BEFORE THE PUBLIC SERVICE COMMISSION

OF THE COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) APPROVAL OF TARIFFS AND RIDERS; (3) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; (4) APPROVAL OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF	Case No. 2020-00174

PREPARED SUPPLEMENTAL TESTIMONY OF
RICHARD McCANN, PH.D

ON BEHALF OF
THE KENTUCKY SOLAR ENERGY INDUSTRY ASSOCIATION

February 25, 2021

Statement of Qualifications: Richard McCann, Ph.D

M.CUBED
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Professional Experience

M.Cubed, Partner, 1993-2008, 2014-present
Aspen Environmental Group, Senior Associate, 2008-2013
Foster Associates/Spectrum Economics/QED Research, Senior Economist, 1986-1992
Dames & Moore, Economist, 1985-1986

Academic Background

PhD, Agricultural and Resource Economics, University of California, Berkeley, 1998
MS, Agricultural and Resource Economics, University of California, Berkeley, 1990
MPP, Institute of Public Policy Studies, University of Michigan, 1986
BS, Political Economy of Natural Resources, University of California, Berkeley, 1981

Selected Relevant Projects

- **Regulatory Analysis and Support, Northern California CCAs (2016-present)**, **CalCCA (2018-present) and CalChoice (2017-2019)**. Testifying at the California Public Utilities Commission (CPUC) in rulemaking proceedings on the power charge indifference adjustment (PCIA) "exit" fee and resource adequacy, and Pacific Gas and Electric's (PG&E) and Southern California Edison's (SCE) rate proceedings.
- **Agricultural Rate Setting Testimony, Agricultural Energy Consumers Association (1992-present).** Testified about agricultural economic issues related to energy use, linkage to California water management policy, and utility rates in numerous proceedings at the California Public Utilities Commission, California Energy Commission, and California State Legislature.
- **Testimony on Protecting Solar Project Investment by Customers, County of Santa Clara (2017-2020)**. Testified before the California Public Utilities Commission in PG&E's 2017 General Rate Case on preserving current time of use rate structures applicable to existing RES-BCT solar projects owned by local governments.
- **Master-Metered Utility Systems Transfer Program, Western Manufactured Housing Communities Association (2003-present)**. Prepared petition that opened a rulemaking to facilitate transfer of master-metered utility systems to serving utilities and testified in that proceeding. Testified before the State Legislature on proposed legislation. Persuaded all electric and gas utilities in California to institute a pilot program to convert 10% of privately-owned MHP systems to utility ownership.
- **Master-Meter Rate Setting Testimony, Western Manufactured Housing Communities Association (1998-2019).** Examined issues associated with the structure of and cost associated with providing electric service to master-metered mobile home parks. Testified in Pacific Gas and Electric Co., Southern California Edison Co., Southern California Gas Co. and San Diego Gas and Electric Co. rate proceedings on establishing "master-meter/submeter credits" provided to private mobile home park utility systems.
- **Community Solar Gardens Testimony, Sierra Club (2014).** Testified in Pacific Gas and Electric and Southern California Edison Green Tariff applications on changes needed to encourage the

development of neighborhood and community-scale renewable distributed generation by allowing direct contracting and removing unnecessary transaction costs.

