BEFORE THE PUBLIC SERVICE COMMISSION
OF THE COMMONWEALTH OF KENTUCKY

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

PREPARED DIRECT TESTIMONY OF
RICHARD McCANN, PH.D

ON BEHALF OF
JOINT INTERVENORS
KENTUCKY SOLAR ENERGY SOCIETY AND
KENTUCKIANS FOR THE COMMONWEALTH

Dated: March 13, 2024

Table of Contents

Table of Figures

I. INTRODUCTION

Q. Please state your name, business address and current position.

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

Q. Please summarize your professional background and its relevance to this proceeding?

A. 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 Kentucky in an application submitted by Kentucky Power, Case No. 202-00174, 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 protecting solar project investment by customers and setting appropriate level of exit fees for community choice aggregators. 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 also 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.

Q. What is the purpose of your testimony and how it is organized?

A. 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, and quantifying the level of that compensation. The Kentucky Public Service Commission (Commission) itself has set out the principles to be used for setting rates for net metering (NM) customers.[1] These customers are predominantly using solar panels. 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. Economic systems work best when regulatory bodies do not institute sudden changes with little transition.

My testimony first discusses the principles adopted by the Commission for calculating the avoided cost to be applied to the NM rate. Next, I summarize 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 further 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 then lay out the valuation for elements of the NM tariff. Finally, I provide an estimate of the net economic benefits from increasing rooftop solar over relying on utility-scale plants.

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[1] In the Matter of: *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, Ky. PSC Order at pp. 21-24 (May 14, 2021) ("KPCo Order"). https://psc.ky.gov/pscscf/2020%20Cases/2020-00174//20210514_PSC_ORDER.pdf.

Q. Please summarize your final recommendations on setting the avoided costs to be used for crediting customer-generators on the NM tariff?

A. Following the principles provided by the Commission, I recommend that **residential generator-customers receive a credit of $0.1627 kilowatt-hour** and **commercial/non-residential a credit of $0.1630 per kilowatt-hour**. I discuss in detail the basis for these recommendations below.

II. PRINCIPLES FOR RATEMAKING

Q. What are the general ratemaking principles the commission should follow in this case?

A. In making any changes to Duke Energy Kentucky's (DEK) NM tariff, especially as the sunset threshold approaches in the next couple of years, the Commission should adopt the profound advice of those who have set out ratemaking principles, and as often cited in Commission proceedings.[2] 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 and in addition to the principles previously laid out in the KPCo Order, the Commission should design NM 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,

[2] James C. Bonbright, 1961, *Principles of Public Utility Rates,* New York City: Columbia University Press.; Alfred E. Kahn, 1988, *The Economics of Regulation: Principles and Institutions*, Cambridge, Massachusetts; London, England: MIT Press.

- ensuring that self-generating customers gain the same level of financial assurances that large generators have in their power purchase agreements (PPAs),
- applying cost causality similar to other customers and other energy management programs,
- fixing costs only for customer-specific system components and acknowledging the wide extent that other costs are displaced by new resources, and
- smoothly transitioning customers from one rate regime to another.

Fortunately, the Commission has already directed utilities such as DEK to follow many of these principles in setting rates for customer-generators.

Q. What principles has the commission established in this situation?

A. The Commission in the 2021 Kentucky Power rate application (in which I testified this matter on behalf of the Kentucky Solar Energy Industry Association) spelled out "Principles for Compensation for Eligible Customer-Generators." The Commission wrote:

> Intervenors provided several examples of other states undergoing similar proceedings and provided a description of best practices for compensating eligible customer-generators.[67] While the Commission declined, in the January 13, 2021 Order, to adopt a recommendation for a separate proceeding to determine a NEM rate methodology, the Commission concludes that many of the best practices supported by intervenors are reasonable and should be incorporated into NMSII for the reasons set forth below. These principles are as follows [removing explanations]:

- Evaluate eligible generating facilities as a utility system or supply side resource…
- Treat benefits and costs symmetrically…
- Conduct forward-looking, long-term, and incremental analysis…
- Avoid double counting…
- Ensure transparency…

> While the principles above were offered in the context of compensating eligible customer-generators, similar principles apply to rate design. For a net metering tariff, rate design principles are relevant not only to the export rate structure, but also to the underlying retail rate that customer-generators pay for their energy consumption. When considering rate designs for either export or consumption, it is important to consider the above principles alongside the additional principles of stability and simplicity.[3]

The Commission goes on to specify what elements are to be included "to ensure a just and reasonable estimate of avoided generation and transmission capacity, energy, and ancillary service costs. The Commission also finds that intervenors and the record support including additional avoided cost components to customers-generators through the export rate."[4]

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[3] KPCo Order at pp. 21-24.
[4] KPCo Order at p. 25.

