COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR AN ADJUSTMENT TO RIDER NM RATES AND FOR TARIFF APPROVAL	))))	CASE NO. 2023-00413

MOTION FOR LEAVE TO FILE CORRECTED RESPONSES OF JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Come now Joint Intervenors Kentucky Solar Energy Society and Kentuckians for the Commonwealth ("Joint Intervenors") and move the Commission for leave to file Corrected Responses to the March 22, 2024 Request for Information from Duke Energy Kentucky, Inc. In support of their motion Joint Intervenors state that in reviewing their Responses filed on April 05, 2024 counsel discovered the Verification of their Witness, Dr. Richard McCann, was inadvertently omitted. Corrected Responses are attached to this motion with the only change being the inclusion of the previously-omitted verification, and updated dates of the filing and Certificate of Service.

Respectfully Submitted,

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CORRECTED RESPONSES OF JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

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Counsel for Joint Intervenors Kentucky Solar Energy Society and Kentuckians for the Commonwealth

Dated: April 09, 2024

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 1

Q1 Other than Mr.[sic] McCann, please identify any persons, including experts whom KSES has consulted, retained, or is in the process of retaining with regard to evaluating the Company's Application in this proceeding.

RESPONSE:

Joint Intervenors Kentucky Solar Energy Society ("KYSES" or "KSES") and Kentuckians for the Commonwealth ("KFTC") (collectively, "Joint Intervenors" or "JI") object to this request to the extent it is not reasonably calculated to lead to the discovery of admissible evidence, or seeks information prepared in anticipation of litigation or for trial by or for another party or by or for that other party's representative. Information concerning persons "consulted, retained, or … in the process of retaining" for purposes of evaluating the Company's Application in this proceeding," but not called as witnesses is generally obtainable through discovery only upon a showing that the party seeking discovery has substantial need of the materials in the preparation of his case and that he is unable without undue hardship to obtain the substantial equivalent of the materials by other means. Further, to the extent Joint Intervenors' employees, members, and representatives are themselves experts, any consultation between counsel and client employees, members, or representatives constitutes attorney-client communications privileged from disclosure.

Without waving these objections, Joint Intervenors state that they do not intend to call at hearing any persons other than Dr. Richard McCann and potentially any witnesses identified by the Company or other party in these proceedings if not called by the Company or another party for cross-examination.

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 2

Q2 For each person identified in (prior) response to Data Request No. 1 above, please state (1) the subject matter of the discussions/consultations/evaluations; (2) the written opinions of such persons regarding the Company's Application; (3) the facts to which each person relied upon; and (4) a summary of the person's qualifications to render such discussions/consultations/evaluations.

RESPONSE:

Joint Intervenors object to this request to the extent it is not reasonably calculated to lead to the discovery of admissible evidence, or seeks information prepared in anticipation of litigation or for trial by or for another party or by or for that other party's representative. Information concerning persons "consulted, retained, or … in the process of retaining" for purposes of "evaluating the Company's Application in this proceeding," but not called as witnesses is obtainable through discovery only upon a showing that the party seeking discovery has substantial need of the materials in the preparation of his case and that he is unable without undue hardship to obtain the substantial equivalent of the materials by other means. Further, to the extent Joint Intervenors' employees, members, and representatives are themselves experts, any consultation between counsel and client employees, members, or representatives constitutes attorney-client communications privileged from disclosure.

Without waving these objections, Joint Intervenors state that they do not intend to call at hearing any persons other than Dr. Richard McCann and potentially witnesses identified by the Company or any other party in these proceedings if not called by the Company or another party for cross-examination.

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 3

Q3 For each person identified in response to Data Request No. 1 above, please identify all proceedings in all jurisdictions in which the witnesses/persons have offered evidence, including but not limited to, pre-filed testimony, sworn statements, and live testimony. For each response, please provide the following:

(a) The jurisdiction in which the testimony or statement was pre-filed, offered, given, or admitted into the record;
(b) The administrative agency and/or court in which the testimony or statement was pre-filed, offered, admitted, or given;
(c) The date(s) the testimony or statement was pre-filed, offered, admitted, or given;
(d) The identifying number for the case or proceeding in which the testimony or statement was pre-filed, offered, admitted, or given; and,
(e) Whether the person was cross-examined.

RESPONSE:

Joint Intervenors object to this request to the extent it is not reasonably calculated to lead to the discovery of admissible evidence, or seeks information prepared in anticipation of litigation or for trial by or for another party or by or for that other party's representative. Information concerning persons “consulted, retained, or … in the process of retaining” for purposes of “evaluating the Company’s Application in this proceeding,” but not called as witnesses is obtainable through discovery only upon a showing that the party seeking discovery has substantial need of the materials in the preparation of his case and that he is unable without undue hardship to obtain the substantial equivalent of the materials by other means. Further, to the extent Joint Intervenors' employees, members, and representatives are themselves experts, any consultation between counsel and client employees, members, or representatives constitutes attorney-client communications privileged from disclosure.

Without waving these objections, Joint Intervenors state that they do not intend to call at hearing any persons other than Dr. Richard McCann or witnesses identified by the Company in these proceedings if not called by the Company or another party for cross-examination.

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 4

Q4 Identify and provide all documents or other evidence that KSES may seek to introduce as exhibits or for purposes of witness examination in the above-captioned matter.

RESPONSE:

Joint Intervenors have not determined what, if any, documents or other evidence they intend to introduce as exhibits or for purposes of witness examination. Joint Intervenors will update this response timely as that determination is made.

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 5

Q5 Please provide copies of any and all presentations made by Mr.[sic] McCann within the last three years involving or relating to the following: 1) net metering (NEM); 2) cogeneration; 3) power purchase agreements; and 4) demand response programs.

RESPONSE:

Please see attached seven testimonies, presentations and reports.

ATTACHMENTS:

JI-DEK-DR-01-001 PREPARED SUPPLEMENTAL TESTIMONY OF RICHARD McCANN, PH.D ON BEHALF OF THE KENTUCKY SOLAR ENERGY INDUSTRY ASSOCIATION in Kentucky PSC Case No. 2020-00174

JI-DEK-DR-01-002 TESTIMONY OF RICHARD McCANN, Ph.D. ON BEHALF OF THE AGRICULTURAL ENERGY CONSUMERS ASSOCIATION AND THE CALIFORNIA FARM BUREAU FEDERATION in California PUC Docket No. R.20-08-020

JI-DEK-DR-01-003 REBUTTAL TESTIMONY OF RICHARD McCANN, Ph.D. ON BEHALF OF THE AGRICULTURAL ENERGY CONSUMERS ASSOCIATION AND THE CALIFORNIA FARM BUREAU FEDERATION in California PUC Docket No. R.20-08-020

JI-DEK-DR-01-004 PREPARED DIRECT TESTIMONY OF RICHARD McCANN, PH.D. ON BEHALF OF THE CALIFORNIA FARM BUREAU FEDERATION in California PUC Case No. A.21-06-021

JI-DEK-DR-01-005 DIRECT TESTIMONY OF RICHARD MCCANN, PH.D. AND STEVEN J. MOSS, MPP ON BEHALF OF SMALL BUSINESS UTILITY ADVOCATES in California PUC Case Nos. A.22-05-015 and A.22-05-016

JI-DEK-DR-01-006 Comments on *Washington Utilities NEM Evaluation-Draft Results* Submitted by Richard McCann, Ph.D., M.Cubed on behalf of the Washington Solar Energy Industries Association

JI-DEK-DR-01-007 WASEIA Comments on *Review of Tariff Design for Customer Generation* Submitted by Richard McCann, Ph.D., M.Cubed on behalf of the Washington Solar Energy Industries Association

JI-DEK-DR-01-001

PREPARED SUPPLEMENTAL TESTIMONY OF RICHARD McCANN, PH.D ON BEHALF OF THE KENTUCKY SOLAR ENERGY INDUSTRY ASSOCIATION in Kentucky PSC Case No. 2020-00174

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

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

[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.

JI-DEK-DR-01-002

TESTIMONY OF RICHARD McCANN, Ph.D. ON BEHALF OF THE AGRICULTURAL ENERGY CONSUMERS ASSOCIATION AND THE CALIFORNIA FARM BUREAU FEDERATION in California PUC Docket No. R.20-08-020

Docket No.: R.20-08-020
Exhibit No.: AEC-01
Date: June 18, 2021
Witness: Richard McCann, Ph.D.

TESTIMONY OF RICHARD McCANN, Ph.D. ON BEHALF OF THE AGRICULTURAL ENERGY CONSUMERS ASSOCIATION AND THE CALIFORNIA FARM BUREAU FEDERATION

TABLE OF CONTENTS

Page

1 Introduction

The Agricultural Parties are composed of the Agricultural Energy Consumers Association (AECA) and the California Farm Bureau Federation (CFBF).

AECA is a nonprofit organization that represents the energy interests of California agriculture. AECA was founded in 1991 by growers and other members of the agricultural community concerned about rapidly rising electricity costs. AECA represents the collective interests of the state's leading agricultural associations and works on behalf of the combined interests of several county Farm Bureaus and more than forty agricultural water districts. AECA's membership is broad-based, reflecting family farmers from Redding in the north to San Diego in the south who grow crops ranging from alfalfa to walnuts. Through its members and membership associations, AECA represents in excess of 40,000 California agricultural producers.

CFBF is California's largest farm organization, working to protect family farms and ranches on behalf of its nearly 32,000 members statewide and as part of a nationwide network of more than 5.5 million members. Organized over 100 years ago as a voluntary, non-governmental and nonpartisan organization, it advances its mission throughout the state together with its 53 county Farm Bureaus. It works with its members throughout the state to elevate issues of concern. Farm Bureau strives to protect and improve the ability of farmers and ranchers engaged in production agriculture to provide a reliable supply of food and fiber through responsible stewardship of California's resources.

The Agricultural Parties recommend that the California Public Utilities Commission (Commission or CPUC) adopt the following findings and recommendations to address the unique circumstances for agricultural customers with regards to net energy metering:

- Agricultural customers on aggregated net energy metering (NEMA) tariffs pay the full costs of distribution, transmission and nonbypassable charges due to the rate design of agricultural schedules and, therefore, there are no material cross subsidies from other ratepayers to NEMA customers. For this reason, these agricultural customers should not be allocated any additional cost responsibilities.

- Existing agricultural net energy metering (NEM) and NEMA customers have made investments in new generation that benefit all customers through reduced and avoided investment in transmission and distribution facilities and deferred acquisition of generation resources. The Commission should respect the substantial investment these customers have made through continuation of the terms of the NEM 1.0 and 2.0 tariffs that they are currently on.

- New NEM 3.0 customers will be taking similar investment risks as previous NEM/NEMA customers and if the Commission wishes to encourage a broad range of customer investments in energy management and savings technologies, the Commission should provide a level of certainty about investment return that is commensurate with the risk. For this reason, the Commission should provide a 20-year term on the NEM 3.0 tariff.

- Payment for exported power, whether for existing or new customers, should reflect the cost of acquiring new generation resources as authorized by the CPUC, not the short-run market prices, to reflect the investment burden and risk taken by NEM/NEMA customers. NEM/NEMA customers are signing long-term agreements with the utility and the value of those exports should reflect that commitment. If the Commission chooses to compensate NEM 3.0 customers at the short-run market prices, then these customers should also be exempt from the Power Charge Indifference Adjustment (PCIA).

- Under the current framework, customers are not allocated a specific share of the grid that they can buy and sell—the utility must act as the dealer selling those shares in hourly increments to avoid the immense transaction costs if a different market exchange system is used. As a result, NEM/NEMA customers should pay a variable charge for the distribution grid.

1.1 What is the role of solar net energy metering in agriculture?

The Agricultural Parties appreciate the opportunity to provide information to the Commission regarding the self-generation applications that agricultural customers have been able to optimize through the NEM framework, particularly with regard to aggregating contiguous loads. Agricultural customers use net metering in conjunction with wind, hydroelectric, and solar facilities. However, the vast majority of agricultural customers use solar for self-generation.

With NEMA, agricultural customers have been able to optimize land resources in conjunction with solar generation because they are able to place the facilities on land that may be underperforming in agricultural commodity production. The implementation of the provisions of the Sustainable Groundwater Management Act (SGMA), which caps groundwater pumping in many basins, may lead to land fallowing and retirement that will further expand the amount of acreage available for local solar production.[1] The shift in time of use (TOU) periods means that water pumping is cheapest when the sun is the brightest; this introduces another incentive to aggregate loads.

Generally solar photovoltaic generation facilities used for self-generation fall into one of three categories:

1. Aggregated accounts under the NEMA tariff with a single generation account delivering to a set of benefiting accounts that receive a credit against each account's bill. This arrangement is typical for an agricultural operation on multiple parcels with multiple pumps served by a single solar array. This probably represents the largest segment of the agricultural customers with solar.

2. A single account with load and self-generation located behind a single meter on an agricultural rate schedule. These may include dairies or other agricultural facilities.

3. A single account with load and self-generation located behind a single meter on a commercial rate schedule, most likely an Option R schedule.

The Agricultural Parties' testimony focuses on the first situation since it presents a unique situation for the Commission to consider. We leave the third situation to those parties addressing Option R and Option S issues.

[1] However, land retirement may not occur in large contiguous patches that would allow for construction of utility-scale renewable generation. Aggregating NEM agricultural accounts provides the best option for serving loads with the smaller projects that will fit into the parcels taken out of production.

1.2 Agricultural NEM customers should be able to rely on a stable price signal and continuous terms during a transition

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.[2] 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.

In the past two years, electricity systems have experienced several major multi-hour and multi-day 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 2020 in the area served by the California Independent System Operator (CAISO) due to a mix of

[2] 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.

market actions during a 1-in-35 year weather event while several thousand megawatts of capacity remained available;[3] (2) public safety power shutoffs (PSPS) to mitigate potential wildfire hazards in California utilities' service areas, sometimes lasting for days at a time;[4] and (3) widespread rolling outages in Texas caused by extreme freezing weather.[5]

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.

The Commission should adopt the profound advice of those who have set out ratemaking principles, and as often cited in Commission proceedings.[6] These sages advise "gradualism" in any changes so that customers are able to invest with certainty when California and the United States set out policy objectives.

Growers are already exposed to larger variability, risks, and vulnerabilities than any other customer class, due to effects from weather, water availability, and competition from global commodity markets. The Agricultural Parties have demonstrated in various Commission

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[3] "California begins rolling blackouts after first Stage 3 emergency since 2001," *Los Angeles Times*, August 14, 2020, https://www.latimes.com/california/story/2020-08-14/la-me-statewide-power-outages-warning; and California ISO, CPUC and CEC, *Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave*, http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf, January 13, 2021 (included as Attachment A hereto).

[4] "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; and Decision 19-05-042.

[5] "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.

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

proceedings that agricultural electricity loads vary more year to year than any other class.[7] Much of the agricultural crop insurance system is managed directly by the federal government because the risks in the sector are too great for private sector insurance firms. The only other industries that see similar swings in global commodity prices are populated by large corporations that can manage these risks, rather than the small family farms that grow much of the crops in California. The Commission should not be switching up NEM tariffs, particularly NEMA, in a manner that heaps even more uncertainty on these customers.

With this guidance, the Commission should design NEM tariffs to achieve a gradual transition that is not jarring to existing NEM/NEMA customers or prohibitive for new customers and avoids a potential for rapid switching among different cost and rate frameworks. The rates should include these elements:

- use stable long-term costs to represent costs saved and incurred by the utility when a customer installs a self-generation system,
- ensure that self-generating customers gain the same level of financial assurances that large generators have in their power purchase agreements (PPA) given the similar risks that each face, and
- smoothly transition customers from one rate regime to another when that transition occurs.

2 Agricultural NEMA customers pay for distribution and nonbypassable charges on all usage

In the agricultural rate schedules, distribution charges are largely collected through either a fixed monthly customer charge or a demand charge based on metered usage. Nonbypassable charges are unbundled and recovered separately from the generation cost charges. Only

[7] *See, e.g.*, Testimony of Richard McCann and Laura Norin on Behalf of the Agricultural Parties in Pacific Gas & Electric's (PG&E's) 2017 General Rate Case Phase 2 Application Addressing PG&E's Agricultural Class Balancing Account Study, A.16-06-013, March 15, 2017 (included as Attachment B hereto).

generation charges are offset by customer-owned renewable generation under the NEMA tariff. Even then, only the energy charges are offset and the demand charges are still collected towards generation costs.

Commission staff, in a memorandum prepared in 2012 regarding Senate Bill (SB) 594 – the legislation that among other things authorized aggregated agricultural NEM, stated:

> Because of their lower rates, non-residential projects cost non-participating ratepayers substantially less: the levelized net total cost of non-residential NEM facilities averages $0.03 per kWh-exported, compared to an average $0.19 per kWh-exported for residential facilities, as shown in Table 1.[8]

The Commission recognized that non-residential NEM and NEMA customers do not impose a burden on non-NEM customers and could even be providing a large benefit. Based on this analysis, the Commission supported SB 594.

A cost of $0.03 per kilowatt-hour (kWh) (or $30 per megawatt-hour) is below any market price benchmark (MPB) energy issued for use in calculating the PCIA in the Energy Resource Recovery Account (ERRA) proceedings and well below the MPB for renewable power purchase agreements. This indicates that these customers could have a *negative* PCIA if it was imposed on them. These customers are contributing substantially to the margin that covers overall utility costs which justifies maintaining the current means of addressing nonbypassable charges; no additional cost responsibility should be allocated to non-residential NEM and NEMA customers.

3 The Commission should continue to assure that solar customers receive service under the terms established when choosing a tariff

The timing and rules established in D.14-03-041 in connection with NEM 2.0, including a 20-year transition period, ensured that customers who interconnected renewable distributed

[8] Lynn Sadler, "SB 594 (Wolk) – Energy: net energy metering. As amended: March 1, 2012," Office of Governmental Affairs (OGA) — Sacramento, Memorandum to the Commission, May 8, 2012, p. 3 (included as Attachment C hereto, without attached bill language).

generation systems under the then applicable NEM program had a reasonable opportunity to recoup their investments in those systems. In addition, a 20-year transition period was consistent with some estimates of the expected useful life of such systems, reflected in many existing PPAs and financing arrangements for renewable distributed generation.[9]

Customer-generators relied on D.14-03-041 and the terms specified in the implementing tariffs, including the assurance of being able to take service under the tariff terms for 20 years and having access to legacy TOU periods, when they committed to invest in NEM/NEMA projects. Another important element of the existing tariffs is the annual true-up of credits for self-generators, which should stay intact.

The importance of regulatory certainty for such customers cannot be overstated. As the Commission recognized in D.14-03-041, the wide variety of projects and circumstances necessitated an equitable commitment to the framework. Already, the benefits associated with net metering have been impacted and reduced by changing TOU periods and relative pricing, changes that did not occur until after a successor to NEM 1.0 was considered.

3.1 Existing NEM customers have saved California consumers substantial avoided generation and distribution costs

Distributed solar generation installed under the NEM/NEMA program has mitigated and even eliminated load and demand growth in areas with established customers. This benefit supports protecting the investments that have been made by existing NEM/NEMA customers.

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

[9] D.14-03-041, p. 3.

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 CPUC proceedings 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 5% from 2010 to 2018 and other utilities had similar declines.[10] Peak loads in the CAISO balancing authority reach their highest point in 2006 and the peak last August was 6% below that level.[11]

Much of that decrease appears to have been driven by the installation of rooftop solar. Figure Agricultural Parties-1 illustrates the trends in CAISO peak loads in the set of top lines and the relationship to added NEM installations in the lower corner. Prior to 2006, the CAISO peak was growing at annual rate of 0.97%; after 2006, peak loads have declined at a 0.28% trend. Over the same period, solar NEM capacity grew by over 9,200 megawatts.[12] The correlation factor or "R-squared" between the decline in peak load after 2006 and the incremental NEM additions is 0.93, with 1.0 being perfect correlation. Based on these calculations, NEM capacity has deferred 6,500 megawatts of capacity additions over this period, saving all ratepayers both reliability and energy costs while delivering zero-carbon energy.

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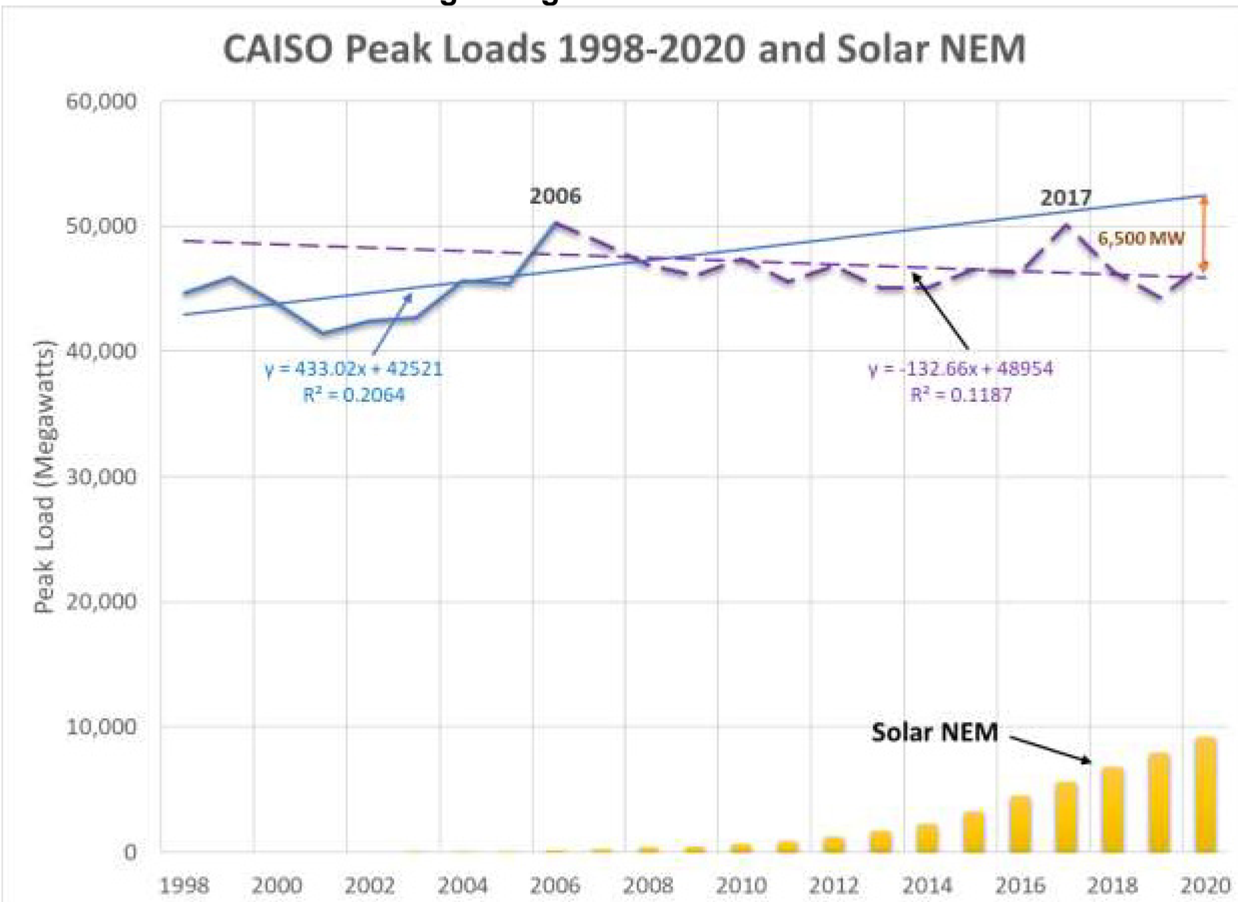
[10] PG&E 2017 General Rate Case Phase II Updated and Amended Prepared Testimony, Exhibit PG&E-08, Volume 2, December 2, 2016 (PG&E-08, Vol. 2), Appendix F; and PG&E ERRA Forecast testimony for 2015-2019, Tables 2-3.

[11] CAISO, "California ISO Peak Load History 1998 through 2020," https://www.caiso.com/documents/californiaisopeakloadhistory.pdf, retrieved April 2021 (included as Attachment D hereto).

[12] California Distributed Generation Statistics, https://www.californiadgstats.ca.gov, retrieved June 2021 (included as Attachment E hereto).

Figure Agricultural Parties-1



3.2 Agricultural NEM/NEMA generators should be treated commensurately with any other generator with a long-term PPA with guaranteed terms and prices as appropriate

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, either a ratebased generation asset would have been constructed by the utility at a cost that would have been recovered over a standard 30-year period or more likely, additional PPAs would have been signed. Additionally, the utilities' investments and procurement costs are not subject to retroactive ratemaking under the rule prohibiting such ratemaking and Public Utilities Code Section 728, thus protecting shareholders from any risk of future changes in state or Commission policies.[13] Utility customers who similarly invest in generation should be afforded at least the same assurances as the utilities with respect to protection from future Commission decisions that may diminish the value of those investments. Moreover, customers do not have the additional assurances of achieving a certain net income so they already face higher risks than utility shareholders for their investments.

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 investments 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 the CAISO demands so. Generators are only required to do so when they sign a PPA with an assured payment toward investment recovery.

Ratepayers who make investments that benefit all ratepayers over the long term should be offered tariffs that provide a reasonable assurance of recovery of those investments, similar to the PPAs offered to generators. Ratepayers should be able to gain the same assurances as generators who sign long-term PPAs, or even utilities that ratebase their generation assets, that they will not be forced to bear all of the risk of investing of clean self-generation. These ratepayers should have some assurance over the 20-plus year expected life of their generation investment.

Agricultural customers, like all business operators, make decisions based on regulatory direction among many other factors. Growers now face a particularly complex regulatory

[13] In fact, quite the opposite happened when the Commission reversed earlier decisions that had limited cost recovery for ratebased generation built after 2001 through the cost recovery surcharge (CRS) and later the PCIA to ten years in issuing D.18-10-019. That decision extended the cost recovery period to the full book life for those generators.

environment encompassing not only potential changes in their NEM/NEMA arrangements, but also in their ability to rely on groundwater sources to make up for swings in water availability due to the implementation of SGMA, and new regulations to manage greenhouse gas emissions from the sector. This situation makes agriculture particularly vulnerable to significant economic harm if exposed excessively to market volatility as the utilities are proposing by pricing all generation under the NEMA tariff at current market prices instead of the current practice based on the applicable retail rate for the generating account.[14]

Up to this point NEM/NEMA customers have been assured that the construct for their operations allows them to remain on the current tariffs for 20 years from the date of interconnection. The Commission should maintain that commitment to NEM 3.0 customers. Doing so will provide customers with certainty regarding their investments in clean energy and avoid regulatory whiplash.

4 Payment for exported power should reflect the cost of acquiring new generation resources as authorized by the CPUC, not short-run market prices, to reflect the investment burden and risk taken by customers

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.

[14] Joint Utilities, "Joint Proposal of Pacific Gas and Electric Company (U 39-E), San Diego Gas & Electric Company (U 902-E) and Southern California Edison Company (U 338-E)," March 15, 2021, p. 26.

These new markets have not created new resource investment on their own. The ISO markets such as PJM and 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 separate 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.

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 over-invest 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 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.

Tariffs offered to customers should be viewed as contracts that allocate risks and rewards between the utility and ratepayers, in the same way that PPAs allocate 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. 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 prices. The same methodology should apply to sales from NEM/NEMA projects.

If NEMA ratepayers are to face short-term market prices as proposed by the Joint Utilities,[15] 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 and no

[15] Joint Utilities, p. 26.

PPA requires wholesale generators to compensate the utility for excess generation created by the addition of the new generator. If the Commission adopts the utilities' proposal to shift to paying only short-term market prices for all generation for NEMA customers, then those same customers should not have to pay the PCIA from their benefiting accounts as a matter of equity.

4.1 Customers under NEM 3.0 should be credited for the incremental cost of added transmission investment that is otherwise needed for new bulk power generation

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 CAISO transmission grid, the reduction in bulk power generation opens up that grid to send power from other plants to other customers. The incremental cost of new transmission is determined by the installation of new generation capacity as transmission delivers power to substations before it is then distributed to customers.

The value of displacing transmission requirements can be determined from the utilities' filings with FERC and the accounting for new power plant capacity from California Energy Commission (CEC) data. Table Agricultural Parties-1 summarizes the calculation of this incremental cost. Transmission investment additions were collected from the FERC Form 1 filings for 2017 to 2020.[16] The Wholesale Base Total Revenue Requirements submitted to FERC were collected for the three utilities for the same period. The average fixed charge rate for the Wholesale Base Total Revenue Requirements was 12.1% over that year. That fixed charge rate is applied to the average of the transmission additions to determine the average incremental revenue

[16] FERC Form 1 for Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric, Years 2017-2020, p. 206.

requirements for new transmission for the period. The plant capacity installed in California for 2017 to 2020 is calculated from the CEC's "Annual Generation – Plant Unit".[17] This metric is conservative because (1) it includes the entire state while CAISO serves only 80% of the state's load and the three utilities serve a subset of that, and (2) the list of "new" plants includes a number of repowered natural gas plants at sites with already existing transmission. A more refined analysis would find an even higher incremental transmission cost. Based on this analysis, the appropriate marginal transmission cost is $171.17 per kilowatt-year. Applying the average CAISO load factor of 52%, the marginal cost equals $37.54 per megawatt-hour. This amount should be used to calculate the net benefits for NEM/NEMA customers who avoid the need for additional transmission investment by providing local resources rather than remote bulk generation when setting rates under NEM 3.0.

Table Agricultural Parties-1

Average Additions	$2,379,513,874
Average Incremental RRQ	$287,104,235
Average Added kW/Year	$1,677,325
Incremental $/kW-Yr	$171.17
Incremental $/MWH	$37.54

4.2 NEM/NEMA customers should pay a 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 single final load transformer, and 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

[17] CEC, "Annual Generation – Plant Unit," https://ww2.energy.ca.gov/almanac/electricity_data/web_qfer/Annual_Generation-Plant_Unit_cms.php, retrieved June 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.

Local 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. 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.

5 Conclusion

The Agricultural Parties ask that the Commission continue to provide the financial and contractual assurances required to maintain and encourage clean energy investment by utility customers in California, including customers participating in existing NEM/NEMA programs and those who chose to participate in a NEM 3.0 program. The larger scale customer-owned generation of the type installed to serve NEMA accounts is particularly attractive. It avoids the environmental damages created by bulk power solar and wind projects by building on already-disturbed lands or even buildings and displaces the expensive transmission required to transmit that bulk power. In addition, NEMA projects transmit within a distribution circuit and the rates are designed to cover distribution and nonbypassable charges. The Commission and the utilities should be treating relationships with NEM/NEMA customers similarly to generators under PPAs, with terms fixed at signing unless directly renegotiated and prices known over the life of the agreement. Rates for compensating NEM/NEMA customers should be based on accurate long-run costs. Customers are not market speculators and they should not be treated as such. Agricultural customers especially already face substantial market and regulatory uncertainty from other forces. The Commission should be encouraging choices that move toward broader state goals—giving agricultural customers the assurances they need is an important step in that direction.

STATEMENT OF QUALIFICATIONS

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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

Electricity Testimony and Resource Planning

- **Regulatory Analysis and Support, CalCCA (2018-present)**. Testifying at the California Public Utilities Commission (CPUC) in rulemaking proceedings on the power charge indifference adjustment (PCIA) "exit" fee and resource adequacy.
- **Regulatory Analysis and Support, Sonoma Clean Power (2016-present)**. Testifying at the California Public Utilities Commission (CPUC) in Pacific Gas and Electric's (PG&E) rate proceedings on the power charge indifference adjustment (PCIA) "exit" fee and other issues.
- **Regulatory Analysis and Support, CalChoice (2017)**. Testifying at the California Public Utilities Commission (CPUC) in Southern California Edison's (SCE) rate proceedings on the power charge indifference adjustment (PCIA) "exit" fee and other issues.
- **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-present)**. 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-Meter Rate Setting Testimony, Western Manufactured Housing Communities Association (1998-present).** 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.
- **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.

- **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.
- **Exploratory Modeling Methodology Project, California Energy Commission (2008-2011).** Developed a pilot modeling exercise in cooperation with the CEC Staff and the Rand Corporation to demonstrate the usefulness of exploratory modeling techniques and their use in robust decision making.
- **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, using the Stockholm Environmental Institute's Water-Energy Analysis Program (WEAP) hydropower model.
- **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.
- **Generation Facility Uncertainties and the Need for a Flexible Infrastructure for Nevada, Energy Foundation (2007-2008).** Assessed potential availability and costs for alternative resources to defer or replace proposed coal plants in Nevada and to better use a proposed transmission link. Co-authored *Laying a Foundation for Nevada's Electricity Future*.
- **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.
- **Statewide Pricing Pilot, Track B Analysis, California Public Utilities Commission (2003-2005).** Developed experimental program to examine whether providing educational "treatments" communicated through a community-based organization in an environmentally-impacted neighborhood enhanced responses to critical peak pricing among residential energy users. The project included survey and econometric research.
- **Environmental Performance Report-Potential Impacts of Global Climate Change on California's Hydropower System, California Energy Commission (2005).** Assessed a potential range of impacts on the operations of California's hydropower system from different hydrological scenarios related to GCC projections. The interrelated nature of the hydropower, water supply and flood control systems was highlighted. Results presented in the CEC's 2005 Integrated Energy Policy Report.
- **Environmental Performance Report Hydropower Relicensing Cost Evaluation, California Energy Commission (2003).** Developed estimates of lost value and incurred costs for California hydropower facilities subject to relicensing. Results presented in Appendix D of the CEC's 2003 Integrated Energy Policy Report.
- **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.
- **Agricultural Electricity Rates Report, California Energy Commission (2001).** Studied how electricity rates in California impact agricultural energy costs given restructuring. The report modeled groundwater pumping for multiple depths across nine crops and dairy operations. This included a

comparison with rates in neighboring states. Developed a broad range of policy proposals to improve agricultural energy management and to lower energy costs.

