulatory-Activities/Electricity
[8] Catherine Morehouse, "Maryland 50% RPS bill doubles offshore wind target, expands solar-carve out," April 10, 2019, https://www.utilitydive.com/news/maryland-50-rps-bill-doubles-offshore-wind-target-expands-solar-carve-out/552421/
[9] Data listed are for 2020. "Electricity Data Browser," U.S. Energy Information Administration (EIA), accessed April 27, 2021, https://www.eia.gov/electricity/data/browser/
[10] Calculated by subtracting total retail sales from total generation. "Maryland Electricity Profile 2019," EIA, accessed April 27, 2021, https://www.eia.gov/electricity/state/maryland/
[11] "Maryland at a Glance: Energy," Maryland State Archives, November 19, 2020, accessed April 27, 2021, https://msa.maryland.gov/msa/mdmanual/01glance/html/energy.html
[12] "Maryland State Energy Profile," EIA, October 15, 2020, accessed April 27, 2021, https://www.eia.gov/state/print.php?sid=MD

determined as part of a rate case, which is initiated by the utility, typically to increase its revenues. For costs to be approved by the PSC, they must be deemed "prudent" on property that is "used and useful" by the utility.[13]

Cost-of-service regulation is standard practice among most American utilities and PSCs. There are several critiques, however, of this model, the main one being that it does not incentivize utilities to minimize cost, as they are guaranteed to make enough money to pay off all costs deemed "prudent."[14] In practice, because the regulator (PSC) is at an information imbalance (i.e., they know less about the utility's operations than the utility may care to share), the regulator is more likely to approve than deny costs, out of the fear that if they deny too many costs, the utility will not make enough money to stay in business. As a result, costs for ratepayers under a cost-of-service regulation model are hypothesized to be higher than what would be expected under a perfectly competitive market environment.[15] Introducing competition in distribution, however, has been widely dismissed, due to the impracticality of allowing multiple companies to own and operate distribution lines, given how expensive and bulky this infrastructure is. Distribution is a natural monopoly, so the aim of regulation is to drive costs down as much as possible to prevent monopoly pricing.

Importantly, there are several modifications that can be made to incentivize utilities to lower their costs and engage in innovative behavior under cost-of-service regulation. One is to use forecasting methods to determine the rate base. Under traditional cost-of-service regulation, past data in the form of a historical test year (HTY) is used to determine the rate base and, thus, how much the utility can earn. This disincentivizes investment in new innovations, such as energy efficiency or demand response programs. Using a forward-looking method instead, which uses a reference network model (RNM) to determine costs for a future test year (FTY), can help to address this, determining a rate base using projections that take into account costs associated with new innovations for the next year.[16] Another modification is the lengthening of the period of time between rate cases. The longer this time period is, the greater the incentive is to the utility to cut its costs, as it knows its revenues *ex ante* for several years, so it can earn a greater profit by reducing its expenditures. This is known as a multi-year rate plan (MRP).[17] A third modification is the use of performance metrics, such as quality of service indicators, to determine revenues for the utility (i.e., the amount of money they earn is dependent on the level of service provided). This is known as performance-based regulation (PBR).[18]

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[13] "Public Service Commission Cost of Service Ratemaking Overview Before the House Economic Matters Committee," Maryland Public Service Commission, January 10, 2019, https://www.psc.state.md.us/wp-content/uploads/MD-PSC-Ratemaking-Overview-House-ECM_01102019.pdf
[14] Tomás Gómez, "Electricity Distribution," in *Regulation of the Power Sector*, ed. Ignacio J. Pérez-Arriaga (London: Springer-Verlag, 2013).
[15] Mark Lewton Lowry and Tim Woolf, *Performance-Based Regulation in a High Distributed Energy Resources Future*, Lawrence Berkeley National Laboratory, January 2016.
[16] Jesse Jenkins and Ignacio Pérez-Arriaga, *The Remuneration Challenge: New Solutions for the Regulation of Electricity Distribution Utilities Under High Penetrations of Distributed Energy Resources and Smart Grid Technologies*, MIT Center for Energy and Environmental Policy Research, September 2014.
[17] Ibid.
[18] "Order No. 89226: Exploring the Use of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or Gas Company," Maryland Public Service Commission, August 9, 2019,

Maryland's PSC has begun incorporating some of these modifications into its ratemaking procedures as of 2019, although it is much later at doing this compared to other neighboring states. Prior to 2019, Maryland allowed for its HTY method to use "partially forecasted test years." It also allowed for revenue decoupling (called a Bill Stabilization Adjustment, or BSA) since 2007 for determining BGE's revenues; this decouples BGE's revenues from its costs and ensures that BGE continues to earn sufficient revenue as it implements energy efficiency and demand-side management programs.[19] In 2019, the PSC proposed a shift to an MRP method following a Technical Conference and several public comment periods on how to improve its existing cost-of-service regulatory method. While the MRP would still be based on an HTY, it would allow for future test years of up to three years. Moreover, utilities would be entitled to a "true-up," i.e., an *ex post* correction of revenues earned based on actual costs, at the end of each year within the MRP. Although the Commission did not include PBR implementation tactics at the time of the MRP proposal, it did note that it is their eventual aim to incorporate PBR goals into an MRP framework.[20] In early 2020, the MRP proposal was finalized as a pilot program, and BGE became the first utility to participate. Its rates were set at the end of 2020 for 2021-2023.[21]

The shift to MRP regulation, with the potential to add PBR components, is very promising for the future of energy efficiency, demand response, and other programs within BGE that assist in decarbonizing the grid and reduce costs. MRP regulation was launched as a part of the Maryland PSC's Public Conference 44 ("Transforming Maryland's Electric Grid"), which was initiated in 2017 with the goal of modernizing PSC regulation for the 21st century. PC44 includes other goals besides correcting distribution utility remuneration, including establishing clear guidelines for energy storage interconnection and rates, expanding time-variant rates (which I discuss more in the Retail Sector section of this paper) for electric vehicles (EVs) and distributed energy resources (DERs), and publishing "hosting capacity maps" to indicate to homeowners where DERs are most desired to achieve grid benefits.[22]

PC44 and the resulting MRP pilot illustrates that Maryland regulators are finally thinking of the changes that need to be made to accommodate grid decarbonization. Moving forward, when it comes to distribution utility remuneration, it will be interesting to see how (and how soon) the PSC decides to add PBR onto an MRP framework. PC44, for instance, has a goal for Maryland's utilities like BGE to assist with deploying EV charging units (BGE has committed to spending $48 million to help the state deploy 24,000 new charging stations by 2023) and recoup

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https://www.psc.state.md.us/wp-content/uploads/Order-No.-89226-PC51-and-Case-No.-9618-Order-on-Alternative-Forms-of-Rate-Regulation-and-Establishing-Working-Group-Processes.pdf

[19] "Regulatory Activities—Electricity—Current Issues," Maryland Office of People's Council, accessed April 27, 2021, http://opc.maryland.gov/Regulatory-Activities/Electricity/Emerging-Issues

[20] "Order No. 89226," Maryland PSC

[21] "Maryland PSC Approves BGE Rate Plan for 2021-2023," Maryland Public Service Commission, December 16, 2020, https://www.psc.state.md.us/wp-content/uploads/MD-PSC-Decision-in-BGE-MRP-9645_1216220-FINAL.pdf

[22] "Transforming Maryland's Electric Grid (PC44)," Maryland Public Service Commission, January 31, 2017, https://www.psc.state.md.us/transforming-marylands-electric-grid-pc44/

their costs via rate increases.[23] Setting PBR metrics that incentivize programs like this one for energy efficiency and demand-side management will help to further accelerate decarbonization.