The Commission states that "the avoided [energy] cost should be the publicly available LMPs at the Kentucky Power Residual Load Aggregate pricing node, averaged from 2017-2019."[5] That forecast is to be "levelized the average LMPs over a 25-year period to account for long-term change in energy pricing."[6] Line losses also are to be accounted for and "Kentucky Power appears to use static losses as opposed to marginal losses, which are a superior estimate when calculating avoided costs."[7]

For the avoided generation capacity value, the Commission states "the capacity price should be replaced with the Net CONE values…Net CONE reflects an approximate capacity market equilibrium and therefore better reflects long-term avoided capacity value"[8]

For calculating the value of solar, the Commission states "the dollar value should be divided by exported annual MWh because dividing by total annual MWh production double counts the self-consumption portion of production."[9]

The Commission then states "the avoided transmission capacity cost is estimated with historical data and represents present day avoided cost expectations… (W)e find that it is reasonable to estimate the net present value of the avoided transmission capacity cost value over a typical eligible generating facility life."[10]

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[5] KPCo Order at p. 26.
[6] KPCo Order at p. 26.
[7] KPCo Order at p. 28.
[8] KPCo Order at p. 29.
[9] KPCo Order at p. 30.
[10] KPCo Order at p. 32.

The Commission found that "(o)ptimally, the value of ancillary services would be forward looking," and it "expects additional support and development of this cost component in future cases."[11]

"Additional Avoided Cost Components" specified by the Commission to be included:

- Avoided distribution capacity costs
- Avoided carbon cost
- Environmental compliance
- Jobs benefits
- Avoiding DER participation in wholesale market.

Unfortunately, DEK's proposal does not adhere to most of these principles, and should be rejected in favor of an approach that does address these issues.

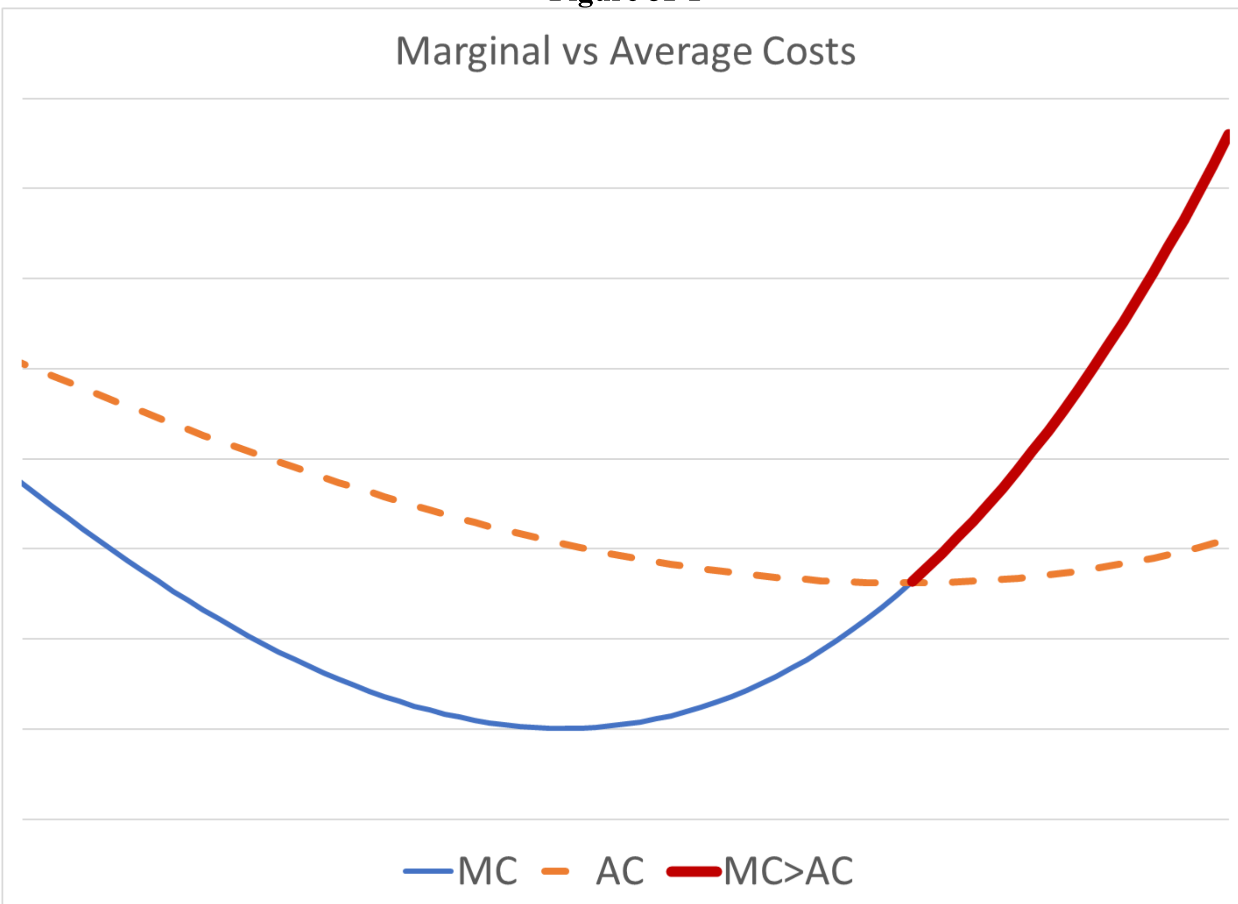
Q. What other key economic principle should the commission consider in setting avoided cost?