- **California Energy Crisis Assessment, National Rural Electric Cooperative Association (2001).** Prepared assessment of California's energy situation for summer of 2001.
- **Energy Crisis Solutions, California Energy Commission (2001).** Developed policy proposals to address coming energy crisis in the summer of 2001 for the draft executive summary of the CEC's AB970 Report. Estimated stranded cost recovery by PG&E and SCE.
- **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.
- **Municipalization Feasibility Study, CCSF Hetch Hetchy Water and Power (1996).** Evaluated the bulk power options and costs of other services in the restructured California electricity market in assessing the attractiveness of municipalizing the PG&E system within the City and County of San Francisco.
- **Restructuring Proposals Evaluation, Western States Petroleum Association and Shell Oil Co. (1995).** Advised clients on the implications of the proposed methods to restructure California's energy market to large consumers.
- **Restructuring and Renewables, California Energy Commission (1995).** Evaluated two alternatives to restructure California's electricity industry, by examining how the proposed market structures and methods of funding stranded assets would affect the development of a competitive marketplace. Testified for the CEC Research and Development Office, in the 1994 Electricity Report Proceedings.
- **Barriers to Biomass Energy, California Energy Commission (1994).** Assessed the institutional barriers that threaten the survival of existing biomass generating plants and limit their further development in California.
- **Municipals Avoided Costs Study, California Energy Commission (1989).** Assessed and forecasted avoided-cost rates and offers of California's 14 largest municipal utilities, using the Elfin production-cost model.
- **Gas Pipeline Need Assessment, South Coast Air Quality Management District (1989).** Prepared analysis and testimony presented to the California Public Utilities Commission on the need for additional interstate natural gas pipeline capacity to implement the Liquid and Solid Fuel Phase-out Policy for the South Coast Air Quality Management District.
- **Rancho Seco NGS Evaluation, Sacramento Municipal Utility District (1988).** Independently reviewed resource planning alternatives and recommended action on Rancho Seco NGS operations, for SMUD QUEST Team.
- **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 Avoided Costs Forecast, Independent Power Technologies (1989).** Prepared Pacific Gas and Electric industrial electricity rate and avoided-cost forecasts, with Diablo Canyon settlement agreement and natural gas price sensitivities, for a cogeneration developer.

- **QF Development Forecast, Sacramento Municipal Utility District (1988).** Identified and assessed the viability of qualifying facilities (QF) projects in PG&E's service territory.
- **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.

Climate Change and Air Quality Testimony and Analysis

- **AB 32 GHG Allowance Auction Market Monitor, California Air Resources Board (2012-2013).** Supported Monitoring Analytics in monitoring operations of the AB 32 cap and trade market which launched August 2012.
- **Food Processing Industry Emission Intensive Trade Exposed Indices Analysis for AB 32, California League of Food Processors (2011).** Calculated California-specific Energy Intensive Trade Exposed (EITE) Industry Indices for California's food processing sector using federal and state data sources that could be updated by the Air Resources Board staff.
- **Petroleum Industry Emission Intensive Trade Exposed Indices Analysis for AB 32, Western States Petroleum Association (2010).** Calculated California-specific Energy Intensive Trade Exposed (EITE) Industry Indices for California's petroleum production and refining sectors using federal and state data sources that could be updated by the Air Resources Board staff.
- **Prepare Regulatory Proposals for High Global Warming Potential Gases, Environmental Defense Fund (2009).** Assessed proposed regulation of high global warming potential (HGWP) gases by the California Air Resources Board under AB 32. HGWP gases included HFCs used for refrigeration and space cooling and replacements for ozone-depleting substances (ODS).
- **Review of AB 32 Proposed Scoping Plan Economic Modeling, Environmental Defense Fund (2008).** Reviewed economic modeling by the California Air Resources Board Staff used to assess the Proposed Scoping Plan to meet greenhouse gas emission reduction goals specified in AB 32..
- **Analysis of Proposed Low Carbon Fuel Standard, Western States Petroleum Association. (2007-2008).** Analyzed the California Air Resources Board's proposed LCFS that would reduce the average carbon content for transportation fuels by 10%. This included a review of the GREET model and its inputs, and assessing life-cycle emissions for various alternative fuels.
- **Review of Economic Analysis of Proposed In-Use On-Road Diesel Fleet Regulations, Construction Industry Air Quality Coalition (2008).** Highlighted key issues in CARB Staff analysis of potential health benefits and costs to complying firms for proposed accelerated mandated scrappage and retrofit program.
- **Construction Fleet Emission Standard Impacts, Construction Industry Air Quality Coalition (2006-2007).** Reviewed ARB Staff regulatory proposal and analysis. Prepared responding economic impact analysis using the ARB's emission inventory database of 170,000 pieces of equipment.
- **Analysis of Governor's Executive Order on GHG Regulation, Environmental Defense Fund (2005).** With Lawrence Berkeley National Laboratory and Resources for the Future, described the current regulatory regime and policies for electricity related to regulated greenhouse gas emissions. This analysis was included in the state's Climate Action Team report.

- **Petroleum Reduction Strategies Analysis, Diesel Technology Forum (2003).** Analyzed California Energy Commission proposals in its AB 2076 Report for reducing California's petroleum usage. Estimated fuel use reduction through increased penetration of light-duty diesel vehicles under different market scenarios.

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
- Member, Western Manufactured Housing Communities Association Utilities Task Force
- Former Member, City of Davis Citizens Electricity Restructuring Task Force
- Former Member, Yolo County Housing Commission
- Member, Phi Beta Kappa Honorary Fraternity

ATTACHMENT A

Final Root Cause Analysis, Mid-August 2020 Extreme Heat Wave

FINAL

Root Cause Analysis

Mid-August 2020 Extreme Heat Wave

January 13, 2021

California ISO

Prepared by:
California Independent System Operator
California Public Utilities Commission
California Energy Commission

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January 13, 2021

The Honorable Gavin Newsom
Governor, State of California
State Capitol
Sacramento, CA 95814

Dear Governor Newsom:

In response to your August 17, 2020 letter, the California Independent System Operator (CAISO), California Public Utilities Commission (CPUC), and California Energy Commission (CEC) are pleased to provide you the attached Final Root Cause Analysis (Final Analysis) of the two rotating outages in the CAISO footprint on August 14 and 15, 2020. This Final Analysis builds on the Preliminary Root Cause Analysis report published on October 6, 2020 and provides updates on the progress made on a number of the recommendations identified in the preliminary analysis. It also incorporates data that was not available when the preliminary analysis was developed, information from the Labor Day weekend heat wave and updated analysis of resource performance.

We recognize our shared responsibility for the power outages many Californians unnecessarily endured. The findings of the Final Analysis underscore this shared responsibility and give greater definition to actions that can be taken to avoid or minimize the impacts to those we serve.

The Final Analysis confirms there was no single root cause of the August outages, but rather, finds that the three major causal factors contributing to the outages were related to extreme weather conditions, resource adequacy and planning processes, and market practices. Although this combination of factors led to an extraordinary situation, our responsibility and commitment going forward is to be better prepared for extreme climate change-induced weather events and other operational challenges facing our evolving power system.

The Final Analysis provides recommendations for immediate, near and longer-term improvements to our resource planning, procurement, and market practices, many of which are underway. These actions are intended to ensure that California's transition to a reliable, clean, and affordable energy system is sustained and accelerated. This is an imperative – for our citizens, communities, economy, and environment. Implementation of these recommendations will involve processes within state agencies and the CAISO, partnership with the state Legislature, and collaboration and input from stakeholders within California and across the western United States.

This Final Analysis has served as an important step in learning from the events of August 14 and 15, as well as a clear reminder of the importance of effective communication and coordination.

We remain committed to meeting California's clean energy and climate goals and value your personal engagement on these issues and your unequivocal commitment and leadership on addressing climate change.

Regards,

Elliot Mainzer
President and Chief Executive Officer
California Independent System Operator

Marybel Batjer
President
California Public Utilities Commission

David Hochschild
Chair
California Energy Commission

Table of Contents

List of Tables

List of Figures

GLOSSARY OF ACRONYMS

ACRONYM	DEFINITION
AAEE	Additional Achievable Energy Efficiency
AB	Assembly Bill
A/S	Ancillary Services
AWE	Alerts, Warnings, and Emergencies
BA	Balancing Authority
BAA	Balancing Authority Area
BPM	Business Practice Manual
CAISO	California Independent System Operator Corporation
CARB	California Air Resources Board
CCA	Community Choice Aggregator
CDWR	California Department of Water and Power
CEC	California Energy Commission
CHP	Combined Heat and Power
COI	California Oregon Intertie
CPM	Capacity Procurement Mechanism
CPUC	California Public Utilities Commission
DMM	CAISO Department of Market Monitoring
EIM	Energy Imbalance Market
ELCC	Effective Load Carrying Capability
ESP	Energy Service Provider
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
HASP	Hour-Ahead Scheduling Process
IEPR	Integrated Energy Policy Report
IFM	Integrated Forward Market
IOU	Investor Owned Utility
IRP	Integrated Resource Planning
JASC	Joint Agency Steering Committee
LADWP	Los Angeles Department of Water and Power
LMS	Load Management Standards
LOLE	Loss of Load Expectation
LRA	Local Regulatory Authority
LSE	Load Serving Entity
MW	Megawatt
MWD	Metropolitan Water District
NCPA	Northern California Power Agency
NERC	North American Electric Reliability Corporation

ACRONYM	DEFINITION
NOB	Nevada Oregon Border
NQC	Net Qualifying Capacity
NWS	National Weather Service
PDCI	Pacific DC Intertie
PDR	Proxy Demand Resource
PGE	Portland General Electric
PG&E	Pacific Gas and Electric
PIME	Price Inconsistency Market Enhancements
POU	Publicly Owned Utility
PRM	Planning Reserve Margin
QC	Qualifying Capacity
RA	Resource Adequacy
RAAIM	Resource Adequacy Availability Incentive Mechanism
RDRR	Reliability Demand Response Resource
RMO	Restricted Maintenance Operations
RMR	Reliability Must Run
RUC	Residual Unit Commitment
SB	Senate Bill
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SMUD	Sacramento Municipal Utility District
TAC	Transmission Access Charge
TOU	Time of Use
WAPA	Western Area Power Administration
WECC	Western Electric Coordinating Council

Executive Summary

On August 14 and 15, 2020, the California Independent System Operator Corporation (CAISO) was forced to institute rotating electricity outages in California in the midst of a West-wide extreme heat wave. Following these emergency events, Governor Gavin Newsom requested that, after taking actions to minimize further outages, the CAISO, the California Public Utilities Commission (CPUC), and the California Energy Commission (CEC) report on the root causes of the events leading to the August outages.

The CAISO, CPUC, and CEC produced a Preliminary Root Cause Analysis (Preliminary Analysis) on October 6, 2020, and have since continued their analysis to confirm and supplement their findings. This Final Root Cause Analysis (Final Analysis) incorporates additional data analyses that were not available when the Preliminary Analysis was published, but does not substantively change earlier findings and confirms that the three major causal factors contributing to the August outages were related to extreme weather conditions, resource adequacy and planning processes, and market practices. In summary, these factors were the following:

1. The climate change-induced extreme heat wave across the western United States resulted in demand for electricity exceeding existing electricity resource adequacy (RA) and planning targets.
2. In transitioning to a reliable, clean, and affordable resource mix, resource planning targets have not kept pace to ensure sufficient resources that can be relied upon to meet demand in the early evening hours. This made balancing demand and supply more challenging during the extreme heat wave.
3. Some practices in the day-ahead energy market exacerbated the supply challenges under highly stressed conditions.

Although August 14 and 15 are the primary focus of this Final Analysis because the rotating outages occurred during those days, August 17 through 19 were projected to have much higher supply shortfalls. If not for the leadership of the Governor's office to mobilize a statewide mitigation effort and significant consumer conservation, California was also at risk of further rotating outages on those days.

ES.1 Current Actions to Prepare for Summer 2021

The CAISO, CPUC, and CEC have already taken several actions and are continuing their efforts to prepare California for extreme heat waves next summer without having to resort to rotating outages. These actions include the following:

1) The CPUC opened an Emergency Reliability rulemaking (R.20-11-003) to procure additional resources to meet California's electricity demand in summer 2021. Through this proceeding, the CPUC has already directed the state's three large investor-owned utilities to seek contracts for additional supply-side capacity and has requested proposals for additional demand-side resources that can be available during the net demand peak period (*i.e.*, the hours past the gross peak when solar production is very low or zero) for summer 2021 and summer 2022. The CPUC and parties to the proceeding, including the CAISO, will continue to evaluate proposals and procurement targets for both supply-side and demand-side resources.
2) The CAISO is continuing to perform analysis supporting an increase to the CPUC's RA program procurement targets. Based on the analysis to date, the CAISO recommends that the targets apply to both the gross peak and the critical hour of the net demand peak period during the months of June through October 2021.
3) The CAISO is expediting a stakeholder process to consider market rule and practice changes by June 2021 that will ensure the CAISO's market mechanisms accurately reflect the actual balance of supply and demand during stressed operating conditions. This initiative will consider changes that incentivize accurate scheduling in the day-ahead market, appropriate prioritization of export schedules, and evaluate performance incentives and penalties for the RA fleet. The CAISO is also working with stakeholders to ensure the efficient and reliable operation of battery storage resources given the significant amount of new storage that will be on the system next summer and beyond. Through a stakeholder process, the CAISO will pursue changes to its planned outage rules.
4) The CPUC is tracking progress on generation and battery storage projects that are currently under construction in California to ensure there are no CPUC-related regulatory barriers that would prevent them from being completed by their targeted online dates. The CAISO will continue to work with developers to address interconnection issues as they arise.
5) The CAISO and CEC will coordinate with non-CPUC-jurisdictional entities to encourage additional necessary procurement by such entities.
6) The CEC is conducting probabilistic studies that evaluate the loss of load expectation on the California system to determine the amount of capacity that needs to be installed to meet the desired service reliability targets.
7) The CAISO, CPUC, and CEC are planning to enhance the efficacy of Flex Alerts to maximize consumer conservation and other demand side efforts during extreme heat events.

8) Preparations by the CAISO, CPUC, and CEC are underway to improve advance coordination for contingencies, including communication protocols and development of a contingency plan. The contingency plan will draw from actions taken statewide under the leadership of the Governor's Office to mitigate the anticipated shortfall from August 17 through 19, 2020.

In the mid-term, for 2022 through 2025, the CAISO, CPUC, and CEC will continue to work toward: (1) planning and operational improvements for the performance of different resource types (such as batteries, imports, demand response, and so forth); (2) improvements to accelerate the deployment and integration of demand side resources; and (3) consideration of generation and transmission buildouts to evaluate options and constraints under the SB 100 scenarios. This planning will also account for the pending retirements of some existing natural gas units and the Diablo Canyon nuclear power plant.

For the longer term, 2025 and beyond, the CAISO, CPUC, and CEC are working closely together and with other regional stakeholders to establish a modernized, integrated approach to forecasting, resource planning and RA targets. The enhanced collaboration and alignment are to more fully anticipate events like last summer's climate change-induced extreme heat wave and better plan and account for the transitioning electricity resource mix necessary to meet clean energy goals. This is a statewide concern that requires assessing resource sufficiency and reliability for all of California. As such, building on the CEC's statewide statutory responsibilities, the CAISO, CPUC, and CEC will define and develop necessary assessments as part of the *Integrated Energy Policy Report (IEPR)*, to create improved understanding into statewide, and WECC-wide resource sufficiency.

To provide complete transparency into the various summer 2021 preparedness efforts underway, the CAISO, CPUC, and CEC will continue to report monthly to the California State Legislature as requested by the Chair of the Assembly Committee on Utilities and Energy, Chris Holden. In addition, the CAISO is holding monthly open stakeholder calls to discuss progress toward ensuring its readiness for next summer's high heat events.

Information and updates on these efforts can be found at:

http://www.caiso.com/about/Pages/News/SummerReadiness.aspx

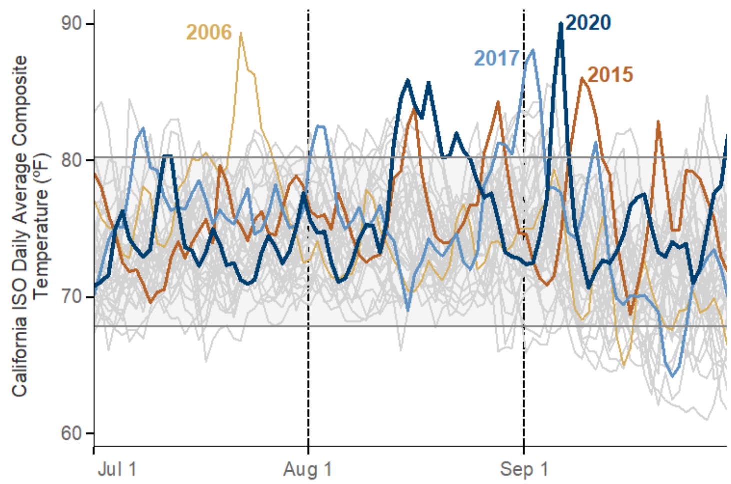
https://www.cpuc.ca.gov/summerreadiness/

ES.2 Three Major Factors that Led to Rotating Outages

1. *The climate change-induced extreme heat wave across the western United States resulted in demand for electricity exceeding existing electricity resource adequacy (RA) and planning targets*

Taking into account 35 years of weather data, the extreme heat wave experienced in August was a 1-in-30 year weather event in California. In addition, this climate change-induced extreme heat wave extended across the western United States. The resulting demand for electricity exceeded the existing electricity resource planning targets and resources in neighboring areas were also strained. As Figure ES.1 below shows this demand was the result of a historic West-wide heat wave.

Figure ES.1: July, August, and September Temperatures 1985 - 2020



Source: CEC Weather Data/CEC Analysis

2. *In transitioning to a reliable, clean, and affordable resource mix, resource planning targets have not kept pace to ensure sufficient resources that can be relied upon to meet demand in the early evening hours. This made balancing demand and supply more challenging during the extreme heat wave.*

The rotating outages both occurred after the period of gross peak demand, during the "net demand peak," which is the peak of demand *net of solar and wind generation* resources. With today's new resource mix, behind-the-meter and front-of-meter (utility-scale) solar generation declines in the late afternoon at a faster rate than demand decreases. This is because air conditioning and other load previously being served by solar comes back on the bulk electric system. These changes in the resource mix and the timing of the net peak have increased the challenge of maintaining system reliability, and this challenge is amplified during an extreme heat wave.

Since 2016, the CAISO, CPUC, and CEC have worked to examine the impacts of significant renewable penetration on the grid. By performing modeling that simulates each hour of the day, not just the gross peak, the RA program has adjusted for this change in resource mix by identifying reliability problems now seen later in the day during the net demand peak. However, additional work is needed to ensure that sufficient resources are available to serve load during the net peak period and other potential periods of system strain.

3. *Some practices in the day-ahead energy market exacerbated the supply challenges under highly stressed conditions.*

A subset of energy market practices contributed to the inability to obtain or prioritize energy to serve CAISO load in the day-ahead market that could have otherwise relieved the strained conditions on the CAISO grid on August 14 and 15. The practices which obscured the tight physical supply conditions included under-scheduling of demand in the day-ahead market by load serving entities or their scheduling coordinators, and convergence bidding, a form of financial energy trading used to converge day-ahead and real-time pricing. In addition, the CAISO implemented a market enhancement in prior years. In combination with real-time scheduling priority rules, this enhancement inadvertently caused the CAISO's day-ahead Residual Unit Commitment process to fail to detect and respond to the obscuring effects of under-scheduling and convergence bidding during August's stressed operating conditions. Although the CAISO is now actively developing solutions to these market design issues, most of the day-ahead supply challenges encountered were addressed in the real-time market as a result of additional cleared market imports, energy imbalance market transfers and other emergency purchases.

ES.3 Summary of Performance of Different Types of Resources

Since the Preliminary Analysis was published, the CAISO, CPUC and CEC completed their analysis of how specific resource types performed during the August and September extreme heat waves. The additional analysis and potential improvements are provided below for each resource type.

- Natural gas – Under very high temperatures, ambient derates are not uncommon for the natural gas fleet, and high temperatures reduce the efficiency of these resources. The CEC hosted a workshop to explore potential technology options for increasing the efficiency and flexibility of the existing natural gas power plant fleet to help meet near-term electric system reliability and the longer-term transition to renewable and zero-carbon resources.[1] Subsequently, the CPUC issued a ruling intended to get the most out the existing

[1] See: https://www.energy.ca.gov/event/workshop/2020-12/morning-session-technology-improvements-and-process-modifications-lead and https://www.energy.ca.gov/event/workshop/2020-12/afternoon-session-finance-and-governance-lead-commissioner-workshop

gas fleet in its recently opened procurement rulemaking focused on summer 2021 resources.[2] All reasonable efforts should be made to increase the efficiency of the existing fleet.

- Imports – In total, import bids received in the day-ahead market were between 40 to 50% higher than imports under RA obligations, which indicates that the CAISO was relying on imports that did not have a contract based obligation to offer into the market. In addition to the rule changes the CPUC made to the RA program with regard to imports for RA year 2021, the CPUC may consider additional changes to current import requirements.
- Hydro and pumped storage – RA hydro resources provided above their RA amounts and various hydro resources across the state managed their pumping and usage schedules to improve grid reliability. There should be increased coordination by communicating as early as possible the need for additional energy or active pump management ahead of stressed grid conditions and leverage existing plans for efficiency upgrades to improve electric reliability.
- Solar and wind – The CPUC has improved the methods for estimating the reliability megawatt (MW) value of solar and wind over the years, but the reliability value of intermittent resources is still over-estimated during the net peak hour. Improvements to the RA program should account for time-dependent capabilities of intermittent resources.
- Demand response – While a significant portion of emergency demand response programs (reliability demand response resources or RDRR) provided load reductions when emergencies were called, the total amount did not approach the amount of demand response credited against RA requirements and shown as RA to the CAISO. Some, but not all of this difference, is the result of the credited amounts including a "gross up" that the CPUC applies to demand response resources consisting of approximately 10% for avoiding transmission and distribution losses, and 15% for avoided planning reserve margin procurement for customers who agree to drop load in grid emergencies. Additional analysis and stakeholder engagement are needed to understand the discrepancy between credited and shown RA amounts, the amount of resources bid into the day-ahead and real-time markets, and performance of dispatched demand response.
- Battery storage – During the mid-August events and in early September, there were approximately 200 MW of RA battery storage resources in the CAISO market. It is difficult to draw specific conclusions about fleet performance from such a small sample size. The CAISO will continue to track and understand the

[2] CPUC, R.20-11-003, December 11, 2020 Ruling.

collective behavior of the battery storage fleet and work with storage providers to effectively incentivize and align storage charge and discharge behavior with the reliability needs of the system.

ES.4 Analyses Conducted Since the Preliminary Analysis

As mentioned, this final root cause analysis incorporates additional data analysis that was not available when the preliminary root cause analysis was published. Specifically, the following updates were made:

- Additional information and discussion of the Labor Day weekend extreme heat wave
- Updated temperature analysis (Section 4)
- Updated information on gas fleet resource forced outages during the extreme heat wave (Section 4)
- Discussion on performance of resources credited against RA requirements by CPUC and non-CPUC jurisdictional entities (Section 4 and Appendix B)
- Updated analysis of performance of demand response resources based on available settlement quality metered data (Section 4 and Appendix B)
- Updated analysis of load under-scheduling based on available settlement quality metered data and a survey of load scheduling entities, with recommendations (Section 4 and Appendix B)
- Updated recommendations on communications to utility distribution companies to ensure appropriate load reduction response during future critical reliability events and grid needs (Section 3)
- Discussion of performance of resources during the extreme heat wave (Section 4 and Appendix B)
- Update to discussion and Figures 4.2 and B.1 for actual metered load drop from demand response resources
- Additional analysis on net import position during August 14 and 15 (Appendix B)
- Corrections and clarifications:
    - Figures 4.4, B.16, B.17, B.18, and B.19 were all corrected because of a copy-and-paste error that repeated day-ahead awards data for each of these charts comparing real-time awards data. This change does not affect the shown RA amounts or actual generation data.

- The cause of a major transmission line outage in the Pacific Northwest was a storm in May 2020. The line remained derated through the mid-August extreme heat wave.
- Table 5.1 was amended with the correct forecast and peak numbers, and additional September dates were added.

In addition, since the publication of Preliminary Analysis, on November 24, 2020, the CAISO's Department of Market Monitoring (DMM) released its independent review of system conditions and performance of the CAISO's day-ahead and real-time markets from mid-August to September 7, 2020, and some of the findings in the DMM report are incorporated into this Final Analysis.[3] Notably, the DMM concurred with many of the key findings and recommendations of the Preliminary Analysis and confirmed that there was no single root cause but a series of factors that contributed to the emergencies. The DMM also confirmed that "[c]ontrary to some suggestions in the media, DMM has found no evidence that market results on these days were the result of market manipulation."[4]

ES.5 Conclusion

This Final Analysis provides a comprehensive look at the causes of the rotating outages on August 14 and 15, assesses how resources performed during those periods, and sets forth important recommendations and actions that are being addressed by the CAISO, CPUC and CEC. All three organizations have committed to working expeditiously and collaboratively, with the valuable input and engagement of critical partners and stakeholders, to position California for success in reliably meeting its climate and energy goals.

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[3] Department of Market Monitoring, California ISO, *Report on system and market conditions, issues and performance: August and September 2020*, November 24, 2020. Available at: http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf

[4] Department of Market Monitoring, California ISO, *Report on system and market conditions, issues and performance: August and September 2020*, November 24, 2020, p. 3.

ATTACHMENT B

Testimony of Richard McCann and Laura Norin on Behalf of the Agricultural Parties in PG&E's 2017 General Rate Case Phase 2 Application Addressing PG&E's Agricultural Class Balancing Account Study (Excerpt)

Docket No.: A.16-06-013

Exhibit No.: ____________________

Date: March 15, 2017

Witnesses: Richard McCann and Laura Norin

TESTIMONY OF RICHARD MCCANN AND LAURA NORIN ON BEHALF OF THE AGRICULTURAL PARTIES IN PACIFIC GAS & ELECTRIC'S (PG&E'S) 2017 GENERAL RATE CASE PHASE 2 APPLICATION ADDRESSING PG&E'S AGRICULTURAL CLASS BALANCING ACCOUNT STUDY

AS REVISED ON FEBRUARY 9, 2018

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2012, the Agricultural class FLTs used in PG&E's Study are 8% higher than those in the historical dataset for 2013 and 2014.[25]

On account of the myriad problems with PG&E's data and analysis, PG&E's Study cannot be relied on to draw any conclusions regarding the relationship between Agricultural class sales variance and revenue under- or overcollections.

IV. RATE DISTORTIONS FROM AGRICULTURAL CLASS SALES VARIABILITY

Year-to-year fluctuations in water availability, primarily due to oscillations in rainfall and snowpack, result in a high degree of year-to-year variability in the amount of electricity needed by agricultural customers to pump irrigation water. As demonstrated below, because these variations are not accounted for in the revenue allocation process, which is based on "normal" water conditions, they create rate distortions for all ratepayers.

A. AGRICULTURAL CLASS LOAD VARIABILITY AND LOAD FORECAST ERROR (WITNESS: L. NORIN)

Attachment 4, Table 1, of PG&E's Study confirms the unusually high load variability of the Agricultural class and the associated difficulty for PG&E in forecasting Agricultural class sales. Table 2, which was calculated from Table 1 of PG&E's Study, compares actual sales for each customer class to the class's 1995-2014 average sales.

[25] Calculated from PG&E study workpaper, "GRC comparison.xlsx," sheet "FLT & PCAF by Year," P12 and V12, and from PG&E CONFIDENTIAL response to CFBF Data Request 05 Question 1, attachment 1, sheets "DIVSWNCL13," cells C2:E20, and "DIVSWNCL14," cells E2:G20 and AA2:AC20. (See Attachment B)

Table 2: Sales Variability: Annual Sales Compared to 1995-2014 Class-Average Sales[26]

	Residential	Commercial	Industrial	Agricultural
1995	-16%	-15%	8%	-25%
1996	-12%	-12%	1%	-22%
1997	-10%	-9%	9%	-15%
1998	-7%	-9%	5%	-34%
1999	-4%	-4%	8%	-20%
2000	-1%	1%	9%	-18%
2001	-7%	-2%	8%	-11%
2002	-6%	-3%	-14%	-15%
2003	0%	1%	-5%	-16%
2004	2%	2%	-4%	-7%
2005	3%	3%	-4%	-19%
2006	7%	6%	-2%	-17%
2007	6%	8%	-2%	16%
2008	9%	8%	4%	20%
2009	8%	5%	-4%	25%
2010	6%	4%	-7%	9%
2011	7%	4%	-6%	1%
2012	7%	4%	-1%	33%
2013	7%	4%	-3%	51%
2014	3%	3%	1%	64%
Minimum	-16%	-15%	-14%	-34%
Maximum	9%	8%	9%	64%

For the Residential, Commercial, and Industrial classes, annual sales over this 20-year period varied between about 15% below and 10% above the class's average annual sales. For the Agricultural class, the variability was much greater, with annual sales ranging from about 35% below to 65% above annual average sales. In fact, Agricultural class sales were only within 15% below and 10% above the average annual sales in four of the 20 years analyzed.[27]

[26] Calculated from PG&E-08, Vol. 2, page F-Atch4-1.
[27] The four years in which agricultural load variability was within the range exhibited by the other customer classes were 2001, 2004, 2010, and 2011.

The reason for this high level of Agricultural class sales variability is that PG&E's agricultural customers use electricity predominantly to pump groundwater for irrigation and other agricultural purposes.[28] The amount of pumping that is needed in a given year depends heavily on the amount of surface water that is available and how deep the available groundwater is. In drought years, surface water deliveries through the State Water Project and the Central Valley Project are often sharply curtailed, as shown in Table 3. In addition, particularly in multi-year droughts, groundwater levels fall, requiring farmers to pump to deeper depths to obtain much-needed water to irrigate their crops and/or to let their fields lie fallow.[29] During the 2015 drought year, even with extensive fallowing,[30] PG&E agricultural customers' electricity usage was 63% higher than it had been in 2011,[31] due to the low availability of surface water and the need for deeper pumping. In particular, the deepening drought over the prior five years had depleted groundwater aquifers so that water was being pumped from greater depths, increasing electrical loads.

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[28] Irrigation Training and Research Center, "California Agricultural Electrical Energy Requirements," Prepared for the California Energy Commission PIER Program, ITRC Report No. R 03-006, California Polytechnic State University, San Luis Obispo, California, December 2003, Table 1. (See Attachment D)

[29] The general energy use equation is 1.024 kilowatt-hours for each acre-foot lifted one more foot in depth at 100% efficiency. Tulare County Cooperative Extension, "Energy and Cost Required to Lift or Pressurize Water," Pub. IG6-96, University of California, page 2. (See Attachment E)

[30] For example, in 2015, farmers in the Central Valley fallowed more than a million acres, which was well over double the 400,000 acres that were fallowed during 2011. Melton, Rosevelt, Guzman, et. al. "Fallowed Area Mapping for Drought Impact Reporting: 2015 Assessment of Conditions in the California Central Valley," NASA Ames Research Center Cooperative for Research in Earth Science Technology and Education & CSU Monterey Bay, U.S. Geological Survey, U.S. Department of Agriculture National Agricultural Statistics Service, and California Department of Water Resources. October 14, 2015, Table 1, page 4. (See Attachment F)

[31] 63% = 7,657 GWh of 2015 retail Ag sales/4,691 GWh of 2011 retail Ag sales –1. (PG&E response to CFBF Data Request 04 Question 1d. (See Attachment B))

ATTACHMENT C

Memorandum from Lynn Sadler to the Commission
Regarding SB 594 (Wolk) – Energy: net energy metering

STATE OF CALIFORNIA | Public Utilities Commission
Fresno

M e m o r a n d u m

Date: May 8, 2012

To: The Commission
(Meeting of May 10, 2012)

From: Lynn Sadler, Director
Office of Governmental Affairs (OGA) — Sacramento

Subject: **SB 594 (Wolk) – Energy: net energy metering.**
As amended: March 1, 2012

LEGISLATIVE SUBCOMMITTEE RECOMMENDATION: SUPPORT WITH TECHNICAL AMENDMENTS

SUMMARY OF BILL

SB 594 would allow Net Energy Metering (NEM) customer-generators with multiple meters to aggregate the electrical load of the meters located on the property where the generation facility is located and on all property adjacent or contiguous to the property on which the generation facility is located, if those properties are solely owned by the eligible customer-generator. This will allow a customer to install one renewable energy facility sized to serve their entire aggregated multi-meter on-site load (up to one megawatt) instead of installing separate generators at each meter. This bill would prohibit an eligible customer-generator that chooses to aggregate from receiving net surplus electricity compensation (NSC) and require the electric utility to retain surplus kilowatt-hours generated in a 12-month period.

SUMMARY OF SUPPORTING ARGUMENTS FOR RECOMMENDATION

This bill expands the NEM program in helpful ways that support the State's achievement of distributed generation (DG) related policy goals:

(1) NEM meter aggregation across multiple meters allows a customer to install one renewable energy facility sized to offset their entire aggregated multi-meter on-site load (up to one megawatt) instead of installing separate facilities at each meter. This is particularly important for agricultural, commercial, school, and government customers who can have several meters on one property.

(2) Significant obstacles continue to block some customers from efficiently and economically participating in the NEM program. Specifically, customers with multiple meters, such as farmers with separate meters for each of their irrigation pumps and other functions, are currently required to have separate renewable facilities for each meter to utilize NEM. This can be very costly and inefficient.

(3) Aggregation of multiple meters behind larger DG systems will improve the cost-effectiveness of NEM by enabling larger more efficient installations which represent a lower marginal cost to ratepayers.

SUMMARY OF SUGGESTED AMENDMENTS

1. After the sentence:

An eligible customer-generator with multiple meters may elect to aggregate the electrical load of the meters located on the property where the generation facility is located and on all property adjacent or contiguous to the property on which the generation facility is located, if those properties are solely owned by the eligible customer-generator.

Insert the sentence:

Parcels may be divided by a street, highway or public thoroughfare as long as they are otherwise contiguous, and under the same ownership.

DIVISION ANALYSIS (Energy Division)

1. **Offering NEM to more non-residential customer-generators will lower the cost of NEM to ratepayers**.

The vast majority of renewable facilities that will take advantage of the multiple meter aggregation opportunity created by this bill will be larger non-residential applications. On that basis, any modification of the NEM program that incentivizes non-residential projects will result in the NEM program costing ratepayers less on a per project and per kWh basis.

The CPUC analyzed the net cost of the NEM program to ratepayers in March 2010[1], and found that commercial customer-generators cost comparatively less per kWh of exported generation than do residential customer-generators. The NEM program is currently capped at 5% of utility system peak load (known as the NEM “cap”).[2] As of

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[1] Net Energy Metering Cost-Effectiveness Evaluation (“NEM Cost-Effectiveness Evaluation”) (March 2010). http://www.cpuc.ca.gov/PUC/energy/DistGen/nem_eval.htm. A summary of the key findings is attached as Appendix A.

[2] The statutory definition of the NEM cap is the point where “total rated generating capacity used by eligible [NEM] customer-generators exceeds 5 percent of the electric utility's aggregate customer peak demand.” PU Code 2827(c)(1).