- **Time of Use Rates in California Residential Rates Rulemaking, Environmental Defense Fund (2013-2014).** Modeled how increased penetration of TOU rates in the residential sector for all three investor-owned utilities would reduce peak and energy demand, reduce residential bills, and reduce utility costs. Changes in revenues and costs were developed from the utilities' most recent general rate case filings.
- **Southern California Edison v. State of Nevada Department of Taxation, Nevada Attorney General's Office (2013-2014)**. Testified on whether the sales tax imposed on coal delivered to SCE's Mohave Generating Station created a competitive disadvantage for SCE in the Western power market during the 1998-2000 period.
- **Alternative Generation Technology Assessment, California Energy Commission (2001-2014).** Developed and maintained the Cost of Generation Model, spreadsheet-based tool used by the CEC to produce generation cost estimates for the Integrated Energy Policy Report (IEPR).
- **Time of Use Rates in Consolidated Edison Rate Case, Environmental Defense Fund (2013).** Modeled how increased penetration of TOU rates in the residential sector for Consolidated Edison serving the New York City metropolitan area would reduce peak and energy demand, reduce residential bills, and reduce utility costs.
- **Analytic Support for Long Term Procurement Plan OIR, California Public Utilities Commission Energy Division (2011-2012).** Reviewed California Independent System Operator (CAISO) and three utilities' resource acquisition plan out to 2020.
- **Analysis of Rocky Mountain Power Pilot Solar Incentives Program, Utah Clean Energy (2010).** Analyzed ratepayer and utility impacts analysis conducted by RMP to assess whether the three-year pilot program should be extended.
- **Electricity System Simulation Modeling Methodology Evaluation, California Energy Commission (2009-2010).** Constructed and applied an evaluation structure equivalent to the California's software purchasing Feasibility Study Report for assessing acquisition of a new production cost simulation model.
- **PG&E/NID/PCWA Relicensing Economic Analysis, Foothills Water Network (2009).** Conducted economic analysis for relicensing of PG&E's Drum-Spaulding, Nevada Irrigation District and Placer County Water Agency FERC projects on the American, Bear and Yuba Rivers for coalition of environmental group.
- **Reliability and Environmental Regulatory Tradeoffs in the LA Basin, California Energy Commission (2009).** Developed analytic tool in Analytica to assess local capacity requirements (LCR) in the CAISO and LADWP control areas for the 2009-2015 period, and how air and water quality regulations impact the ability to meet the LCR. The analysis was used to evaluate policy options for addressing new regulations on once-through-cooling at aging power plants and restriction on new air permits from the South Coast Air Quality Management District.
- **Nevada Collaborative Group Renewables and Transmission Policy, Energy Foundation (2008).** Developed policy alternatives for creating incentives to finance new renewable resources and transmission access in Nevada.
- **Analytic Support for Klamath Project FERC Relicensing Case, California Energy Commission (2005-2007).** Prepared economic analysis comparing potential costs and benefits of proposed relicensing conditions and decommissioning scenarios for a consortium of government agencies.

- **US v. Reliant Resources CR04-125, US Attorney (2005-2007).** Testified in a wire fraud case as to the air quality regulatory constraints that Reliant may have faced when scheduling and operating its power generation facilities June 20 to June 23, 2000. That testimony addressed whether Reliant traders improperly used environmental regulations as a cover for illegal market manipulation behavior.
- **Agricultural Engine Conversion Program, Agricultural Energy Consumers Association (2005).** Testified before the CPUC on program to convert agricultural diesel engines to electricity. The analysis identified the rate reduction needed to induce such conversions while still covering the utilities' (PG&E and SCE) incremental costs. The program converted 2,000 diesel pumps to electricity.
- **California Electricity Anti-trust Actions, California Office of the Attorney General (2002-2004).** Consulted on developing anti-trust cases and actions against merchant power generators as a result of the California 2000-2001 energy crisis.
- **FERC California Refund Case Testimony, California Electricity Oversight Board (2001-2003).** Testified before the Federal Energy Regulatory Commission on electricity price refund issues related to air emission and environmental permit costs, and effects on power plant operations from environmental regulations. Included analysis of the RECLAIM market performance during the crisis. EL-00-95 et al.
- **PG&E Hydro Divestiture EIR, California Public Utilities Commission (2000).** Evaluated the environmental impacts from divesting hydropower facilities and related lands by Pacific Gas and Electric Company.
- **Thermal Power Plant Divestitures Environmental Assessments, California Public Utilities Commission (1997-1998).** Evaluated the environmental impacts of the generating plant divestiture by Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric Companies.
- **QF Avoided Cost Rates, Oklahoma Corporation Commission Staff (1989).** Testified on Oklahoma Gas and Electric avoided-cost methodology and made projections for payments to cogeneration facilities using the PROMOD production-cost model. Testified for the OCC Staff, in Cause No. PUD 000600 and Cause No. PUD 000345.
- **QF Siting Certification Cases, Sun Oil/Mission Energy (1987), Signal Energy (1988), Luz Engineering (1988).** Prepared testimony on need-for-power in Southern California Edison and San Diego Gas and Electric, for three qualifying facility project siting applicants at the CEC.
- **QF Siting Certification Cases, IBM (1985), Arco Refining (1986), Mobil Oil (1986).** Prepared testimony on need-for-power in Southern California Edison and Pacific Gas and Electric, for three qualifying facility project siting applicants at the CEC.