Transmission Sector

Transmission planning and cost allocation in Maryland is performed by PJM as part of their annual Regional Transmission Expansion Plan (RTEP), in which they use load forecasting, looking 15 years in advance, to determine necessary network upgrades (new transmission lines, substation and transmission line retrofits, etc.). Findings from each RTEP influence which lines are actually constructed, and projects are assigned to one of three categories: baseline (related to reliability standards), network (related to new generation interconnects), and supplemental (proposed by incumbent utilities, who automatically get the right to build them). PJM then opens a competitive solicitation window for transmission owners (TOs) to build baseline projects (network and supplemental projects are exempted from this process and go to the incumbent).[24]

TOs are remunerated through PJM's Open Access Transmission Tariff (OATT), specifically via (1) Network Integration Transmission Service (NITS) Charges levied by PJM on each Network Customer (i.e., Load-Serving Entity, or LSE) on a zonal basis and (2) Transmission Enhancement charges for new projects. NITS charges are set based on the annual Transmission Revenue Requirement that each TO submits and are distributed across customers based on their fractional contribution to the daily peak demand (multiplied by 1/365 of the zonal rate for the zone in which the customer is located).[25] This method is also known as the Load Ratio Share method and effectively aligns charges with coincident peak demand, incentivizing LSEs who contribute more to the coincident peak to lower their consumption (this is ideal).

For the Transmission Enhancement charges, under FERC Order 1000, remuneration follows a "beneficiary pays" framework.[26] The way PJM does this is using a distribution factor (DFAX) model, which evaluates whether customers see a change (decrease) in their Net Load Energy Payment (NLEP) and Total Energy Production Cost (TEPC) as a result of the transmission project. Cost reductions count as a benefit, and those who see reductions have to pay for the transmission addition accordingly. Lines are remunerated differently depending on whether they were built for reliability or market enhancement purposes as well as the line's size. See Table 1 on the next page for how costs are allocated.[27]

[23] David Iaconangelo, "Md. group submits plans for utility-led charger expansion," *E&E News*, January 29, 2018, https://www.psc.state.md.us/wp-content/uploads/ELECTRIC-VEHICLES_-Md.-group-submits-plans-for-utility-led-charger-expansion-Monday-January-29-2018-www.eenews.pdf

[24] *2020 Regional Transmission Expansion Plan*, PJM, February 28, 2021, https://www.pjm.com/-/media/library/reports-notices/2020-rtep/2020-rtep-book-1.ashx

[25] Vilna Gaston, "PJM Transmission Replacement Processes Senior Task Force," June 3, 2016, https://www.pjm.com/~/media/committees-groups/task-forces/trpstf/20160603/20160603-item-04-education-module-6-cost-allocation-and-recovery.ashx

[26] Federal Energy Regulatory Commission, "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities," July 21, 2011, https://www.ferc.gov/sites/default/files/2020-04/OrderNo.1000.pdf

[27] Grace Niu, "Cost Allocation Education: Reliability Baseline Upgrade," September 25, 2020, https://www.pjm.com/-/media/committees-groups/committees/pc/2020/20200925-special/20200925-item-04-cost-allocation-education.ashx

	Baseline Projects (Reliability)	**Network Projects** (Economics)
Regional Size (345 kV double circuit or ≥500 kV and >$5M)	- 50% DFAX - 50% load ratio share	- 50% based on change in TEPC - 50% based on change in NLEP[28] (using 15-yr horizon and NPV)
Lower Voltage (<500 kV and >$5M)	- 100% based on DFAX	- 100% based on change in NLEP (using 15-yr horizon and NPV)
Local (<$5M and <200 kV)	- 100% to zone in which construction occurs	- 100% based on change in NLEP (using 15-yr horizon and NPV)

Table 1. Method of Transmission Enhancement charge determination for different types of new transmission projects.

Generally, best practices on transmission cost allocation are to use a beneficiary pays approach, as this is the most economically efficient and sends effective cost signals to those who benefit from the transmission asset the most. PJM is largely using beneficiary pays approaches in both components of its OATT (NITS and TE charges). One major critique of PJM's current transmission practices is that the majority of lines built in PJM over the past decade have continued to be built by incumbents, despite FERC's attempt with Order 1000 in 2011 to open up transmission construction to competition. Economist Paul Joskow at MIT found that all but three of 140 transmission projects built in PJM between 2013 and 2017 went to non-incumbents. This is in part due to the Network and Supplemental project exemptions that PJM has in place (for context, between 2013 and 2018, Baseline projects cost $12 billion while Supplemental projects cost $19 billion).[29] Modifying these rules to open up more construction to competition will be essential for continuing to promote economic efficiency.

Another issue that is becoming increasingly important in the transmission world is the siting of long-distance power lines. PJM has begun to incorporate inter-regional transmission lines into its RTEP process, which is a step in the right direction to expand transmission and facilitate transportation of renewable energy across the U.S. over long distances.[30] Notably, however, transmission siting remains a state-level issue to resolve. Any power line passing through Maryland must receive a Certificate of Public Convenience and Necessity (CPCN). Worrisomely, Maryland is one of a few states that bans non-incumbent utilities from using eminent domain to build power lines.[31] This could prove to be an enormous barrier to competitive transmission, as third-party merchant transmission owners would have a more difficult time constructing power lines across Maryland without the ability to use eminent domain. This would need to be modified by law, however.

[28] Only net decreases in NLEP are counted here. This is essentially another way of approaching the "beneficiary pays" method, just without using the DFAX model.
[29] Paul Joskow, "Competition for Electric Transmission Projects in the U.S.: FERC Order 1000," March 2019, http://ceepr.mit.edu/publications/reprints/698
[30] *2020 Regional Transmission Expansion Plan*, PJM, February 28, 2021, https://www.pjm.com/-/media/library/reports-notices/2020-rtep/2020-rtep-book-1.ashx
[31] Alexandra Klass and Jim Rossi, "When Do State Transmission Siting Laws Violate the Constitution?," *Electricity Journal* 28, no. 7 (2015): 14, http://dx.doi.org/10.1016/j.tej.2015.07.003

Generation Sector

PJM uses a two-market clearing system to determine wholesale energy prices: the Day-Ahead Market (DAM), which is a forward market operated one day in advance for hourly intervals, and the Real-Time Balancing Market, which is operated real-time in 5 minute increments. In both markets, PJM co-optimizes energy and reserves using a least-cost security constrained resource commitment model. Generators submit hourly complex bids (including any operating constraints) into the DAM. PJM also allows for bilateral "futures" contracts (outside of the energy market) and accounts for these in running the DAM optimization.