2008, NEM solar commercial-generators supplied about 56% of the capacity enrolled in the NEM program, but were responsible for just 10% of the total cost of the solar NEM program. Thus, while the NEM program overall represents a net cost to ratepayers, through this bill, the NEM program is likely to be more frequently subscribed by larger DG resources, which represent a lower marginal cost to ratepayers.

CPUC's study found that the nature of the customer being served made a difference in the cost borne by ratepayers. Because of their lower rates, non-residential projects cost non-participating ratepayers substantially less: the levelized net total cost of non-residential NEM facilities averages $0.03 per kWh-exported, compared to an average $0.19 per kWh-exported for residential facilities, as shown in Table 1.[3]

Table 1 also summarizes the characteristics of the solar NEM participation and impacts by residential and non-residential-sectors.

- Non-residential NEM facilities represent the majority of the MWs enrolled in the program. By the end of 2008, 7% of all solar NEM accounts were non-residential, and at the same time, non-residential NEM represented 56% of installed generation capacity.[4]

- Non-residential NEM facilities represented a net cost of $2.5 million/year, which was 13% of the total net cost of the NEM program on a per annum basis in 2008.

- The NEM program represented an annual net cost to ratepayers of $19.7 million in 2008, which is equivalent to 0.08% of annual utility revenue.

Table 1. Net Cost of Net Energy Metering Program (Solar NEM only installed through 2008)

	Residential	**Non-Residential**	**Total**
Number of Solar NEM Projects	38,380 accounts (93%)	2,864 accounts (7%)	41,244 accounts
Installed Solar NEM Capacity	162 MW (44%)	203 MW (56%)	365 MW
20-year Annualized Cost for Solar NEM Installed through 2008[5]	$17.2 Million (87%)	$2.5 Million (13%)	$19.7 Million (0.08% of total utility revenue)
Levelized ($/kwh-exported) for Solar NEM installed through 2008	$0.19/ kWh-exported	$0.03/ kWh-exported	Average $0.12/ kWh-exported

[3] NEM Cost-Effectiveness Evaluation, p. 11.
[4] Id., pp. 15-16.
[5] The 20-year annualized cost considers the net (or sum) of the bill impacts (the bill savings of a NEM customer), the billing cost (the utility's cost to bill a customer), and the avoided costs (the amount of energy the utility did not have to buy). See id., p. 47.

2. **Facilitating non-residential NEM applications would move California closer to reaching its DG goals and closer to reaching the NEM cap, but those are not reasons to oppose the bill.**

As set out in the PU Code, when NEM penetration levels reach 5% of each utility's aggregate customer peak demand (known as the NEM "cap")[6], the IOUs can stop interconnecting new NEM facilities. This bill's expansion of larger non-residential NEM systems is likely to accelerate the advance toward the cap. However, this also means that California is moving faster toward its DG policy goals, and the reconsideration of the NEM cap will be an inevitable part of the conversation.

3. **The bill maintains alignment between NEM, CSI, and Interconnection rules regarding generators sized up to 1.0 MW.**

The bill does not alter the current structure of the NEM program regarding the 1 MW system size cap and thus maintains alignment between the NEM, CSI, and the CPUC's Rule 21 interconnection standards for customer-side generators. Under the CSI program, rebates are offered for up to 1.0 MW of capacity, and capacity above 1.0 MW does not receive an incentive. Under Rule 21, systems sized up to 1.0 MW on the customer side of the meter are eligible for "Simplified Interconnection," which is a form of accelerated and less-expensive interconnection.

4. **Ratepayers would incur NEM-related costs, in the form of billing credits for T&D services, to a higher degree than otherwise permitted.**

Under current rules, NEM is only offered to customer-generators who are using NEM to offset onsite load at a specific meter. It would encourage facilities sized up to 1 MW to serve the aggregated load of multiple meters, but would only offset the load of one meter. The net generation would be exported to the grid. The other aggregated meters would still consumer energy from the grid, but not be charged for the T&D costs associated with the serving those meters which would be a cost borne by non-NEM customers.

PROGRAM BACKGROUND

NEM is an electricity tariff billing mechanism whose intent is to facilitate the installation of DG by offering retail-rate billing credits for any electricity exported to the grid at times when there is no simultaneous energy demand to utilize the generation onsite.

Under existing complementary state laws, the CPUC oversees a range of policies that support self-generation:

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[6] The statutory definition of the NEM cap is the point where "total rated generating capacity used by eligible [NEM] customer-generators exceeds 5 percent of the electric utility's aggregate customer peak demand." PU Code 2827(c)(1).

1. Rebates: Rebates through the California Solar Initiative (CSI) and Self Generation Incentive Program (SGIP). The CSI program provides rebates for systems up to 1 MW (and allows systems up to 5 MW), with the exception of certain state-owned facilities (per AB 2724, 2010).

2. Simplified Interconnection: Reduced interconnection costs are available under utility Rule 21 tariffs that exempt self-generation renewable energy systems under 1 MW from most studies and fees. Rule 21 also offers these systems accelerated interconnection timelines. Separately, the CPUC exempted renewable self-generation systems from standby charges in 2003.

3. Net Energy Metering: Per PU Code 2827, NEM customer-generators who take service from IOUs have their net generation valued at the full retail rate at the time the energy is exported.[7] AB 920 requires compensation of net surplus generation above annual load.

4. Virtual Net Energy Metering: First established as part of the Multifamily Affordable Solar Housing (MASH) Program[8] in D.08-10-036, VNM allows customers to allocate the kilowatt-hour credits from the electricity generated from a single solar energy system on an affordable housing property to multiple customer accounts within that property. VNM was originally limited to MASH customers only, and D.11-07-031, among other directives, expanded both the types of customers and generation technologies eligible for VNM.

   Specifically, D.11-07-031 does not limit the expanded VNM to CSI customers. Whereas VNM was previously limited to solar PV technologies, D.11-07-031 now allows all technologies that are eligible for the full retail NEM tariff to participate in VNM. D.11-07-031 also limits the expanded VNM to customers served by a single service delivery point (SDP).[9]

LEGISLATIVE HISTORY

1. At least four other bills modifying the NEM program are pending as of this writing in this legislative session:

   - AB 2165 (Hill): Increases the generation-only NEM program cap for eligible fuel cell projects;
   - AB 2514 (Bradford): Requires the CPUC to complete a study by June 30, 2013, to determine the extent to which each class of ratepayers receiving service under NEM is paying the full cost of the services provided to them by electrical corporations and the extent to which those customers pay their share of the costs

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[7] PU Code 2827(h)(2)(B).
[8] The MASH Program is a component of the CSI Program that provides incentives to multifamily affordable housing residences.
[9] Multifamily Affordable Solar Housing (MASH) participants remain the exception to the single SDP limitation in VNM.

of public purpose programs;
- SB 843 (Wolk): Facilitates a Community-Based Renewable Energy Self-Generation Program with unlimited virtual full retail rate bill credit sharing and RECs owed by interconnecting utility;
- SB 1537 (Kehoe): Prohibits the CPUC from adopting any new demand charges for NEM customers.

2. The NEM statute has been modified numerous times in the past decade. It was first established in response to AB 656 (1996), and subsequently modified by: AB 1755 (1998), AB 918 (2000), AB X1-29 (2001), SB 1038 (2002), AB 2228 (2003), AB 1214 (2004), AB 920 (2009), AB 510 (2010), and SB 489 (2011).

FISCAL IMPACT

SB 594 would require ongoing costs for 1 PURA V, for a total cost of approximately $120,234.

STATUS:

SB 594 is pending consideration in the Assembly Utilities and Commerce Committee.

SUPPORT/OPPOSITION

Support

None on file.

Opposition

None on file.

STAFF CONTACTS

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ATTACHMENT D

California ISO Peak Load History
1998 through 2020

California ISO Peak Load History
1998 through 2020

Year	Megawatts at Peak Load*	Date	Time
1998	44,659	August 12	14:30
1999	45,884	July 12	16:52
2000	43,784	August 16	15:17
2001	41,419	August 7	16:17
2002	42,441	July 10	15:01
2003	42,689	July 17	15:22
2004	45,597	September 8	16:00
2005	45,431	July 20	15:22
2006	50,270	July 24	14:44
2007	48,615	August 31	15:27
2008	46,897	June 20	16:21
2009	46,042	September 3	16:17
2010	47,350	August 25	16:20
2011	45,545	September 7	16:30
2012	46,846	August 13	15:53
2013	45,097	June 28	16:54
2014	45,089	September 15	16:53
2015	46,519	September 10	15:38
2016	46,232	July 27	16:51
2017	50,116	September 1	15:58
2018	46,427	July 25	17:33
2019	44,301	August 15	17:50
2020	47,121	August 18	15:57

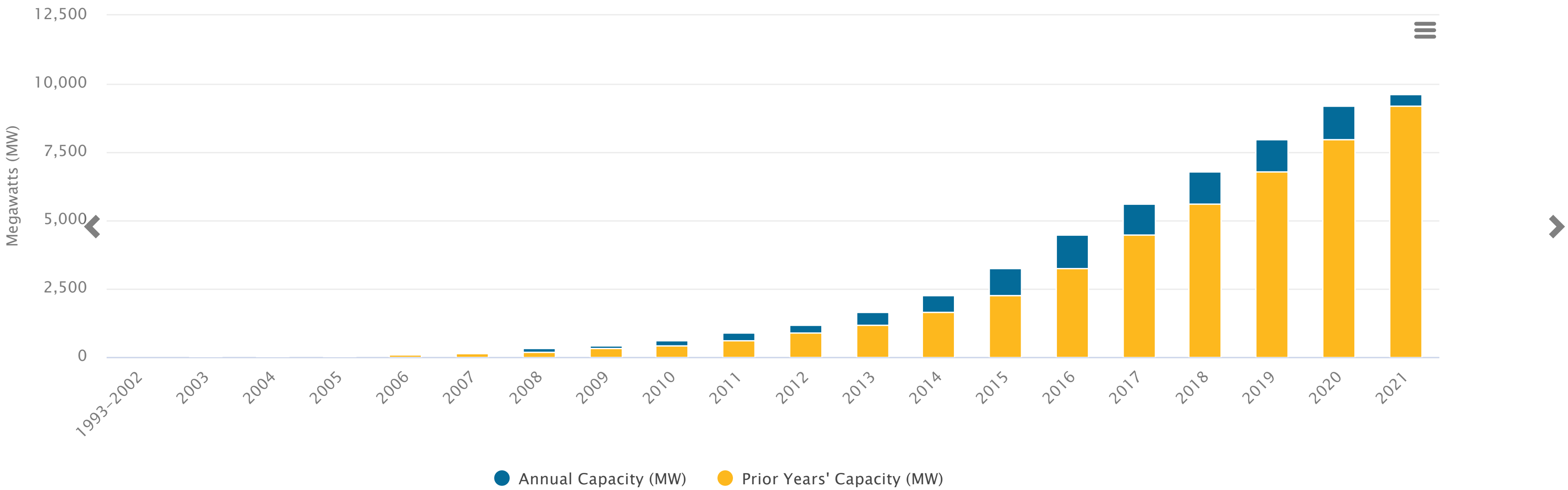
*This value is an instantaneous MW value at the time specified in the Time column

ATTACHMENT E

California Leads the Nation in Distributed Generation

California Leads the Nation in Distributed Generation

1,268,904 Solar Projects **10,640** Megawatts (MW) Installed (/faq/totals)



Data Current Through 2021-04-30 (/faq/availability)

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About California DG Statistics

JI-DEK-DR-01-003

REBUTTAL TESTIMONY OF RICHARD McCANN, Ph.D. ON BEHALF OF THE AGRICULTURAL ENERGY CONSUMERS ASSOCIATION AND THE CALIFORNIA FARM BUREAU FEDERATION in California PUC Docket No. R.20-08-020

Docket No.: R.20-08-020
Exhibit No.: AEC-02
Date: July 16, 2021
Witness: Richard McCann, Ph.D.

REBUTTAL TESTIMONY OF RICHARD McCANN, Ph.D.
ON BEHALF OF THE AGRICULTURAL ENERGY CONSUMERS ASSOCIATION
AND THE CALIFORNIA FARM BUREAU FEDERATION

TABLE OF CONTENTS

1 Introduction

The Agricultural Parties are composed of the Agricultural Energy Consumers Association (AECA) and the California Farm Bureau Federation (CFBF). The Agricultural Parties served direct testimony in this proceeding on June 18, 2021, on proposals for aggregated net energy metering (NEMA) tariffs and rates.

The Agricultural Parties recommend that the California Public Utilities Commission (Commission or CPUC) adopt the following findings and recommendations to address the unique circumstances for agricultural customers with regards to net energy metering:

- Agricultural NEMA customers should not be allocated any additional cost responsibilities.
- The Commission should respect the substantial investment agricultural customers have made through continuation of the terms of the NEM 1.0 and 2.0 tariffs that they are currently on.
- The Commission should provide a 20-year term on the NEM 3.0 tariff.
- If the Commission chooses to compensate NEM 3.0 customers at the short-run market prices, then these customers should also be exempt from the Power Charge Indifference Adjustment (PCIA).
- NEM/NEMA customers should pay a variable charge for the distribution grid.

The Agricultural Parties submit rebuttal to the direct testimony filed by the Joint Investor Owned Utilities (Joint IOUs) and The Utility Reform Network (TURN), with a focus on NEMA issues. Consistent with the November 19, 2020 Scoping Memo, the Agricultural Parties address Scoping Memo issues 4, 5 and 6:

4. What program elements or specific features should the Commission include in a successor to the current net energy metering tariff?
5. Which of the analyzed proposals should the Commission adopt as a successor to the current net energy metering tariff and why? What should the timeline be for implementation?
6. Other issues that may arise related to current net energy metering tariffs and subtariffs, which include but are not limited to the virtual net energy metering tariffs, net energy metering aggregation tariff, and the Renewable Energy Self-Generation Bill Credit Transfer program.

2 The Joint IOUs' proposal would eviscerate the legislative intent behind authorizing the NEMA tariff

The State Legislature established the NEMA tariff to allow customers with multiple contiguous parcels to mimic the opportunities available to industrial and commercial customers who can aggregate all of their loads behind a single meter.[1] The ability to aggregate load particularly benefits agricultural customers who often have pumping loads dispersed across neighboring parcels but all on the same electric circuit. Public Utilities (PU) Code Section 2827(h)(4)(A) is quite specific in the limitations imposed on eligible NEMA accounts: "An eligible customer-generator with multiple meters may elect to aggregate the electrical load of the meters located on the property where the renewable electrical generation facility is located and on all property adjacent or contiguous to the property on which the renewable electrical generation facility is located, if those properties are solely owned, leased, or rented by the

[1] Senate Bill 594 (Wolk 2012).

eligible customer-generator." The law directs the Commission to treat these accounts as an aggregated whole, not as separate individual accounts to be charged separate bills.[2]

The Joint IOUs propose to abolish the NEMA tariff for new aggregated NEM customers and to merge it with the DG-ST-V for virtual NEM customers.[3] The generating account would be paid for its *gross* or total output at a rate based on the Avoided Cost Calculator, which is the proposed basis for paying standard NEM 3.0 customers for their *net* generation output. The "aggregated" accounts are treated like any other standard account, paying the otherwise applicable schedule (OAS) rate for total output while receiving a monetary credit for the output from the generating account. This Joint IOUs' proposed new tariff would eliminate the benefits of physically offsetting generation with onsite use and turn the generating account into a quasi-Renewable Market Adjusting Tariff (ReMAT) or qualifying facility (QF) generator that is paid an avoided cost rate. There is no practical difference between paying the customer directly for the output from the generating account on the one hand, and providing a monetary credit to a different set of benefitting accounts on the other hand—in either case it is simply a monetary transaction (through different channels).

The law is quite specific about how the accounts are to be aggregated physically, not just financially. PU Code Section 2827(h) states "For eligible customer-generators, the net energy metering calculation shall be made by measuring the difference between the *electricity supplied* to the eligible customer-generator and the *electricity generated* by the eligible customer-generator and fed back to the electrical grid over a 12-month period" (emphasis added). The law

[2] *See, e.g.*, PU Code § 2827(h)(4)(C).

[3] Joint Opening Testimony of Southern California Edison Company (U 338-E), Pacific Gas and Electric Company (U 39-E) and San Diego Gas & Electric Company (U 902-E) on Issues 2-6 of Joint Assigned Commissioner's Scoping Memo and Administrative Law Judge Ruling Directing Comments on Proposed Guiding Principles (Joint IOUs' Testimony), p. 152.

does not reference the *value* of electricity—it lists the physical units of electricity as the credits and debits in calculating the aggregated net loads. This is a physical unit calculation, not a crediting and debiting of monetary transactions and is akin to the same physical flow that occurs when the generation plant is on the same side of the customer meter as the benefiting load. (Additionally, the law requires a 12-month true up period, not monthly or daily.)

The approach proposed by the Joint IOUs eviscerates the purpose of the NEMA option to mirror the arrangement available to other customers who have loads and generation behind a single meter. Any new power projects built by agricultural customers will be treated just like a new generator under short-term ReMAT or QF contracts. Instead of gaining a physical-unit credit based on the retail rate, the new projects will be paid a set generation sales price that may not be established in accordance with the standards set out by the Public Utilities Regulatory Policies Act (PURPA) since it has not been evaluated in that context nor protected by a standard contractual agreement. The benefitting accounts lose the cost assurance from relying directly on the generator which was the objective of the NEMA law. The Joint IOUs' proposed DG-ST-V rate structure should be rejected as it is contrary to existing law, and the current method of aggregating total physical generation and loads should be maintained.

2.1 The Joint IOUs incorrectly assert that NEMA customers do not cover their distribution costs

NEMA customers only receive credit for the generation portion of their output. The accounts still pay most of the distribution costs for the accounts through the demand and customer charges as described in the Agricultural Parties' opening testimony.

Further, the Joint IOUs assert that there is no displacement of load on the distribution, and even the transmission, grid because the generation is not "on site." The Joint IOUs ignore the fact that NEMA accounts must all be contiguous which also means that they are also all on the same circuit. The cost of the service lines and final line transformer to each of these accounts is recovered through the customer charge. Due to Kirchoff's Law, electricity flows through a path in inverse proportion to the impedance on each path. This means that when electricity is exported from an adjacent generator, it will first flow towards the neighboring loads within the circuit. This generation will displace generation coming from outside of the circuit. As result, the generator will displace the electricity that would have flowed through the transmission and distribution grid to the transformer at the top of the circuit both serving the customer loads and receiving the local generation.

The Joint IOUs' rationale about the lack of benefits to the distribution and transmission grid should be rejected because (1) NEMA customers pay for the portion of the distribution used to deliver power from the generating account, and (2) the generating account output displaces the electricity that would have flowed through the remainder of the grid.

2.2 The Joint IOUs' claims of higher NEMA administrative costs should be ignored because the claims are not supported by commensurate data

The Joint IOUs claim that the NEMA tariff must be radically transformed because customers cannot understand how it works, which in turn means the utilities must spend inordinate time at the call center with them, and the costs of billing are excessive.[4] The fundamental problem with this claim is that the comparisons are made to customers that are not on comparable tariffs. Additionally, there is no representation of how many such calls are being made. Is this just a few a month? Is the amount truly representative of how well customers understand the tariff? It is impossible for the Commission to make any conclusions from the superficial anecdotes presented.

[4] Joint IOUs' Testimony, pp. 155-156.

The appropriate comparisons should be made to agricultural customers in general. Those customers generally have multiple accounts on different rates and have complex energy management decisions. A grower's call to the call center is likely to last much longer than the average, particularly compared to a Solar Hot Line customer with a single account. The question is whether the NEMA customer calls are significantly longer than the calls on other agricultural accounts. Furthermore, it may be that calls regarding NEMA accounts also incorporate other tariff questions as well that may not be related to a NEMA account given that NEMA customers manage an *aggregation* of accounts served under various tariffs. The Joint IOUs provide no evidence on this aspect, so their claim about the complexity of NEMA tariffs and customer calls must be rejected due to lack of substantiation.

The comparison of billing costs faces the same issue. Agricultural accounts in general are more complex to bill and the higher monthly customer charge reflects this difference. The correct comparison is not to other NEM customers, most of whom are residential, but rather to the more complex agricultural accounts. Further, it is not possible to determine whether a billing cost of $8.40 is somehow burdensome when compared to the alternative for standard agricultural customers. Finally, the Joint IOUs do not specify whether that cost is for each individual account that is aggregated up into the NEMA billing or if it is the total cost across all of the accounts under the tariff. State law requires that NEMA customers pay the full cost of billing services, so the utilities already have authorization and tools to cover any additional costs.[5] Here also, the Joint IOUs fail to provide the data necessary to make the appropriate comparison and their claim regarding billing costs should be rejected.

[5] PUC Section 2872(h)(4)(H): "Notwithstanding subdivision (g), an eligible customer-generator electing to aggregate the electrical load of multiple meters pursuant to this subdivision shall remit service charges for the cost of providing billing services to the electric utility that provides service to the meters."

The Joint IOUs have not presented sufficient evidence to determine if the NEMA tariff is too complex for customers or whether billing costs are excessive. Even so, it is hard to justify a radical revision of the NEMA tariff over a cost of $8 per month.

3 TURN's proposed Market Transformation Credit should not be imposed on NEMA customers due to the complexity of its implementation and lack of a complete proposal

TURN proposes that an unspecified charge be imposed on existing NEM 1.0 and 2.0 customers to fund a yet to be designed Market Transition Credit (MTC) that would subsidize NEM 3.0 customers to achieve the 10-year discounted payback necessary to justify a 10-year term on the NEM 3.0 tariff.[6] TURN's testimony does not refer to the NEMA or virtual NEM (VNEM) tariffs, so it is unclear whether TURN's proposal extends to these existing customers. Due to the likely complexity of designing and implementing such a charge across aggregated accounts and the lack of a fully developed proposal on determining the amount and applicability of the MTC, this charge should not be imposed on existing NEMA and VNEM customers.

The contemplated MTC is an ill-conceived fix for the most obvious problem—NEM 3.0 rates that rely solely on the current Avoided Cost Calculator values do not reflect the full economic value of distributed energy resource self-generation resources. TURN is proposing to create a subsidy payment funded 50% by a charge on subsidized customers, with "subsidy" defined in the context of an assumption that the electricity system is static, has existed in its current state and will continue to exist in this state going forward. As the Agricultural Parties described in their initial testimony, solar NEM customer growth is highly correlated with the

[6] Direct Testimony of Michele Chait on Net Energy Metering Reform Proposals, R.20-08-020, on behalf of TURN (TURN Testimony), pp. 5-6.

reduction in California Independent System Operator (CAISO) peak load growth,[7] and the incremental cost of transmission is $37 per megawatt hour. Instead of an MTC, the Commission should establish the terms and rates in the NEM 3.0 tariffs to reflect at least the cost, if not the full value, of these systems to all customers.

Unlike standard NEM accounts, NEMA customers aggregate their accounts. What would be the terms for billing these customers? At what point in the transaction would these charges be imposed? How would these charges be made equitable with standard NEM customers? How would the fact that NEMA customers already pay a portion of distribution costs be considered in determining the charge? As reflected in our Opening Testimony, customers on NEM 1.0 and 2.0 should not have the fundamental parameters of the tariffs revised in this proceeding. Belatedly adding a charge like the proposed MTC would significantly impact the expectations of customers who have invested in clean energy and change the anticipated economics of the projects.

3.1 TURN's proposal to impose a charge to recover Nonbypassable, Unavoidable and Shared costs from onsite usage should be rejected

TURN proposes that a charge be imposed on consumption of generation output for Nonbypassable, Unavoidable and Shared costs.[8] This proposal is based on the premise that either the utility or the state owns *all* of the electricity generated, regardless of whether it is self-generated or generated elsewhere and passes through a meter. This is in effect an unrealistic and impractical attempt to acquire private property. It is also contrary to the current structures for

[7] Based on the data presented on the demand load forecast presented in the California Energy Commission's *2005 Integrated Energy Policy Report*, the 2020 CAISO peak load was over 11,000 megawatts lower than the forecast prepared in 2005. This value is almost double the amount presented in the Agricultural Parties' direct testimony, confirming the substantial impact and cost savings from NEM customers' investments. (CEC, *2005 Integrated Energy Policy Report*, CEC-100-2005-007-CTF, November 2005, page 41, included as Attachment A hereto.)

[8] TURN Testimony, pages 5 and 48.

self-generation and customers' ability to generate their own electricity without interference from the Commission or the utility. TURN's proposal is the equivalent of forcing those who buy energy-efficient appliances or install home insulation to pay the utility for electricity that would have been used otherwise or "negawatts." From the perspective of other customers, there is no difference between saving electricity or generating one's own electricity—both free up generation, transmission and distribution facilities for use by other customers.

4 Conclusion

The Joint IOUs and TURN have made proposals that impact existing and future NEMA customers based on erroneous or unsubstantiated assumptions, premises and assertions.

The Joint IOUs' proposal to transform the NEMA tariff into a quasi-ReMAT/QF agreement ignores the legislative intent to create a rate schedule that operates in the same manner as a conventional single-account NEM. NEMA customers cover most if not all of the distribution costs that they are responsible for and the Joint IOUs have presented no evidence to contradict this other than an unsubstantiated assertion about generation not being located on-site. The Agricultural Parties cited in direct testimony to the only study on the issue that showed that NEMA customers actually generated net benefits for the system. The Joint IOUs' evidence about the burden of NEMA on the grid and to the utilities is flimsy at best and must be rejected. Moreover, an increase in call center calls of six minutes or billing costs of $8 can hardly be called burdensome in the overall context of billions of dollars of revenue requirements and does not warrant eradication of the value NEMA provides to customers.

TURN's proposals to impose "taxes" on future NEMA customers' internal usage violates the fundamental principle that the customers should not be charged for reducing consumption from the grid regardless of means. TURN’s MTC proposal creates a complex web of subsidies and cross subsidies that only makes the knot of subsidies worse.

The Agricultural Parties recommend that the terms in the tariffs for existing NEMA customers under NEM 1.0/2.0 remain unchanged. For new NEMA customers the pricing terms must reflect the law, and physical electricity quantities must be netted against physical electricity generation. Using monetary quantities as credits and debits is contrary to state law and should be rejected.

ATTACHMENT A

CALIFORNIA
ENERGY
COMMISSION

2005 INTEGRATED ENERGY POLICY REPORT

COMMITTEE FINAL REPORT

NOVEMBER 2005
CEC-100-2005-007-CTF

Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

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DISCLAIMER

This report was prepared as part of the Integrated Energy Policy Report Proceeding, Docket 04-IEP-1. The report will be considered for adoption by the full Energy Commission at its Business Meeting on November 21, 2005. The views and recommendations contained in this document are not official policy of the Energy Commission until the report is adopted

The electricity and procurement policies recommended in this report are driven to a large extent by concerns about the need to diminish California's growing dependence on natural gas. Though the state's primary supply diversity strategy is the development of renewable resources, a lengthy and complex administrative and solicitation process hinders the state's ability to meet Renewable Portfolio Standard (RPS) targets. Untested thus far is the implementation of the CPUC's 2004 directive that renewables should be the "rebuttable presumption" for all IOU long-term procurement. Similarly, distributed generation sources, especially combined heat and power facilities, have not received the focused regulatory attention necessary for their expanded development.

The following chapter outlines the Energy Commission's assessment of electricity demand and supply trends, along with recommendations for IOU procurement. Chapter 4 outlines the steps the state must take to make sure that energy efficiency, demand response, and distributed generation goals are met. Renewable resource issues are examined in Chapter 5.

Electricity Demand

Electricity demand is measured in two ways: consumption and peak demand. Electricity consumption is the amount of electricity — measured in gigawatt hours (GWh) — that consumers in the state actually use. Consumption is primarily a money question for consumers and businesses: how much electricity am I being charged for and what will it cost me? In contrast, peak demand — measured in MW — is the amount of generation needed to keep electrons flowing in the system at any given moment of peak demand. Meeting peak demand is primarily an operational issue for system operators — how much will be needed to keep the lights on under worst case conditions?

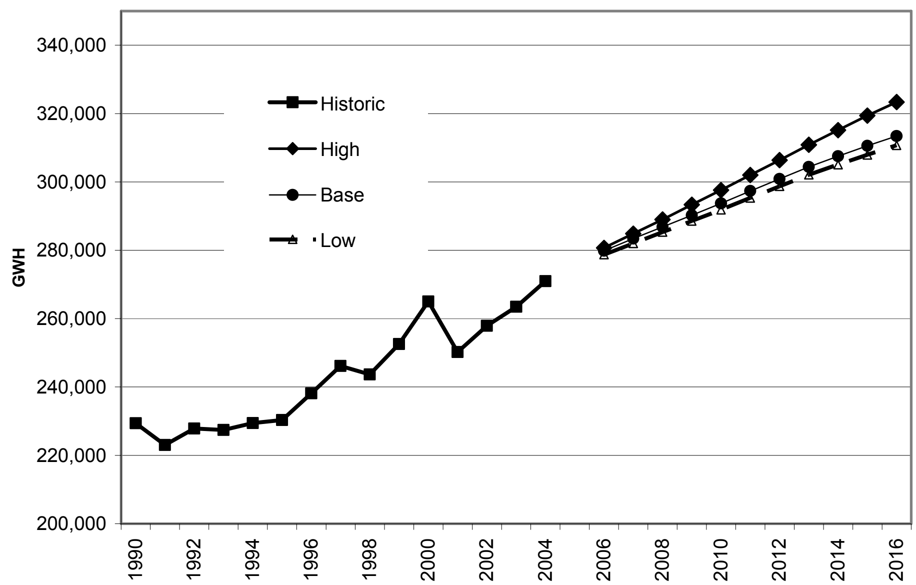
Electricity consumption in California grew from 250,241 GWh in 2001 to 270,927 GWh in 2004. The state's annual electricity consumption increased almost 3 percent over those three years, higher than forecast in the *2003 Energy Report*.[45] Over the same period, consumption increased in all areas except the industrial sector, which remained relatively flat. Residential and commercial use increased an average of 3.3 percent. Primary reasons for the increased growth include a shorter and milder recession than projected in the 2003 forecast, along with diminished voluntary consumer conservation efforts compared to those achieved during the 2000-2001 energy crisis.

As shown in Figure 6, consumption is forecast to grow between 1.2 and 1.5 percent annually, from 270,927 GWh in 2004 to between 310,716 and 323,372 GWh by the end of the forecast period in 2016. Population is a key driver for residential consumption, commercial growth, demand for water pumping, and other services. The 2003 demand

[45] *California Energy Demand 2006-2016*, *Staff Energy Forecast, Revised September 2005*, September 2005, CEC-400-2005-034-SF-ED2, and *California Energy Demand 2003-2013 Forecast*, August 2003, 100-03-002.

forecast assumed 1.4 percent population growth. The demand forecast for the *2005 Energy Report* projects consumption will be higher than in the 2003 forecast, but the annual demand growth rate will be lower due to lower population forecasts from the Department of Finance (DOF).[46] The DOF projects annual population growth at 1.2 percent and is based upon lower immigration and fertility assumptions than its 1998 forecast. The highest consumption growth is forecast for the Sacramento Municipal Utility District (SMUD) control area and Southern California portions of the CA ISO control area, reflecting strong population growth in those areas. Another key driver of California's energy demand is personal income.

Figure 6: Statewide Electricity Consumption (1990-2016)



Source: California Energy Commission, *California Energy Demand 2006-2016*, *Staff Energy Forecast, Revised September 2005*, September 2005, CEC-400-2005-034-SF-ED2.

Statewide noncoincident peak demand reached 56,435 MW in 2004, up from 50,245 in 2001. Peak demand in California is forecast to grow between 1.4 and 1.75 percent, rising from 56,435 MW in 2004 to between 66,656 and 69,473 MW in 2016, as shown in Figure 7. On the peak demand side, the 2004 recorded peak was 3.3 percent higher than forecast, a difference of more than 2,000 MW, the approximate capacity of three of the state's largest fossil-fueled generators. The 2005 demand forecast uses this higher peak demand as its starting point.

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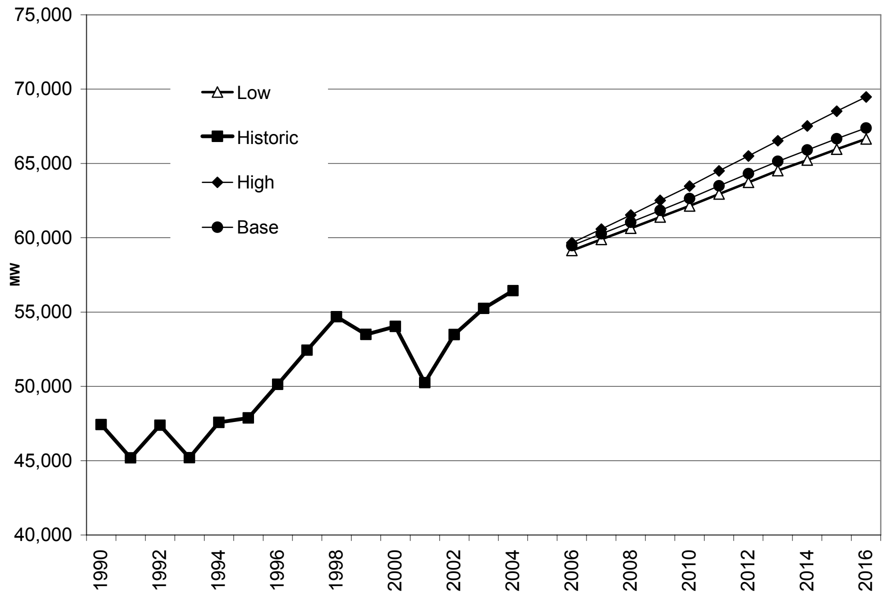
[46] State of California, Department of Finance, *Population Projections by Race/Ethnicity for California and its Counties 2000–2050,* Sacramento, California, May 2004. These population projections were prepared under the mandate of Government Code, Sections 13073 and 13073.5. In addition, the State Administrative Manual, Section 1100 on state plans, sets the general policy of …"(3) The use of the same population projections and demographic data that is provided by the State's Demographic Research Unit."

Figure 7: Statewide Peak Demand (1990-2016)



Source: California Energy Commission, *California Energy Demand 2006-2016*, *Staff Energy Forecast, Revised September 2005*, September 2005, CEC-400-2005-034-SF-ED2.

One of the difficulties in using long-term forecasts is that they are designed to project a *growth rate* in consumption and peak over a ten-year period. As shown in Figure 7, there is considerable variability in any given year. It can be quite misleading to simplistically apply a forecasted ten-year growth rate to predict demand in the early years of the forecast. The Energy Commission generally finds the staff's detailed end-use models more reliable in the long-term and the utilities econometric methodologies more useable in the near-term.