An immutable economic fact is that average costs equals the sum of marginal costs. Or inversely, marginal cost equals the incremental change in average costs when adding a unit of demand or supply. The two concepts are interlinked so that one must speak of one when speaking of the other. This fundamental economic relationship is as true as 1+1=2. Figure JI-1 replicates a figure included in almost every introductory microeconomics text book. It shows the relationship of marginal and average costs. Average costs begin to rise when marginal costs surpass average cost. Most importantly, it is not mathematically possible to have rising average costs when marginal costs are below average costs. So

[11] KPCo Order at p. 32.

any assertion that any marginal costs are less than the average costs when average costs are rising beyond underlying inflation must be mathematically false.

Figure JI-1



The burden of proof lies with those who assert that this relationship is not accurate for a particular situation. That burden includes presenting specific empirical evidence of the factors that are causing average costs to rise that are not related to marginal costs. Simple or broad simplistic statements are not sufficient to overturn this relationship.

III. ANTICIPATING A CHANGING WORLD

Q. How is the electricity market changing and how should that influence the commission's ratemaking policies in this case?

A. 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.[12] 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). Now new technologies enable customers to produce their own energy and to substantially or fully escape reliance on the centralized utility grid.

Over the last several years, 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 2020 and again in September 2022 in the area served by the California Independent

[12] Kahn (1988); National Economic Research Associates, 1977, "A Framework for Marginal Cost-Based Time-Differentiated Pricing in the United States," Prepared for EPRI Rate Design Study.

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;[13] (2) power safety power shutoffs (PSPS) to mitigate potential wildfire hazards in California utilities' service areas;[14] (3) widespread rolling outages in Texas caused by extreme freezing weather; [15] and (4) Winter Storm Elliot in 2022 that also caused widespread outage across Kentucky and many other states.[16]

In this case, these evolving constructs are being crammed into the old analytic 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 between the utility and its customers. The Commission should recognize that a single specific approach adopted today may have to be soon cast aside as technology evolves further.

IV. PROVIDING CUSTOMER-GENERATORS WITH EQUITABLE TREATMENT

Q. How are utility-scale generators provided assurance of recovering their investment costs?

A. 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

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[13] "California begins rolling blackouts after first Stage 3 emergency since 2001," *Los Angeles Times*, https://www.latimes.com/california/story/2020-08-14/la-me-statewide-power-outages-warning, August 14, 2020.

[14] "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.

[15] "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.