Following the DAM, binding hourly Day-Ahead Locational Marginal Prices (LMPs) are determined on a zonal basis, split into three components: System Energy Price, Congestion Price, and Loss Price. To hedge against congestion, PJM auctions off Financial Transmission Rights (FTRs) in four different timescales: long-term, annual, monthly, and secondary (trading of existing FTRs). Those who hold Financial Transmission Rights (FTRs) can collect the net congestion revenues (based on day-ahead congestion portion of LMP) for lines. Money collected during the auctions are distributed according to Auction Revenue Rights (ARRs) to Network Service Customers and Firm Point-to-Point Transmission Customers.

In addition to the two-market clearing system, PJM runs three ancillary services markets to ensure system reliability, based on response time of the resources: a Regulation Market (5-15 minute response time), a Synchronized Reserve Market (10-30 minute response time), and a Non-Synchronized Reserve Market (10-30 minutes). They also run a Day-ahead Scheduling Reserve (DASR) Market, which provides additional reserves on a 30-minute basis, as well as a Coordinated Transaction Scheduling (CTS) system with MISO (a neighboring ISO) as part of their RTM (only those bids with low enough prices across both ISOs will clear the market).[32]

Generally, PJM's energy markets have been functioning relatively smoothly. PJM's Market Monitoring Unit (MMU), a third party that releases annual reports on the "state of the markets," noted in 2020 that there is still evidence of market power exertion, particularly during times of peak demand, in PJM and that price caps have not fully mitigated this issue. The MMU states that "aggregate market power needs to be addressed," although it deems PJM's energy markets to be overall competitive.[33] Another important challenge facing PJM's energy markets is the need to provide an accurate reflection of the availability of variable resources like wind and solar.[34] Relying on the DAM may no longer be the most economically efficient solution, as it is biased toward resources that have a predictable output with set daily schedules (e.g., thermal

[32] This citation applies to the previous three paragraphs. "PJM Manual 11: Energy & Ancillary Services Market Operations," PJM, March 29, 2021, https://www.pjm.com/-/media/documents/manuals/m11.ashx

[33] I leave a discussion of mitigating market power largely out of this report, as it is not directly linked to grid decarbonization, although it is still critical to address. "State of the Market Report for PJM," Monitoring Analytics, March 11, 2021, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020-som-pjm-vol1.pdf

[34] E. Ela, M. Milligan, A. Bloom, A. Botterud, A. Townsend, and T. Levin, "Evolution of Wholesale Electricity Market Design with Increasing Levels of Renewable Generation," National Renewable Energy Laboratory (NREL), September 2014, https://www.nrel.gov/docs/fy14osti/61765.pdf

resources like coal and natural gas).[35] In the Recommendations section, I discuss the need to shift the DAM to be later in the day so that it can incorporate more accurate forecasting of variable resources into the market.

The larger point of contention in PJM's markets lies in its centralized capacity market, called the Reliability Pricing Model (RPM). Starting with the Base Residual Auction, which is run in May three years before the intended Delivery Year (defined as June 1 to May 31), PJM uses load forecasting tools to predict what peak load will be in future years and how much capacity it must procure to meet its required Installed Reserve Margin (IRM) (i.e., to maintain its reliability standards). To take transmission and "load deliverability" into account, PJM runs the RPM on a zonal level using Locational Deliverability Areas (LDAs). Costs are allocated among all participating LSEs using a Locational Reliability Charge. As an alternative to the RPM, LSEs can opt to submit a capacity plan to meet a "fixed capacity resource requirement" set by PJM (this is called the Fixed Resource Requirement option, or FRR). LSEs must participate in either the RPM or FRR.[36]

The strongest critique of PJM's RPM has been the use of a price floor, called a Minimum Offer Price Rule (MOPR), at or above which all resources must bid. While the MOPR was initially put in place to prevent gas plants from exerting market power by bidding in their generation units at too low prices, it has come under criticism for essentially preventing renewables from participating in the RPM by forcing them to bid at a price above that at which the RPM normally clears. Proposals to remove the MOPR, however, have come under fire from fossil fuel generators, who argue that without the MOPR, renewable generators would be able to bid at artificially low prices, due to state-level subsidies they receive from states like Maryland.[37]

Several proposals to fix the PJM capacity market have been floated around. These include establishing a two-step capacity market (e.g., Integrated Clean Capacity Market proposed by New Jersey, Competitive Carve Out Auction proposed by MD PSC) in which clean and non-clean resources are procured separately in different auctions or eliminating the mandatory capacity market entirely and shifting back to a voluntary residual model (like the one currently used by MISO). All of the proposals agree that either eliminating the MOPR or limiting it only to instances of demonstrated market power is an important next step,[38] and PJM, as of last week, has proposed exempting state-subsidized resources like renewables from the MOPR.[39] I comment more on my preferred proposal in the Recommendations section, but one important thing to keep in mind is the wide range of stakeholders within PJM, including states who favor renewable energy deployment (Maryland, New Jersey) and those who favor fossil fuels (West Virginia, Kentucky, Ohio). Maryland, New Jersey, and Illinois have all threatened to withdraw

[35] Ignacio Herrero, Pablo Rodilla, and Carlos Batlle, "Enhancing Intraday Price Signals in U.S. RTO Markets," MIT Energy Initiative, May 2016.
[36] "PJM Manual 18: PJM Capacity Market," PJM, January 27, 2021, https://www.pjm.com/-/media/documents/manuals/m18.ashx
[37] Cheryl LaFleur (former FERC commissioner) in conversation with the author, April 2021.
[38] A full list of all proposals can be found in PJM's meeting materials from stakeholder sessions held this spring. "Capacity Market Workshop—Session 3, Meeting Materials," PJM, March 12, 2021, https://www.pjm.com/forms/registration/Meeting%20Registration.aspx?ID=%7B6e82522e-d855-494b-9567-bcb6379d6fe1%7D
[39] Eric Wolff, "PJM floats renewable power exemption to MOPR," Politico, April 28, 2021, https://subscriber.politicopro.com/article/2021/04/pjm-floats-renewable-power-exemption-to-mopr-3988551

from the PJM capacity market (and go with the FRR alternative) over the MOPR issue.[40] While states should be allowed to make their own decisions on whether they participate, it would be most economically efficient for PJM to facilitate capacity procurement on a regional scale, and research has shown that states who opt for the FRR would pay significantly higher prices.[41]

Besides the MOPR, there are several other issues with PJM's capacity market to keep in mind. One is that capacity markets, in how they are structured currently, are biased toward resources with low fixed costs and high operating costs, which tend to be fossil resources like natural gas peaking plants. Resources with high fixed costs, such as nuclear and renewables, do not benefit as much from the capacity market. This innate bias, combined with the MOPR, skews heavily toward carbon-intensive resources.[42]