The Commission's forecasts project consumption and peak demand assuming average weather conditions. Because weather is unpredictable, the actual consumption and peak will almost always vary from the forecasted projection. To account for this, the Commission develops demand forecasts under hot-weather scenarios. In any given year, there is a 10 percent chance of temperatures that will increase statewide demand by 6 percent – about 3,600 MW in 2006.

Given that California covers a large geographical area, with many diverse climates, the demand forecast is adjusted for weather based on average temperatures and the relationship between demand and temperature within each planning area. Northern California usually has its hottest temperatures in July and August while Southern California's occur in late August and September.[47] Total statewide peak will be different when the temperature in San Jose is 95 and Burbank is 75 than when those temperatures are reversed, even though the average temperature is the same.

[47] The timing of peak is based on historical data. This year, it appears that Los Angeles Department of Water and Power had its peak much earlier in the summer in July, demonstrating the difficulty of predicting weather with any precision.

Depending on the temperature patterns across the state, the statewide or CA ISO coincident annual peak demand has been between 1 and 5 percent lower than the sum of the individual planning area peaks.

A cornerstone of the Energy Commission's demand forecast is the reporting of electricity sales by economic sector for each retail electricity seller in the state. Since restructuring of the state's electric industry, unclassified sales — sales not identified by economic sector — have become the fastest-growing consumption category. For forecasting purposes, these sales must be allocated to one of the various sectors, and improper allocation can cause forecasting errors. For example, because commercial and industrial customers have very different load shapes, assigning their usage to the wrong customer class could result in a forecast of system peak that is either too high or low, with a possible difference of over 1,000 MW. The Energy Commission, with the state's utilities, must continue its efforts to address these unclassified sales discrepancies.

At the demand forecast hearing, participants identified several key uncertainties driving the differences between staff and utility forecasts, including trends in commercial energy use and residential demographics and the currency of data. Staff forecasts decreasing commercial electricity use per square foot, reflecting the effects of building and appliance standards, which most participants thought unlikely when the standards were adopted. In the residential sector, utility forecasts generally assumed more growth in income and the number of households than the staff forecast, but smaller household size.

In response to these factors, the *Energy Report* Committee directed staff to vary these key assumptions to develop a reasonable range of possible outcomes. These forecast ranges also use more recent consumption data and new information on population and income. The resulting forecasts will be used in the *2005 Transmittal Report* to the CPUC.

Another issue was the treatment of energy efficiency savings from IOU programs planned for later than 2008. The three IOUs included these impacts in their electricity demand forecasts. The revised staff forecasts do not include them because the significance of their impacts is dependent upon future CPUC decisions that could modify the energy efficiency targets before approving funding for post-2008 programs.

Growing "Peakiness" in Demand

Electricity demand in California increases most dramatically in the summer, driven by high air conditioning loads. The generation system must be able to accommodate these high summer peaks, in addition to the demand swings caused by weather variability and the economy. Though peak demand periods typically occur only between 50-100 hours a year, they impose huge burdens on the electric system.

JI-DEK-DR-01-004

PREPARED DIRECT TESTIMONY OF RICHARD McCANN, PH.D. ON BEHALF OF THE CALIFORNIA FARM BUREAU FEDERATION in California PUC Case No. A.21-06-021

Docket No.	A.21-06-021
Exhibit No.	CFBF-01
Date:	June 13, 2022
Witness:	Richard McCann, Ph.D.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2023.	A. 21-06-021

PREPARED DIRECT TESTIMONY OF
RICHARD McCANN, PH.D.
ON BEHALF OF
THE CALIFORNIA FARM BUREAU FEDERATION

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Dated: June 13, 2022

PREPARED DIRECT TESTIMONY OF
RICHARD McCANN, PH.D.
ON BEHALF OF
THE CALIFORNIA FARM BUREAU FEDERATION
SUBJECT MATTER INDEX

1. Introduction

The California Farm Bureau Federation (CFBF) is California's largest farm organization, working to protect family farms and ranches on behalf of its nearly 32,000 members statewide and as part of a nationwide network of more than 5.5 million members. Organized over 100 years ago as a voluntary, non-governmental and nonpartisan organization, it advances its mission throughout the state together with its 53 county Farm Bureaus. It works with its members throughout the state to elevate issues of concern. Farm Bureau strives to protect and improve the ability of farmers and ranchers engaged in production agriculture to provide a reliable supply of food and fiber through responsible stewardship of California's resources.

CFBF submits this testimony on a relatively narrow point in this proceeding that has a very large financial impact on customers—whether Pacific Gas and Electric Company's proposal to underground over 3,600 miles of distribution lines should be substantially reduced and replaced with less costly alternatives such as microgrids. Because the wildfire risk is greatest in rural areas where CFBF members work and live, CFBF is interested in achieving the most cost-effective solution that delivers a multitude of benefits. Beyond just reducing local fire risk, rural customers should see improved reliability and resilience as well as lower costs. PG&E's current proposal could lead to an increase in electricity rates of 10 cents per kilowatt-hour (kWh) or more by 2030 on top of the exorbitant increases that have been imposed over the last half dozen years.

Based on the analyses presented below, implementing community-scale, commercial enterprise and residential microgrids save about 90% to 95% over undergrounding. Even if the estimated microgrid costs are double—or even quadruple—those calculations, the potential savings are immense. Unfortunately, PG&E has not conducted such a benefit-cost analysis, instead plunging ahead with singular focus on its preferred solution. CFBF asks that the Commission order PG&E evaluate alternatives such as microgrids as proposed here and covered conductors as Southern California Edison is using successfully (and more quickly) in its service area for each circuit and feeder considered for system hardening.[1] This evaluation should be an open, transparent process, much like PG&E's current North Coast Resiliency Initiative.[2] Further, if microgrids are to be included in the portfolio of solutions, the Commission should order PG&E to conduct an open bidding process while encouraging local government participation so as to gain the benefits of competition to further limit costs to ratepayers.

2. The cost of undergrounding requires a closer examination of alternatives

PG&E has proposed to reduce wildfire risk by putting underground about 40% of its rural grid in High Fire Threat Districts (HFTD). There are a number of problems with undergrounding including increased maintenance costs, seismic and flooding risks, and problems with excessive heat (including exploding underground vaults).[3] Even ignoring those issues, the costs look to be extraordinary—the largest single construction project ever managed by PG&E even exceeding Diablo Canyon Power Plant.

An economically-attractive alternative is shifting rural service to microgrids during high wildfire risk periods instead. These microgrids could serve communities, farms, businesses and

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[1] SCE, "How Covered Conductor Lines Help Reduce Wildfire Risk," https://energized.edison.com/stories/how-covered-conductor-lines-help-reduce-wildfire-risk, December 8, 2021.

[2] CPUC, "Introduction to the North Coast Resiliency Initiative Workshop," https://www.cpuc.ca.gov/events-and-meetings/north-coast-resiliency-initiative-workshop-05-13-2022, May 13, 2022.

[3] Chris Gajeck, "Underground Electrical Vaults: Safety Concerns and Controls," *Incident Prevention*, https://incident-prevention.com/ip-articles/underground-electrical-vaults-safety-concerns-and-controls, 2016; Joel Ravang, "Overhead vs. Underground," Ram LLC, http://www.ramutilities.com/overhead-vs-underground.html, retrieved June 2022; Clarion Energy Content Directors, "Underground vs. Overhead: Power Line Installation-Cost Comparison and Mitigation," *Power Grid International*, https://www.power-grid.com/td/underground-vs-overhead-power-line-installation-cost-comparison/, February 2013.

isolated homes expeditiously while saving everyone money. Distribution outages in California have occurred about three times more often than transmission system outages.[4] Agricultural customers are twice as likely to experience outages as the system average.[5] Microgrids are easier to maintain and provide reliability independent of the transmission grid as well as generation by distributing back up generation amongst the distribution system. Finding a fault in an underground line is difficult, especially in long stretches. Microgrids can eliminate this issue and allow for extended outages on distribution lines, while ensuring customers have continued power service.

CFBF submitted testimony in PG&E's 2020 General Rate Case Phase II that described the special circumstances that increase the costs of agricultural customers more than for other customers due to public safety power shutoffs (PSPS):

Because of the possibility that power will be shut off for many hours or days because of a PSPS, agricultural customers may be forced to irrigate their fields outside of the schedule otherwise utilized in their operations, thereby increasing their costs of irrigation compared to the costs under their typical irrigation schedules. This could result in much higher usage than would be normally expected during peak price hours if no PSPS were called, which, in turn, could result in much higher bills for those agricultural customers. In addition, in order to protect property from potential fire

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[4] Based on comparing the System Average Interruption Duration Index (SAIDI) for 2020 of 153.2 minutes to the National Electricity Reliability Corporation reliability standard of one hour of outage in 10,000. See PG&E, " Learn about PG&E reliability reports," https://www.pge.com/en_US/residential/outages/planning-and-preparedness/safety-and-preparedness/grid-reliability/electric-reliability-reports/electric-reliability-reports.page, retrieved June 2022.

[5] Richard McCann, "Prepared Direct Testimony of Richard McCann, Ph.D. on Marginal Costs, Revenue Allocation, And Rate Design Issues on Behalf of the Agricultural Energy Consumers Association," PG&E 2011 GRC, A.10-03-014, October 6, 2010, pp. 16-19.

damage, irrigating properties can provide much needed moisture that will slow or forestall the spread of fire in some instances.[6]

This situation makes farmers particularly sensitive to potential outages that they can anticipate. Any solution must provide reasonable reliability in a manner that also supports resilience for farm operations. If an outage in an underground system is going to take at least twice as long to fix (and could be longer for rural service) than the current overhead systems, that further pressures farmers financially.

Microgrids confer an additional advantage through flexibility to serve added loads without substantial pre-planning and investment. As customers electrify their buildings, vehicles and equipment to help the state achieve its greenhouse gas reduction goals, they will be able to add local generation and storage without needing to expand the rural distribution network, whether underground or overhead.

2.1. The high cost of PG&E's system hardening proposal

PG&E has about 107,000 miles of distribution voltage wires and 18,500 in transmission lines.[7] PG&E listed 25,500 miles of distribution lines being in the HFTD wildfire risk zones.[8] In its 2022 Wildfire Mitigation Plan Update (WMPU),[9] PG&E has estimated that it would cost about $3 million per mile to underground the first 3,460 miles (and ignoring the higher maintenance and replacement costs than for existing overhead lines).[10] This is just over a third of

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[6] "Direct Testimony of William A. Monsen and Carlo Bencomo-Jasso on Behalf of the California Farm Bureau Federation Concerning Revenue Allocation and Agricultural Rate Design in Application 19-11-019," PG&E 2020 General Rate Case Phase II, A.19-11-019, November 20, 2020, p. 2.

[7] PG&E Company Profile, https://www.pge.com/en_US/about-pge/company-information/profile/profile.page, retrieved June 2022.

[8] PG&E-4, Chapter 4.

[9] PG&E, "2022 Wildfire Mitigation Plan," https://www.pge.com/en_US/safety/emergency-preparedness/natural-disaster/wildfires/wildfire-mitigation-plan.page, February 25, 2022; and PG&E-4, Chapter 4.

[10] PG&E-4, Chapter 4.

the initial proposed target of 10,000 miles. Based on PG&E's proposed ramping up, the utility would reach its target by 2030. PG&E estimates the total installation cost will be $10.5 billion by 2026;[11] that implies an annual revenue requirement of $2 billion at the current cost of capital.[12]

PG&E's overall annual revenue requirement for electric operations is currently about $17.6 billion for 2022 (which is already $2.5 billion more than the 2020 revenue requirements) and most of the increase of $2.4 billion to 2026 is attributable to undergrounding lines. If PG&E builds out the entire 10,000 miles by 2030, the total cost of $30 billion would add $5.7 billion in revenue requirements, ***adding one-third (~32%)*** to PG&E's overall rates. It would *double* the distribution component of rates from current levels.

The increases in the 2023 GRC would lead to bundled rates increasing from 27.8 cents per kilowatt-hour today (already 23% higher than December 2020) to 31.5 cents in 2026—14% higher than in 2022. As shown in Figure CFB-1, virtually all of that increase is attributable to the WMPU as proposed by PG&E.

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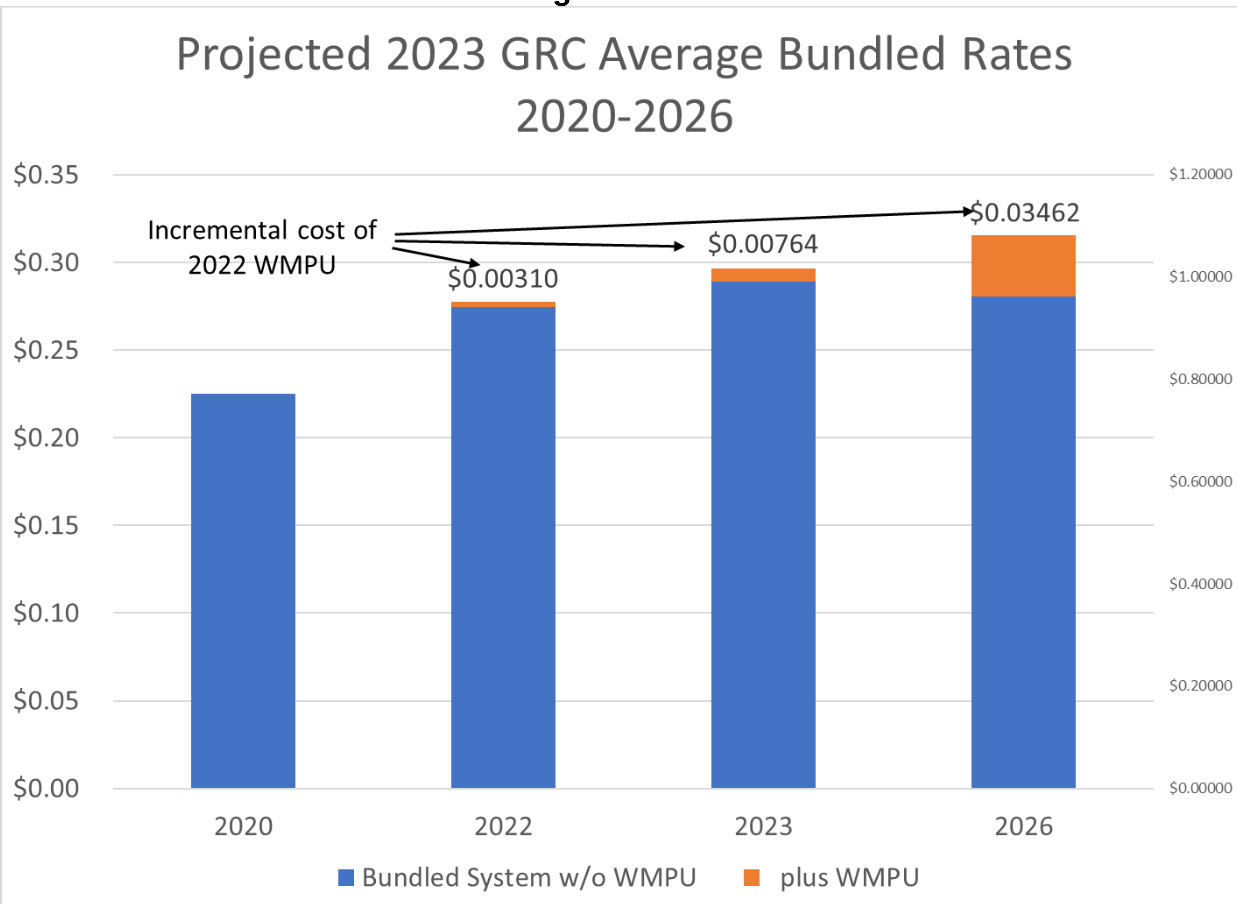
[11] PG&E-4, Table 4.3-11.
[12] Calculated using PG&E-10, Appendix A, Table 13 and Table 14.

Figure CFB-1



In the meantime as an alternative to PSPS events for mitigating wildfire risks, PG&E has installed fast-trip circuit breakers in certain rural areas to mitigate fire risks from line shorts and breaks, but it has resulted in a vast increase in customer outages.[13] Commission President Batjer wrote in an October 25 letter to PG&E, "[s]ince PG&E initiated the Fast Trip setting practice on 11,500 miles of lines in High Fire Threat Districts in late July, it has caused over 500 unplanned power outages impacting over 560,000 customers." She then ordered a series of compliance

[13] Julie Johnson, "New PG&E safety measures in fire-prone areas lead to spike in unplanned power shut-offs," *San Francisco Chronicle*, https://www.sfchronicle.com/bayarea/article/New-PG-E-safety-measures-in-fire-prone-areas-lead-16489072.php, September 26, 2021.

reports and steps. The question given this situation is whether undergrounding is the most cost-effective solution that can be implemented in a timely manner.

3. A cheaper wildfire mitigation solution: using microgrids instead of undergrounding

Microgrids can mitigate wildfire risk by the utility turning off overhead wire service for extended periods, perhaps weeks at a time, during the highest fire risk periods. The advantage of a periodically-islanded microgrid is 1) that the highest fire risk coincides with the most solar generation so providing enough energy is not a problem and 2) the microgrids also can be used during winter storms to better support the local grid and to ride out shorter outages. Customers' reliability may degrade because they would not have the grid support, but such systems generally have been quite resilient. In fact, reliability may *increase* because distribution grid outages are about three times more likely than system or regional outages. A recent National Renewable Energy Laboratory (NREL) study conducted in Maryland showed that such microgrids could run for a week with reliability in excess of 99% and for two weeks in excess of 96%.[14] In California, we have the advantage that the highest wildfire risk periods also are some of the sunniest so these systems should have sufficient energy given that PSPS and red flag events rarely last for more than a few days, much less a week.

3.1. Comparing cost effectiveness

Because microgrids would be installed solely for the purpose of displacing undergrounding, the relative costs should be compared without considering any other services such as energy delivered outside of periods of fire risk or outages or increased green power.

[14] Jeffery Marquise, et al, "Resilience and economics of microgrids with PV, battery storage, and networked diesel generators," Advances in Applied Energy, 3 (2021), https://www.nrel.gov/docs/fy21osti/78837.pdf.

Thus, the cost comparison ignores the energy benefits (and emission reductions) created for customers from microgrids and treats the two alternatives simply as though they are wires for delivering electricity.

Microgrids come in a range of configurations and sizes with the ability to be modified for use. For microgrid costs, NREL published estimated costs for at least five different configurations for customer-direct systems. These can serve communities, industrial plants, commercial operations, farms, and residences. The analysis in this testimony presents the two bracketing cases for meeting the needs of a small rural community and an individual remote residence, but each circuit or feeder would have a mix across the range of these microgrids; that mix cannot be anticipated without detailed study of each grid segment. Those two bookend configurations are: (1) commercial or community scale projects of 1 megawatt with 2.4 megawatt-hours of storage and (2) residential scale of 7 kilowatts with 12.5 kilowatt-hours of storage.[15] For the larger configuration, NREL shows ranges of $1.85 to $1.9 million; we include an upper end estimate double of NREL's top range. For a single residence, the range in the NREL study is $34,000 to $37,000; we add 50% to this upper end to compare a range of costs. The comparisons presented look only at each of these alternatives separately without determining an overall mix on a grid segment as stated previously.

Using this cost information from PG&E and NREL, we can make comparisons between undergrounding or installing microgrids based on the density of customers or energy use per mile of targeted distribution lines. In other words, we can determine if its more cost-effective to

[15] Vignesh Ramasamy, et al, *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks: Q1 2021*, National Renewable Energy Laboratory, Technical Report NREL/TP-7A40-80694, https://www.nrel.gov/docs/fy22osti/80694.pdf, November 2021.

underground distribution lines or install microgrids based on how many customers or how much load is being served on a specific line.

As one benchmark, PG&E's average overall system density per mile of distribution line is 50.6 customers and 286 kW (or 0.286 MW) of noncoincident demand.[16] PG&E reports that 10% of its customers reside and are served within the HFTDs, and that about 24% of its line miles are in the HFTDs. Based on that relationship, the average customer density per line mile in the HFTDs is 21.7 customers and the average noncoincident demand is 118 kW (or 0.118 MW) per line mile.

Turning to the comparison of undergrounding costs to microgrids, these two charts illustrate how to evaluate the opportunities for microgrids to lower these costs. The figures show the relative cost effectiveness for undergrounding compared to the two examples of community/commercial and residential microgrids. If the load density falls below the value shown, microgrids are more cost effective.

The first Figure CFB-2 looks at community scale microgrids, using NREL study estimates.[17] It shows how the cost effectiveness of installing microgrids changes with density of peak loads on a circuit on the vertical axis, cost per mile for undergrounding on the horizontal axis, and each line showing the division where undergrounding is less expensive (above) or microgrids are less expensive (below) based on the cost of undergrounding. As a benchmark, the dotted line shows the average load density in the HFTD areas. Assuming average conditions, community microgrids are cheaper regardless of the costs of microgrids or undergrounding.

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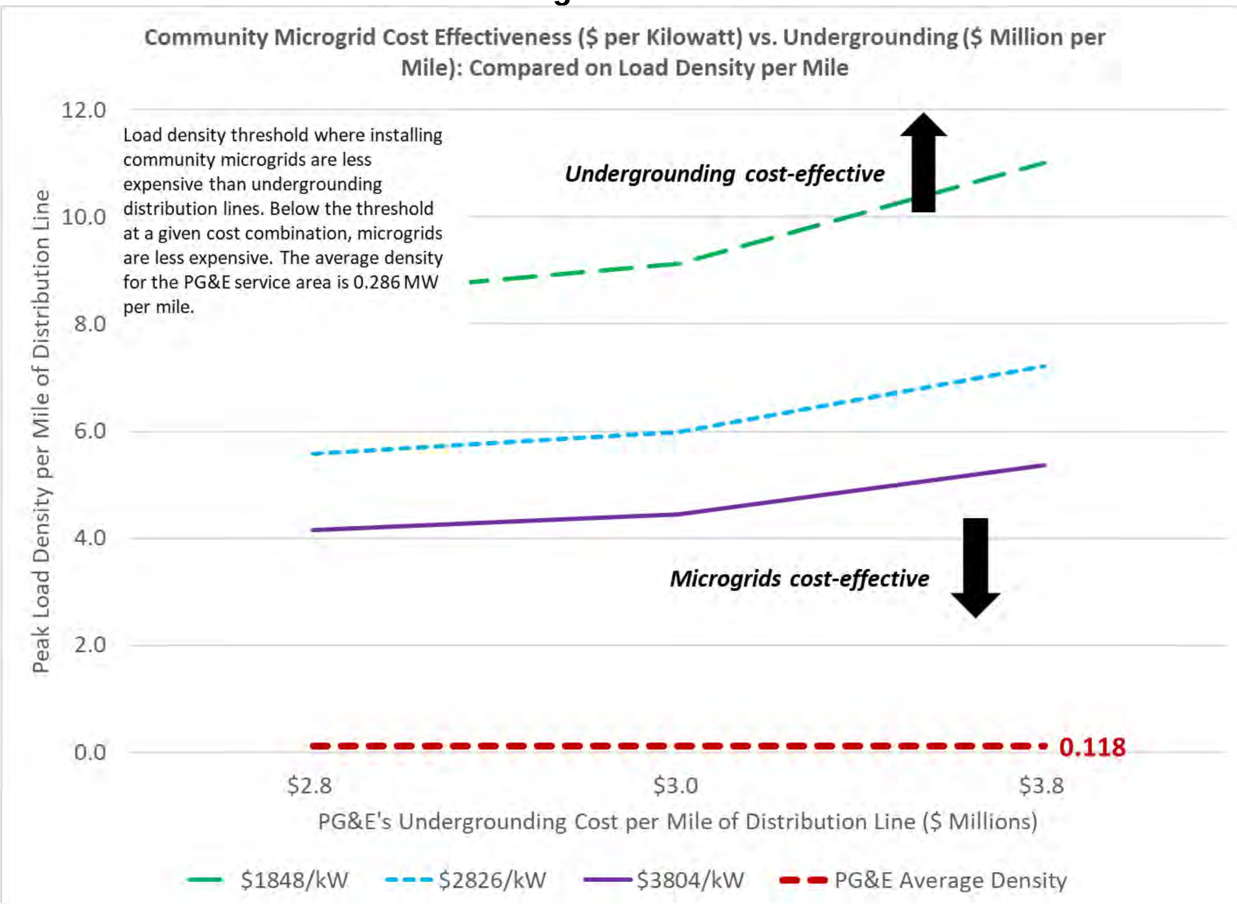
[16] Based on the 2019 customer count in PG&E's 2021 Energy Resource Recovery Account (ERRA) application, and the California Energy Commission's 2020 IEPR Demand Forecast scaled upward for the final load transformer (FLT) versus peak cost allocation factor (PCAF) reported in PG&E's 2017 GRC Phase II application.

[17] Ramasamy (2021).

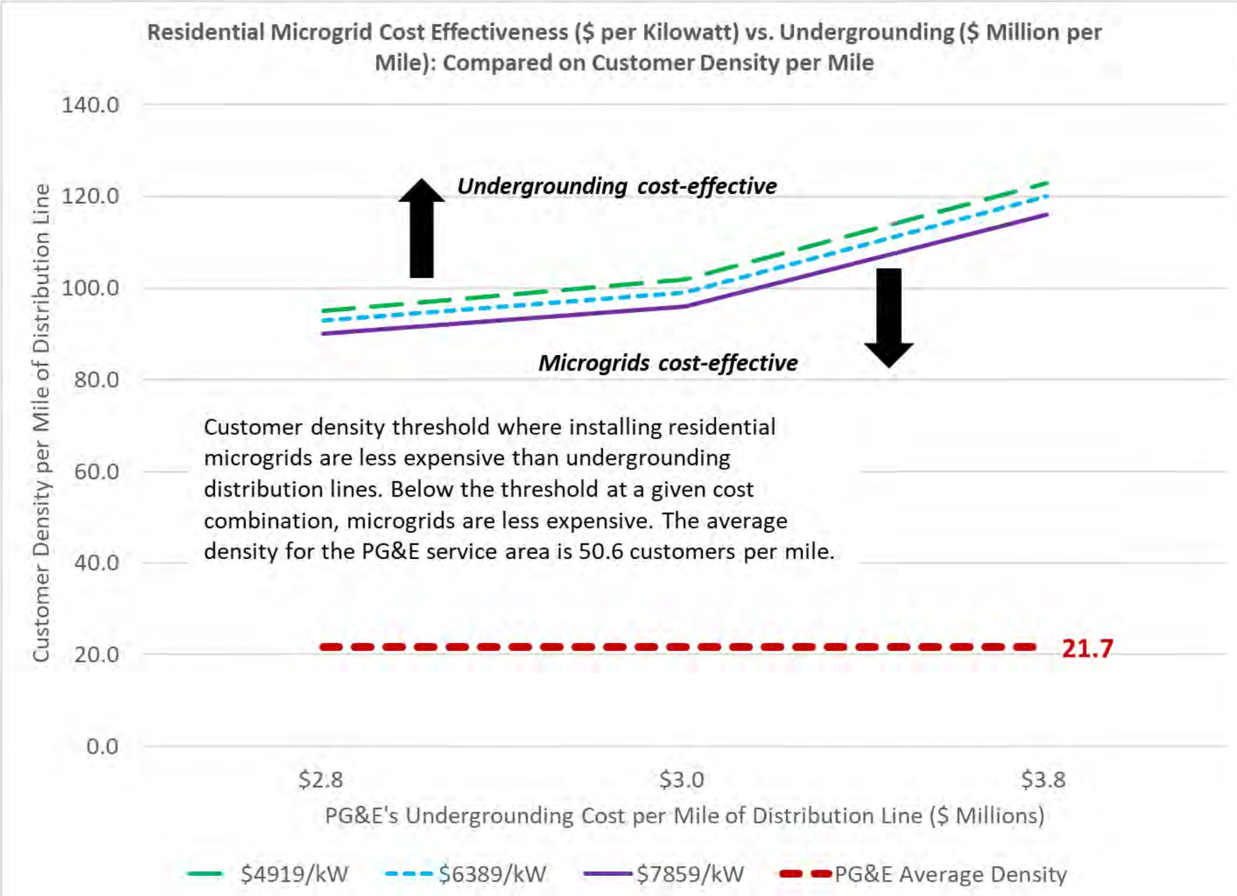
Figure CFB-2



The second Figure CFB-3 looks at individual residential scale microgrids, again using NREL estimates.[18] It shows how the cost effectiveness of installing microgrids changes with customer density on a circuit on the vertical axis, cost per kilowatt for a microgrid on the horizontal axis, and each line showing the division where undergrounding is less expensive (above) or microgrids are less expensive (below). As a benchmark, the dotted line shows the average customer density in the HFTD areas. Again, residential microgrids are less expensive in most situations, especially as density falls below 85 customers per mile.

[18] Ramasamy (2021).

CFB-3



Given the strength of the findings for these two bookends, we can presume the same conclusions will hold for microgrids serving individual farms or businesses. Based on these analyses, implementing community-scale microgrids appear to have the potential to save 90% to 95% over the costs of undergrounding. Even if the estimate microgrid costs are double—or even quadruple—NREL's calculations, the potential savings are immense.

4. Implementing the microgrid solution

The important question is whether microgrids can be built much more quickly than undergrounding lines and in particular whether PG&E has the capacity to manage such a buildout at a faster rate? The State Auditor issued a report criticizing PG&E's proposed plan as inadequate and mistargeted:

> *Among the nearly 40,000 miles of bare power lines in high fire-risk areas, the state's utilities have only completed hardening projects on just 1,540 miles of lines, according to the report.*[19]

The Auditor went on to further criticize the operation of the utilities' wildfire mitigation plans to date:

> *The Energy Safety Office's process for approving utilities' plans for mitigating the risk of wildfires does not ensure that the improvements are in high fire-threat areas. The office approved plans despite some utilities' failure to demonstrate that they are appropriately prioritizing their mitigation activities, and subsequent reviews have found that some utilities failed to focus their efforts in high fire-threat areas.*[20]

This critique and others call into question whether moving down the path currently proposed in PG&E's WMPU is the most effective for achieving the required wildfire safety goals.

PG&E has the Community Microgrid Enablement Program.[21] The utility was recently authorized to build several isolated microgrids as an alternative to rebuilding fire-damaged distribution lines to isolated communities.[22] PG&E has installed six community-scale microgrids in remote locations so far according to its testimony,[23] and reportedly is

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[19] California State Auditor, *Electrical System Safety*, http://auditor.ca.gov/pdfs/reports/2021-117.pdf, Report 2021-117, March 2022.

[20] Ibid.

[21] PG&E, "Community Microgrid Enablement Program (CMEP)," https://www.pge.com/en_US/safety/emergency-preparedness/natural-disaster/wildfires/community-microgrid-enablement-progam.page, retrieved June 2022; New Sun Road, "Remote Grid System – Briceburg, California" https://newsunroad.com/blog/remote-grid-system-briceburg-california, retrieved June 2022; Jeff St. John," PG&E Plans Utility-Owned 'Remote Grids' for Isolated Communities," *GTM*, https://www.greentechmedia.com/articles/read/pge-plans-utility-owned-remote-grids-for-isolated-communities, February 2, 2021.

[22] PG&E, "Strengthening and Improving the Electric System: PG&E Completes Microgrid in Magalia ," *Currents*, https://www.pgecurrents.com/2021/07/02/strengthening-and-improving-the-electric-system-pge-completes-microgrid-in-magalia/, July 2, 2021.

[23] PG&E-04, Chapter 4.

considering up to 20 such projects.[24] However, PG&E fell behind on those projects, prompting the CPUC to reopen its procurement process in its Emergency Reliability rulemaking.[25] In addition, PG&E has relied heavily on natural gas generation for many of these distributed generation projects. Yet PG&E has not conducted a full analysis of using permanent microgrids to displace undergrounding, instead generally using temporary set ups.[26]

PG&E simply may not have the capacity to construct either microgrids or install undergrounded lines in a timely manner solely through its organization. PG&E already is struggling to meet its targets for converting privately-owned mobilehome park utility systems to utility ownership.[27] A preferable choice may be to rely on local governments working in partnership with PG&E to identify the most vulnerable lines to construct and manage these microgrids. Turning to local governments to manage many different construction projects likely would improve this schedule, like how Caltrans delegates road construction to counties and cities. The community microgrids could be run under several different models including PG&E, municipal ownership, or perhaps a Joint Powers Authority. Local administration by local governments is likely to be more effective and responsive than trying to centralize operations out of PG&E's headquarters. This also can allow for tailoring to local circumstances rather than

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[24] Kavya Balaram," PG&E is betting heavily on microgrids. But can it move away from fossil fuels?," *Utility Dive*, https://www.utilitydive.com/news/pge-microgrid-public-safety-shutoffs-offers-distributed-energy-request-fossil-fuel-reliance/571017/, January 28, 2020.

[25] Brian Stevens, CPUC Administrative Law Judge, "Subject: Rulemaking 20-11-003: E-mail ruling providing staff guidance on the contents of all program proposals submitted in Opening Testimony by parties to this proceeding," E-mail to Rulemaking 20-11-003 Service List, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/proposal-guidance-to-parties-august-11-2021.pdf, August 11, 2021.

[26] PG&E, "GRC-2023-PhI_DR_CAFB_001-Q008," June 9, 2022.

[27] Based on data provided in PG&E, "Revised Mobile Home Park Utility Upgrade Program 2021 CPUC Report," Public Version, R.18-04-018, March 1, 2022; PG&E, "Utility upgrade for mobile home parks," https://www.pge.com/en_US/safety/contractor-construction-business-and-agriculture/mobile-home-park-utility-upgrade/mobile-home-park-utility-upgrade.page, retrieved June 2022.

trying to impose uniform operational standards and protocols across different circumstances. Microgrids serving individual customers in farms and residences would be operated remotely.

5. Conclusion

A movement towards energy self-sufficiency is growing in California due to a confluence of factors and the Commission has opened a number of proceedings to address the issues raised by this opportunity. PG&E's WMPU should reflect these new choices in manner that can reduce rates for all customers. Choosing to facilitate the installation of microgrids to meet a range of uses in rural areas while improving reliability appears to be a highly cost-effective option that takes advantage of this movement.

CFBF asks that the Commission order PG&E evaluate alternatives such as microgrids as proposed here and covered conductors as Southern California Edison is using successfully (and more quickly) in its service area, for each circuit and feeder considered for system hardening. This evaluation should be an open, transparent process, much like PG&E's current North Coast Resiliency Initiative. Further, if microgrids are to be included in the portfolio of solutions, the Commission should order PG&E to conduct an open bidding process while encouraging local government participation so as to gain the benefits of competition to further limit costs to ratepayers.