[16] FERC, "FERC, NERC Release Final Report on Lessons from Winter Storm Elliott," https://www.ferc.gov/news-events/news/ferc-nerc-release-final-report-lessons-winter-storm-elliott, November 7, 2023.

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 even decades, and often the economic life of their assets. Utilities are able to put investment in the 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) such as PJM demands so. Generators are only required to do so when they sign a long-term PPA with an assured payment toward investment recovery.

Q. Given this treatment of utility-scale generators' investments, how should rooftop solar generators' investments be considered in designing a NM rate?

A. 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 later cost more than market purchases, then those ratepayers should receive credit for avoiding future costs based on *long-term* market costs at the time of contracting. **If on the other hand ratepayers are to face *short-term* market**

prices that are updated every year, then they should not have to bear the excess 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 individual 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.

Q. Have wholesale bulk power markets delivered realistic or accurate measures of the true value of generation resources?

A. 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 separate price adder of up to $9,000 per megawatt-hour ($9 per kilowatt-hour)[17] during specified load conditions to provide sufficient revenue to cover generators' full costs.

Q. Why are these short-run hourly markets falling short in reflecting true resource value?

A. 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 and market prices. 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

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[17] Since revised downward to $5,000 per MWH.

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. The ability to sell to a different consumer is a fundamental principle of a properly functioning market—that is not possible in an electricity market. 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 instead generators have true and enforceable must-offer requirements, then their bids are artificially capped in some manner. For this reason, 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.

V. DETERMINING THE APPROPRIATE AVOIDED COSTS FOR CUSTOMER-GENERATORS

Q. Does rooftop solar provide a substantial benefit to the regional electricity grid?

A. A recent study from the Lawrence Berkeley National Laboratory examines the physical value of solar to the grid, including to PJM.[18] That study found that solar generation continued to provide the same level of reliable capacity over the 2012 to 2019 period in PJM,[19] and that the amount of the credit is about 55% of installed capacity for distributed solar.[20] While distributed solar capacity has grown since then, the share in PJM is still below 5%.[21] 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.[22]

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

Q. Is generation from rooftop solar a "random and intermittent" resource?

A. DEK in testimony and data responses erroneously asserts that rooftop solar generation is "random and intermittent" and therefore cannot be credited for deferring investment in either transmission or distribution.[23] DEK even went so far as to claim that demand side management (DSM) was more reliable than solar.[24]

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[18] 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 Laboratory, Energy Analysis & Environmental Impacts Division, Electricity Markets & Policy. Available at https://eta-publications.lbl.gov/sites/default/files/solar-to-grid_technical_report.pdf.
[19] LBNL (2021), p. 24.
[20] LBNL (2021), p. 76.
[21] LBNL (2021), p. 32.
[22] LBNL (2021), p. 32.
[23] Direct Testimony of Bruce L. Sailers, p. 19.
[24] DEK Response to KSES-DR-02-016.

DSM, whether as demand response as implied by the DEK data response or more broadly as energy efficiency is a critical component of meeting DEK's future energy needs and environmental compliance goals. However, DSM and rooftop solar are much more alike than different, contrary to what DEK tries to assert. This strong similarity and overlap is why the Joint Intervenors are involved in this case—DEK should not be allowed to treat them differently.

The facts are that solar has a more constant and predictable output than DSM; DSM has an advantage of being more closely matched to customer usage. For DSM to deliver capacity value, a customer in a DSM program must first have the appliance or device on before the utility can dial it back during periods when DSM is being called. Even heating and air conditioning cycles on and off at random, intermittent times. The utility cannot rely on any one single customer to provide capacity savings at a given moment. Instead, DSM works through the aggregation of many customers and the law of large numbers allows a utility to fairly accurately predicted the saving from that aggregated number. Rooftop solar not only also delivers those resources through aggregation, but the output from a single solar unit can be predicted fairly accurately through modeling and weather forecasting. That a model like PV Watts, used by DEK in this case,[25] is able to predict solar unit output reliably while no such similar broad-application model exists for DSM or other energy efficiency measures speaks to the relative certainty around deliverability between the two types of resources. DEK is willing to bank on DSM to make decisions about transmission and distribution investments. It must do the same with rooftop solar to be internally consistent.

[25] Sailers, Attachment BLS-2.