Second, the way in which PJM measures the reliability of a resource can bias against their participation. Energy storage, for instance, is currently subjected to a "10-hour rule," in which it cannot participate in the RPM unless it can dispatch for at least 10 hours. This effectively excludes most forms of modern storage (e.g., lithium-ion batteries) and biases the RPM against storage, an important component of a decarbonized grid. FERC is currently investigating the "10-hour rule," and PJM has proposed changing it, but this is just one example of how faulty measurements of performance and availability in capacity market rules can bias the market toward certain resources.[43] Another example is PJM's annual obligation periods, which assume uniform resource performance throughout the year. This does not take into account the seasonal and even diurnal variability of resources like variable renewables.[44]

One final flaw is the systematic over procurement of capacity by the capacity market. In 2020, PJM's target reserve margin was 15.9%, but its actual reserve margin was 35.5%. This is largely a result of a poorly designed demand curve (mainly flat, not downward sloping) and has shifted revenue from energy to capacity markets, further overcompensating resources with low capital costs, such as fossil fuels, and resulting in greater air pollution. It has also cost consumers a significant amount of money—$4.4 billion annually.[45] Fixing all of these issues will be important to keep in mind when proposing overall capacity market changes and addressing the MOPR (as I do in the Recommendations section).

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[40] Catherine Morehouse, "Maryland, Illinois may pursue legislative MOPR exit, despite new FERC nearing," Utility Dive, December 11, 2020, https://www.utilitydive.com/news/maryland-illinois-may-pursue-legislative-mopr-exit-despite-new-ferc-neari/592020/

[41] Sylwia Bialek, Justin Gundlach, and Christine Pries, "Resource Adequacy in a Decarbonized Future: Wholesale Market Design Options and Considerations," March 2021.

[42] Rob Gramlich and Michael Goggin, *Too Much of the Wrong Thing: The Need for Capacity Market Replacement or Reform*, Grid Strategies, November 2019, https://gridprogress.files.wordpress.com/2019/11/too-much-of-the-wrong-thing-the-need-for-capacity-market-replacement-or-reform.pdf

[43] Bialek, Gundlach, and Pries, March 2021

[44] Ibid.

[45] Ibid.

Retail Sector

Retail rates are determined based on the revenue requirement set for BGE by the MD PSC. After the revenue requirement is set, costs are allocated across customer classes based on cost drivers. BGE has several different customer classes.[46] Here, I focus on residential and small commercial customers, who pay a mix of a fixed tariff and a volumetric tariff (based on kWh of consumption). Notably, although time-invariant pricing is the default for these customers, BGE has begun to implement time-of-use (TOU) pricing as an opt-in pilot program.[47] This has been facilitated by BGE's early adoption and rollout of "smart meters" (advanced metering infrastructure, or AMI) using a $200 million federal grant.[48] BGE also has a TOU pilot program specific to electric vehicle (EV) users, with lower rates available for off-peak times (but higher rates at peak times). In addition to TOU pricing, BGE offers peak time rebates (PTRs) during Critical Event Days (i.e., extremely hot summer days when the system peak is highest) from 12 to 8 PM.[49] Through their PeakRewards and Connected Rewards programs, BGE also allows customers to have their thermostat controlled by the utility during peak demand periods (essentially aggregating demand response).[50]

Many of the pilot programs that BGE has are very promising, although not in line with the best economic practices laid out by scholars studying retail rate design. More specifically, although TOU rates are a step in the right direction, it has been shown to not influence peak demand reductions as much as real-time pricing (RTP), which exposes customers to hourly changes in electricity prices.[51] In the Recommendations section, I comment on how I believe BGE should transition from TOU rates to an RTP model.

Another important component of Maryland's retail rate design is retail choice. Maryland is one of 14 states that allows its customers to choose their own electric supplier.[52] This decision was made in an effort to lower retail rates via economic competition. However, over two decades after retail choice was introduced in 1999, the jury is still out on whether or not retail choice is effective.[53] For one, third-party retailers have engaged in predatory pricing, offering low

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[46] "Electric Service Rates and Tariffs," BGE, accessed April 27, 2021, https://www.bge.com/MyAccount/MyBillUsage/Pages/ElectricServiceRatesTariffs.aspx

[47] These are divided into three times of day: peak, intermediate, and off-peak. They are also divided into two times of year: summer (June 1 to September 30) and non-summer.

[48] Nate Rabner, "Utilities Spread 'Smart Meters,' But Some Homeowners Hold Out," Capital News Service, June 16, 2015, https://marylandreporter.com/2015/06/16/utilities-spread-smart-meters-but-some-homeowners-hold-out/

[49] "Energy Savings Days," BGE, accessed April 27, 2021, https://www.bge.com/WaysToSave/ForYourHome/Pages/EnergySavingsDays.aspx

[50] Note that the PeakRewards program seems to have undergone some discontinuations during COVID. Connected Rewards is like PeakRewards but under a bring-your-own-thermostat model. "PeakRewards," BGE, accessed April 27, 2021, https://bgesavings.com. "Connected Rewards," BGE, accessed April 27, 2021, https://enrollmythermostat.com/bge/.

[51] Jim Lazar, Paul Chernick, and William Marcus, "Electric Cost Allocation for a New Era," Regulatory Assistance Project, January 2020.

[52] Kimberly Palacios, "Electricity residential retail choice participation has declined since 2014 peak," U.S. Energy Information Administration, January 17, 2019, https://www.eia.gov/todayinenergy/detail.php?id=37452

[53] Scott Dance, "More utility competition was supposed to drive down prices, but many Marylanders are paying more for energy," *The Baltimore Sun*, December 7, 2018, https://www.baltimoresun.com/business/bs-md-energy-deregulation-20181205-story.html

introductory rates (mainly to low-income customers) before raising rates to be significantly above those of the Standard Offer Service (SOS) offered by the incumbent utility like BGE. A 2018 report found that Marylanders buying from third-party suppliers have been spending $255 million more than if they had stayed with the incumbent utility.[54] Although some of this cost increase can be attributed to a desire by some customers to pay more for 100% clean energy suppliers, much of it has been attributed to predatory pricing imposed on lower-income customers. Reforms have been proposed, such as requiring third-party providers to charge at or below the utility rates or increasing transparency on the physical bills provided to customers. While these reforms will need to be via legislation (not regulation), it is important to be aware of this issue when considering other retail sector reforms for Maryland.

Recommendations

Recommendation #1: Combine Clean Energy Goals with Capacity Market Reforms

The most pressing issue facing the region today is reforming PJM's capacity market. Without significant change, fossil generators will continue to be incentivized over renewables,[55] hampering any attempts to reduce emissions in the electricity sector. In the short term, several key modifications can be made to the capacity market to make it more competitive and less hostile to renewables. As a start, the MOPR should be scaled back and applied only to proven instances of market power—PJM has, as of last week, proposed making this change.[56] This restores the MOPR to its original intended use, helping to limit the influence of rampant market concentration observed by the PJM MMR. Notably, state subsidization of resources like renewables is not an instance of market power and should be fully allowed in capacity markets.