JI-DEK-DR-01-005

DIRECT TESTIMONY OF RICHARD MCCANN, PH.D. AND STEVEN J. MOSS, MPP ON BEHALF OF SMALL BUSINESS UTILITY ADVOCATES in California PUC Case Nos. A.22-05-015 & A.22-05-016

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Gas Company (U904G) for Authority, Among Other Things, to Update its Gas Revenue Requirement and Base Rates Effective on January 1, 2024.	Application 22-05-015 (filed May 16, 2022)
Application of San Diego Gas & Electric Company (U 902 M) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2024.	Application 22-05-016 (filed May 16, 2022)

DIRECT TESTIMONY OF RICHARD MCCANN, PH.D. AND STEVEN J. MOSS, MPP ON BEHALF OF SMALL BUSINESS UTILITY ADVOCATES

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March 27, 2023

SBUA
Small Business Utility Advocates

TABLE OF CONTENTS

I. IDENTIFICATION & QUALIFICATIONS

Q: Dr. McCann, please state your name, occupation, and business address.

A: My name is Richard McCann. I am a Partner at M.Cubed. My office is located at 426 12th Street, Davis, California 95616.

Q: Summarize your professional education and experience.

A: I have consulted on energy, water, and resource-related issues since 1985. I have a master's degree in public policy and a doctorate in agricultural and resource economics and am a member of several professional associations. I have analyzed many different aspects of energy utility and market operations in California. I have testified numerous times before the California Public Utilities Commission (CPUC or Commission) on impacts of electricity rates on agricultural groundwater pumping, reimbursement to master-metered manufactured housing community customers for utility services, competitive fuel choices, and proposed drought-mitigation policies. I testified on the appropriate level of exit fees for community choice aggregators, and suitable protection of solar project investment by customers. I also testified before the Federal Energy Regulatory Commission (FERC) on behalf of the California Parties in the California energy crisis Refund Proceeding. I worked with the California Energy Commission (CEC) to estimate the costs for new alternative generating technologies and developing several system modeling tools for local capacity planning and renewable generation integration. For the CEC, I examined the potential consequences of decommissioning the dams on the Klamath River, and for the State Water Resource Control Board, changes in greenhouse gas emissions from hydro licensing conditions. I also led the modeling efforts on behalf of the Commission to assess the environmental impacts of proposed generation plant divestitures.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified in numerous proceedings at the Commission, as well as before FERC and several other state commissions, including the 2012 Southern California Edison (SCE or Edison) 2012 General Rate Case (GRC) Phase I, every SCE GRC Phase II case since 2000, and the 2019 consolidated applications requesting increases in the authorized returns on equity by the four largest investor-owned utilities.

Q: Mr. Moss, please state your name, occupation, and business address.

A: My name is Steven J. Moss. I am a Partner at M.Cubed. My office is located at 296 Liberty Street, San Francisco, CA 94114.

Q: Summarize your professional education and experience.

A: I have a graduate degree in public policy, have been awarded several professional fellowships, including a Fulbright, and taught graduate-level economics and policy analysis courses. Over the past thirty years I've engaged in multiple aspects of the energy system, including developing and managing a first-of-its-kind demand response program focusing on small businesses, conducting research on grid and customer benefits associated with distributed energy resources (DER), and examining the role of tariffs in influencing energy user behaviors.

Q: Have you testified previously in utility proceedings?

A: Yes. I've testified before the CPUC on multiple occasions, including recently related to Public Safety Power Shutoffs, microgrid deployment, and appropriate rate characteristics.

II. INTRODUCTION

Q: On whose behalf are you testifying?

A: We are testifying on behalf of Small Business Utility Advocates (SBUA). SBUA's mission is to represent the small business community in energy regulatory proceedings. In particular, SBUA seeks to promote rates that facilitate provision of affordable, clean and renewable electricity to small commercial customers.[1]

California's approximately 4.1 million small businesses comprise 99.8% of all employer firms and are responsible for roughly 42.1% of California's $165.6 billion in exports.[2] Small businesses are vital to the state's economic health and welfare and constitute an important customer class for utility companies. Small business needs are critical to consider in this proceeding both because these ratepayers are essential to California's economy and because productive engagement from them and their employees is important to the state's energy future.

Small businesses' electricity needs and interests often diverge from residential and industrial customers. Under normal circumstances small business loads tend to peak in the middle of the day during weekdays while residential ratepayers have daily evening demand peaks. Many small businesses are tenants that lack direct control over building changes that might modify energy use and reduce associated bills. Some only see their electricity costs as

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[1] *See,* SBUA website at www.utilityadvocates.org.

[2] California Small Business Profile, U.S. Small Business Administration Office of Advocacy. *See* www.cdn.advocacy.sba.gov/wp-content/uploads/2020/06/04142955/2020-Small-Business-Economic-Profile-CA.pdf.

a line item on their rent. Likewise, small enterprises do not have the same resources or time to manage their loads as large companies, making it difficult for them to take advantage of utility programs that might lower their energy costs. And small business revenues tend to be more volatile than larger companies because they cannot diversify as easily against risks.

Q: What is the scope of this testimony?

A: We reviewed the Applications of Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) (hereinafter, collectively Sempra when not specifically identified) considering its potential impacts on small commercial customers and the State's significantly changed economic circumstances since this application was filed last August.

Q: Please summarize the primary issues addressed in this testimony

We discuss the following key issues in the remainder of this testimony:

- The utilities rely on a hodgepodge of budgeting approaches, most of which do not follow rigorous formal forecasting processes or methods. The utilities lack an overarching financial forecasting approach that allows the Commission or parties to evaluate appropriate benchmarks for future spending.
- While the utilities submitted affordability benchmarks for residential customers, they did not do the same for commercial class customers. Given the headwinds small businesses are encountering, including already high energy rates that would escalate dramatically if the utilities' applications are approved as-is, this is grievous gap.
- Rapidly escalating SDG&E electricity rates will incentivize customer exit, either to other states as is currently caused by housing prices and assertions of overly burdensome State

taxes and regulations, or through adoption of DERs and microgrids.[3] Rate design alone will not solve this dilemma—it will require a transformation of the relationships within the market, including shareholders taking on more risk. If rates rise to the levels requested by SDG&E for 2027, California's electrification goals for buildings and transportation will be jeopardized. The utility could face a "death spiral" of falling demand and rising rates. The Commission must consider the best options for containing the utility's costs and not imposing further burdens on ratepayers.

- Neither utility fully considers the opportunity presented by microgrids to cost effectively displace portions of the distribution grid that are at-risk to wildfires, improve local reliability, and replace natural gas lines while reducing greenhouse gas (GHG) emissions. Microgrids can be linked with existing backup generation (BUG) resources to increase resiliency and reduce BUG runtimes, thereby lowering GHG and criteria pollutant emissions.
- Both utilities predict substantial growth in customer service and safety calls. This is contrary to recent historical patterns – service and safety calls have fallen substantially over the last GRC cycle – and expectations about future customer growth.[4] For the gas utilities, the recent Commission decision related to line extensions and the California Air Resources

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[3] As is happening in Hawaii and Australia. ("More than 1,000 MW of solar now online across Hawaiian Electric grids," *The Maui News*, https://www.mauinews.com/news/local-news/2022/01/more-than-1000-mw-of-solar-now-online-across-hawaiian-electric-grids/, January 14, 2022; and Australian Renewable Energy Agency, "Solar energy," https://arena.gov.au/renewable-energy/solar/, June 27, 2022.)

[4] "San Diego Metro Area Population 1950-2023," *Macrotrends*, https://www.macrotrends.net/cities/23129/san-diego/population

Board's (CARB) new regulations ending the purchase of new and replacement gas-fueled appliances and furnaces suggest that customer growth should largely disappear. Electrification is likely to erode the gas customer base, a variable that is not reflected in the gas utilities' budgeting forecasts.

In other sectors customers increasingly rely on the Internet to access information. The service call forecast implies that web pages are not being designed to serve customers effectively, and that the utilities' have significant communication problems that need to be resolved. Alternatively, the expected growth in safety calls prompts the question: why are the utilities' systems apparently becoming more dangerous?

III. CONSIDERATION OF CUSTOMER EXIT DUE TO HIGH RATES

Q. What is SDG&E forecasting for increases in residential and commercial rates in its Application?

Table SBUA-1 shows SDG&E's proposed increases in electric revenue requirements and rates for residential and small commercial customers from 2022 to 2027.[5] For residential customers, the average rate jumps from 34.5 cents per kilowatt-hour (kWh) in 2022 to 45.3 cents in 2027 or 31.3%. For small commercial customers, the increase is from 32.2 cents to 42.7 cents or 32.5%. The system average rate increase is 27.0% while the revenue requirements increase is 33.3%.

[5] Revised Prepared Direct Testimony Of Jeff P. Stein (Present And Proposed Electric Revenues And Rates), Exhibit SDG&E-48-R, August 2022, pp. JPS-2-3; and Revised Prepared Direct Testimony Of Melanie E. Hancock (Post-Test Year Ratemaking), Exhibit SDG&E-45-R, August 2022, p. MEH-10.

Table SBUA-1 - SDG&E Proposed Rate Increases

	Average Cents per kWh					
Rates	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Residential	34.5	35.8	38.0	40.7	43.1	45.3
% Increase over 2022		3.8%	6.1%	7.2%	6.0%	5.0%
Small Commercial	32.2	33.4	35.6	38.2	40.6	42.7
% Increase over 2022		3.7%	6.6%	7.4%	6.2%	5.2%
Total	31.1	32.0	33.8	36.0	37.9	39.5
% Increase over 2022		2.9%	5.6%	6.4%	5.3%	4.3%
Revenue Requirements	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Residential	$1,670	$1,740	$1,860	$2,004	$2,136	$2,254
Small Commercial	$558	$584	$627	$679	$726	$770
Total	$4,080	$4,243	$4,522	$4,861	$5,167	$5,440
Increase		$163	$279	$339	$306	$273
% Increase		4.0%	6.6%	7.5%	6.3%	5.3%
% Cumulative Increase			**10.8%**			**33.3%**

SDG&E has among the highest, if not the highest, retail rates in the continental U.S. The U.S. Energy Information Administration listed SDG&E's average rate for 2021 as 27.15 cents per kWh; the national average was 11.10 cents.[6] SDG&E rates were 144% above the national average. Yet SDG&E is requesting another increase amounting to one-third of its current rates.

Q: What are the potential savings that a residential customer can gain by departing the SDG&E system and installing a self-sufficient microgrid?

For an average residential customer in 2027 that rate translates to $1,970 per year per kilowatt of peak demand at the system average load factor of 49.6%.[7] Using SDG&E's cost of

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[6] U.S. Energy Information Administration, *Electric Sales, Revenue, and Average Price*, https://www.eia.gov/electricity/sales_revenue_price/, October 6, 2022, Tables 4 and 10.

[7] California Energy Commission, *2022 Integrated Resource Plan Update*, Demand Forecast, Forms 1.5a and 1.5b.

capital, that implies that an independent self-sufficient microgrid costing $14,910 per kilowatt could be funded from avoiding paying SDG&E bills. And this projection ignores potential savings from further increases in the future.

Q: How much is the estimated cost of a residential microgrid with the capability to stand alone?

A National Renewable Energy Laboratory (NREL) study estimates that a standalone residential microgrid with 7 kilowatts of solar paired with a 5 kilowatt / 20 kilowatt-hour battery would cost between $35,000 and $40,000.[8] Customers' reliability may degrade without grid support, but such systems generally have been quite resilient. In fact, reliability may *increase* because distribution grid outages are about three times more likely than system or regional outages.

A recent National Renewable Energy Laboratory (NREL) study conducted in Maryland demonstrated that such microgrids could run for a week with reliability in excess of 99% and for two weeks in excess of 96%.[9] A Lawrence Berkeley National Laboratory (LBNL) study found that a properly sized solar plus storage system in San Diego County can serve a residential customer

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[8] Vignesh Ramasamy, et al, *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks: Q1 2021*, National Renewable Energy Laboratory, Technical Report NREL/TP-7A40-80694, https://www.nrel.gov/docs/fy22osti/80694.pdf, November 2021; and Vignesh Ramasamy, et al, *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks: Q1 2020*, National Renewable Energy Laboratory, Technical Report NREL/TP- 6A20-77324, https://www.nrel.gov/docs/fy21osti/77324.pdf, January 2021. (The witness recently reviewed a private bid for another individual in Northern California that confirmed the validity of these estimates.)

[9] Jeffery Marquise, et al, "Resilience and economics of microgrids with PV, battery storage, and networked diesel generators," Advances in Applied Energy, 3 (2021), https://www.nrel.gov/docs/fy21osti/78837.pdf.

reliably for days during an outage, and perhaps indefinitely,[10] suggesting that under SDG&E's rate proposal it could be cost effective for households to become entirely self-reliant.

Q: How much could a customer who defects from SDG&E save over a 25-year period?

The savings from avoiding SDG&E rates could justify spending $75,000 to $105,000 on a microgrid system; a customer could save $35,000 to $70,000 by defecting from the grid.[11] Even if NREL has underpriced and undersized this example system, there is a substantial margin for uncertainty. The expense of adding a propane or natural gas backup generator would be easily covered by these savings. Defectors would achieve largely stable energy costs, similar to owning rather than renting a house, as well as long-term savings.

Q: What are the risks of this potential defection to SDG&E shareholders and those ratepayers left behind?

Unlike in the 1990s when restructuring was implemented, the potential for widespread grid exiting is not limited to just a few large customers with choice thermal demands and electricity needs—a large swath of SDG&E's residential and commercial customers is at stake. This population consists of customers who are most affluent or capitalized, and ironically best able to pay SDG&E's extraordinary costs. If many of these customers start to exit the system, the utility could face a death spiral that encourages even more customers to leave as costs are spread over an

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[10] Will Gorman, et al, "Evaluating the Capabilities of Behind the Meter Solar plus Storage for Providing Backup Power during Long Duration Power Interruptions," Lawrence Berkeley National Laboratory, September 2022.

[11] At a 5% home mortgage rate for financing such a project, the potential savings rise to nearly $200,000.

ever-shrinking load, forcing rates up further. Those left behind will demand relief, but customers able to fully severe their ties to the grid will not be available to bail out the company, as they will be beyond the reach of Commission regulation.

The path proposed by SDG&E in this proceeding is financially and economically unsustainable for both the company and its customers. SDG&E needs to response to this emerging reality in a similar fashion as any other business that faces a disadvantageous competitive market environment—cut costs or sell assets at a discount to another entity, such as local governments, cooperatives, or energy service providers. The Commission should consider opening a rulemaking to consider alternative sustainable pathways, including fundamental changes in ratemaking, investment approval, and shareholder risk sharing.

IV. SMALL COMMERCIAL CUSTOMER AFFORDABILITY METRIC

Q: Is an affordability metric and benchmark analysis needed for small commercial customers?

Although the utility has presented affordability analyses for residential customers, it has not conducted a similar evaluation for non-residential classes, despite asserting that it is "acutely aware" of the challenges its high and still escalating rates impose on customers. Commercial class customers face distinctly different economic pressures than residential ratepayers, including related to supply chain challenges; the lingering effect of the pandemic on consumer demand, particularly in areas with high commercial vacancy rates; and the need to increase wages, a primary factor mitigating SDG&E's steadily rising rates on residential customers.[12] Likewise, small

[12] Supplemental Testimony Of Rachelle R. Baez (Affordability Metrics), Exhibit SDG&E-50-S, November 2022.

commercial customers lack the resources and personnel of larger commercial ratepayers to manage their energy bills. Without affordability standards for non-residential customers, neither the utility nor the Commission can effectively evaluate the economic consequences to these ratepayers of SDG&E's proposed rate increase.[13]

Table SBUA-2 shows the changes in commercial customer counts for SoCalGas for 2019 to 2021.[14] The smaller meter sizes correspond generally with small businesses. While the overall numbers grew and large accounts grew significantly, the three smallest groups shrunk. This indicates that the service area was losing small business customers. Given the overall growth that reflects economic vitality in the region, small businesses were being financially squeezed,[15] causing them sufficient distress to close existing establishments. This trend reinforces the need for an affordability metric for small businesses as well as residential customers.

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[13] The GRC Phase 1 Scoping Memo accurately provides: "In D.22-08-023, the Commissioner did not adopt a metric for nonresidential customers' affordability. Therefore, Sempra Utilities is not required to develop metrics for non-residential customers in Phase 1 of this GRC."

[14] Response to SBUA Data Request SBUA-SEU-002__ATTCH_Q3_11305.xlsx

[15] The impact on small businesses is captured in the Public Comment of Pete Sanford on March 16, 2023, "I spoke with some of the small business owners that support the efforts of the Orange County Workers Benefit Council this week, and they consistently told me that the steep increases from SoCalGas would hurt them. I would like to use one representative example, Fanny, who is the owner of the Las Brisas restaurant in Santa Ana. Her restaurant has been a local community favorite for the past 29 years. Fanny told me that her monthly SoCalGas bill has increased from $600 in 2020 to $1,400 in 2022 and now has more than doubled to $3,000.This restaurant is busy but modest in size and customer base. About 1,500 square feet, enough for 17 tables and a kitchen with 2 gas stoves. Nearly all of Fanny's customers are low-income workers and seniors on fixed income budgets. Unlike SoCalGas, she cannot pass along these increased costs to her customers. Fanny told me that she has survived the 2008 "Great Recession" but is not sure that she will be able to survive this "Great Inflation". If the CPUC does not roll back this latest rate increase for SoCal Gas, Fanny likely will have to close her restaurant, which will be devastating to her employees, suppliers and customers."

Table SBUA-2

Meter size (cubic ft/hr)	Average Count 2022	% of Total Customers 2019	2020	2021	2022	% Change Annually 2020	2021	2022
0-230	137,241	55.4%	55.2%	55.0%	54.9%	-0.24%	-0.26%	-0.28%
231-350	4,311	1.8%	1.7%	1.7%	1.7%	-0.59%	-0.58%	-0.48%
351-530	40,351	16.1%	16.1%	16.1%	16.1%	0.10%	0.08%	0.16%
531-800	26,951	10.6%	10.7%	10.8%	10.8%	1.05%	0.44%	0.19%
801-1150	6,039	2.2%	2.3%	2.3%	2.4%	1.79%	2.65%	3.88%
1151-1750	16,388	6.5%	6.5%	6.5%	6.6%	0.52%	0.52%	0.48%
1751-2600	721	0.3%	0.3%	0.3%	0.3%	-0.67%	-0.65%	-0.80%
2601-4000	11,603	4.6%	4.6%	4.6%	4.6%	0.71%	0.58%	0.54%
4001-6000	3,387	1.3%	1.3%	1.4%	1.4%	1.22%	0.56%	0.25%
6001-7000	1,170	0.5%	0.5%	0.5%	0.5%	0.90%	1.13%	1.48%
>7000	841	0.3%	0.3%	0.3%	0.3%	6.02%	2.99%	3.21%
Total	250,197					0.16%	0.06%	0.06%

V. PROGRAM BUDGET FORECASTING

Q: What forecasting methods are the Sempra utilities using to budget programmatic capital expenditures?

Both companies' rates are extremely high compared to national averages, and they are requesting extraordinary increases over the next four years. Yet in reviewing Sempra's workpapers on individual programs, SBUA was struck by the variety of methods used to set budgets for future capital investments. Most of these methods appeared to assume that capital investment would just continue as it had in the past without any examination of whether the results would be used and useful, or cogent justifications for expenditures that could encumber ratepayers with decades of financial obligations. This is not appropriate, especially for a regulated utility. Instead, capital investments should be carefully considered and fully defended. The Commission has an obligation to deny proposed expenditures that are not accompanied with a robust, empirically based, consistent analytical basis.

Table SBUA-3 lists the different methods found in each of the utilities' workpapers and sums the capital expenditures by method. Most of the methods rely on simply taking a past year or a series of years and projecting that amount for the 2024 Test Year. Only the zero-based method builds the capital budget from a specific plan that evaluates the associated required spending level.

Table SBUA-3: Capital Budgeting Method

Forecast Method	SDG&E	SOCALGAS	Description
Base Year	$259.5	$865.1	Most recent recorded year
Three-year Average	$87.4	$169.4	Average of preceding three-year period
Four-year Average	$3.6	$0.0	Average of preceding four-year period
Five-year Average	$33.5	$163.3	Average of preceding five-year period
Zero-based	$451.2	$597.2	Buildup of spending from specific plan
Mixed	$2,018.8	$1,252.7	Mix of above methods
Total	**$2,854.0**	**$3,047.6**	

Q: Why is the budgeting method important for controlling costs?

The best way to control spending is to understand why it is occurring. If the budgeting method relies on simply continuing what was done in the past, the rationale for the expenditures becomes hidden behind historical decisions that can be difficult to reveal and review. The situation that gave rise to the original spending levels may have changed; the original rationale may no longer be justified.

This situation is even more salient in the context of a rapidly changing energy landscape as the state moves to reduce natural gas use and customers consider whether to depart utility service by adopting new technologies. Simply using last year's budget or the average of previous years indicates a lack of review about whether the investment is serving its intended purpose, or whether the purpose itself has changed.

Q: How should Sempra change its budgeting methods to best adapt to this changing environment?

First, Sempra should rely on no more than two appropriate budgeting methods to reinforce consistency across programs, enhance transparency and better enable review by the Commission and other parties. Some programs may be overlapping and trending in different directions; using diverse budget methods could obscure these trends.

Second, the preferred method is a zero-based approach that establishes the rationale for each expenditure on a forward-looking basis. Another method that relies on looking back could be used where continuing expenditures at a current level makes sense, but those programs need strong justification for relying on such a method; it cannot be the default.

VI. MITIGATING WILDFIRE RISK USING MICROGRIDS

Q: What is SDG&E proposing to spend and recover through rates on mitigating wildfire risk?

In 2024 SDG&E proposes to recover $738 million in capital expenditures and $174 million in operating and maintenance.[16] Of the capital expenses, $691 million is for grid design and system

[16] Revised Prepared Direct Testimony Of Jonathan T. Woldemariam (Wildfire Mitigation And Vegetation Management), Exhibit SDG&E-13-R, August 2022, p. JTW-v.

hardening.[17] SDG&E is planning to underground 330 miles in High Fire Threat Districts (HFTD) between 2022 to 2024 at a cost of $954 million, $412 million of which in 2024.[18]

Q: Should SDG&E consider expanding a cost-effective alternative to conventional grid-hardening methods to mitigate wildfire risk?

Because wildfire risks are greatest in rural areas, like many stakeholders, and the Commission, SBUA is interested in achieving the most cost-effective risk-mitigation approach that delivers the greatest benefits. In addition to reducing local fire risks, rural customers should see improved reliability and resilience as well as lower costs from risk-mitigation investments.

SDG&E's risk-mitigation proposal in this proceeding could lead to an increase in electricity rates of two cents per kilowatt-hour (kWh) or more by 2027 on top of the exorbitant hikes that have been imposed over the last half dozen years. In contrast, and as discussed below, implementing community-scale, commercial enterprise and residential microgrids cost 70% to 85% less than undergrounding. Even if estimated microgrid costs are double these calculations, the savings compared to SDG&E's approach are immense. SDG&E has installed a dozen microgrids to address wildfire risks, most notably Borrengo Springs,[19] yet the application omits evidence of a wider evaluation of deploying this lower cost approach.

SBUA recommends that the Commission order SDG&E to properly evaluate alternatives, such as microgrids, in its service area for each circuit and feeder considered for system hardening.

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[17] Exhibit SDG&E-13-R, p. JTW-3.

[18] Exhibit SDG&E-13-R, p. JTW-134.

[19] SDG&E, *Microgrids Help Integrate Renewable Energy and Improve Community Resiliency*, https://www.sdge.com/more-information/environment/smart-grid/microgrids, retrieved March 2023.

The State Legislature encouraged this type of assessment in Senate Bill 1339 (2018) and the Commission has begun implementing it as part of R.19-09-009. Installing microgrids in this context would meet Public Utilities Code Section 8371(d):

> *Without shifting costs between ratepayers, develop separate large electrical corporation rates and tariffs, as necessary, to support microgrids, while ensuring that system, public, and worker safety are given the highest priority.*[20]

SDG&E's evaluation should be conducted transparently, similar to Pacific Gas and Electric's (PG&E) North Coast Resiliency Initiative.[21] Further, when microgrids are included in the portfolio of solutions SDG&E should be required to conduct an open bidding process that encourages local government participation so as to gain the benefits of competition and associated cost-savings. For this reason, SBUA proposes that SDG&E be denied authorization of any of its undergrounding costs for 2024 and beyond until it presents a transparent, complete assessment of options for mitigating wildfire risk in HFTDs that includes more extensive use of microgrids.

Q: Why should microgrids be considered for wider deployment to mitigate wildfire risk than what SDG&E has planned?

SDG&E has proposed to reduce wildfire risk by "hardening" its rural grid in High Fire Threat Districts. Undergrounding creates a number of problems, such as increased maintenance costs, seismic and flooding risks, and problems with excessive heat, including exploding

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[20] See https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB1339

[21] CPUC, "Introduction to the North Coast Resiliency Initiative Workshop," https://www.cpuc.ca.gov/events-and-meetings/north-coast-resiliency-initiative-workshop-05-13-2022, May 13, 2022.

underground vaults.[22] Even setting aside those issues, the costs would be extraordinary, likely approaching $2 billion by 2027.

An economically attractive alternative to this expensive path would be to shift rural service to microgrids during high wildfire risk periods. These microgrids could serve communities, farms, businesses, and isolated homes expeditiously while saving money. Distribution outages in California have occurred about three times more often than transmission system outages.[23] Rural customers are twice as likely to experience outages as the system average.[24] Microgrids are easier to maintain and provide reliability independent of transmission and generation by distributing backup generation amongst the distribution system. Finding a fault in an underground line is difficult, especially in long stretches. Microgrids can eliminate this challenge and allow for extended outages on distribution lines, while ensuring customers have continued power service.

Any solution must provide reasonable reliability in a manner that also supports resilience for rural customers who are often electric-only or have operations that do not tolerate interruptions

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[22] Chris Gajeck, "Underground Electrical Vaults: Safety Concerns and Controls," *Incident Prevention*, https://incident-prevention.com/ip-articles/underground-electrical-vaults-safety-concerns-and-controls, 2016; Joel Ravang, "Overhead vs. Underground," Ram LLC, http://www.ramutilities.com/overhead-vs-underground.html, retrieved June 2022; Clarion Energy Content Directors, "Underground vs. Overhead: Power Line Installation-Cost Comparison and Mitigation," *Power Grid International,* https://www.power-grid.com/td/underground-vs-overhead-power-line-installation-cost-comparison/, February 2013.

[23] Based on comparing the Customer Average Interruption Duration Index (CAIDI) for 2021 of 114.8 minutes to the National Electricity Reliability Corporation reliability standard of one hour of outage in 10,000. See SDG&E, "How We Measure Electric Reliability," https://www.sdge.com/system-reliability, retrieved March 2023.

[24] Richard McCann, "Prepared Direct Testimony of Richard McCann, Ph.D. on Marginal Costs, Revenue Allocation, And Rate Design Issues on Behalf of the Agricultural Energy Consumers Association," PG&E 2011 GRC, A.10-03-014, October 6, 2010, pp. 16-19.

well. Outages in an underground system that take at least twice as long to fix – even longer for rural service – than overhead systems would further pressure customers financially.

Microgrids confer an additional advantage through their flexibility to serve augmented loads without substantial pre-planning and investment. As customers electrify their buildings, vehicles and equipment to help the state achieve its greenhouse gas reduction goals, microgrids enable local generation and storage to be added without the need to expand the rural distribution network, whether underground or overhead.

Q: Is using microgrids a cheaper wildfire mitigation solution instead of undergrounding?

Microgrids mitigate wildfire risk by enabling the utility to turn off distribution service for extended periods, upwards of weeks at a time, during the highest fire risk periods. Periodically islanded microgrids are well suited to wildfire mitigation because,

1) High fire risk times coincide with the most productive solar generation, with ample local energy available;[25] and

2) Microgrids can be used during winter storms to better support the local grid and to ride out shorter outages. As with public safety power shutoffs (PSPS), these outages are distribution system related. Providing generation closer to loads will reduce the scope of these types of outages.

[25] The highest wildfire risk periods occur during the sunniest weather. Photovoltaic supported systems should have sufficient energy when they are needed, given that Public Safety Power Shutoffs (PSPS) and Red Flag events rarely last for more than a few days.

In cases where a customer or community is still connected to the main grid most of the time, only being islanded during fire risk periods, the microgrid will be available to supply power when the distribution system has a random outage.

Q: How does the cost-effectiveness of microgrids compare to undergrounding?

Because microgrids would be installed solely for the purpose of displacing undergrounding in this situation, SBUA ignored other ancillary benefits, such as distribution deferral, increase resiliency, and local renewable generation. While these are valuable assets, they add complexity to the analysis, which can speak for itself without them.[26] The relative costs of the two options— undergrounding or microgrids – can be compared without considering any other services such as energy delivered outside of periods of fire risk or outages or increased green power. That is, the cost comparison ignores the energy benefits (and emission reductions) created for customers from microgrids and treats the two alternatives simply as though they are wires for delivering electricity.

One of microgrids' strengths is that they can be arrayed in a diversity of configurations and sizes with the ability to be modified as needed. NREL published estimated costs for at least five different configurations for customer-direct systems that do not use the larger utility grid and can serve communities, industrial plants, commercial operations, farms and residences. This analysis presents two bracketing cases for meeting the needs of a small rural community and an individual remote residence, but each circuit or feeder could have a mix of microgrid formations that cannot be anticipated without detailed study of each grid segment.

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[26] These benefits should be considered in a more complete analysis of these options. This testimony is only establishing a frame for the Commission to order SDG&E to undertake this effort. Such an analysis is beyond the capability of an intervenor to undertake without full cooperation of SDG&E.

The two configurations are:

(1) commercial or community scale projects with 1 MW of solar and a 600-kW battery with 2.4 MWh of storage; and

(2) residential scale of 7 kW with a 5-kW battery with 12.5 kWh of storage.[27]

NREL estimates between $1.85 to $1.9 million for the larger configuration; an upper end approximation double NREL's top range is included in this analysis. For a single residence, the NREL study quotes $34,000 to $37,000.[28]

Cost information from SDG&E and NREL enable comparisons between undergrounding or installing microgrids based on the density of customers or energy use per mile of targeted distribution lines. In other words, it can be determined if it is more cost-effective to underground distribution lines or install microgrids based on how many customers or how much load is being served on a specific line.

As one benchmark, SDG&E's average overall system density per mile of distribution line is 63 customers and 312 kW (or 0.312 MW) of noncoincident demand.[29] SDG&E reports that about 15% of its line miles are in HFTDs.[30].

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[27] Ramasamy, et al, (2021).

[28] The comparisons look only at each of these alternatives separately without determining an overall mix on a grid segment as stated previously.

[29] Revised Prepared Direct Testimony Of Tyson Swetek (Electric Distribution O&M), Exhibit SDG&E-12-R; and California Energy Commission, 2020 Integrated Resource Plan, CEDU 2020 Baseline Forecast - LSE and BA Tables Mid Demand Case, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=20-IEPR-03, March 2021.

[30] SDG&E, *2022 Wildfire Mitigation Plan Update*, p.213.

The two figures below illustrate how to evaluate the opportunities for microgrids to address wildfire mitigation as compared with distribution undergrounding. The figures show the relative cost effectiveness for undergrounding compared to the two examples of community/commercial and residential microgrids. If the load density falls below the value shown, microgrids are more cost effective.

Figure SBUA-1 reflects community scale microgrids, using NREL study estimates.[31] It shows how the cost effectiveness of installing microgrids changes with the density of peak loads on a circuit on the vertical axis, cost per mile for undergrounding on the horizontal axis, with each line showing where undergrounding is less expensive (above) or microgrids are less expensive (below) based on the cost of undergrounding. As a benchmark, the dotted line shows the average load density in HFTD areas. A community microgrid dominates undergrounding as the preferred choice when load density falls below 1.5 MW per mile. Undergrounding is only preferred in the high microgrid cost scenario with a load density above 3 MW per mile.

[31] Ramasamy (2021).