Professional Affiliations

- American Agricultural Economics Association
- Association of Environmental and Resource Economists
- American Economics Association

Civic Activities

- Member, City of Davis Natural Resources Commission
- Former Member, City of Davis Utilities Rate Advisory Commission
- Former Member, City of Davis Community Choice Energy Advisory Committee
- Co-Chair, Cool Davis Energy Steering Committee
- Former Member, City of Davis Citizens Electricity Restructuring Task Force
- Former Member, Yolo County Housing Commission

PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND CURRENT POSITION.

Richard J. McCann, M.Cubed, 426 12th Street, Davis, California. My current position is Partner with M.Cubed

PLEASE SUMMARIZE YOUR PROFESSIONAL BACKGROUND AND ITS RELEVANCE TO THIS PROCEEDING?

I have been consulting since 1985. I specialize in environmental and energy resource economics and policy. I have testified before and prepared reports on behalf of numerous federal, state and local regulatory agencies on energy, air quality, and water supply and quality issues. I have testified in Illinois, Oklahoma, Nevada, and Utah, as well as California. I also testified before the Federal Energy Regulatory Commission in the California Energy Crisis Refund Proceeding. I have analyzed many different aspects of energy utility and market operations in the Western Interconnect. I have testified on the appropriate level of exit fees for community choice aggregators, and appropriate protection of solar project investment by customers. I have testified numerous times on impacts of electricity rates on qualifying facilities, agricultural groundwater pumping, reimbursement to master-metered manufactured housing community customers for utility services, and competitive fuel choices. I worked with the California Energy Commission to estimate the costs for new alternative generating technologies and developing several system modeling tools for local capacity planning and renewable generation integration.

I have been a partner with M.Cubed since 2014, and I was a founding partner in 1993 until I left for a stint at another firm in 2008. My resume with further details is attached to this testimony.

WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY AND HOW IT IS ORGANIZED?

The focus of my testimony is on the principles for setting the appropriate compensation and retail rates for customers who self-generate to serve part of their load. These customers are predominantly using solar panels. These customers also have made long-term commitments by investing in capital-intensive generation equipment with an expectation that retail rates will be relatively stable over a couple of decades. Economic systems work best when regulatory bodies do not institute sudden changes with little transition. I lay out the basic principles that the Kentucky Public Service Commission (Commission) should use in setting rates for net energy metering (NEM) customers.

My testimony first discusses how the electricity market is changing and how that affects ratemaking principles. I then discuss the importance of providing assurance to customers if the Commission wants to provide credible incentives for investing in many beneficial resources, not just rooftop solar. I then discuss how to value the resources displaced by beneficial investments such as solar (principles which are applicable to energy efficiency and demand management as well). I also describe what amount of utility costs are actually fixed and customer-specific. Finally, I lay out potential elements of a NEM tariff.

HOW IS THE ELECTRICITY MARKET CHANGING AND HOW SHOULD THAT INFLUENCE THE COMMISSION'S RATEMAKING POLICIES IN THIS CASE?

The electricity market is in flux, due to technology innovation, changing utility-customer relationships, and growing impacts of climate change on the grid. Meanwhile, the principles used in the industry to guide cost allocation for retail rate design have largely been static for fifty years.[1] Those now-quaint doctrines held that marginal costs reflecting market values could be captured entirely in the average incremental energy cost or market clearing price and the cost of new generation capacity to meet the single highest peak load hour of demand. The belief was that marginal generation costs could be reflected simply as a supply-side matter represented through two proxy measures. That simple world may have held for a period but is no longer a reality.

The world, and electricity sector, has changed profoundly, particularly in the last 25 years. Hourly electricity markets have not delivered on their envisioned promises; they do not economically incent necessary new capacity addition without regulatory intervention and have not incorporated environmental costs sufficiently to drive clean energy investments alone. Large-scale fossil fuel generation is being replaced by more dispersed renewables, storage, and distributed energy resources (DER). New technologies enable customers to produce their own energy and to substantially or fully escape reliance on the centralized utility grid.