Other short-term changes to the PJM capacity market, proposed by a variety of researchers and summarized here,[57] should include (1) modifying the demand curve to be more downward sloping and reflective of the true Value of Lost Load (VOLL) in order to reduce overprocurement of capacity by PJM, (2) rating all capacity based on its Effective Load Carrying Capacity (ELCC), a metric that PJM has already been considering using that is more accurate than PJM's current method of evaluating the capacity of certain resources, particularly renewables, (3) eliminating the "10 hour rule" for storage and allowing for a new categorization of a capacity resource as flexible (incentivizing greater storage deployment for fast response), and (4) adopting seasonal and even diurnal granularity to capacity bids and procurements (this allows for renewables to more accurately reflect their different output and could save consumers between $100-600 million per year, according to research done by the Brattle Group[58]).

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[54] Laurel Peltier and Arjun Makhijani, "Maryland's Dysfunctional Residential Third-Party Energy Supply Market: An Assessment of Costs and Policies," Abell Foundation, December 2018, https://abell.org/sites/default/files/files/Third%20Party%20Energy%20Report_final%20for%20web.pdf

[55] Jacob Mays, David Morton, and Richard O'Neill, "Asymmetric Risk and Fuel Neutrality in Capacity Markets," *Nature Energy* 4 (2019): 948-956.

[56] Eric Wolff, "PJM floats renewable power exemption to MOPR," Politico, April 28, 2021, https://subscriber.politicopro.com/article/2021/04/pjm-floats-renewable-power-exemption-to-mopr-3988551

[57] Bialek, Gundlach, and Pries; Gramlich and Goggin.

[58] Gramlich and Goggin, p. 12.

In the longer term, it will be interesting to see whether short-term changes such as these help to better adapt the capacity market to greater deployment of renewables. Many authors argue that RTOs should rely more on energy markets to handle scarcity events, pointing to the high prices and resource biases of capacity markets.[59] Raising the price cap in the energy market is one way to facilitate this, and PJM is on the cusp of doing this, allowing prices during scarcity events to spike to over $10,000/MWh.[60] However, critics of an energy-only market approach discuss how without price caps, there are stronger incentives for exerting market power and inducing scarcity. Moreover, regional procurement of capacity, when done right, is purported to attain lower prices for capacity than when it is done at a piecemeal level.[61] This is why capacity markets evolved in locations in PJM, and I don't believe that the centralized capacity market is about to disappear from PJM anytime soon.

Therefore, in addition to the short-term changes I've listed above, I also believe that PJM must begin looking into ways to combine state clean energy goals with the capacity market's inherent biases. Out of all the proposals presented in front of PJM so far, the Brattle Group's Integrated Clean Capacity Market (ICCM) concept[62] is most compelling to me, as it harmonizes diverse state policy interests with the economic benefits of procuring capacity and clean energy on a regional basis.

The ICCM is effectively a two-stage capacity market, the first of which procures Clean Energy Attribute Credits (CEACs, essentially a renaming of Renewable Energy Credits, or RECs, already traded by states with Renewable Portfolio Standard, RPS, policies) designed to pay clean energy for its climate benefits. This is aligned with the consistent recommendation by the PJM MMR to integrate states' REC trading with PJM's regional scale to achieve lower prices.[63] By trading for CEACs in a different market that is co-optimized with and unbundled from the capacity market, the ICCM separates reliability needs from climate concerns while taking into account the capacity provided by clean energy resources. States can choose to bid into the CEAC market to meet their climate goals or can bypass the CEAC market and focus solely on procuring reliability, making this design highly responsive and adaptive to the diverse stakeholder needs within PJM. Auctioning CEACs off several years in advance, in parallel with the capacity market, provides sufficient forward-looking incentives for renewable generators to come online.

As it currently stands, many states within PJM will continue to accelerate their clean energy goals. Forcing them to continue to pay for reliability products in the capacity market that are skewed toward non-clean resources is increasingly incompatible, as New Jersey's,

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[59] Gramlich and Goggin; William Hogan, "On an 'Energy Only' Electricity Market Design for Resource Adequacy," John F. Kennedy School of Government, Harvard University, September 23, 2005.
[60] Bialek, Gundlach, and Pries, p. 14.
[61] CeCe Coffey (FERC analyst specializing in PJM) in conversation with the author, April 2021.
[62] Kathleen Spees, Walter Graf, and Samuel Newell, "Integrated Clean Capacity Market," Brattle Group, March 12, 2021, https://www.pjm.com/-/media/committees-groups/committees/mic/2021/20210312-workshop-3/20210312-item-02f-brattle-iccm.ashx
[63] PJM's MMR has been recommending this since 2010. "State of the Market Report for PJM," Monitoring Analytics, March 11, 2021, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020-som-pjm-vol1.pdf

Maryland's, and Illinois's requests to leave PJM over the capacity market have illustrated. Having states continue to procure their own clean energy independent of the markets is also a less economically efficient solution. The ICCM is the strongest proposal that I've seen so far that addresses these multitude of concerns, allowing for greater economic efficiency by operating on a regional scale while giving states flexibility in their procurement decisions.

Recommendation #2: Implement Real-Time Pricing (Retail)

Even with reforms to the capacity market, I agree that relying on the energy market as much as possible to handle instances of scarcity would be a more economically efficient solution. To that end, another modification that could be made to encourage demand reduction during scarcity is to institute real-time pricing (RTP), which not only allows for a better response to scarcity but also sends more accurate signals on economic value to resources that are time-dependent, like rooftop solar PV or energy storage. Time-invariant rates, which are currently in use, do not incentivize resources like storage to perform energy arbitrage and get paid fully for their value, as these rates ignore the daily variation of demand. Moreover, current rates frequently overcompensate other distributed energy resources (DERs) like rooftop PV through net metering policies, which pay homeowners time-invariant rates for their solar generation, even if their energy does little to benefit the grid at times of peak solar generation.[64]

Moving forward, I believe BGE should expand on their current opt-in pilot programs for time-of-use (TOU) pricing and peak time rebates (PTRs) by ultimately pursuing an opt-out hourly RTP model. Continuing to rely on TOUs will not be granular enough to fully reflect the real-time value of demand curtailment.[65] Additionally, opt-in programs are proven to have less engagement and be less effective than opt-out programs, so choosing an opt-out model will be critical for success. As a parallel to an opt-out RTP model, I also recommend that the Maryland PSC begin examining how to integrate locational marginal prices (LMPs) on a distributional level to best incentivize distribution companies to install (or pay their customers to install) non-wires alternatives like DERs and storage.