Q. What is the avoided cost of energy created by customer-generators?

A. DEK uses forecasted locational market prices (LMPs) at the proximate PJM market hub to determine avoided costs to 2045.[26] Mr. Sailers reports a **net present value of $0.041491 per kilowatt-hour for residential customers** and **$0.041901 per kilowatt-hour for commercial customers**.[27]

Unfortunately, I am not able to examine the validity of these forecasts in detail because the work was performed by an unnamed third-party vendor who has not been presented for data inquiries and cross examination.[28] Issues that can greatly influence this forecast include natural gas prices, demand growth expectations and changes in the composition of the generation fleet. None of these assumptions and others have been presented for review by stakeholders and the Commission. In addition, the stakeholders have not been given an opportunity to develop alternative forecasts within a common forecasting framework.[29]

That said, I use this forecast as the base forecast, but with an important adjustment for the inherent uncertainty in any forecast compared to the relative certainty of the upfront cost for rooftop solar.

Q. How does relying on simple market price forecasts underestimate the true value of renewables such as rooftop solar?

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[26] Sailers at p. 16.

[27] This includes line losses.

[28] DEK Response to KSES-DR-02-019.

[29] Further, separately contracting for these forecasting services can be as much as $50,000. These consulting firms typically prepare forecasts for market participants like DEK who can spread these costs over many different operations and multiple instances.

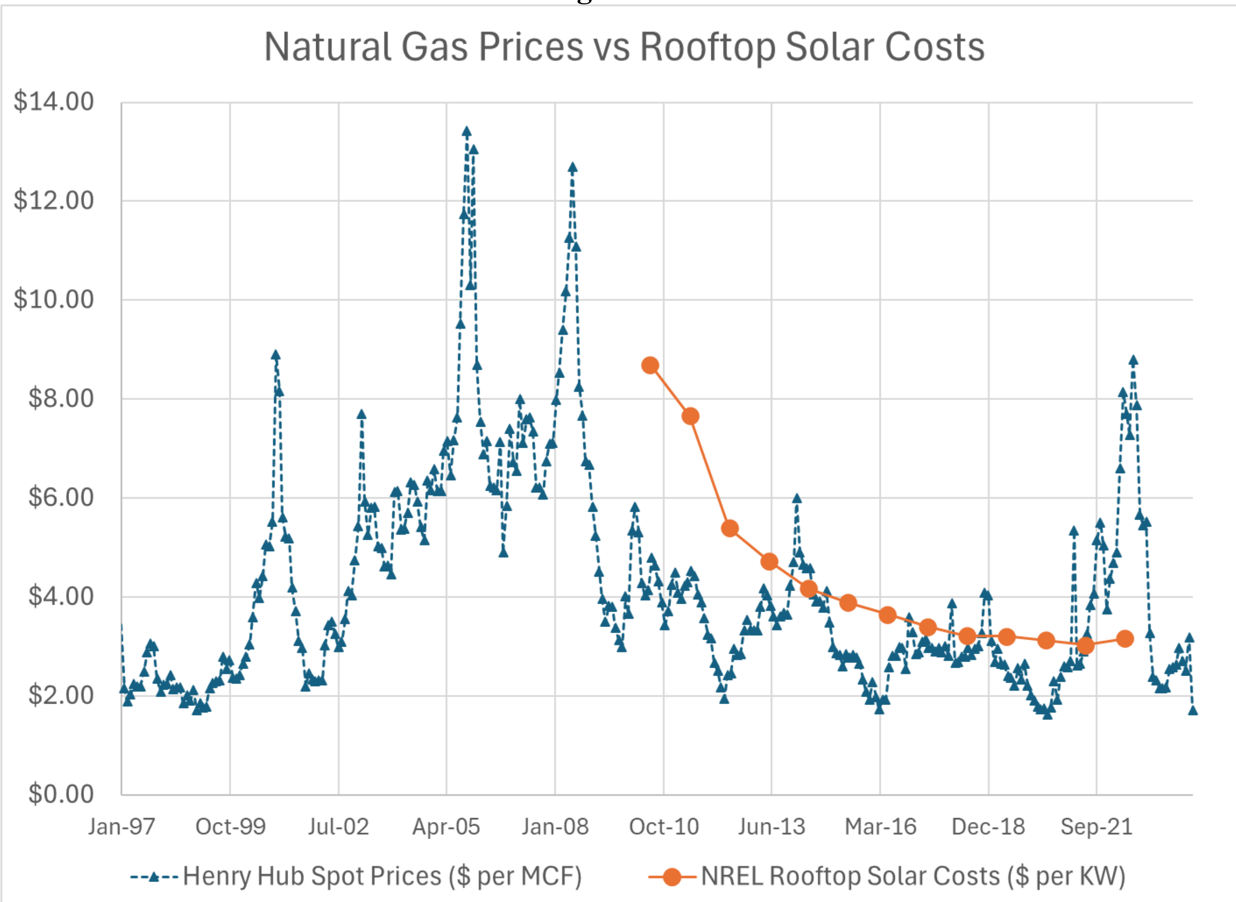
A. The wholesale prices in PJM can be quite volatile, both within the year and across years. The average cost of wholesale power in 2023 was half of what it was in 2022.[30] Much of this volatility is created by variable natural gas prices that power the generators which set those LMPs. Figure JI-2 charts the path of the Henry Hub natural gas market place and the volatility is quite evident.[31] That figure also shows the steadily declining cost per kilowatt of residential rooftop solar in comparison.[32] The difference between $2 per thousand cubic feet (MCF) and $8 gas prices translates to 4.2 cents per kilowatt-hour. Relying on a single-line LMP forecast ignores the historic volatility of fuel costs and likely continued risk exposure for ratepayers in the future.