This year, electricity systems have experienced several major multi-hour outages, most notably in California and Texas for reasons other than a failure to have sufficient installed capacity to meet the single highest peak load: (1) rolling blackouts in August in the area served by the California Independent System Operator (CAISO) due to a mix of market actions during a 1-in-35 year weather event while several thousand megawatts of capacity remained available;[2] (2) power

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[1] Alfred E. Kahn, 1988, *The Economics of Regulation: Principles and Institutions*, Cambridge, Massachusetts; London, England: MIT Press; National Economic Research Associates, 1977, "A Framework for Marginal Cost-Based Time-Differentiated Pricing in the United States," Prepared for EPRI Rate Design Study.

[2] "California begins rolling blackouts after first Stage 3 emergency since 2001," *Los Angeles Times*, August 14, 2020.

safety power shutoffs (PSPS) to mitigate potential wildfire hazards in California utilities' service areas;[3] and (3) widespread rolling outages in Texas caused by extreme freezing weather.[4]

In this case, these evolving constructs are being crammed into the old paradigm and do not adequately capture the cost of service consequences of new and emerging challenges, such as the many different dimensions of reliability revealed over the last year as well as the advent of bilateral transactions. The Commission should avoid committing to a single specific approach that will have to be soon cast aside as technology evolves further.

WHAT PRINCIPLES SHOULD THE COMMISSION ADOPT IN THIS SITUATION?

The Commission should adopt the profound advice of those who have set out ratemaking principles, and as often cited in Commission proceedings.[5] These sages advise "gradualism" in any changes so that customers are able to invest with certainty when Kentucky and the United States set out policy objectives. Serious errors have been made when the need for gradualism has been ignored, a salient example than I am quite familiar with being California's electricity industry restructuring begun in 1998, from which that state is still recovering.

With this guidance, the Commission should design NEM rates with a set of principles that it can also apply to designing other rates under its consideration. Those principles are:

- using long-term costs to represent what the utility saves,
- ensuring that self generating customers gain the same level of financial assurances that large generators have in their PPA,

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[3] "Nearly half a million PG&E customers to lose power amid planned fire-safety shut-offs Sunday," *San Francisco Chronicle,* https://www.sfchronicle.com/bayarea/article/Lafayette-Orinda-Moraga-brace-for-PG-E-outages-15670411.php , October 24, 2020.

[4] "Millions in Texas, Oklahoma without power as grid operators call for conservation," *Utility Dive*, https://www.utilitydive.com/news/millions-in-texas-oklahoma-without-power-as-grid-operators-call-for-conser/595122/, February 16, 2021.

[5] James C. Bonbright, 1961, *Principles of Public Utility Rates,* New York City: Columbia University Press.; Kahn (1988).

- applying cost causality similar to other customers,
- fixing costs only for customer-specific system components, and
- smoothly transitioning customers from one rate regime to another.

HOW ARE UTILITY-SCALE GENERATORS PROVIDED ASSURANCE OF RECOVERING THEIR INVESTMENT COSTS?

One of the key principles of providing financial stability is setting prices and rates for long-lived assets such as solar panels and generation plants at the economic value when the investment decision was made to reflect the full value of the assets that would have been acquired otherwise. If that new resource had not been built, a ratebased generation asset would have been constructed by the utility as a cost that would have been recovered over a 30 year period, no questions asked. There is no reason why other resource owners should be treated differently than the utility.

Generators are almost universally afforded the ability to recover capital investments based on prices set for multiple years, and often the economic life of their assets. Utilities are able to put investment in ratebase to be recovered at a fixed rate of return plus depreciation over several decades. Third-party generators are able to sign fixed price contracts for 10, 20 and even 40 years. Some merchant generators may choose to sell only into the short-term “hourly” market, but those plants are not committed to selling whenever a load-serving entity or a regional transmission operator (RTO) or independent system operator (ISO) demands so. Generators are only required to do so when they sign a long-term power purchase agreement (PPA) with an assured payment toward investment recovery.

GIVEN THIS TREATMENT OF UTILITY-SCALE GENERATORS’ INVESTMENTS, HOW SHOULD ROOFTOP SOLAR GENERATORS’ INVESTMENTS BE CONSIDERED IN DESIGNING A NEM RATE?