Importantly, opt-out RTP programs in other areas, like Arizona, have been met with ratepayer resistance due to increased costs.[66] When designing an opt-out RTP, thus, BGE must make sure to prevent expensive spikes in consumer prices. This could be done by imposing RTP on the distribution side (not retail side) and letting retailers choose how to structure their rates for consumers to reduce consumption during peak periods. RTP rates should be designed with a price cap and more gradual slope than wholesale market prices so that ratepayers do not end up having to pay exorbitant bills, like the ones received by some ratepayers in Texas after the

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[64] John Kassakian and Richard Schmalensee (lead authors), *The Future of the Electric Grid*, Massachusetts Institute of Technology, 2011.
[65] Lazar, Chernick, and Marcus, January 2020.
[66] This is partly due to Arizona's interest in demand charges rather than TOU, which levies a hefty fee on ratepayers based on their highest peak demand use per month, ignoring whether or not the peak is coincident with system peak. Herman Trabish, "Demand charges vs. TOU rates: The great Arizona rate design experiment," Utility Dive, September 26, 2016, https://www.utilitydive.com/news/demand-charges-vs-tou-rates-the-great-arizona-rate-design-experiment/426902/

February 2021 storm.[67] There could be alternative plans offered with more extreme pricing for those ratepayers who wish to significantly change their lifestyles in order to save money. Rollout of an RTP plan should also be paired with an extensive consumer education campaign on how to load shift (e.g., run dishwasher at night, run laundry on the weekend, etc.). BGE should also promote and expand their opt-in PeakRewards and Connected Rewards programs as part of an opt-out RTP plan, allowing ratepayers to have their load "controlled" by BGE in return for lower rates under an RTP model (I find this last point particularly important, as I'm somewhat skeptical of how responsive most consumers will be to RTP rates, so giving as much automated control over to BGE as possible will help).

It is also important to emphasize an equitable rollout of an opt-out RTP program, i.e., one that does not disproportionately affect low-income households. As I've previously mentioned, many Baltimore ratepayers are already struggling to understand the complexities of retail choice, with many low-income residents being scammed by third-party providers with predatory pricing. Adding the additional challenge of demand response to ratepayers who are not equipped with the knowledge or means to adapt could become a costly burden. To ensure that low-income households do not pay more under RTP rates, BGE should partner with existing energy affordability nonprofits, like EmPOWER Maryland,[68] to perform targeted household outreach and retrofits. They should also consider providing subsidized smart thermostats and devices to households that cannot otherwise afford them as an extension of their PeakRewards automatic load management program. Ultimately, an opt-out RTP should be evaluated both before and after implementation to assess impacts on lower-income households and make adjustments as needed.

Recommendation #3: Move DAM to be Closer to Real-Time (Generation)

There is currently a mismatch between the timeline of PJM's energy markets and the temporal variability of renewable energy generation. PJM's continued reliance on a Day-Ahead Market (DAM) expects renewable generation forecasts to be accurate as far as 24 hours in advance. However, forecasts change much more sooner to real-time usage than that. PJM has acknowledged that "when higher levels of renewable generation increase the levels of uncertainty in day-ahead forecasts, the present practice could lead to increased CT [combustion turbine] usage."[69] This bias toward fossil fuel generation will only become worse with increased penetration of renewables.

To counteract this, the DAM should be moved closer in time to real-time conditions. During a class discussion, for instance, Andrew Levitt from PJM hypothesized that a 6-hour forward market could be a sufficient replacement, achieving the advanced scheduling and optimization that the DAM accomplishes to ensure system reliability while incorporating more up-to-date forecasting information from generation units.[70] Authors from the MIT Energy

[67] Shannon Najmabadi, "Texans blindsided by massive electric bills await details of Gov. Greg Abbott's promised relief," *Texas Tribune*, February 22, 2021, https://www.texastribune.org/2021/02/22/texas-pauses-electric-bills/
[68] EmPOWER Maryland is a state-run initiative funded by charges on utility bills. BGE administers it under the "Smart Energy Savers" program. "EmPOWER Maryland," Maryland Energy Administration, accessed April 27, 2021, https://energy.maryland.gov/pages/facts/empower.aspx
[69] Herrero, Rodilla, and Batlle, May 2016, p. 8.
[70] Andrew Levitt (PJM) in conversation with the author and classmates, April 2021.

Initiative have also called for a reform to the DAM to make it more similar to Europe's rolling intraday setup (but maintaining the benefits of centralized optimization and commitment).[71] Notably, PJM already allows for generation to modify its bids between the DAM and Real-Time Market (RTM)—up to 65 minutes ahead of the RTM. But these modified bids apply only to the RTM and are more limited for generation that already committed in the DAM.[72] Since "PJM's present practice is to commit most generation resources in the day-ahead forward market, and only commit combustion-turbine resources in the real-time market,"[73] this means that the DAM should be as reflective of the most accurate forecasts as possible, making shifting DAM commitment schedules to later in the day (sooner to actual generation time) essential.

Recommendation #4: Add PBRs (Distribution)

Shifting to the distribution utility side, the updates that the Maryland PSC has been making as part of PC44—adding multi-year rate plans (MRPs) and allowing for revenue decoupling—are very promising and are certainly steps in the right direction. Building on this progress, the PSC should develop and integrate performance-based ratemaking (PBR) standards into the MRP structure. These should include quality-based standards (e.g., measurements like SAIDI and SAIFI)[74] and climate-based standards (e.g., demonstrated improvements in energy efficiency or demand reduction) that correlate to utility remuneration (perpetuating the PSC's allowance of revenue decoupling) as well as *ex ante* guarantees of recovery for certain climate-friendly programs, like deploying subsidized smart thermostats (as I mentioned above in Recommendation #2) or educating consumers in preparation for implementing an opt-out TOU program. The PSC may want to consider offering these incentives as part of a menu of contracts, first recommended by Jenkins and Pérez-Arriaga in 2014, to allow BGE and other utilities to choose a contract that works for their level of ambition on, for instance, enhancing efficiency.[75] They should also begin to include profit sharing mechanisms to allow ratepayers to reap some of the benefits of increased cost savings from an MRP framework.[76]

Recommendation #5: Socialize Generation Interconnection Costs for Transmission, and Facilitate Inter-Regional Transmission Buildout

My last recommendation has more to do with the broader ecosystem in which Baltimore, Maryland, and PJM are situated. Renewable energy deployment is going to require large-scale construction in remote areas that will frequently be outside of the PJM footprint.[77] Building transmission connecting PJM to other RTOs should be an integral part of PJM's Regional

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[71] Herrero, Rodilla, and Batlle, May 2016.
[72] "PJM Manual 11: Energy & Ancillary Services Market Operations," March 29, 2021.
[73] Herrero, Rodilla, and Batlle, May 2016, p. 8.
[74] SAIDI stands for System Average Interruption Duration Index. SAIFI stands for System Average Interruption Frequency Index. Both are common measurements of quality of service. Elena Fumagalli, Florence Delestre, and Luca Lo Schiavo, "Handbook of service quality regulation in the electricity distribution and retail sectors," Council of European Energy Regulators (CEER), December 6, 2006.
[75] Jenkins and Pérez-Arriaga, September 2014.
[76] Ibid.
[77] Eric Larson et al., *Net-Zero America: Potential Pathways, Infrastructure and Impacts*, Princeton University, December 15, 2020, https://environmenthalfcentury.princeton.edu/sites/g/files/toruqf331/files/2020-12/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf

Transmission Expansion Planning (RTEP) process moving forward. Last year, for instance, PJM built its first inter-regional line to reduce congestion between MISO and PJM via a competitive solicitation process.[78] Building more projects like this will help to construct a larger electricity grid that is more resilient and can carry more renewables from farther away to the PJM territory. FERC Order 1000 required that protocols be set up for interregional transmission cost allocation,[79] but it did not go so far as to require that interregional transmission be included in the planning process, an extension that I believe must be made eventually by FERC, perhaps even through the establishment of a coordinating body like what Europe has in ENTSO-E.