[30] PJM, "Markets Report," MC Webinar, September 18, 2023, p. 2. Available at https://www.pjm.com/-/media/committees-groups/committees/mc/2023/20230918-webinar/item-08a---market-operations-report.ashx.

[31] U.S. Energy Information Administration, "Henry Hub Natural Gas Spot Price," https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm, data retrieved March 2024.

[32] National Renewable Energy Laboratory, "Solar Installed System Cost Analysis," https://www.nrel.gov/solar/market-research-analysis/solar-installed-system-cost.html, retrieved March 2024.

Figure JI-2



Distributed solar allows customer-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. DEK has ignored this benefit in calculating the full set of avoided costs created by rooftop solar.[33]

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

[33] In DEK Response to KSES-DR-02-037, DEK stated, “The Company does not derive a hedging value to evaluate non-fossil-fueled generation, demand management and/or storage resources.” This is akin to your financial advisor saying, "we're just going to invest like day traders, risking it all everyday to make the big bucks." Of course, a prudent advisor suggests a mix of financial instruments for a portfolio to mitigate market risks.

setting the market clearing price in the PJM market.[34] 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 7,000 British thermal units per kilowatt-hour (BTU per kWh),[35] that translates to a benefit of an additional 1.125 to 1.875 cents per kWh or \$10.50 to \$17.50 per megawatt-hour (MWH) provided by distributed solar. Using the average of these is \$14 per MWH or **\$0.0140 per kilowatt-hour** for calculating the avoided cost benefit.

Other customers on a customer-generator's respective utility benefit from this load reduction. That in turn reduces the prices in the PJM market paid on all load served from that market, in turn reducing their exposure to market volatility. DEK 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 DEK.

Q. What is the value of avoided generation capacity investment based on the principle specified by the commission?

A. As discussed previously, the Commission determined that PJM's Net CONE calculation best represents the long-term value of avoided generation capacity. Furthermore, PJM's

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[34] Lisa Huber, "Utility Scale Wind and Natural Gas Volatility, Rocky Mountain Institute, https://rmi.org/wp-content/uploads/2017/05/RMI_Document_Repository_Public-Reprts_2012-07_WindNaturalGasVolatility.pdf, July 2012; and Amory Lovins and Jon Creyts, "Hot Air About Cheap Natural Gas," https://rmi.org/hot-air-cheap-natural-gas/, September 6, 2012. Another example of such a study is 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.)

[35] Brattle Group, "PJM CONE 2026/2027 Report," April 21, 2022, p. v. Available at https://www.pjm.com/-/media/library/reports-notices/special-reports/2022/20220422-brattle-final-cone-report.ashx. Combined cycle plants typically run at capacity factors between 30% and 60% averaged over the year, and the midpoint between the full and minimum load heat rates is about 7,000 Btu/kWh.

analysis is rigorously reviewed and critiqued by a large group of stakeholders including DEK. PJM members make many procurement decisions at least influenced by, if not relying on, the Net CONE values. The Commission recognized the usefulness of a universal benchmark in directing the utilities it regulates to use this value in their avoided cost calculations for ratemaking purposes.