Figure SBUA-1

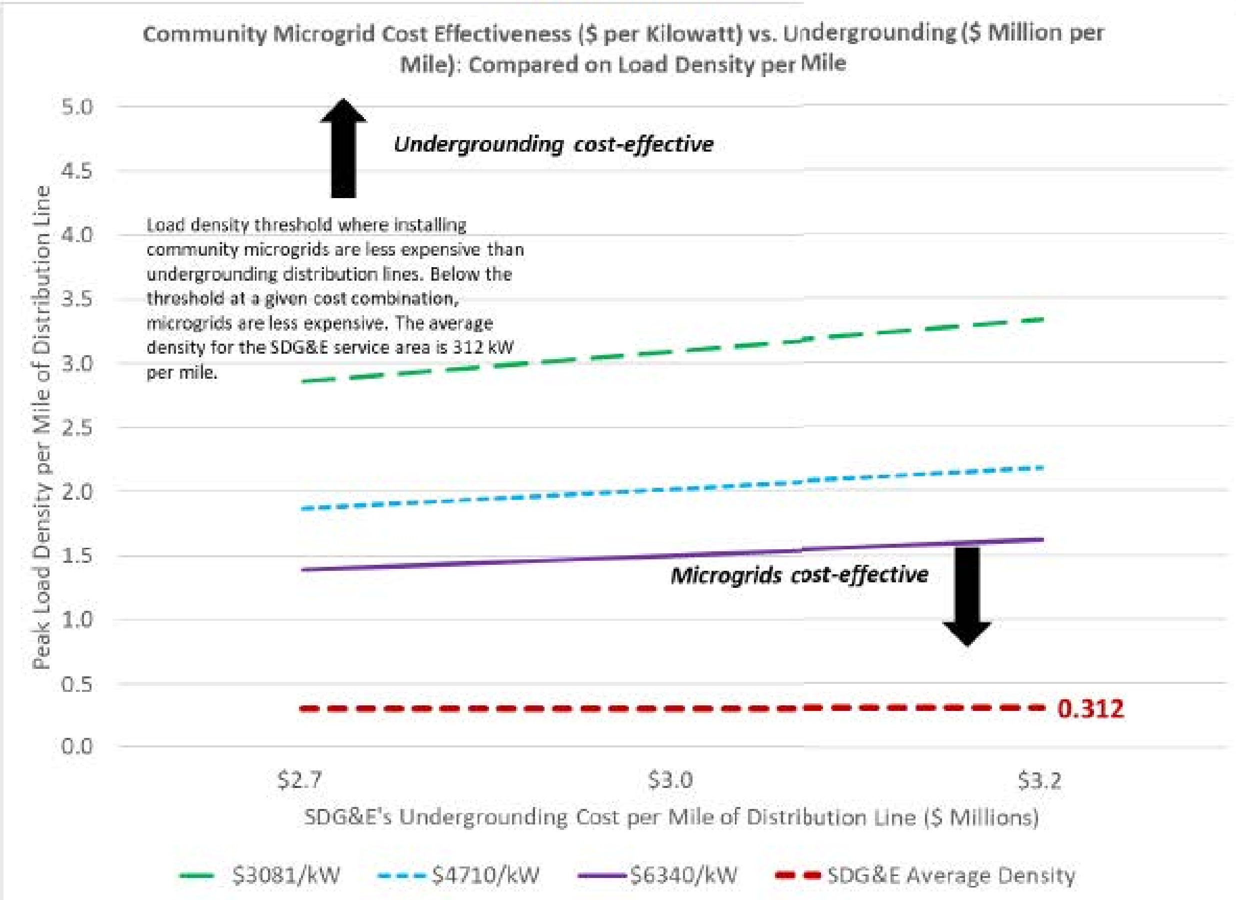
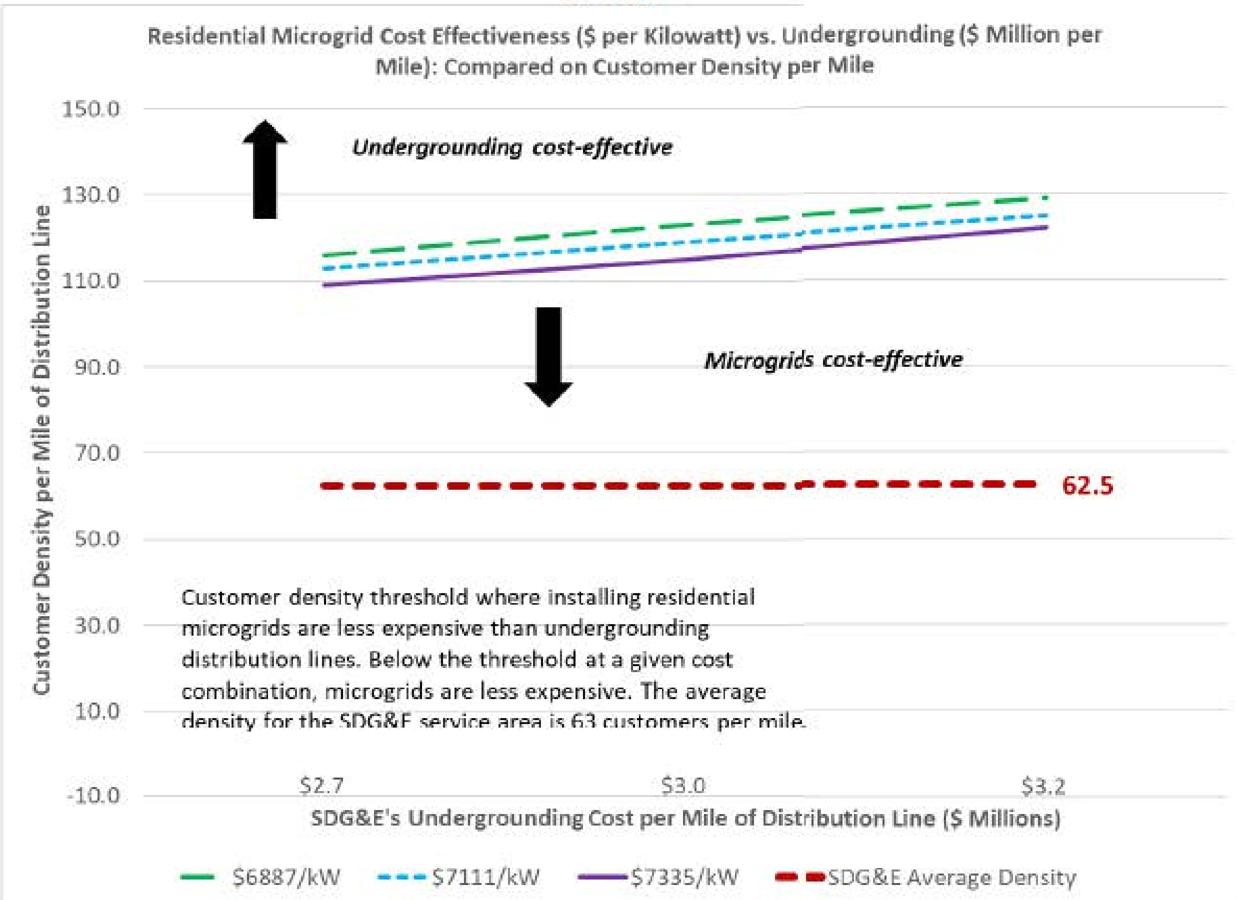


Figure SBUA-2 evaluates individual residential scale microgrids, again using NREL estimates.[32] Similar to the community scale example, it shows how the cost effectiveness of installing microgrids changes with customer density on a circuit on the vertical axis, cost per kilowatt for a microgrid on the horizontal axis, with each line reflecting where undergrounding is less expensive (above) or microgrids are less costly (below). As a benchmark, the dotted line shows average customer density in HFTDs. Residential microgrids are less expensive in most situations, especially as density falls below 100 customers per mile. Undergrounding is preferred when

[32] Ramasamy (2021).

density rises above 130 customers per mile. It is quite likely that the same conclusions will hold for microgrids serving individual farms or businesses.

SBUA-2



Based on these analyses, implementing community-scale microgrids appear to have the potential to save 70% to 95% over the costs of undergrounding. Residential scale microgrids look to save 80%. Even with a substantial margin for uncertainty, this option appears much less expensive than the undergrounding proposed by SDG&E.

Q: Can microgrids be implemented as quickly as undergrounding?

The important question is whether microgrids can be deployed more rapidly than undergrounding, and whether SDG&E has the capacity to manage such a buildout at a faster rate.

Acting alone SDG&E may not have the ability to construct either microgrids or install undergrounded lines and other grid hardening measures in a timely manner. A more cost-effective pathway would be to engage local governments in a collaborative effort to identify the best locations to construct and manage these microgrids. The rapid buildout of California's solar rooftop fleet shows how quickly such a distributed construction program can perform.[33]

This approach would be akin to the way in which the Department of Transportation (Caltrans) delegates construction and maintenance on many state-owned roads to counties and cities through which those roads pass. Community microgrids could be operated under several different models, including SDG&E, municipal ownership, a joint powers authority such as a community choice aggregator (CCA) or even a homeowner's association. Local government administration is likely to be more cost-effective and responsive than a centralized approach and allow for tailoring to match home-grown circumstances rather than trying to impose lockstep operational standards and protocols. Microgrids serving individual customers in small businesses, farms and residences would be operated remotely.

Q: What are the rate impacts of each option?

Table SBUA-4 compares the incremental revenue requirements for 2022 to 2027 for (1) undergrounding as proposed in the Wildfire Management Plan Update, (2) installing only residential microgrids instead, and (3) installing only community microgrids. The percentage increase over base 2022 rates excluding these costs.[34] Pursuing SDG&E's undergrounding plan

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[33] "California Distributed Generation Statistics," https://www.californiadgstats.ca.gov/

[34] Undergrounding revenue requirements are shown for all three cases for 2022 and 2023 as those costs are considered committed.

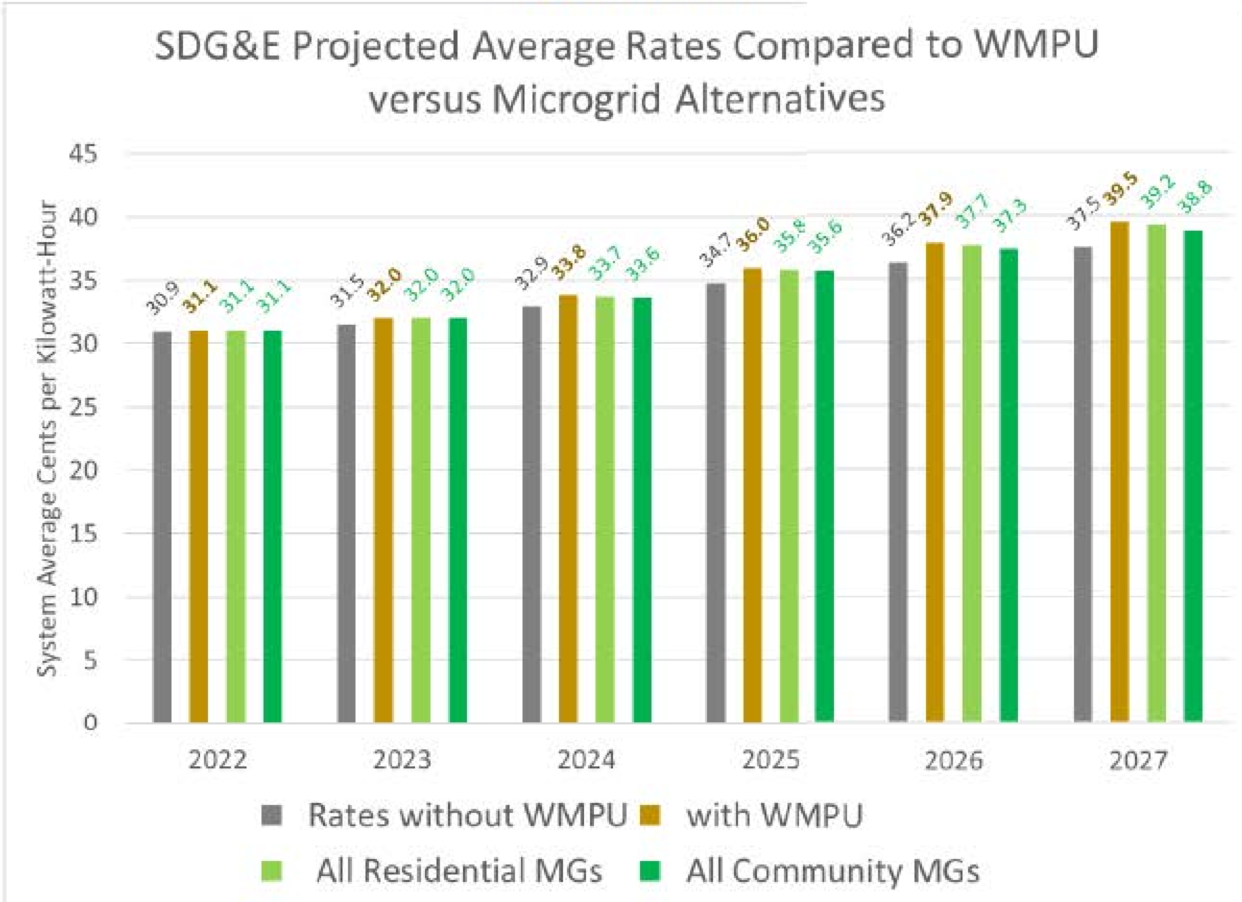
increases rates an additional 5.0% by 2027. Installing residential microgrids at SDG&E's cost of capital increases rates 4.3%; implementing community microgrids raises rates 3.3%. The annual savings are nearly $100 million for community microgrids in this scenario.

Table SBUA-4: Comparison of Revenue Requirements for Distribution Hardening Options

Options	2022	2023	2024	2025	2026	2027
UG RRQ	$24	$68	$119	$171	$222	$274
Increase over 2022	*0.6%*	*1.6%*	*2.6%*	*3.5%*	*4.3%*	*5.0%*
Residential MG RRQ	$24	$68	$110	$151	$193	$234
Increase over 2022	*0.6%*	*1.6%*	*2.4%*	*3.1%*	*3.7%*	*4.3%*
Community MG RRQ	$24	$68	$95	$123	$151	$178
Increase over 2022	*0.6%*	*1.6%*	*2.1%*	*2.5%*	*2.9%*	*3.3%*

Figure SBUA-4 illustrates the differences in rate impacts across the three options. The figure shows the projected system average rates from 2022 to 2027 starting with excluding any hardening expenditures, and then adding the increment associated with undergrounding, residential microgrids, or commercial microgrids. By 2027, average rates rise to 39.5 cents per kWh with undergrounding or 27% above 2022 rates. Relying on community microgrids instead reduces that rate to 38.8 cents per kilowatt-hour for a savings of 1.7%.

Figure SBUA-4



VII. BACKUP GENERATION, MICROGRIDS AND IMPROVED RELIABILITY

Q: Does a large population of individually-owned generation sets in San Diego suggest reliability concerns?

SBUA is concerned that, despite CARB's ambitious goals to reduce fossil fuel use, SDG&E's implicitly or explicitly relies on backup generators (BUGs) as the backbone of its reliability strategy.[35] Under the utility's Resiliency Assistance Program (GAP) customers are

[35] By 2045 CARB proposes to cut statewide greenhouse gas emissions by 85% below 1990 levels, with a 71% reduction in smog-forming air pollution; and decrease fossil fuel consumption (liquid petroleum) to less than one-tenth of present use, a 94% demand decline.

provided a $300 rebate on the purchase of a qualified fuel generator; a $100 rebate on the acquisition of a portable power station. GAP has induced the acquisition of more than 2,000 fuel generators and in excess of 70 portable power stations.[36] In addition to immediately contributing to polluting air emissions, the RAP program embeds premature obsolescence into SDG&E's and its customers' energy management protocols, at no small cost.

These ratepayer-subsidized fossil-fueled distributed generators are in addition to the 3,364 BUGs permitted in San Diego County Air Pollution Control District's (SDCAPCD) service territory, which have a total electricity production capacity of more than one gigawatt (GW). The collective generating size of permitted BUGs alone, excluding the RAP program, is about one-quarter the size of SDG&E's total peak demand.[37]

Q: What are the characteristics of BUGs in the SDG&E service territory?

Roughly 85 percent of the BUGs are diesel-powered, with an average capacity of 356 kilowatts (kW) as shown in Figure SBUA-5. Figure SBUA-6 shows that the next most popular fuel is natural gas – seven percent of the portfolio, with an average size of 121 kW – followed by propane; 4 percent of the population, averaging 77 kW.

[36] Data Request Number SBUA-SDGE-001, 11/21/2022.

[37] Federal Energy Regulatory Commission Form 1.4

Figure SBUA-5

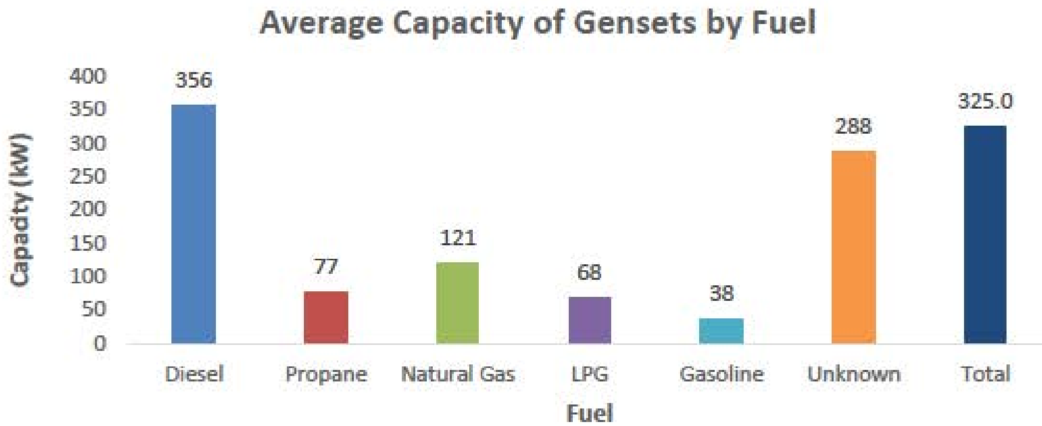
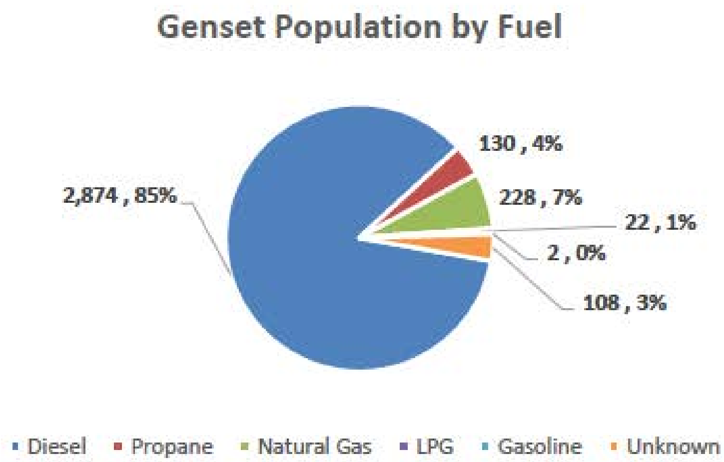


Figure SBUA-6



Over the past year the genset portfolio in the District has collectively operated for more than 31,000 hours, generating more than 10 GW/hours of electricity and in excess of 8,400 tons of carbon dioxide (CO_2).[38,39] Most BUGs run on average just 13 hours per year, an indication of how they might be redeployed as part of a more intentional, cost-effective, microgrid strategy.

The maps below show where BUGs are located in SDCAPCD's service territory in relationship to CalEnviroScreen, a mapping tool that identifies communities that are most affected by multiple pollution sources and where people are often especially vulnerable to pollution's effects. As indicated in the maps, BUGs are often sited in disadvantaged communities.

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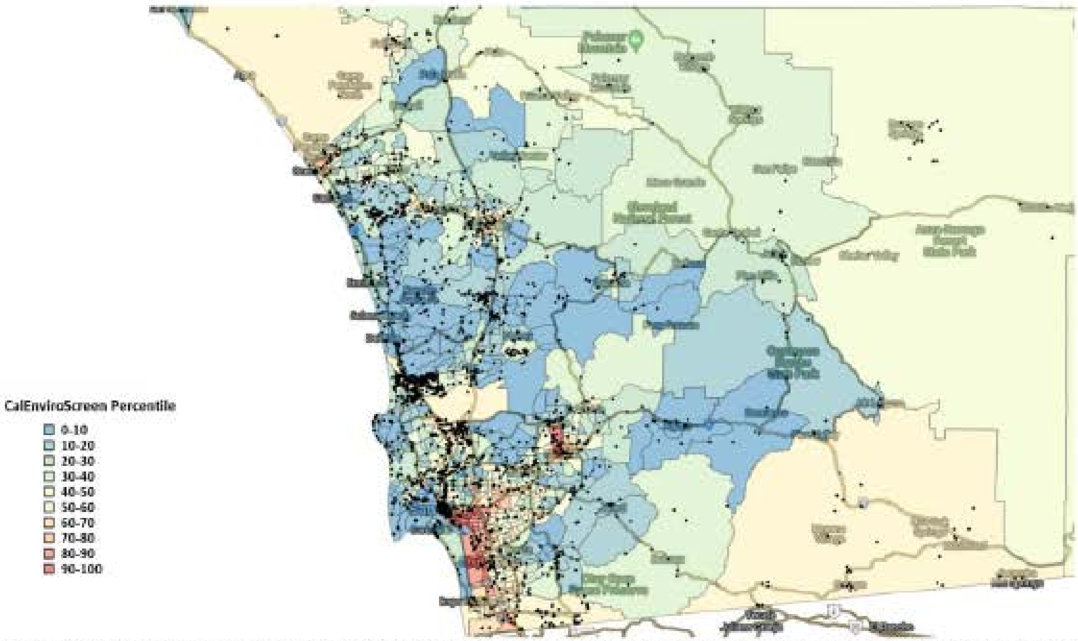
[38] Operating and emissions estimates should be considered lower bounds. Operating hours were not reported for about 25 percent of the gensets included in the data provided by the District in response to a public records request. Recorded hours appear to be metered actuals according to the District, which stated that, "If there is no reading, then there were no new readings during inspections for that time period or proper records were not maintained by the facility. Readings are done at any inspections completed by our Compliance team."

[39] The California Air Resources Board maintains genset emission estimates; matching these data with field conditions and generator types can be challenging. An alternative estimation approach would rely on Air Pollutant 42 averages, which would require genset performance assumptions and may be less accurate.

Figure SBUA-7

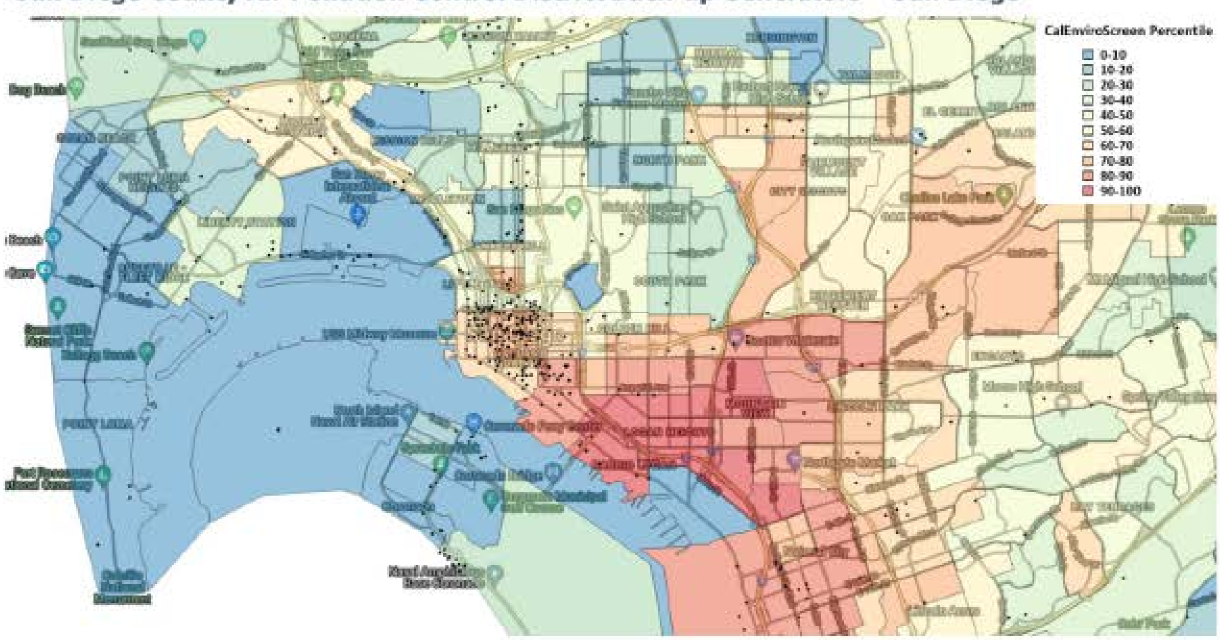
San Diego County Air Pollution Control District Back-up Generators



There are almost 3,300 BUGs capable of generating 1.08 GW in San Diego County. The map shows the siting of these generators in the context of CalEnviroScreen; red/orange indicates the most environmental burdened, vulnerable communities, blue/green the least.

Figure SBUA-8

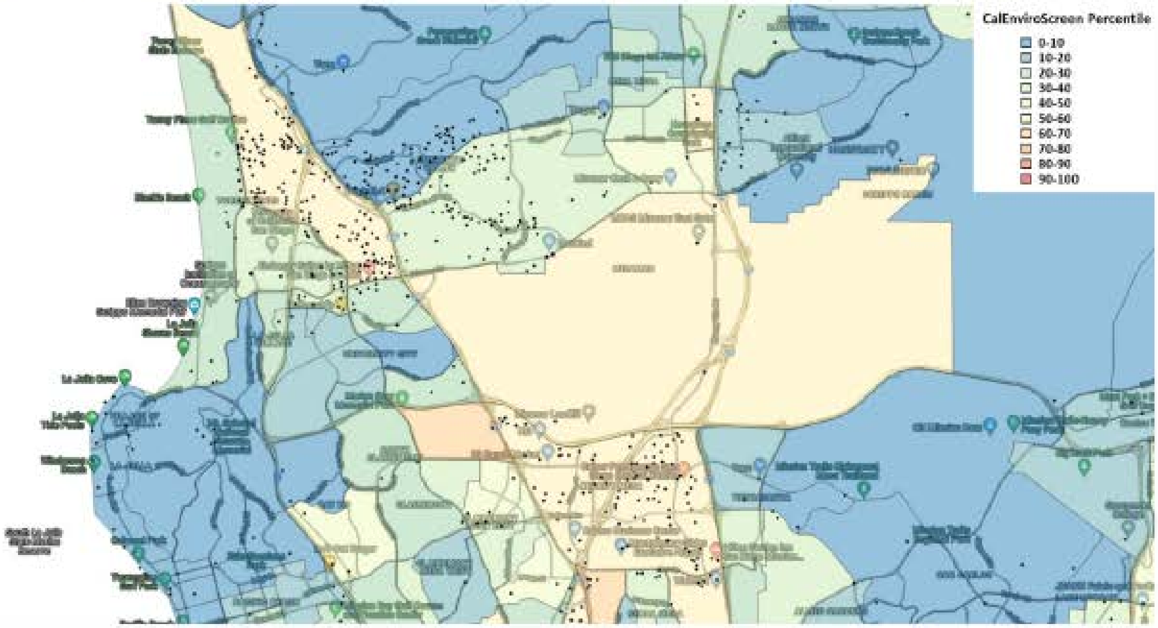
San Diego County Air Pollution Control District Back-up Generators – San Diego



Map of back-up generators in San Diego overlayed on CalEnviroScreen classifications for environmental justice communities – red/orange indicates most burdened communities (80-100th percentile for CalEnviroScreen) and blue/green indicates least burdened communities (0-20th percentile for CalEnviroScreen)

Figure SBUA-9

San Diego County Air Pollution Control District Back-up Generators – University City



Map of back-up generators in University City overlayed on CalEnviroScreen classifications for environmental justice communities – red/orange indicates most burdened communities (80-100th percentile for CalEnviroScreen) and blue/green indicates least burdened communities (0-20th percentile for CalEnviroScreen)

Although existing BUGs should be repurposed to provide greater resiliency benefits, as discussed below, SBUA recommends that SDG&E replace its RAP program for commercial class customers with a more environmentally benign resiliency strategy that relies on deployment of storage devices, including vehicle-to-grid technologies. That is, rebates should be offered to different size batteries and support necessary electric panel upgrades as backup resources.

Q: How can the use of microgrids and BUGs be integrated to improve the environment and lower rates?

SDG&E should collaborate with SDCAPCD to develop a strategy to initially leverage existing BUGs as reliability assets, by explicitly accounting for them as part of reliability planning and identifying ways in which their excess capacity can be used to socialize resiliency. By the end of this decade deployment of fossil fuel BUGs should be discouraged by the availability of and Commission support for solar, storage, and other measures. As part of this strategy a pilot program oriented towards small commercial customers should be developed that leverages existing BUGs in service of implementing microgrids as a reliability, distribution-deferral, and wildfire mitigation strategy.

VIII. CUSTOMER SERVICE EXPENDITURES

Q: Is SoCalGas' request for increased customer service call expenditures justified?

Southern California Gas Company (SoCalGas) requests notable funding increases for customer support and associated services based on a handful of buzzwords and unsubstantiated workload forecasts. For example, the utility states that it is requesting additional budget to better serve "A diverse customer base with evolving expectations regarding their available options to contact SoCalGas."[40] In a data request (DR) SBUA asked,

> *Please explain how expectations are evolving, and what SoCalGas is doing to address new expectations…How does a diverse customer base newly influence operations? Is customer diversity increasing?*

SoCalGas' response was,

> *As customer interaction preferences evolve, SoCalGas is implementing new ways to meet evolving customer preferences and expectations. For example: Billing delivery is offered via mail or electronically. Payment can be made electronically, and customers can interact via live person or Interactive Voice Recognition channel.*[41]

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[40] Bernardita M. Sides, BMS-iv, bullet one.

[41] Data Request Number: SBUA-SOCALGAS-002 Proceeding Name: A2205015_016 - SoCalGas and SDGE 2024 GRC Publish To: Small Business Utility Advocates Date Received: 10/6/2022 Date Responded: 10/19/2022.

Electronic bill paying has been available to customers in most industries for at least 20 years,[42] while voice technology has existing for more than thrice that long.[43] Artificial Intelligence (AI) is fast overtaking basic Interactive Recognition channels. These are hardly "new ways to meet evolving customer preferences and expectations," nor have they emerged as a response to increasing customer diversity.

SoCalGas' use of these approaches is neither innovative, nor should it merit a budget increase. In addition, at least in the case of commercial class customers, the utility can offer no evidence that ratepayers consider this service to be an improvement:

> *SoCalGas has no specific supporting information from research or surveys with SoCalGas's small/medium business customers that view Conversational Interactive Voice Recognition as an improvement.*[44]

Likewise, as indicated in Figures SBUA-10 and SBUA-11, SoCalGas deploys forecasts for which there appears to be little empirical basis to attempt to support program budgets, and associated requested increases.[45] For example, both recorded volume of emergency calls and safety

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[42] Lawrence J. Radecki and John Wenninger, "Paying Electronic Bills Electronically," *Current Issues in Economics and Finance*, Federal Reserve Bank of New York, 5:1, https://www.newyorkfed.org/medialibrary/media/research/current_issues/ci5-1.pdf, January 1999.

[43] Samantha Silver, "A History of Voice Technology," Key Lime Interactive, https://info.keylimeinteractive.com/history-of-voice-technology, August 21, 2020.

[44] Data Request Number: SBUA-SOCALGAS-002 Proceeding Name: A2205015_016 - SoCalGas and SDGE 2024 GRC Publish To: Small Business Utility Advocates Date Received: 10/27/2022 Date Responded: 11/4/2022.

[45] "Proceeding Name: A2205015_016 - SoCalGas and SDGE 2024 GRC Publish To: Small Business Utility Advocates Date Received: 10/6/2022 Date Responded: 10/19/2022."

related orders have steeply declined over the past several years. Yet for both services SoCalGas predicts a "dead cat bounce" to higher demand levels.

Figure SBUA-10

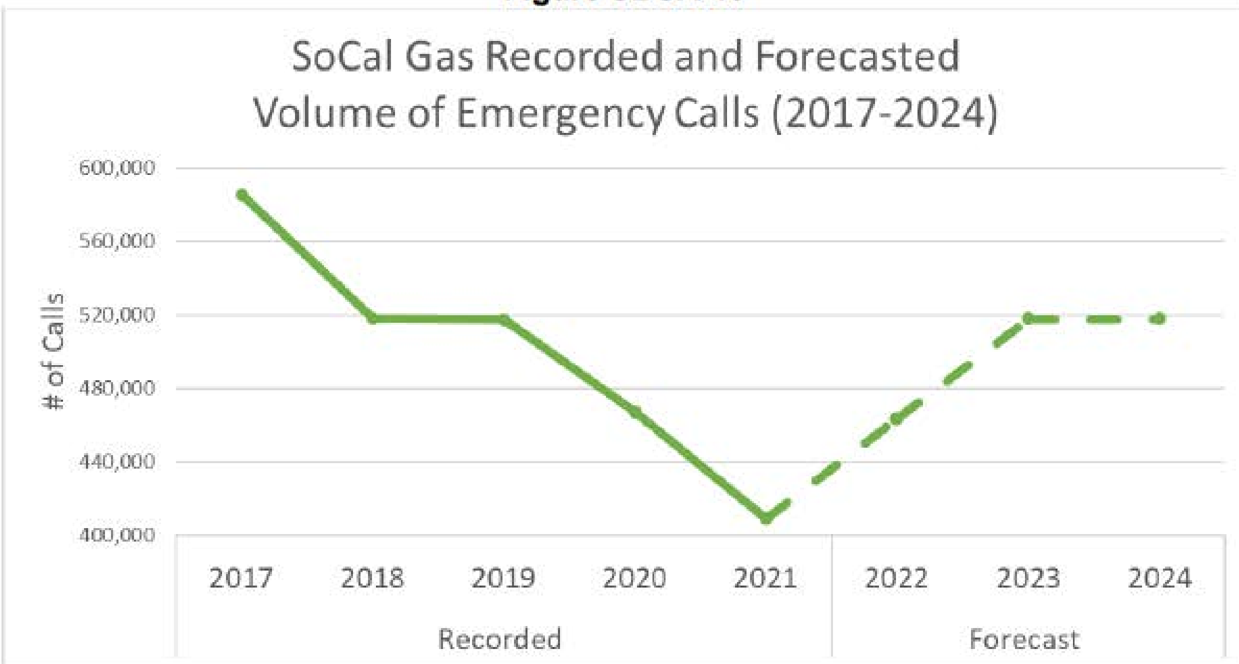

Figure SBUA-11

SoCalGas has offered insufficient evidence that its requests for increases for customer support and associated services are merited. Instead, a budget decrease in these elements is merited based on improvements the utility has apparently made in addressing the cause of emergency calls and safety-related orders.

Q: Is SDG&E's request for increased customer service call expenditures justified?

Although more reasonable for the residential class, SDG&E similarly projects a rosy scenario for increases in business customer call volume, as indicated in Table SBUA-5 below.[46] Service calls by business customers show a distinct downward trend for 2018-2021.[47] No reason is provided for why this trend is expected to suddenly reverse, just as is the case for the forecasts of emergency calls and safety orders. Seemingly, SDG&E is assuming that its customer experience will degrade in the near future and the solution is to provide more service call support rather than addressing the underlying causes for these unexplained reversals.

Table SBUA-5

SDG&E ESS Historical Call Volume by Residential and Business Customer Class (2018 – 2024)

Year	Total ESS Calls	Residential	Business
2018	1,504,660	1,380,904	123,756
2019	1,587,054	1,469,714	117,340
2020	1,521,589	1,432,788	88,801
2021	1,450,943	1,370,835	80,108
2022 (FCT)	*1,462,995*	*841,223*	*61,568*
2023 (FCT)	*1,476,577*	*1,376,998*	*103,360*
2024 (FCT)	*1,491,247*	*1,386,860*	*104,387*

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[46] *Id.*

[47] The call volumes in 2022 for residential and business do not match the overall total and do not fit with the trends for the other years.

The Company's own data does not support provision of additional funds in the manner it requests. In this context, and as bolstered by the previously discussed need to rationalize underlying budgeting processes, SBUA recommends that any additional funds be spent collecting and analyzing customer satisfaction and needs data, specifically small business clients, to identify and determine ways to properly address service gaps. In general, SBUA proposes that future customer service budgets (for small businesses) be based on these types of data, much of which can be gathered as part of customer interactions, with supplemental surveys conducted as needed. The data collected should focus on how best to connect available programs and information to small business customers to enable them to better manage their utility bills.