Attention must also be paid to enhancing competition in PJM's transmission solicitation processes, given the lack of non-incumbent transmission providers currently winning contracts in PJM. Many long-distance high-voltage direct current (HVDC) transmission lines carrying renewable energy will most likely be built by third party non-incumbents ("merchant transmission"). Ensuring that these lines do not face barriers in integrating into the PJM system or securing a bid to be constructed will be essential. One interesting question is whether HVDC lines injecting one-way into the PJM grid qualify as generators or transmission (this is a point of contention with a newly proposed underground HVDC project, SOO Green, linking wind power in Iowa to load in Illinois; categorizing it as a generator would put it into the interconnection queue and subject it to lengthy delays).[80] Establishing clear and fair guidelines will be important here (e.g., perhaps one-way transmission should be expedited in the queue if categorized as a generator, or maybe a new sub-categorization under transmission is required).

Another important point is reducing the costs for interconnections for renewable projects. Because renewables are generally much farther from transmission infrastructure and load centers, they usually require longer—and thus more expensive—grid interconnections. These costs can often serve as barriers to building out more renewable energy. Under current cost allocation practices (the "participant funding" model established under FERC Order 2003), generators pay 100% of the costs of associated interconnection *and* network upgrades. This has been shown to be cost-prohibitive for new generator entry in PJM, the overwhelming majority of which are renewable energy facilities. FERC gives some leeway to RTOs to establish their own interconnection fee processes, so PJM should therefore consider socializing a portion of the interconnection fees for renewable projects across the entire region, on the beneficiary pays basis that such lines facilitate grid decarbonization and thus provide diffuse benefits to all members. Such a justification was used for past network upgrades, such as transmission for Texas's Competitive Renewable Energy Zones (CREZ),[81] and PJM is aiming to use this method with a proposed New Jersey offshore wind development, which is very promising.[82]

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[78] *2020 Regional Transmission Expansion Plan*, February 28, 2021.
[79] FERC, July 21, 2011.
[80] CeCe Coffey (FERC analyst specializing in PJM) in conversation with the author, April 2021.
[81] Jay Caspary, Michael Goggin, Rob Gramlich, and Jesse Schneider, *Disconnected: The Need for a New Generator Interconnection Policy*, Americans for a Clean Energy Grid, January 12, 2021, https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.14.21.pdf
[82] Jonathan Wright, "FERC Accepts Study Agreement to Assess New Jersey Offshore Wind Deliverability," Inside Energy & Environment, Covington & Burling LLP, February 24, 2021, https://www.insideenergyandenvironment.com/2021/02/ferc-accepts-study-agreement-to-assess-new-jersey-offshore-wind-deliverability/

Finally, PJM should work with state PSCs to alleviate perpetual siting concerns by establishing PJM-wide "transmission-friendly corridors," designed for new lines specifically interested in connecting renewable resources to load (similar to Texas's CREZ model). By proactively building transmission (as Texas did with CREZs and MISO did with their Multi-Value Projects, or MVPs, in 2011), PJM can reduce congestion and incentivize renewables to come online now, reducing the "chicken-and-egg" problem of transmission and renewables. In addition to identifying sites for new transmission, PJM could also identify transmission that is currently unutilized formerly in use by generators that have seen been retired (e.g., coal plants) and offer sites around that unutilized transmission for priority siting.[83] Although siting remains an issue under state jurisdiction that will require policy reform (e.g., changing Maryland's policy that prohibits merchant third-party transmission companies from using eminent domain to site their power lines), PJM can do a lot to facilitate siting on a larger, regional scale by explicitly incorporating planning requirements for renewable energy transmission lines into their RTEP.

[83] I got this idea from Kris Ohleth (Director, Special Initiative on Offshore Wind), who spoke at an event I recently attended. She mentioned that one of New Jersey's proposed offshore wind farm, Ocean Wind, is going to interconnect to transmission from two recently retired coal plants and called this "grid recycling." A really good idea to promote a circular economy and cost reduction!

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Acknowledgements

Thank you to CeCe Coffey and Cheryl LaFleur for their helpful FERC advice and willingness to speak with me. You two are the reason I fell in love with energy. Thank you as well to Stephanie Eyocko at the Maryland PSC and Laurel Peltier (journalist on retail competition in MD) for their key insider insights.

Thank you to Professor Jenkins and Malini for a life-changing class. This is hands down one of the best classes I have taken and will ever take at Princeton. I am so appreciative of the chance to learn about utilities and the electric grid, a very niche topic that has nonetheless captivated me. Here's to a future of trying to reduce greenhouse gas emissions in the face of regulatory uncertainty, hesitancy, reluctancy, and outright opposition.

This paper represents my own work in accordance with University regulations.
[x] Claire Wayner

Appendix

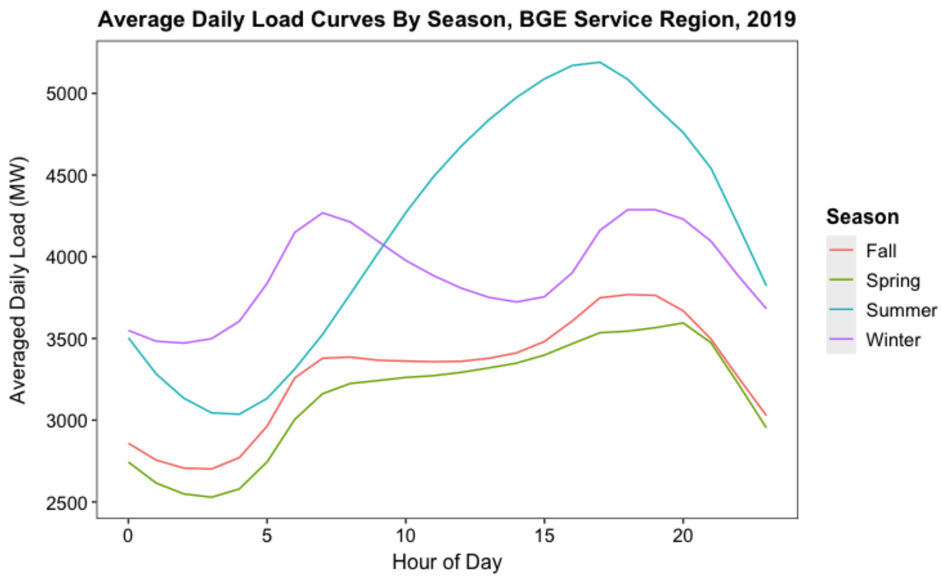

Figure 1. Load curves for four different seasons in the Baltimore area, constructed using hourly metered load data from PJM.[84]