DEK makes specious arguments that it cannot rely on PJM to acquire its capacity resources. DEK is clearly relying on PJM resources for other purposes as expressed in use of the LMP forecast for energy and alluding to the inclusion of the federal Inflation Reduction Act (IRA) incentives invested in other service areas as a means of complying with greenhouse gas (GHG) reduction goals. Further, DEK asserts that the cost of capital used by PJM is too high and not representative, but PJM's weighted average cost of capital of 8.0%[36] is only marginally higher than that of DEK at 7.192%.[37] That makes a difference of 6.3% in the costs between PJM and DEK. The Commission already considered this type of argument by Kentucky Power and dismissed it. For this reason, I present the Net CONE valuation for capacity, adjusted for PJM's capacity value factor applied to fixed mount solar.[38]

I make two adjustments to PJM's calculation. The first is to reflect the difference in available non-spinning reserve capacity between a combined cycle plant (CCGT) and a combustion turbine (CT).[39] A CT can be online in 10 minutes so 100% of its capacity is

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[36] Brattle Group (2022), p. vi.

[37] DEK Response to KSES-DR-02-031.

[38] PJM, "Periodic Review of Default Gross CONE and Gross ACR Values," March 2023. Available at https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230308/20230308-item-04-1---periodic-review-of-default-cone-and-acr-values.ashx.

[39] In the near future, the battery energy storage system (BESS) likely will be the preferred resource for both environmental and cost reasons, as well as it can deliver up to 200% of its capacity for reliability purposes (by

available in this role. A CCGT requires at least 12 hours to ramp up, and preferentially for a number of reasons is operating continually. In this mode, only 67% of its capacity is available to meet increased peak loads.[40] The second is to reduce PJM's calculation for DEK's slightly lower cost of capital. With these adjustments, a CCGT is slightly less expensive than a CT by about 4%.

Using the modified cost of $97.49 per kilowatt-year and adjusting to the solar fixed mount capacity value factor of 31%, the adjusted capacity value is $30.27 per kilowatt-year. Dividing over 1,458 kilowatt-hours per kilowatt, the **avoided capacity value is $0.0207 per kilowatt.**

Q. What is the value of displaced transmission based on the principle specified by the commission?

A. As discussed previously, the Commission directed that avoided transmission costs be based on historic investments. The methodology presented here uses the FERC transmission rate filings by Duke Energy Ohio and Kentucky (DEOK) and evaluates those rate changes against a primary driver of transmission investment which is added generation to serve load. PJM states that transmission investment is driven 20% by new generation and 80% "to evolve the transmission system to meet changing needs."[41] Such evolution likely can be attributed to changes in generation mixes. (PJM does not mention at all that additional transmission is related to load growth, probably because increased load must be served by added generation.)

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shifting from charging to discharging). BESS is currently about 40% more expensive than the conventional alternatives.

[40] Brattle Group (2022), p. vi.

[41] PJM, "The Value of Transmission," 2018, p. 3. Available at https://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/the-value-of-transmission.ashx.

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. For this reason, unless the utility can provide specific empirical information to the contrary, the Commission can safely assume that rooftop solar that displaces generation also displaces transmission.

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 operating company for Duke Energy Kentucky (DEK) within PJM, Duke Energy Ohio and Kentucky (DEOK), files network service rates each year with PJM and FERC. Table JI-1 recounts those rates on a per megawatt-year basis.[42] The rate almost tripled from 2014-2015 to 2023-2024 at average annual increase of 10%.