IX. CONCLUSION

Based on the analyses contained herein, SBUA recommends that the Commission adopt the following findings in this proceeding:

1. Require the utilities to adopt and consistently implement no more than two budgeting approaches, one being zero-based, in all future applications.
2. Require the utilities to propose and apply an affordability benchmark for small commercial class customers in their next GRC.
3. Require the utilities to fully evaluate deployment of microgrids to cost effectively displace portions of the distribution grid that are at-risk to wildfires, improve local reliability, and replace natural gas lines while reducing GHG emissions before Commission authorization of undergrounding or other grid hardening approaches. SDG&E should be denied authorization of any of its undergrounding costs for 2024 and beyond until it presents a

transparent, complete assessment of the options for mitigating wildfire risk in these HFTDs that includes more extensive use of microgrids.

4. Redirect proposed additional funds for customer service and safety calls to properly assess and budget for small business customer service needs.

5. Require the utilities to propose a zero-emission rebate program for backup power, which could be incorporated in vehicle integration or other appropriate rates.

6. Require the utilities to propose a plan to incorporate existing fossil fuel BUGs into their reliability planning, including developing a short-term plan to leverage them to provide societal benefits, and long-term plan to replace them with zero-emission resources, including a pilot program that focuses on small commercial customers.

ATTACHMENTS

ATTACHMENT A

Statement of Qualifications: Richard McCann, Ph.D. & Steven J. Moss, MPP

POLICY ANALYSIS FOR THE PUBLIC AND PRIVATE SECTORS

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

Dr. McCann specializes in environmental and energy resource economics and policy. He has 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.

Selected Projects

- **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 (CPUC), California Energy Commission, and California State Legislature.
- **Utilities Cost of Capital Testimony, Environmental Defense Fund (2019-present).** Testified at the California Public Utilities Commission in the four 2020 Cost of Capital applications and the 2022 Accelerated Cost of Capital Applications.
- **Regulatory Analysis and Support, Joint Community Choice Aggregators (2018-present).** Testified at the CPUC (CPUC) in Pacific Gas and Electric's (PG&E) rate proceedings on the power charge indifference adjustment (PCIA) "exit" fee and other issues. Provides regulatory support. The Joint CCAs include Sonoma Clean Power, East Bay Community Energy, Peninsula Clean Energy, Pioneer Community Energy, Monterey Bay Community Power, Silicon Valley Clean Energy, and Marin Clean Energy.
- **Regulatory Analysis and Support, Sonoma Clean Power (2016-present).** Testified at the CPUC (CPUC) in Pacific Gas and Electric's (PG&E) rate proceedings on the power charge indifference adjustment (PCIA) "exit" fee and other issues.
- **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.
- **Master-Meter Rate Setting Testimony and Regulatory Support, Western Manufactured Housing Communities Association (1998-present).** 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.

- **Testimony on Southern California Edison 2018 General Rate Case, Small Business Utility Advocates. (2018-2019).** Testified on proposed distribution system spending plan in SCE's GRC application.
- **Net Energy Metering Rate Setting for Kentucky Power, Kentucky Solar Energy Industry Association (2021).** Testified before the Kentucky Public Service Commission on the appropriate principles for setting net energy metering rates.
- **Regulatory Analysis and Support, California Community Choice Aggregators (2018-2019).** Testified at the CPUC (CPUC) in CPUC rulemakings on the power charge indifference adjustment (PCIA) "exit" fee and resource adequacy requirements.
- **Regulatory Analysis and Support, CalChoice (2017-2019).** Testified at the CPUC (CPUC) in Southern California Edison's (SCE) rate proceedings on the power charge indifference adjustment (PCIA) "exit" fee and other issues.
- **Testimony on Protecting Solar Project Investment by Customers, County of Santa Clara (2017-2019).** Testified at the CPUC (CPUC) in Pacific Gas and Electric's (PG&E) rate proceedings on the RES-BCT tariff provided to public agencies using renewable generation to supply their own accounts. The testimony addressed the appropriate rate structures for these projects in the context of state policy.
- **Electricity Research & Development Strategic Plan and Roadmap for Sacramento Municipal Utility District (2015-2016).** Reviewed SMUD's ERD Strategic Plan to reflect the changing electric utility environment.
- **Aggregating Agricultural Accounts to Facilitate Load Management, Agricultural Energy Consumers Association (2012-2017).** Analyzed load and billing data from pilot programs to assess the potential load reductions in the PG&E and SCE service area if agricultural customers were given the on-line tools and the rate incentives to manage all of their individual loads as aggregated sets of loads.
- **Davis Community Choice Advisory Committee, City of Davis (2014).** Served on City-appointed committee to assess options for creating a community choice aggregation utility for the City or Yolo County.
- **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.
- **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, CPUC Energy Division (2011-2012).** Reviewed California Independent System Operator (CAISO) and three utilities' resource acquisition plans out to 2020.
- **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.
- **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.
- **Agricultural Engine Conversion Program, Agricultural Energy Consumers Association (2005).** Testified before the CPUC on program to convert agricultural diesel engines to electricity. The adopted program led to the conversion of 2,000 pumps in the San Joaquin Valley. (A.04-11-007 and A.04-11-008)
- **Statewide Pricing Pilot, Track B Analysis, CPUC (2003-2005).** Developed experimental program to examine whether providing educational "treatments" communicated through a community-based organization in an environmentally-impacted neighborhood enhanced responses to critical peak pricing among residential energy users.
- **Environmental Performance Report Hydropower Relicensing Cost Evaluation, California Energy Commission (2003).** Developed estimates of lost value and incurred costs for California hydropower facilities subject to relicensing.
- **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.
- **PG&E Hydro Divestiture EIR, CPUC (2000).** Evaluated the environmental impacts from divesting hydropower facilities and related lands by Pacific Gas and Electric Company
- **Thermal Power Plant Divestitures Environmental Assessments, CPUC (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.
- **Gas Pipeline Need Assessment, South Coast Air Quality Management District (1989).** Prepared analysis and testimony presented to the CPUC on the need for additional interstate natural gas pipeline capacity to implement the Liquid and Solid Fuel Phase-out Policy for the South Coast Air Quality Management District. Developed a probabilistic gas shortage model based on weather and hydrological conditions, using results from the Elfin electric generation simulation model.
- **Rancho Seco NGS Evaluation, Sacramento Municipal Utility District (1988).** Independently reviewed resource planning alternatives and recommended action on Rancho Seco NGS operations, for SMUD QUEST Team.

- **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 Development Forecast, Sacramento Municipal Utility District (1988).** Identified and assessed the viability of qualifying facilities (QF) projects in PG&E's service territory — particularly in the San Joaquin Valley — through database searches and telephone survey.
- **Plant Closure Testimony, Cook County State's Attorney (1988).** Testified on savings from closure of coal-fired plants, based on Elfin production-cost model runs, before the Illinois Commerce Commission.
- **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.

Manufactured Housing Communities Utility Issues

Skills: Master-Metered Utilities Rate Design and Analysis, Rent Control Proceedings Testimony

Professional Affiliations

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

Civic Activities

- City of Davis 2020 Environmental Recognition Award
- Member, City of Davis Natural Resources Commission
- Former member, City of Davis Utilities Rates Advisory Commission
- Former member, City of Davis Community Choice Energy Advisory Committee
- Co-Chair, City of Davis / Cool Davis Georgetown University Energy Prize Implementation Task Force
- Member, Western Manufactured Housing Communities Association Utilities Task Force
- Former Member, City of Davis Citizens Electricity Restructuring Task Force
- Former Member, Yolo County Housing Commission

M.CUBED
POLICY ANALYSIS FOR THE PUBLIC AND PRIVATE SECTORS

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Mr. Moss specializes in environmental and energy resource economics, public policy analysis, and strategic advocacy. He's analyzed many different aspects of energy utility operations, and has developed and implemented a range of distributed energy resource programs (DER) in the context of research and development pilots. He worked with the California Energy Commission (CEC) to examine the distribution-level impacts of DER measures and launched the first demand-response aggregation pool in California oriented towards small enterprises. He led efforts on behalf of Agahozo Shalom Youth Village to develop what for a time was the largest solar photovoltaic facility in East Africa, and is engaged in sustainable/affordable housing development in Rwanda. He's actively participated in a number of California regulatory proceedings that focus on tariff development, distribution resource planning, and integrated demand side management, among other topics. He's worked in India, Niger, Rwanda, and Senegal.

Professional Experience

M.Cubed, Partner, 1993-present
Publisher, *The Potrero View*, 2006-present.
See Far Housing, Director, 2017-present.
San Francisco Community Power, Director, 2001-2014
San Francisco State University, Adjunct Lecturer, 1997-2010
Office of Technical Assistance, U.S. Treasury Department, Budget Advisor, 1997-1998; 2006-2008
Foster Associates/Spectrum Economics/QED Research, Senior Economist, 1988-1992
U.S. Congress, Committee Staff, 1987
U.S. Office of Management and Budget, 1985-1986

Academic Background

M.P.P., Institute of Public Policy Studies, University of Michigan, 1985
B.S., Conservation of Natural Resources, University of California, Berkeley, 1982

Selected Projects

Skills: Distributed Energy Resources Regulatory Analysis, Marketing, Valuation and Siting, including Renewables and Demand Response; Rates Analysis, Tariff Development and Revenue Allocation; Technology Cost Assessment; Regional Economic Analysis; Strategic Advising.

- **Local Government Energy Sustainability Coalition (2019 to present).** Monitored CEC and California Public Utilities Commission proceedings; provided monthly regulatory updates; and intervened in dockets associated with energy management issues.
- **Energy Regulatory Proceedings, Environmental Defense Fund (2012-2019).** Testified on how to catalyze greater DER penetration, particularly load-modifying resources, with an emphasis on tariff- and geographic-specific approaches. Examined methods to create distribution-level DER markets.
- **Pacific Gas and Electric Company (PG&E) General Rate Case (GRC) Intervention, Santa Clara County (2017-2018).** Led successful regulatory strategy to secure "grandfathered" rates for the Renewable Energy Self-Generation Bill Transfer program in PG&E's GRC Phase 2 proceeding.

- **Time Variant Rates, New York and California, Environmental Defense Fund (2013-2015).** Examined proposed time variant rates as part of regulatory processes in California and New York. Modeled how increased penetration of time of use rates in the residential sector for Consolidated Edison serving the New York City metropolitan area would reduce peak and energy demand, lower residential bills, and reduce utility costs.
- **Distributed Generation, Ignite (2015).** Helped identify financing for "solar suitcase" enterprise in Rwanda.
- **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.
- **Aggregating Agricultural Accounts to Facilitate Load Management, Agricultural Energy Consumers Association (2012-2017).** Analyzed load and billing data from nine farms with 368 accounts to assess the potential load reductions in the PG&E service area if agricultural customers were given the online tools and rate incentives to manage all of their individual loads as aggregated sets of loads. Continued with similar analysis in Southern California Edison's service territory, also based on nine farms, with an emphasis on examining the implications of greater electricity demand triggered by water scarcity.
- **Native American Energy and Water Issues, Round Valley, Ohkay Owinga and Ute Mountain Tribes (2014-present).** Examined economic viability of a small hydro-electric facility. Investigated viable energy projects, including renewables, as part of a water rights claim process.
- **Solar Facility, Agahozo-Shalom-Youth Village (2012-2014).** Helped develop an 8.5 megawatt solar array in Rwanda, the largest photovoltaic facility in East Africa.
- **Economic Implications of Water Scarcity, California Water Foundation (2012).** Examined the economic and fiscal implications of water scarcity on a number of state regions and industry sectors.
- **Residential Customer Segmentation, California Institute for Energy and the Environment (2010).** Examined best practices related to market segmentation to vend energy efficiency programs.
- **Equity Issues Associated with Greenhouse Gas Cap and Trade Programs, Environmental Defense Fund, (2008-2010).** Analyzed potential means to engage low income communities and small businesses in greenhouse gas reduction activities, including an examination of financing approaches.
- **Demand Response Regulatory Proceedings, San Francisco Community Power (2004-2008).** Examined issues associated with the structure of and cost related to various DR programs. Testified in proceedings on establishing DR programs catering to low-income communities and small businesses.
- **Renewable Energy Siting, San Francisco Community Power (2001-2005).** Helped households and small businesses site renewable facilities, taking advantage of local, state, and federal incentives. Assisted in the development of a 36 kilowatt solar array at an animal boarding facility, for a time the largest renewable project in San Francisco.
- **Distributed Energy Resources Distribution Feeder Research, California Energy Commission (2005-2008).** Developed and implemented a series of DER measures along two feeder lines in San Francisco, and examined the resulting implications to customers, the utility system, and the environment.
- **Economic Impacts of Assembly Bill 32, Environmental Defense Fund (2008).** Estimated the economic benefits of California's pioneering cap and trade legislation, including potential impacts on technological innovation.
- **Power Plant Closures, San Francisco Community Power, (2001-2008).** Identified, developed, and implemented a series of strategies to close two power plants in San Francisco, including engaging

community members and merchants in deploying conservation, efficiency, and load-shifting measures, and analyzing transmission alternatives.

- **Agricultural Engine Conversion Program, Agricultural Energy Consumers Association (2005).** Testified before the CPUC on program to convert agricultural diesel engines to electricity.
- **Statewide Pricing Pilot, Track B Analysis, California Public Utilities Commission (2003-2005).** Developed experimental program to examine whether providing educational "treatments" communicated through a community-based organization in an environmentally-impacted neighborhood enhanced responses to critical peak pricing among residential energy users.
- **Economic and Fiscal Implications of Affordable Housing, Silicon Valley Citizens for Affordable Housing (2004).** Examined the socio-economic benefits associated with access to affordable housing in Silicon Valley.
- **National Economic Impacts of the Child Care Sector, National Child Care Association (2002).** Estimated the economic benefits, including associated with increased productivity, of child care services.
- **Agricultural Electricity Rates Report, California Energy Commission (2001).** Studied how electricity rates in California impact agricultural energy costs given restructuring. This included a comparison with rates in neighboring states. Developed a broad range of policy proposals to improve agricultural energy management and to lower energy costs.

Professional Affiliations

Board member, Agahozo Shalom Youth Village (2010-2017)
Board member, Ignite (2014-2017)
Member, Equal Opportunity Council of San Francisco (2010-2011)
Candidate, San Francisco Board of Supervisors, District 10 (2010)
Member, Bay Area Air Quality Management District Community Air Risk Evaluation (2008-2010)
Member, California Energy Commission Public Interest Energy Research Distribution Program Committee (2008-2009)
Supervisor's Appointee, Power Plant Task Force (2002-2011)
Governor's Appointee, California Inspection and Maintenance Review Committee (1997-2001)

Awards

Fulbright Indo-American Environmental Leadership Fellow (2004)
Salzberg Seminar Fellow (2001)
Kellogg National Leadership Fellow (2000)
Presidential Management Intern, (1985-1987)
Lyndon B. Johnson Congressional Scholar (1981)

References

Jamie Fine, Senior Economist, Environmental Defense Fund, 415.293.6060, jfine@edf.org.
Irene Moosen, Solo Practitioner in legal, regulatory, strategic planning, and public policy analysis, 415.407.4781, irene@igc.org.
Scott Williams, Partner, Berkey Williams LLP, 510.548.7070, swilliams@berkeywilliams.com.

JI-DEK-DR-01-006

Comments on Washington Utilities NEM Evaluation-Draft Results Submitted by Richard McCann, Ph.D., M.Cubed on behalf of the Washington Solar Energy Industries Association

Comments on *Washington Utilities NEM Evaluation-Draft Results*

Submitted by Richard McCann, Ph.D., M.Cubed
on behalf of the Washington Solar Energy Industries Association

December 1, 2023

M.Cubed, founded in 1993, provides economic and public policy consulting services to public and private sector clients. Practice areas include water energy utility resource planning, ratemaking, water and resource use efficiency, conservation measures, project impact analysis, natural resource allocation policies, and environmental plan preparation and review. Dr. McCann has testified over 50 times on electricity, air quality, water supply and other regulatory and planning matters.

PREFACE

These comments address the draft report prepared by E3 Consulting on behalf of a consortium of Washington electric utilities to evaluate the State's net energy metering (NEM) program for customer-generators. M.Cubed has prepared these remarks on behalf of the Washington State Energy Industries (WASEIA).

There are significant flaws in the report's methodology and technical execution. The study's findings are not sufficiently substantiated, and often draw conclusions beyond both the scope and analysis of the study. Much more work is required before being able to arrive at a satisfactory resolution of the required analysis.

INTRODUCTION

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, have changed profoundly in the last 25 years. Hourly electricity markets have not delivered on their envisioned promises as 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 (DERs). These new technologies enable customers to produce their own energy and to substantially or fully escape reliance on the centralized utility grid. The era of the "prosumer" is upon us.

[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.

In the past several years, electricity systems have experienced several major multi-hour and multi-day 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 2020 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) public safety power shutoffs (PSPS) to mitigate potential wildfire hazards in California utilities' service areas, sometimes lasting for days at a time;[3] and (3) widespread rolling outages in Texas caused by extreme freezing weather.[4]

These emerging and challenging cost-of-service consequences are not adequately captured in this study which crams the prosumer into the old paradigm previously discussed. We recommend the State avoid committing to a single specific approach that will have to be soon cast aside as technology evolves further.

Instead, policymakers should adopt the profound advice of James Bonbright, as often cited in regulatory proceedings.[5] This sage advises "gradualism" in any changes to Washington State policy, so that customers are able to invest with certainty, and technology is able to continue its advance.

METHODOLOGICAL ISSUES

Questions about the study framing

The study's first issue is its framing. It was initially put forward as a cost-shift analysis, but then the authors began to bolt onto their work elements of a value of distributed solar study. The mix of different perspectives used in the analysis reflects this confusion. The split focus of the authors between cost shift, and value of distributed solar, results in three possible frames—they should choose one:

1. A classic cost of service study that takes the current system and revenue requirements as static, assumes that it has been built out optimally, and applies standard cost allocation factors to determine customer revenue responsibility. This type of study ignores the past benefits created through displaced infrastructure investment and lower energy consumption so it overestimates the actual cost shift that has occurred.

2. An assessment of future costs and benefits, with changes in resources and investments, and projected customer usage and resource options. This framing is implied by the use of forecasted 2030 prices in the study. Unfortunately, the report's approach fails to acknowledge that the

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2 "California begins rolling blackouts after first Stage 3 emergency since 2001," Los Angeles Times, August 14, 2020, https://www.latimes.com/california/story/2020-08-14/la-me-statewide-power-outages-warning; and California ISO, CPUC and CEC, Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave, http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf, January 13, 2021 (included as Attachment A hereto).

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; and Decision 19-05-042.

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).

current investments by customers are sunk costs based on expectations about utility rates at the time the solar was installed.

3. An assessment of historic costs and benefits using contemporaneous market values and avoided investments as well as changes in customer usage and resources. This framing is implied in the report by the use of historic customer and DER installation data such as costs. To execute this framing completely the authors would have needed to use historic forecasts and costs. This latter element is missing from this study.

The study's methodology uses forecasted 2030 generation market prices, current rooftop solar costs with no accounting for projected cost reductions, which are then applied to increasing solar installations. There is no accounting for displaced infrastructure, resources (e.g., energy efficiency spending) and greenhouse gas (GHG) emissions in the past. Mix and matching as the authors have, leads the study to an overestimation of the cost-shift, and wide misses of the other elements of the value of distributed solar.

An important missing element includes changes in the electricity market environments, e.g., increased addition of batteries and rate designs that better address time and location costs/benefits. The value of distributed solar in the past when these installation decisions were made is not the same as the value going forward. We encourage the authors to make that distinction.

A cost-shift study is not a value of distributed solar study

A cost-shift study is a ratepayer-impact measure (RIM) or a "no loser" test. This perspective is clearly the motivation and emphasis of this study. Ironically RIM tests are no longer used for energy conservation or efficiency measures in Washington. Instead, Washington uses the total resource cost test (which is defined to match a societal cost test) as a primary assessment, and utility cost as a secondary test.[6] Importantly, distributed solar generation is defined as energy conservation in Washington State law for public buildings.[7] Given these legal specifications, this study does not conform with the standard for evidentiary analysis in this state. The report at a minimum should acknowledge upfront its failure to follow the specifications required.

The State's energy efficiency programs would fail the ratepayer impact test using this methodology

We might for example apply this cost-shift perspective to energy efficiency program spending by the three investor-owned utilities (IOUs) in the state. Because the benefiting customers are a small portion of the total customer base, there is a cost shift from those customers through the utility rebates to other non-participating customers. Avista, Pacific Power and Puget Sound Energy (PSE) collectively are spending $175 million to reduce energy loads by 379,000 megawatt-hours (MWH).[8] Using an expected

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[6] See ACEEE, "State and Local Policy Database: Evaluation, Measurement & Verification," https://database.aceee.org/state/evaluation-measurement-verification.

[7] RCW 43.19.670 - Energy conservation—Definitions.
(3) "Energy conservation measure" means an installation or modification of an installation in a facility which is primarily intended to reduce energy consumption or allow the use of an alternative energy source, including:
(e) Solar space heating or cooling systems, solar electric generating systems, or any combination thereof;
(f) Solar water heating systems;
(https://app.leg.wa.gov/rcw/default.aspx?cite=43.19.670)

[8] See https://www.utc.wa.gov/consumers/energy/company-conservation-programs.

average life of 10 years[9] and PSE's cost of capital,[10] the average utility contribution is $66.23 per MWH. The NEM Avoided Costs Model developed for the report[11] shows an avoided cost value for 2023 of $40.56 per MWH. That gives a net cost to ratepayers of $25.67 per MWH in direct payments, resulting in direct payment from non-participants to participants of these energy efficiency programs of $9.7 million per year.

Additionally, then there are the lost sales revenues that are foregone contributions to the "fixed" transmission and distribution costs. Again, other customers would have to pick up those cost obligations using the rationale in the study. Applying PSE's average rate and subtracting the avoided costs, the avoided bill payments amount to $31.5 million. All of that spending from energy efficiency programs are in fact a "cost shift" from all ratepayers to a small group of ratepayers who benefit through reduced bills.

In total the apparent cost shift is $41.2 million in 2023 for just the three IOUs' ratepayers. That would easily exceed the $43 million purportedly, as per the study, shifted from customer-generators to non-customer-generators. Why do the authors of this study not push for a significant revision of the state's energy efficiency programs due to the apparent inequity? Because *increasing* energy efficiency investment is one of the cornerstones of the State's climate action policies.

This study purports to assess cost shifts from net metered solar, but, as illustrated by using energy efficiency programs, it does not actually do that at all. The study conflates the concepts of *cost shift* and *revenue shift*. A *cost shift* is when one set of ratepayers pays more to benefit another set of ratepayers. Most utility conservation programs include both cost shift and revenue shift. The cost shift is in the form of fees assessed to all ratepayers to subsidize conservation measures for some ratepayers. This is considered acceptable in order to accomplish the social good of reducing energy consumption. The reduced energy consumption results in reduced energy sales and thus revenue for the utility, which is the revenue shift.

As a form of conservation, net metered solar reduces energy consumption from the grid and thus utility revenue. This should be considered a benefit as it is with other conservation measures, not a cost. Additionally, unlike other conservation methods, net metered solar provides this benefit with no fees assessed to other ratepayers. This study calculates the magnitude of the conservation benefit of net metered solar, but then asserts that it is not a benefit, but a cost shift. An honest assessment of any ratepayer costs from NEM systems would include actual utility costs, not reduced sales from unsubsidized conservation.

The underlying premise of this study revives the opposition raised by utilities in the 1970s opposing conservation efforts because of high fixed costs and the supposed immutability of the grid. As Washington has demonstrated by maintaining rates below the national average, while implementing one of the most aggressive energy-efficiency efforts, the utility system is actually quite malleable over the long run. Virtually all system costs can be displaced through reduced energy use, and this study must acknowledge this fundamental lesson from the last 40 years.

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[9] Rachel Gold and Seth Nowak, "Energy Efficiency over Time: Measuring and Valuing Lifetime Energy Savings in Policy and Planning," American Council for an Energy-Efficient Economy, Report U1902, https://www.aceee.org/sites/default/files/publications/researchreports/u1902.pdf, February 2019.

[10] PSE 2023 10Q, https://fintel.io/doc/sec-puget-energy-inc-wa-81100-10q-2023-may-11-19488-2216.

[11] See WA NEM Evaluation - Avoided Costs Model 2023-11-17.xlsb

A value of solar study requires a much more deliberative approach

Going beyond the question of whether a cost-shift/ratepayer impact study is a valid evaluation tool, this study is not structured as a value of distributed solar study, but it really wants to be. The initial study format did not include many acknowledged benefits of either distributed or grid-scale solar, even going so far as to assume that the entire state's utility grid would be entirely GHG-free by 2030 and that the hydropower system has no significant environmental impacts. This ignores the facts. The rest of the Western Interconnect, including California, is relying on Pacific Northwest (PNW) generation to reduce its GHG emissions after 2030, and that the Columbia River system is the focus of fisheries restoration efforts including the potential decommissioning of the Snake River dams.

This oversight arises from two factors. First the Technical Advisory Group (TAG) was given a few weeks to gather a list of possible benefits, without sufficient time or resources to document those benefits. Second, the E3 authors appear to give only cursory consideration to the TAG's list, often rejecting them simply because they would be too difficult to quantify in the short time given for the study. The TAG suggested many sources for the E3 team to research, but none of that information appears to have been used.

E3's failing to use benefits of distributed solar and storage highlights why this cannot be considered a full value of distributed solar study. This process was not provided the necessary time and resources. Other value of solar studies in Oregon and Minnesota have been multi-year efforts. The utility consortium, in their commissioning of this study, allowed only four months.

Conclusions about which resources are preferred cannot be drawn from an incomplete cost-shift study that does not meet the requirements of a value of distributed solar study. Washington State statute requires that the type of conclusions put forward in this report be supported by a full integrated resource plan (IRP), not a "back of envelope" study that focuses on a single resource.[12]

The study asserts that NEM customers have acted irrationally

Equally problematic is the study's finding that customer-generators (or prosumers) are not making rational decisions by choosing to install rooftop solar because it is a money loser for them under E3's analysis. Slide 22 on the Participant Cost Test (PCT) Results shows that for every example utility, customer generators would have been better off to avoid becoming a customer-generator. Clearly the authors are missing the broader motives of NEM customers which might be to reduce environmental impacts, or the comfort of future bill stability. E3 is missing these customers' expectations, and asserting that customers' choices are not a valid basis for assessing the benefits that accrue to participants. This is an analyst who puts themselves in the place of a consumer, and declares that the consumer is consistently making a bad choice. A more likely conclusion would be that the analyst does not have the full picture of the choices being made.

TECHNICAL ISSUES

Missing risk hedging values, and overlooked hydropower flexibility improvements

The study uses forecasted 2030 Mid-Columbia market hub prices to determine avoided costs. But those prices can be quite volatile, both within the year and across years. Distributed solar allows customer-

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[12] See RCW 19.280.030: Development of a resource plan—Requirements of a resource plan—Clean energy action plan. http://app.leg.wa.gov/RCW/default.aspx?cite=19.280.030

generators *and* utilities to limit exposure to that volatility which hedges their risk. How to value this risk hedging is well understood in financial economics and is the basis for a large segment of the financial markets in options and futures. Despite being provided with references on the topic by the TAG, the study's authors have ignored this benefit.[13]

A study from Rocky Mountain Institute (2012) sets out one method for calculating the volatility cost of natural gas-powered electricity, which is the primary source for energy setting the market clearing price in the Mid-Columbia market. That study found the hidden cost of market volatility in market gas price appears to be $1.50 to $2.50 per MMBtu. Assuming a thermal efficiency or "heat rate" for the marginal use of gas in the electricity market of 7,500 British thermal units per kilowatt-hour (BTU per kWh), that translates to an additional 1.125 to 1.875 cents per kWh or $11.25 to $18.75 per megawatt-hour (MWH) provided by distributed solar.

Other customers on a customer-generator's respective utility benefit from this load reduction. That in turn reduces the prices in the Mid-Columbia market paid on all load served from that market, in turn reducing their exposure to market volatility. The E3 study is therefore failing to account for what is called a "pecuniary externality" where a reduction in overall market prices is created by the investments made by customer-generators. Quantifying that added value requires more complete system modeling than was conducted in this study.

Customers relying on full-requirement deliveries by the Bonneville Power Administration (BPA) could possibly assert that they are not exposed to this volatility because they have a fixed price contract. This unfortunately ignores the effects of climate change and drought in the Pacific Northwest. Volatility coming from the variability in hydro availability is substantial and needs to be accounted for in the same manner as gas price volatility. Northwest utilities' witnesses asserted in proceedings at the Federal Energy Regulatory Commission in 2002 that the Western energy crisis of 2000-2001 was triggered by the BPA declaring a shortfall of firm energy in May 2000.[14] The run on those markets illustrates the volatility that all customers face.

The prosumer's "assist" to this dilemma is ignored in the study. While a portion of the state's hydro plants are run of river, the largest plants such as Grand Coulee and BC Hydro's Revelstoke and Mica Dams[15] are managed to provide both summer exports to the rest of the Western Interconnect and irrigation to Columbia Basin farmers.[16] Increased solar generation from customer-generators reduces Pacific Northwest loads, improves flexibility, and also allows those plants to either export more power to

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[13] These references were provided but not included or expanded on in the study: https://rmi.org/wp-content/uploads/2017/05/RMI_Document_Repository_Public-Reprts_2012-07_WindNaturalGasVolatility.pdf; https://rmi.org/hot-air-cheap-natural-gas/; https://rmi.org/blog_managing_natural_gas_volatility_the_answer_is_blowin_in_the_wind/. In fact, E3 personnel published a study on the risk premium embedded in forward prices in the Mid-Columbia hub in 2011. (Andrew DeBenedictis et al, "How Big Is the Risk Premium in an Electricity Forward Price? Evidence from the Pacific Northwest," The Electricity Journal, 24:3, pp. 72-6, https://www.sciencedirect.com/science/article/abs/pii/S1040619011000601, April 2011.) The TAG expected E3 to conduct further research on its own and expand this analysis since it should have all of the expertise and data required to calculate this hedging value.

[14] M.Cubed partner Richard McCann testified on behalf of the California Parties, including on the issue of hydropower availability.

[15] The BC Hydro complex is operated in coordination with the U.S. hydro fleet under the Columbia River Treaty and must be considered as a single system.

[16] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/community/columbia-river-operations-summary-fall-2020.pdf

California, thus reducing customer rates, or release more water at times that can enhance fisheries. As drafted, this study ignores the market reality that the state, and the region as a whole, is interacting with the Western Interconnect as a whole. Prosumers have a role to play in this future. Studying the prosumer's value will take significant time and resources, and the authors are encouraged to acknowledge this massive oversight in their work.

The forward-looking perspective overlooks the shifting of loads to summer peaks and the benefits of reducing those peaks afforded by distributed solar

The heat dome of 2021 highlighted an important trend—that the PNW utility system is becoming dual winter/summer peaking. Average summertime highs in Seattle and Portland have risen substantially over the last 40 years[17] with the number of days over 70 degrees increasing 50% and 90 degree days doubling during the 2010s compared to previous decades.[18] More households are installing air conditioning as a result.[19] Winter temperatures have risen commensurately which leads to reduced heating loads. Average highs have risen 1.8 degrees since the 1970s and the average lows have risen 1.7 degrees over the same period.[20] The number of days below 32 degrees has fallen by a third in the last decade.[21] It is getting hotter in the PNW. This trend is not reflected in the modeling conducted for this study. That leads to a substantial undervaluation of distributed solar generation by E3.

Slide 32 on Avoided Costs: Transmission and Distribution shows the solar generation profile (which is the same for rooftop and grid-scale solar) and compares it to grid peak load cost allocation factors. Those allocators may be valid for the distribution system based on historic data, but as discussed above, the region is now going beyond historic conditions and peak loads will rise in July and August.[22] Rooftop solar can defer when circuits become summer peaking through local supplies. That value is not reflected in the study.

Figure 5 in E3's companion report *Review of Tariff Design for Customer Generation* can be corrected to show how the power flow from rooftop solar is isolated to the local distribution circuit and avoids using transmission. The imports first come from remote generation, then through the transmission system, then the local distribution network which should be shown with multiple customers. Most of the solar output is used to meet household loads and never leaves the customer site. The remainder is exported, flowing from the customer-generator to neighboring local circuit. None of that power flows back up to the transmission network which is not used at being used at that time by the exporting customer-generator. NEM customers should be paying nothing for the transmission system as it relates to their

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[17] In the last 10 years, eight rank among the top 10 with number of days over 80 degrees. (https://www.extremeweatherwatch.com/cities/seattle/yearly-days-of-80-degrees). Number of days over 90 degrees exceeded eight before 2015 only once but has been eight or higher in five years since 2015. (https://www.extremeweatherwatch.com/cities/seattle/yearly-days-of-90-degrees).

[18] https://www.currentresults.com/Weather-Decades/USA/WA/Seattle/temperature-average-by-decade-seattle.php

[19] "The rise in Seattle's 90-degree days, charted all the way back to 1945," *Seattle Times*, https://www.seattletimes.com/seattle-news/data/the-rise-in-seattles-90-degree-days-charted-all-the-way-back-to-1945/, July 27, 2022.

[20] https://www.currentresults.com/Weather-Decades/USA/WA/Seattle/temperature-average-by-decade-seattle.php

[21] https://www.currentresults.com/Weather-Decades/USA/WA/Seattle/temperature-average-by-decade-seattle.php

[22] As an important note, San Diego Gas and Electric went from being a winter peaking utility as late as the early 1980s to a summer peaking utility within 20 years.

exported power. The combination of self-consumption and exports represents transmission capacity freed for generation to be sent to other customers. This value is completely ignored in the E3 study.