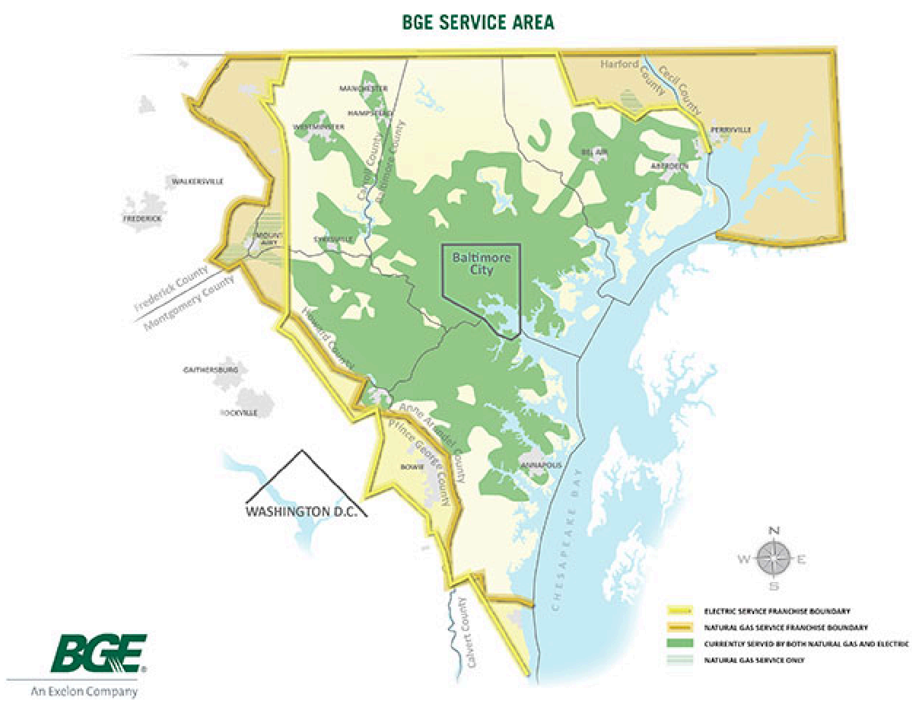

Figure 2. BGE service area (green is both natural gas and electric service, yellow is electric service, orange is gas service).[85]

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[84] "Hourly Load: Metered," PJM Data Miner 2, accessed February 10, 2021, https://dataminer2.pjm.com/feed/hrl_load_metered/definition

[85] "Regional Demographics," BGE, accessed April 27, 2021, https://www.bge.com/DoingBusinessWithUs/Pages/RegionalDemographics.aspx

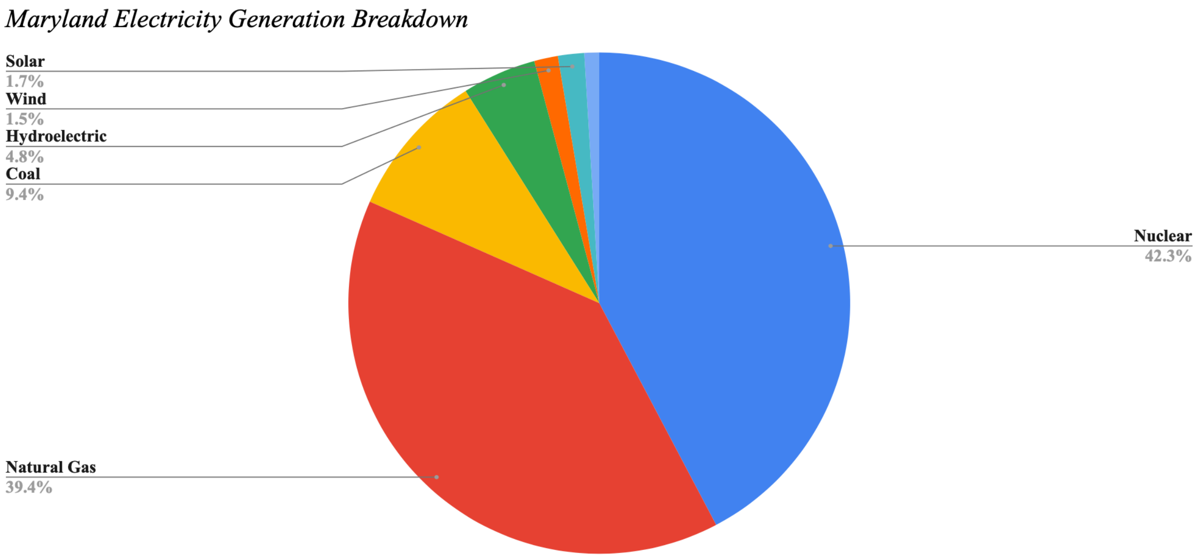

Figure 3. Breakdown of generation sources within Maryland.[86]

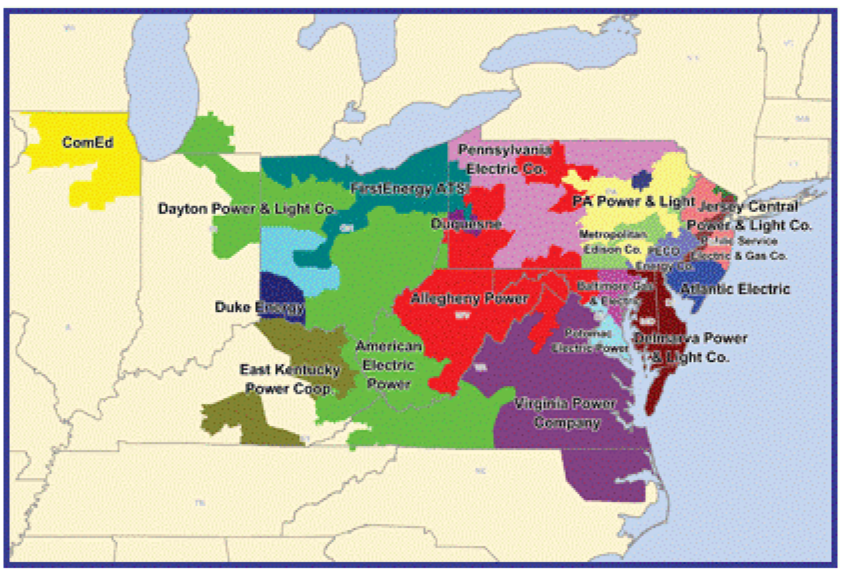

Figure 4. Map of PJM utilities.[87]

[86] Data listed are for 2020. "Electricity Data Browser," U.S. Energy Information Administration (EIA), accessed April 27, 2021, https://www.eia.gov/electricity/data/browser/

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