Tariffs offered to customers should be viewed as contracts that allocate risks and rewards between the utility and ratepayers, in the same way that a PPA allocates risks and rewards between generators and utilities. Ratepayers should not bear all of the risks and utilities should not receive all of the rewards. If ratepayers are responsible for paying for long-term investments, even if those assets now cost more than market purchases, then those ratepayers should receive credit for avoiding future costs based on long-term market costs. If ratepayers are to face short-term market prices, then they should not have to bear the stranded investments made by utility shareholders. Ratepayers should not have to bear stranded costs *and* only receive credit for avoiding resource additions based on short-term market prices. No generator would accept a similar deal.

Investments made by ratepayers that will benefit all ratepayers over the long term should be offered tariffs, as with contracts, that provide a reasonable assurance to recover those investments. This principle implies that ratepayers should be able to gain the same assurances as generators who sign long term power purchase agreements, or even utilities that ratebase their generation assets. These ratepayers should have some assurance over the 20-plus year expected life of their generation investment.

HAVE WHOLESALE BULK POWER MARKETS DELIVERED REALISTIC OR ACCURATE MEASURES OF THE TRUE VALUE OF GENERATION RESOURCES?

The Federal Energy Regulatory Commission (FERC) launched the electricity market reformation in the 1990s on a fundamental premise of neoclassical economics—that market prices in competitive markets reflect short-run marginal costs and that short-run marginal costs will converge with long-run marginal costs over time. Long-run marginal costs in turn will provide sufficient return on investment to incent new resource additions. ISOs such as the PJM

Interconnection were established to transparently provide these market prices, which would then lead to more efficient resource investment and operation.

Instead, these new markets have not created new resource investment on their own. The ISO markets such as PJM and the California Independent System Operator (CAISO) had to initiate additional "markets" for separately purchasing rights to capacity to meet reliability needs, and to institute side payments to bring units on-line early through commitment so as to be available during peak load hours. Even the supposed "hourly" market in the Electricity Reliability Council of Texas (ERCOT) requires a separately price adder of up to $9,000 per megawatt-hour ($9 per kilowatt-hour) during specified load conditions to provide sufficient revenue to cover generators' full costs.

WHY ARE THESE SHORT-RUN HOURLY MARKETS FALLING SHORT IN REFLECTING TRUE RESOURCE VALUE?

The reality for electricity markets is that short-run market transaction prices are unlikely to converge to long-run resource costs, especially on a sustained basis, because of many unique aspects of electricity markets and systems. Economic theory is based on assumptions about pure markets that do not hold in the technological complexity of the electricity grid.

Electricity production is so integral to the function of our economy that regulators, planners and utilities cannot allow supply deficits to exist for long enough to cause the shortages that can create sustained scarcity pricing. Even the ERCOT had to come up with a faux scarcity price mechanism (which is not economically sustainable) to create an appearance that such markets are able to support investment. For this reason, in anticipation of shortage crises, regulators often choose to overinvest in generation assets in a manner that suppresses shortage costs. Regulators and planners have decided that the economic costs of such shortages outweigh any potential "benefits" from supposed improvements in market efficiency.

Further, electricity generators must exercise their option to sell into the market when they interconnect to the grid network. Once the generators are on the network, they cannot sell into an alternative market. A generator cannot pick up its plant and move it to a different service area or balancing authority, and there are not parallel, competing grids that a generator can switch among. Generators can only raise hourly market prices by refusing to sell into that single market while making no other sales elsewhere. That would require withholding of sales just at when consumers need that power the most. This market manipulation was the primary cause of the electricity crisis in California in 2000-01. If generators have true must-offer requirements, then their bids are artificially capped in some manner. Instead, the actual representative marginal cost for generators is the full incremental cost of capital plus the net present value of the expected generation over the life of the project.

Long-term incremental costs can only be measured through the full cost of alternative investments such as the addition of a new generator with supporting transmission interconnections and additional distribution networks. That is why generation PPAs are universally negotiated at expected revenue requirements for a new plant and not just based on a sequence of forecasted short-term market price. Customers are the utility's clients, not generators—the Commission should expect the utility to treat its customers at least as well at the utility's suppliers.

DOES ROOFTOP SOLAR PROVIDE A SUBSTANTIAL BENEFIT TO THE REGIONAL ELECTRICITY GRID?