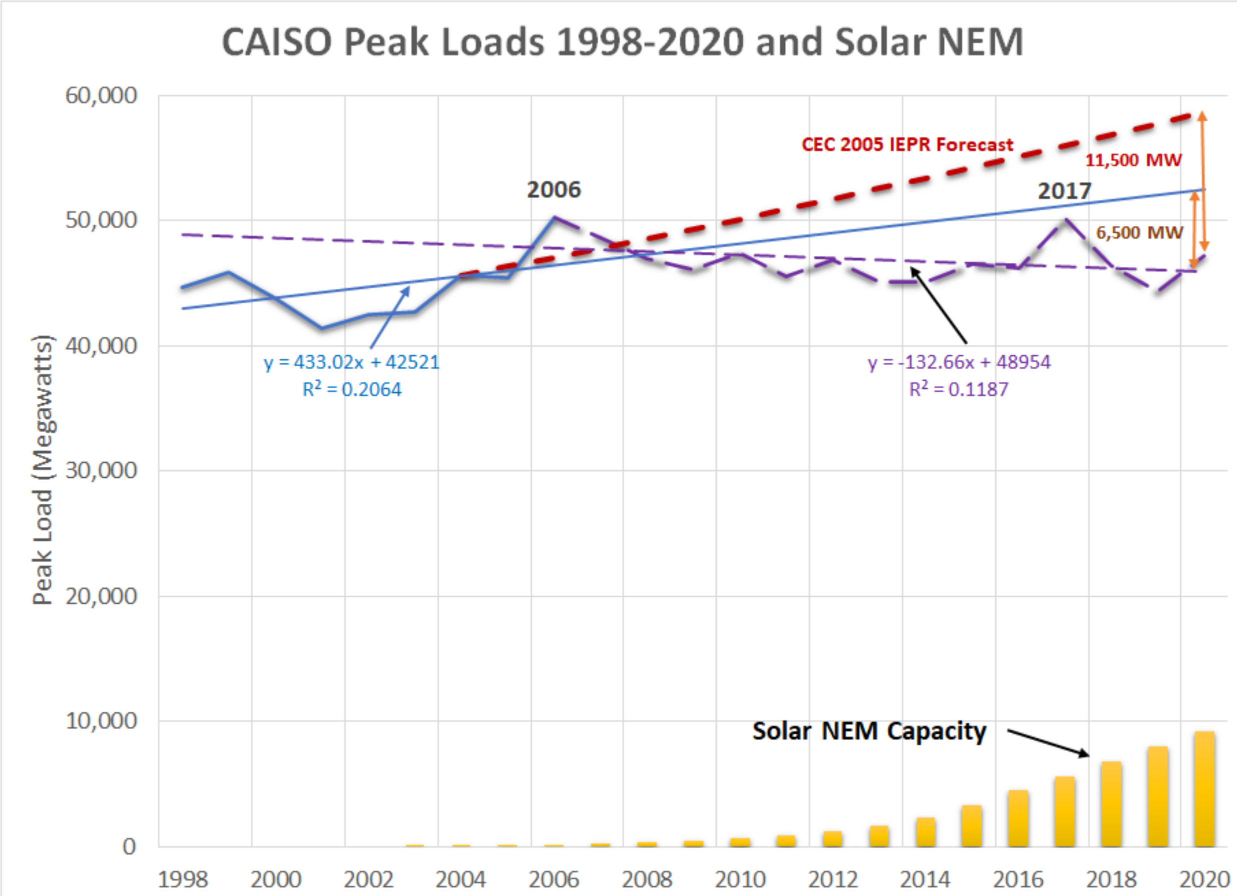
California's experience shows the value of distributed solar

Distributed solar generation installed under California's net energy metering (NEM/NEMA) programs has mitigated and even eliminated load and demand growth in areas with established customers. This benefit supports protecting the investments that have been made by existing customer-generators. Similarly, prosumers can displace investment in distribution assets. That distribution planners are not considering this impact appropriately is not an excuse for failing to value this benefit for the purposes of this study. For example, Pacific Gas and Electric's sales fell by 5% from 2010 to 2018 and other utilities had similar declines. Peak loads in the CAISO balancing authority reach their highest point in 2006, and the peak in August 2020 under exceptional conditions was 6% below that level.[23]

A closer look at California illustrates that much of that decrease appears to have been driven by the installation of rooftop solar. Figure 1 below illustrates the trends in CAISO peak loads in the set of top lines and the relationship to added NEM/NEMA installations in the lower corner. It also shows the CEC's forecast from its 2005 Integrated Energy Policy Report as the top line. Prior to 2006, the CAISO peak was growing at annual rate of 0.97%; after 2006, peak loads have declined at a 0.28% trend. Over the same period, solar NEM capacity grew by over 9,200 megawatts. The correlation factor or "R-squared" between the decline in peak load after 2006 and the incremental NEM additions is 0.93, with 1.0 being perfect correlation. Based on these calculations, NEM capacity has deferred 6,500 megawatts of capacity additions over this period. Comparing the "extreme" 2020 peak to the average conditions load forecast from 2005, the load reduction is over 11,500 megawatts. The obvious conclusion is that these investments by Californian NEM customers have saved all ratepayers both reliability and energy costs while delivering zero-carbon energy. Washington can expect similar benefits if rooftop solar is allowed to flourish.

[23] The peak in September 2022 that falls outside of the analysis period was created by exceptional one-in-35 year weather conditions and still less than 4% above the previous record.

Figure 1



Avoidable transmission costs are underestimated

The "heat map" on the study's Slide 32 misrepresents the loads on Washington's transmission system. Distribution is installed to meet increases in customer connections and loads, and those circuits are connected via feeders to substations. Those increased loads are often offset by decreased loads on other circuits so that system loads do not increase. In the PNW, peak and energy loads have been flat since 2000, reflecting this geographic shifting.[24]

On the utility's end, if needed, generation is added to meet increased loads, and then transmission is added to convey that generation to substations. Added transmission is rarely motivated by increased loads without associated incremental generation capacity. The incremental cost of new transmission is determined by the installation of new generation capacity as transmission delivers power to substations before it is then distributed to customers. For this reason, marginal transmission costs must be attributed to generation.

The report's heat map chart on Slide 32 also does not include perhaps the largest single load on the transmission system-the export of hydropower during the summer peak down the Pacific Intertie. That

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[24] See NPPC: https://www.nwcouncil.org/2021powerplan_historic-trends-energy-use/

is because the chart relies entirely on local loads and ignores the larger wholesale market. Focusing on generation instead would show a different focus for transmission versus distribution.

The cost of transmission for new generation has become a more salient issue.[25] The appropriate metric for distributed solar is therefore the long-term value of displaced transmission. Using similar methodologies for calculating this cost in the CAISO and PJM balancing authorities, the incremental cost in both independent system operators is $37 per megawatt-hour or 3.7 cents per kilowatt-hour. [26] This added cost about doubles the cost of utility-scale renewables compared to distributed resources. The rapid rise in transmission rates over the last decade are consistent with these findings. If economies of scale did hold for the transmission network, those rates should be stable or falling. This amount should be used to calculate the net benefits for the prosumer avoiding the need for additional transmission investment by providing local resources rather than remote bulk generation.

E3 asserts without evidence that it had not seen large transmission costs associated with renewables in Washington. The reason is understandable—the state has added only about 700 MW of grid scale wind and solar power since 2014. In comparison, California has added more than 20,000 MW of solar alone over the same period.[27] To meets its ambitious GHG reduction targets, Washington will have to install a commensurate amount of renewables, distributed and/or grid scale.

Greenhouse gas reductions are likely underestimated

Long term emission reductions, not hourly market emission rates, must be used to calculate GHG savings from DERs. A recent study mistakenly used hourly power GHG emissions as "marginal" which were higher than the average emissions, yet average rates were falling.[28] This is not mathematically possible—when average rates are falling, incremental emission reductions must be above average reductions. Relying on emissions at the Mid-Columbia market hub therefore underestimates the reductions created by reducing metered loads by the prosumer.

Installing customer-owned distributed energy resources is more likely to increase, not stymie, conservation investment

The study makes the assertion that energy conservation is likely to decrease for customers who install rooftop solar. The conservation incentive for customers is upfront when installing customer-owned generation. A customer immediately avoids, with little uncertainty, expensive solar investment by reducing on-site load. The incentive to reduce energy use cost effectively may be even more obvious when installing solar panels than for customers who remain on utility service and see their savings trickle in small amounts over a period of years instead of immediately.

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25 Doug Karpa, "Exploding transmission costs are the missing story in California's regionalization debate," *Utility Dive,* https://www.utilitydive.com/news/exploding-transmission-costs-are-the-missing-story-in-californias-regional/526894/, July 5, 2018.

26 "Testimony of Richard McCann, Ph.D. on Behalf of the Agricultural Energy Consumers Association and the California Farm Bureau Federation," CPUC Rulemaking 20-08-020, June 18, 2021, pp. 15-16; and "Prepared Supplemental Testimony Of Richard McCann, Ph.D on Behalf of the Kentucky Solar Energy Industry Association," before the Public Service Commission of the Commonwealth of Kentucky, Kentucky Power Company Case No. 2020-00174, February 25, 2021, pp. 9-10.

27 https://www.seia.org/state-solar-policy/california-solar

28 Holland et al (2022), " Why marginal CO2 emissions are not decreasing for US electricity: Estimates and implications for climate policy," https://resources.environment.yale.edu/kotchen/pubs/margemit.pdf

CONCLUSION

The study, as presented, has a number of serious methodological inconsistencies and flaws. It also struggles with its technical analysis. This is simply a reflection of the rushed nature of the timeline provided to E3, and limited actual input drawn from the TAG and other stakeholders.

These results should be fully discounted until a more complete study can be prepared that better reflects the perspectives specified by Washington State law, and that reflects the realities of the evolving climate, and energy environment.

JI-DEK-DR-01-007

WASEIA Comments on Review of Tariff Design for Customer Generation Submitted by Richard McCann, Ph.D., M.Cubed on behalf of the Washington Solar Energy Industries Association

WASEIA Comments on
Review of Tariff Design for Customer Generation

Submitted by Richard McCann, Ph.D., M.Cubed
on behalf of the Washington Solar Energy Industries Association

December 1, 2023

M.Cubed, founded in 1993, provides economic and public policy consulting services to public and private sector clients. Practice areas include water and energy utility resource planning, ratemaking, water and resource use efficiency, conservation measures, project impact analysis, natural resource allocation policies, and environmental plan preparation and review. Dr. McCann has testified over 50 times on electricity, air quality, water supply and other regulatory and planning matters.

Figure 1, p. 2 – For California, the report shows the results from the Avoided Cost Calculator. However, the results from this calculator are disputed by many parties. The ACC was adopted in a separate proceeding where it was not identified as being a key component of the upcoming reform to the California's net energy metering (NEM) tariff.

In the next round of ACC updates, significant revisions are expected. The ACC arrives at avoided cost values that are only about half of what the utilities themselves calculate in their rate case filings. This large discrepancy further undermines the validity of these findings.

Avoided costs calculated for the Washington utilities using a similar methodology (as E3 prepared California's ACC model) will likely have significant issues as well.

Figure 5, page 5—The diagram is too simplistic in showing the power flow. The imports first come from remote generation, then through the transmission system, then the local distribution network which should be shown with multiple customers. The exports then flow from the customer-generator's rooftop to neighbors on the local circuit. None of that power flows back up to the transmission system which is not used at all by the customer-generator when exporting electricity .

NEM customers should be paying nothing for the transmission system for their power exported. The combination of self-consumption and exports represents transmission capacity freed for generation to be sent to other customers.

Sections 3.1.1 versus 3.1.2, pages 5-6—Section 3.1.2.1 lists three specific states with non-NEM tariffs, yet Section 3.1.1 states "NEM is currently the most widely used form of compensation for customer generation in the U.S." The section fails to 1) list all of the states with NEM tariffs, 2) identify where states have reviewed those NEM tariffs and made minimal or no changes (e.g., Kentucky) and 3) describe what if any revisions have been made to those tariffs. Section 3.3 does list three more states where NEM tariffs have been revised, including two to net billing tariffs. Only four states total currently have a net billing structure.

<u>The fact is that a preponderance of states, especially those with low adoption rates similar to Washington's, have not acted to revise their NEM tariffs.</u>

Further in Section 3.1.1.2, the report states "NEM generally provides significant bill savings to participating customers, but it may also create a *large* cost shift for non-participating customers." The report fails to define what "large" means. Is 0.3% "large"? Is 1.4% "large"? Is 44 cents per month "large"? Is even $2.43 per month "large"? Most people lose that much money in pocket change each month. Those are the values shown for 2024 estimated residential rate impacts on Slide 35 of *Washington Utilities NEM Evaluation, Draft Results.* The fact is that for most states, the purported "cost shift" is similarly small. Without a definitive threshold for "large" this statement is meaningless to the reader, and even deceptive given the context in Washington.

In addition, the same can be said of energy conservation and efficiency which reduces utilities' loads and shifts costs from participating customers to nonparticipating customers, at least in the short term, even when it provides overall savings. That the customers that invest in energy savings receive the lion's share of financial gains is consistent with incentivizing these investments.

Section 3.1.3 pages 7-8--The report states without supporting evidence "(m)any community solar tariffs and other distributed generation projects are structured around tariffs under which the site owner sells all of the generation to a load-serving entity at a set pricing structure, without any assumed self-consumption or offsetting against customer load." Again, the definition of "many" is lacking. There are many states with community solar tariffs that successfully encourage much more development than states like California where residential solar has been the focus. This report should review the tariffs being offered in those states.[1] Many of the states are also in the northern tier with solar insolation similar to Washington.

A notable observation is that California's adoption of the buy-all/sell-all tariff for virtual NEM and aggregated NEM projects is likely to kill any further interest in those projects as currently structured.[2] The consequence of this approach cannot be underestimated.

Section 3.4, page 13—The report asserts "(m)any economists argue that a shift toward cost-based rates, with greater recovery of fixed and long-run marginal costs outside of volumetric charges, can enable more equitable and efficient customer adoption and dispatch of distributed resources." That statement then lists five citations, of which at least two are self-references to E3 documents. The fact is that many economists dispute the need for large capacity charges beyond the direct service connection (which costs $10-$20 per month) and relying on hourly energy market rates as "cost based." The Regulatory Assistance Project is one such organization that has published reports contradicting this assertion.[3] This statement should be deleted from the report as biased and unsubstantiated.

Section 4 Conclusions, pages 14-15—While about a half dozen states have modified their NEM tariffs, many more have either left those tariffs untouched or made minor tweaks. Unfortunately, this

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[1] See for more information: https://www.energysage.com/community-solar/comparing-top-community-solar-states/ and https://ilsr.org/national-community-solar-programs-tracker/

[2] Jeff St. John, "California's rooftop solar policy is killing its rooftop solar industry," *Canary Media*, California's rooftop solar policy is killing its rooftop solar industry, December 1, 2023.

[3] See https://www.raponline.org/

report emphasizes those small number that have acted rather than the large number that have remained with the existing business-as-usual approach.

As pointed out in comments on Section 3.4, there is no justification provided for including a statement about shifting to “cost-reflective” retail rates. Beyond a small number of citations, several being self-referential, E3 has not presented any supporting analysis to come to that conclusion. This paragraph should be deleted.

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 6

Q6 Please confirm that Mr.[sic] McCann is not offering any opinions regarding any of the other aspects of the Company's Application in these proceedings, besides the principles for setting the appropriate compensation and retail rates for customers who self-generate to serve part of their load, and quantifying the level of that compensation.

(a) If the response is in the negative, please state Mr.[sic] McCann's position.

RESPONSE:

Confirmed.

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 7

Q7 Please confirm that, other than the opinions offered by Mr.[sic] McCann, KSES is not taking a position on any of the other aspects of the Company's filing in these proceedings.

(a) If the response is in the negative, please explain KSES's position.

RESPONSE:

Joint Intervenors object to this request as it calls for speculation or legal conclusion. As testimony is not yet complete, a hearing has not yet been held, and briefing in this matter hasn't been scheduled, it is premature to state Joint Intervenors' positions on all aspects of these proceedings. As parties granted full intervention in this matter, Joint Intervenors are not limited in "taking a position" to matter for which they have provided expert testimony.

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 8

Q8 Please identify all proceedings in all jurisdictions in which Mr.[sic] McCann has offered evidence, including but not limited to, pre-filed testimony, sworn statements, and live testimony and analysis for the last three years. For each response, please provide the following:

(a) the jurisdiction in which the testimony, statement or analysis was pre-filed, offered, given, or admitted into the record;

(b) the dockets by name and number; and,

(c) whether a final commission decision order was issued and what date.

RESPONSE:

See attached table.

ATTACHMENTS:

JI-DEK-DR-01-Table-01

JI-DEK-DR-01-Table-01

Jurisdiction	Docket No.	Docket Name	Commission Decision	Date
Kentucky Public Service Commission	Case No. 2020-00174	Kentucky Power Company General Adjustments of Rates	Order KP-20210514	5/14/2021
California Public Utilities Commission	R.22-07-005	Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates	N/A	N/A
California Public Utilities Commission	A.22-05-015, A22-05-016	2024 Southern California Gas Company Revenue Requirements, 2024 San Diego Gas & Electric Revenue Requirements	N/A	N/A
California Public Utilities Commission	R.20-08-020	Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs	D. 22-12-056	12/15/2022
California Public Utilities Commission	A.21-06-021	2023 Pacific Gas & Electric Rates and Charges	D. 23-11-069	11/16/2023
California Public Utilities Commission	A.20-10-012	2021 Southern California Edison Revenue Allocation and Rate Design	D.22-08-001	8/9/2022
California Public Utilities Commission	A.22-04-008 et al	2023 Cost of Capital for Pacific Gas & Electric, Southern California Edison, Southern California Gas, and San Diego Gas & Electric	D.22-12-031	12/19/2022

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 9

Q9 Please provide copies of any and all documents, analysis, summaries, white papers, workpapers, spreadsheets (electronic versions with cells and formulas intact), including drafts thereof, as well as any underlying supporting materials created by Mr.[sic] McCann:

(a) as part of his evaluation of the Company's proposed compensation and retail rates in this proceeding;
(b) as part of calculating the credit amounts recommended on page 3, lines 4-5 of his testimony;
(c) as part of calculating the avoided cost benefit discussed on page 20, lines 6-7 of his testimony;
(d) as part of calculating the avoided capacity value discussed on page 22, lines 8-9, of his testimony;
(e) as part of calculating the value on page 25, line 6 of his testimony;
(f) as part of calculating the avoided cost for distribution on page 26, line 13 of his testimony;
(g) as part of calculating the value of $0.0466 per kilowatt-hour on page 28, line 8 of his testimony;
(h) as part of calculating the $0.90 cents per kilowatt-hour value on page 28, line 12 of his testimony;
(i) as part of producing Figure JI-2 on page 19, and any other figure or table in his testimony; and
(j) as part of evaluating any other aspect of the Company's Application in the above-styled proceeding reviewed by Mr.[sic] McCann.

RESPONSE:

All workpapers of Dr. McCann developed in connection with his testimony in this proceeding have been attached.

ATTACHMENTS:

JI-DEK-DR-01-008	EIA-HHub gas prices-2024-RNGWHHDmonthly.xlsx
JI-DEK-DR-01-009	DEOK TX rates.xlsx
JI-DEK-DR-01-010	DEK Solar Jobs v6.xlsx
JI-DEK-DR-01-011	DEK Avoided Costs.xlsx

JI-DEK-DR-01-008

EIA-HHub gas prices-2024-RNGWHHDmonthly.xlsx

JI-DEK-DR-01-009

DEOK TX rates.xlsx

JI-DEK-DR-01-010

DEK Solar Jobs v6.xlsx

&

JI-DEK-DR-01-011

DEK Avoided Costs.xlsx

Uploaded as separate attachments

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 10

Q10 Please provide copies of any and all documents not created by Mr.[sic] McCann, including but not limited to, analysis, summaries, cases, reports, evaluations, etc., that Mr.[sic] McCann relied upon, referred to, or used in the development of his testimony.

RESPONSE:

All documents relied upon, referred to, or used in the development of Mr.[sic] McCann's testimony are linked in footnotes in his Direct Testimony, with the exception of the books James C. Bonbright, 1961, *Principles of Public Utility Rates,* New York City: Columbia University Press; and Alfred E. Kahn, 1988, *The Economics of Regulation: Principles and Institutions*, Cambridge, Massachusetts; London, England: MIT Press, referred to in footnote 2. Copies of the title pages and tables of contents of those works are attached here.

ATTACHMENTS:

JI-DEK-DR-01-012 James C. Bonbright, 1961, *Principles of Public Utility Rates,* New York City: Columbia University Press Title Page and Table of Contents

JI-DEK-DR-01-013 Alfred E. Kahn, 1988, The Economics of Regulation: Principles and Institutions, Cambridge, Massachusetts; London, England: MIT Press

Title Page and Table of Contents

JI-DEK-DR-01-012

James C. Bonbright, 1961, *Principles of Public Utility Rates,* New York City: Columbia University Press

Title Page and Table of Contents

POWELL GOLDSTEIN LLP

Principles of Public Utiliity Rates by James C. Bonbright

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JAMES C. BONBRIGHT

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To Martha

CONTENTS

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PART ONE

Basic Standards of Reasonable Rates

JI-DEK-DR-01-013

Alfred E. Kahn, 1988, *The Economics of Regulation: Principles and Institutions*,
Cambridge, Massachusetts; London, England: MIT Press
Title Page and Table of Contents

The Economics of Regulation
Principles and Institutions

Volume I Economic Principles
Volume II Institutional Issues

Alfred E. Kahn

The MIT Press
Cambridge, Massachusetts
London, England

Contents

Volume II Institutional Issues

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 11

Q11 Referring to Mr.[sic] McCann's testimony on pages 21 to 22, how would Mr.[sic] McCann's methodology change if PJM switched to a seasonal capacity auction process?

RESPONSE:

Joint Intervenors object insofar as the question calls for speculation. As such an auction has not yet been operationalized and is not in evidence in this proceeding, answering this requires speculation about the construct of such an auction and its potential impact. No analysis was conducted on this hypothetical situation.

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 12

Q12 Referring to Mr.[sic] McCann's testimony on pages 21 to 22, how would Mr.[sic] McCann's recommended avoided capacity value change if PJM switched to a seasonal capacity auction process.

RESPONSE:

Joint Intervenors object insofar as the question calls for speculation. As such an auction has not yet been operationalized and is not in evidence in this proceeding, answering this requires speculation about the construct of such an auction and its potential impact. No analysis was conducted on this hypothetical situation.

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 13

Q13 Referring to Mr.[sic] McCann's testimony on pages 21 to 22, does Mr.[sic] McCann use an incremental value or average value methodology to calculate the capacity value of solar energy?

RESPONSE:

The capacity value was calculated from PJM's "Periodic Review of Default Gross CONE and Gross ACR Values," and adjusted for the solar capacity value specified in that document as described in the testimony. The NetCONE value is intended to be a market value benchmark which means that it is incremental.

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 14

Q14 Please confirm whether Mr.[sic] McCann agrees that solar capacity has a significantly lower value during the winter time (defined for purposes of this question as December through February). If Mr.[sic] McCann disagrees, please explain the reasoning.

RESPONSE:

The value of solar capacity in the winter is not relevant as Duke Energy Kentucky is a summer peaking utility, and capacity value is determined at the time of system peak. Solar *output* is lower during the winter.

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 15

Q15 Is Mr.[sic] McCann aware of the 2024-2025 PJM ELCC capacity class ratings for Fixed-Tilt Solar and Tracking Solar of 9% and 14% respectively, available at https://www.pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx.

RESPONSE:

The referenced document appears to have little or no relation to the NetCONE calculation. For example, the ELCC Class Rating for a gas combustion turbine is 62%, while the NetCONE update shows a capacity value of 95.5%. Dr. McCann relied on the solar capacity value of 31.0% presented by PJM in its "2026/2027 Default Net CONE Calculation."

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 16

Q16 Does Mr.[sic] McCann believe that all of his avoided cost calculations are applicable equally to utility-owned solar generation?

(a) If not, please explain which components of his calculated avoided costs are applicable and which are not.

(b) If not, please give the reasons on which any distinctions are based.

(c) Please provide all data and workpapers supporting the responses to 16(a) and 16(b) above.

RESPONSE:

(a) The value of distributed solar and utility-scale solar are the same as generators in providing risk hedging and environmental benefits, but differ in conveying power and the economic benefits produced. Referring to Table JI-2, utility-owned solar would not avoid transmission and distribution costs, nor line losses. Transmission and distribution add up to $0.0319 per kilowatt-hour and line losses add another $0.0102 per kilowatt-hour.

Further, utility owned solar does not provide the same level of economic benefits to Kentucky. The economic value added to the state's economy by rooftop solar over utility-owned solar ranges from $1.14 per kilowatt-hour to $1.37 per kilowatt-hour based on the analysis presented in Dr. McCann's testimony.

Finally, the avoided cost considerations for net-metered customer-generators are based on the factors and methodology developed by the Commission in cases 2020-00174 and 2020-00349/00350, and are for use in determining the compensatory value of solar generation from distributed resources, and not for utility-owned solar. Valuation of avoided costs is not a relevant determinant for rate setting for electricity generated by utility-owned solar, so that a comparison is not appropriate.

(b) See response to (a).

(c) Calculations included in workpapers provided in response to Q9.

ATTACHMENTS:

See attachments JI-DEK-01-008 through 011.

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 17

Q17 Referring to Mr.[sic] McCann's testimony on page 35, recommending "that residential generator-customers receive a credit of $0.1627 [per] kilowatt-hour and commercial/non-residential a credit of $0.1630 per kilowatt-hour," would Mr.[sic] McCann recommend the same amount in compensation per kilowatt-hour for utility-owned solar generation?

(a) If not, please describe how the calculation methodology would be modified from the methodology recommended in Mr.[sic] McCann's testimony in this proceeding.

RESPONSE:

No.

(a) First, no compensation is provided under Kentucky's net metering statute, only a credit that is dollar-denominated. Comparison of the calculation and determination of valuation components for distributed generation fed into the system by a customer-generator, with the valuation for utility-owned solar generation is inappropriate. In one case, the utility has proposed to construct and own solar generation, and recovery of costs and any return on equity is determined by a set of rules and calculations that are different than those developed for determining the value of energy incidentally fed into a system by a net-metered solar customer. In the latter case, it is the customer who has borne the costs of the generation asset and who assumes the entire risk of nonperformance, unlike the utility, and provides energy consumed locally by other customers for which the utility is receiving retail compensation under its tariff. The compensatory credit formula and factors developed for such fed-in electricity are dissimilar from those applicable to utility-owned solar generation, so that the comparison is unfair and inappropriate. Additionally, See the calculation in response to Q16.

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 18

Q18 Referring to Mr.[sic] McCann's testimony on page 1, line 10, please confirm that "Case No. 202-00174" refers to Kentucky Public Service Commission (KyPSC) Case No. 2020-00174. If not confirmed, please clarify the precise number of the case referenced.

RESPONSE:

Confirmed.

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 19

Q19 Referring to KyPSC Case No. 2020-00174, to page 27 and footnote 80 of the Order issued on May 14, 2021, does Mr.[sic] McCann confirm that the Commission omitted 2020 locational marginal price (LMP) data from its avoided cost calculation "because the unprecedented COVID-19 pandemic likely impacted load in uncommon ways"? If not, please explain.

RESPONSE:

Yes. The Commission undertook this analysis three years ago. In selecting a representative historic period, sometimes a year understood as being particularly unusual is excluded. The pandemic represented a once in a century situation quite similar to the "Spanish influenza" pandemic that struck the world from 1918 to 1920. Standard and expected volatility in PJM prices does not meet this standard.

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 20

Q20 Referring to Mr.[sic] McCann's testimony on page 17, line 2, that "[t]he average cost of wholesale power in 2023 was half of what it was in 2022," does Mr.[sic] McCann agree that 2022 LMP values were "uncommon"? If not, please explain.

RESPONSE:

LMP prices are volatile and can vary widely from year to year. Such volatility is common, not uncommon. It is that volatility upon which the Federal Energy Regulatory Commission relied on when revamping electricity markets which led to the creation of the PJM wholesale market.

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 21

Q21 Referring to Mr.[sic] McCann's testimony on pages 10-11 advocating for "equitable treatment" for customer-generators and stating that "There is no reason why other resource owners should be treated differently than the utility":

(a) Is it Mr.[sic] McCann's position that customer-generators should be subject to capacity requirements, as a utility is?

(b) Is it Mr.[sic] McCann's position that customer-generators should be subject to performance assessments, as utilities are?

(c) Is it Mr.[sic] McCann's position that customer-generators should be subject to penalties for non-performance, as utilities are?

RESPONSE:

(a) Customer-generators provide as available capacity just as utility owned solar generators do.

(b) Customer-generators are penalized for non-performance by paying retail rates when not self-supplying. Self-supply is by far the predominant use of power generated.

(c) Customer-generators are penalized for non-performance by paying retail rates when not self-supplying. Self-supply is by far the predominant use of power generated. That penalty rate is much higher than that paid by non-performing grid scale generation.

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 22

Q22 Referring to Mr.[sic] McCann's testimony on page 9, lines 15-17, what percentage of Duke Energy Kentucky customers "fully escape reliance on the centralized utility grid" through their ownership of distributed generation?

RESPONSE:

Joint Intervenors object to the question as unduly burdensome. Information regarding Duke Energy Kentucky's customers is either publicly available or more readily available to the Company than to Joint Intervenors.

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 23

Q23 Referring to Mr.[sic] McCann's testimony on page 9, lines 15-17, what percentage of owners of distributed generation resources in Kentucky remain connected to the electric utlity [sic] grid?

RESPONSE:

Joint Intervenors object to the question as unduly burdensome. Any information regarding owners of distributed generation resources in Kentucky is either publicly available or not available at all.

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 24

Q24 Referring to Mr.[sic] McCann's testimony on page 10, mentioning "Winter Storm Elliott in 2022 that … caused widespread outage across Kentucky and many other states,":

(a) How much total energy was provided to the utility grid by Duke Energy Kentucky net metering customer-generators during Winter Storm Elliott, i.e., on December 23 and 24, 2022? Please provide the data by hour.

RESPONSE:

Joint Intervenors object to the question as unduly burdensome. Information regarding Duke Energy Kentucky's customers is either publicly available or more readily available to the Company than to Joint Intervenors.

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 25

Q25 Referring to Mr.[sic] McCann's testimony on page 12, line 20, regarding RTO markets not creating new resource investment, are RTOs the only entities impacting new resource investment? If not, please describe other entities who impact new resource investment.

RESPONSE:

FERC Orders 888 and 889 issued in 1996 were based on the premise that short-run marginal costs as reflected in organized wholesale bulk power markets would provide all of the economic information required to incentivize new generation investment for within ISOs and RTOs that choose to participate. There are economists today who still argue that the single-price market auction for electricity will deliver the most effective investment signal for new generation and other resources.

PJM is one of those RTOs that chose to organize such a market. It has made a number of changes to its resource acquisition incentives to accommodate different resource types such as renewables and dispatchable demand side management. My point is that the RTOs have deviated from the original premise in the FERC Restructuring Orders because the incentives in the bulk power markets alone have not been sufficient.

Instead, utilities and other load serving entities have had to sign power purchase agreements with pricing and terms that better reflect long run marginal costs because the so-called short run marginal costs supposedly reflected in PJM LMPs do not and will not converge with long run marginal costs. So relying solely on LMPs as reflecting long-run marginal costs is incorrect. As such, any valuation of distributed solar resources requires additional adjustments to those LMPs to be accurate.

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 26

Q26 Does Mr.[sic] McCann confirm that the amount of energy produced by solar generation facilities owned by customer-generators is not equivalent to the amount exported to the utility grid by those same solar facilities?

RESPONSE:

The question is ambiguous. What is meant by the term “equivalent”? Is there a metric being implied for determining equivalency? What is the metric for determining the “amount exported to the utility grid”?

DEK should have these quantities in its records for what has been generated by customers and the amounts exported.

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 27

Q27 Regarding Mr.[sic] McCann's testimony on page 17, lines 11-13, please identify all stakeholders who requested an opportunity to develop alternative forecasts.

RESPONSE:

Joint Intervenors object to the question as unduly burdensome. Information regarding requests from stakeholders to Duke Energy Kentucky is more available to the Company than to Joint Intervenors.

ATTACHMENTS:

N/A

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 28

Q28 Referring to Mr.[sic] McCann's testimony on page 2, lines 6-9, that "Importantly, these customers 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," please provide any survey results or other supporting evidence for this statement.

RESPONSE:

No surveys are required to observe that solar panels are a substantial monetary investment with an expected operating life in excess of 20 years. Dr. McCann relies on his three decades of experience of working with customer groups to understand their expectations about utility commitments made in tariffs. Dr. McCann refers DEK to James Bonbright's book about the expectations of rate design stability, listed in response to Q10. As further evidence California's Governor Gray Davis was recalled in 2003 in part because of a dramatic change in electric utility rates approved by the California Public Utilities Commission that he appointed. California's voters expected rate stability and expressed their dismay at the polls.

In addition, Consumer Reports published a study in 2018 finding that 52% of respondents would install rooftop solar if they could recover their investment in five years, including 53% in Ohio and 57% in Tennessee.[1] Further, 48% reported that they didn't feel that electric utilities cared about lowering costs for their customers, including 51% in Ohio and 54% in Tennessee.

ATTACHMENTS:

N/A

[1] Consumer Reports 2018 Energy Utilities Survey Report, https://advocacy.consumerreports.org/wp-content/uploads/2018/10/CR-2018-Energy-Utilities-Survey-Report-1.pdf.

JOINT INTERVENORS KENTUCKY SOLAR ENERGY SOCIETY AND KENTUCKIANS FOR THE COMMONWEALTH

RESPONSE TO MARCH 22, 2024 REQUEST FOR INFORMATION FROM DUKE ENERGY KENTUCKY, INC.

Case No. 2023-00413

Question 29

Q29 Referring to Mr.[sic] McCann's testimony on page 37, line 1, that "any transition should be done gradually," is it Mr.[sic] McCann's position that providing a $0.1627 credit for excess generation would constitute a gradual transition?

RESPONSE:

Dr. McCann has not recommended an immediate adoption of this credit in a revised NM rate. His testimony demonstrates that the credit is likely higher than the proposed NM rate, which justifies continuing the current NM tariff as is, contrary to DEK's proposal to radically change the NM rate. This is consistent with changing rates in a gradual transition.

ATTACHMENTS:

N/A

VERIFICATION

The undersigned, Dr. Richard McCann, being first duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that the information contained therein is true and correct to the best of his information, knowledge, and belief, after reasonable inquiry.

Signature

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 4th day of April, 2024 by

Richard McCann, proved to me on the basis of satisfactory evidence to be the person who

appeared before me.

Signature ________ (seal)

GARY CHRISTENSEN
Notary Public - California
Yolo County
Commission # 2393714
My Comm. Expires Mar 11, 2026

My commission expires: March 11, 2026

CERTIFICATE OF SERVICE

In accordance with the Commission's July 22, 2021 Order in Case No. 2020-00085, *Electronic Emergency Docket Related to the Novel Coronavirus COVID-19*, this is to certify that the electronic filing was submitted to the Commission on April 09, 2024; that the documents in this electronic filing are a true representation of the materials prepared for the filing; and that the Commission has not excused any party from electronic filing procedures for this case at this time.

____

Byron L. Gary