A recent study from the Lawrence Berkeley National Laboratory examines the physical value of solar to the grid, including to PJM.[6] That study found that solar generation continued to

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[6] Andrew D. Mills, et. al. (LBNL), (2021). *Solar-to-Grid: Trends in System Impacts, Reliability, and Market Value in the United States: with Data Through 2019*. Berkeley, California: Lawrence Berkeley National

provide the same level of reliable capacity over the 2012 to 2019 period in PJM,[7] and that the amount of the credit is about 55% of installed capacity for distributed solar.[8] While the capacity credit has diminished over time in the CAISO system as the penetration of utility-scale solar has reached 19% of load (and distributed solar adds another 5%), the share in PJM is still a relatively modest 2%.[9] The amount in PJM is not sufficient to shift the effective peak load away from 2 pm to 6 pm when solar is generating at near full output. In addition, solar puts out energy during the highest value hours. This energy value is 125% to 175% of the average cost of electricity.[10]

The Commission can safely rely on a full value estimate for solar power for current and near-term NEM customers. Not until the solar penetration rate reaches 5% or more could the effective value diminish.

HOW CAN THE VALUE OF DISPLACE TRANSMISSION BE DETERMINED?

When solar rooftop displaces utility generation, particularly during peak load periods, it also displaces the associated transmission that interconnects the plant and transmits that power to the local grid. And because power plants compete with each other for space on the PJM transmission grid, the reduction in bulk power generation opens up that grid to send power from other plants to other customers.

The value of displacing transmission requirements can be determined in several ways. PJM has a market in financial transmission rights (FTR) that values relieving the congestion on the grid in the short term. The holding company for Kentucky Power, American Electric Power (AEP),

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Laboratory, Energy Analysis & Environmental Impacts Division, Electricity Markets & Policy. Retrieved from https://emp.lbl.gov/renewable-grid-insights

[7] LBNL (2021), p. 24.

[8] LBNL (2021), p. 76.

[9] LBNL (2021), p. 32.

[10] LBNL (2021), p. 32.

files network service rates each year with PJM and FERC. Table 1 recounts those rates on a per megawatt-year basis.[11] The rate more than doubled over 2018 to 2021 at average annual increase of 26%.

Table 1 – AEP Transmission Rates 2018-2021

Year	Network service rate per MW-year	Percent Increase
2018	$24,822.32	
2019	$31,173.04	25.6%
2020	$41,759.82	34.0%
2021	$49,798.97	19.3%
Avg.		26.1%

Based on the addition of 22,907 megawatts of generation capacity in PJM over that period,[12] the incremental cost of transmission was $196,000 per megawatt-year or nearly four times the current AEP transmission rate. This incremental cost represents the long-term value of displaced transmission. This equates to about 3.7 cents per kilowatt-hour. The amount of the credit that rooftop solar can claim of that incremental cost would be the subject of a full cost of service study for NEM customers.

WHAT OTHER SAVINGS ARE CREATED BY NEM CUSTOMERS?

Similarly, NEM customers can displace investment in distribution assets. That distribution planners are not considering this impact appropriately is not an excuse for failing to provide this credit.

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[11] AEP, FERC Docket No ER17-405 and Docket No ER17-406.

[12] Monitoring Analytics. (2020). *2020 PJM Generation Capacity and Funding Sources: 2007/2008 through 2021/2022 Delivery Years*. The Independent Market Monitor for PJM. Retrieved from https://www.monitoringanalytics.com/Reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf.

Unfortunately, utilities' forecasts are notorious for overestimating load growth, resulting in part from underestimating savings from resource displacement through solar rooftops and energy efficiency. As a result, utilities build unneeded distribution infrastructure. For example, I have testified in California utility commissions showing how the load forecasts used to justify new distribution investment were consistently set too high and that added distribution for "new growth" could not be justified. Meanwhile for example, Pacific Gas and Electric Company's sales fell by 6% from 2010 to 2020 and other utilities had similar declines. Much of that decrease was driven by the installation of rooftop solar. Even in the case of Kentucky Power's recently issued Integrated Resource Plan (IRP), potentially optimistic assumptions about continued production from the coal industry and underestimating electricity price responsivity could lead to undershooting the demand forecast.[13]

The incremental value of displaced distribution can be calculated by comparing the recorded new investment to the projected load growth used by distribution system planners. Again, the amount to be credited to NEM customers should be derived in a full cost of service study.

SHOULD NEM CUSTOMERS PAY A FIXED OR VARIABLE CHARGE FOR THE DISTRIBUTION GRID?

Distribution capacity is shared among customers even on the local circuit. A customer does not use a fixed, specified portion of the circuit. For example, up to a dozen residential customers may share a final load transformer, and of course thousands share a substation.

If a customer is required to make a fixed monthly payment on that capacity in this physical situation, the economics imply that the customer owns that share of the distribution system. If the

[13] Public Service Commission of the Commonwealth of Kentucky, "Order, In the Matter of: Electronic 2019 Integrated Resource Planning Report of Kentucky Power Company," Case No. 2019-00443, An Appendix to an Order of the Kentucky Public Service Commission in Case No. 2019-00443 Dated Feb 15 2021.

local distribution system was functioning as a market, a customer could then choose to sell a portion of that capacity to another customer who may value it more highly. But such a market would be complex with high transaction costs. Notably, such a market would evolve set prices using a variable charge for electricity grid services. So instead given the logistical challenges and transaction frictions, the utility should act as a central dealer of local distribution capacity and charge a variable cents per kilowatt-hour rate. Local secondary distribution capacity should be priced as a variable cost since customers cannot trade in their share of distribution capacity. There is little justification for using fixed charges to recover those costs.

WHAT PORTION OF THE UTILITY BILL COULD BE RECOVERED THROUGH A FIXED MONTHLY CHARGE?

The customer service connection and metering and billing services are committed to a single customer and can be paid through a fixed monthly customer charge. Those costs do not vary with monthly usage and the service line and meter, and billing services cannot be used readily by another customer.

That said, the current monthly customer charge is sufficient to cover the fixed costs attributable to NEM customers. Kentucky Power's current residential customer charges are a good approximation of those costs at $17.50 to $21.00 per month. There is no need to revise that portion of the rate for NEM customers.

COULD YOU PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS PROCEEDING?

When acting on how to modify Kentucky Power's NEM rate, the Commission should move in a considerate and deliberate manner. Given the low penetration of NEM customers so far, the financial situation will not tip unfavorably against other customers or the utility in the near future.

Rather, the investments made in good faith by NEM customers and solar providers could be unduly and permanently damaged if the Commission does not fully consider all relevant aspects. Providing assurances for financial stability will maintain the Commission's credibility for incenting beneficial investments and actions of all types in the future.

To do so, the Commission should give NEM customers' investments the same consideration given to that of generation owners and even the utility. The value of resources displaced by rooftop solar—generation, transmission and distribution—should be determined based on the cost of assets with similar lifetimes, not on hourly energy prices or single-year capacity auctions. Fixed charges should be held to only the direct service connection costs, as Kentucky Power already does.

Any transition should be done gradually. Rapid shifts have too often resulted in unanticipated economic displacement and adverse consequences.

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AFFIDAVIT OF RICHARD McCANN, PH.D
VERIFICATION

JURISDICTION)
)
County of Yolo)

The undersigned, Richard J. McCann, being first duly sworn, states the following: The prepared pre-filed Supplemental Testimony, and the Exhibits and Appendices attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth pre-filed Supplemental Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further, Affiant saith not.

Richard J. McCann
Richard J. McCann

SUBSCRIBED AND SWORN to before me this 24th day of February, 2021.

NOTARY PUBLIC

See attached CALIFORNIA Jurat L.P 2-24-2021

My Commission Expires: ______________________

CALIFORNIA JURAT WITH AFFIANT STATEMENT **GOVERNMENT CODE § 8202**

☐ See Attached Document (Notary to cross out lines 1–6 below)
☐ See Statement Below (Lines 1–6 to be completed only by document signer[s], *not* Notary)

Signature of Document Signer No. 1 *Signature of Document Signer No. 2 (if any)*

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

State of California
County of YOLO

Subscribed and sworn to (or affirmed) before me on this 24th day of February, 2021, by
Date *Month* *Year*

(1) RICHARD J MCCANN

(and (2) ______),
Name(s) of Signer(s)

proved to me on the basis of satisfactory evidence to be the person(s) who appeared before me.

LALIT PRASAD
Notary Public - California
Yolo County
Commission # 2234498
My Comm. Expires Mar 20, 2022

Signature Lalit Prasad
Signature of Notary Public

Seal
Place Notary Seal Above

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