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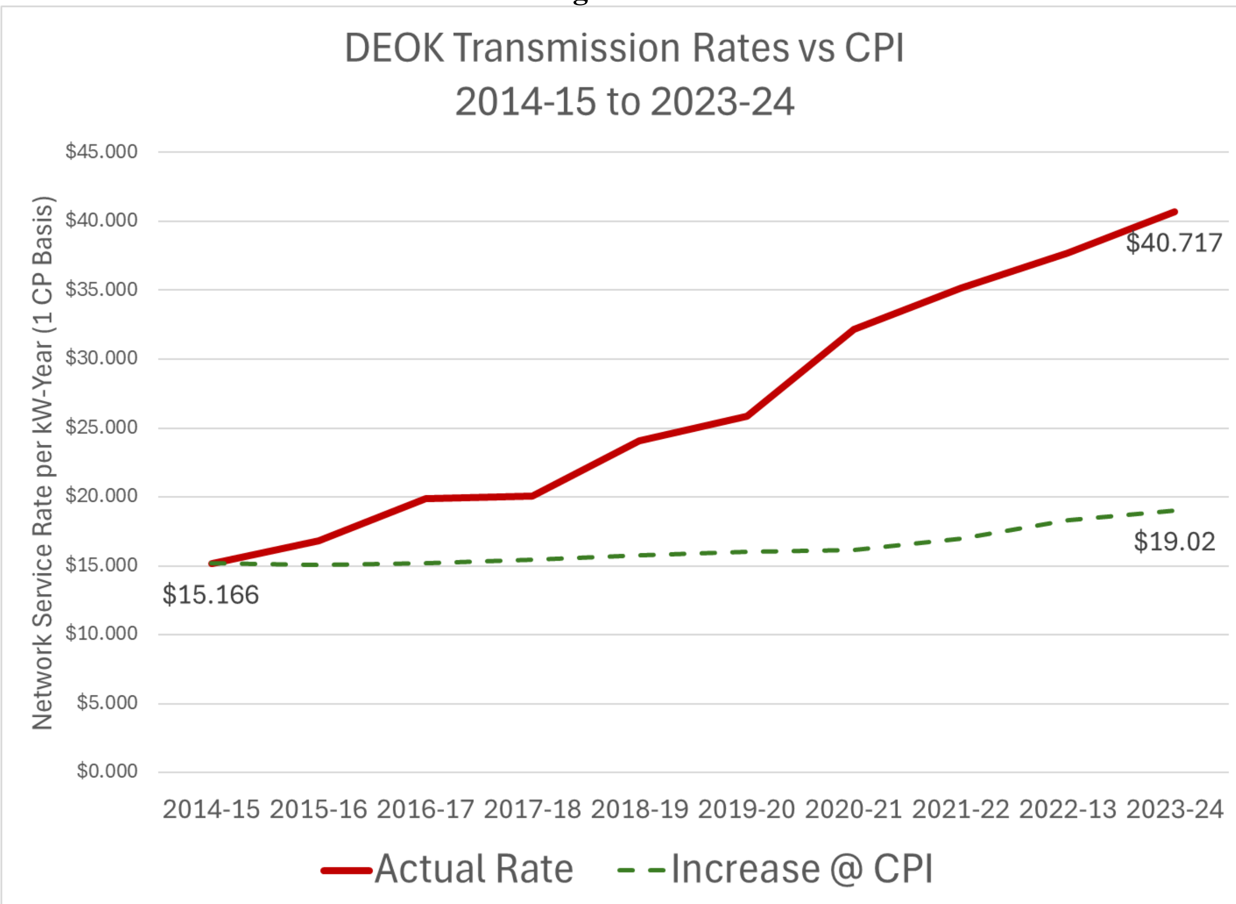
[42] PJM, "Formula Rates," https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates, data retrieved February 2024.

Table JI-1 - DEOK Transmission Rates 2018-2023

Fiscal Year	Network service rate pe kW-year	Increase
2014-15	$15.166	
2015-16	$16.844	11%
2016-17	$19.881	18%
2017-18	$20.055	1%
2018-19	$24.077	20%
2019-20	$25.840	7%
2020-21	$32.143	24%
2021-22	$35.136	9%
2022-13	$37.718	7%
2023-24	$40.717	8%

Figure JI-3 shows how these rates increased compared to the Consumer Price Index measure of inflation.

Figure JI- 3



Based on the addition of 51,330 megawatts of generation capacity in PJM over that period,[43] the incremental cost of transmission was $93,300 per megawatt-year or over four times the current DEOK transmission rate. This incremental cost represents the long-term value of displaced transmission. This equates to **$0.0174 cents per kilowatt-hour**. The amount of the credit that rooftop solar can claim of that incremental cost should be included in a full cost of service study for NM customers.

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[43] PJM, *2023 State of the Market*, Section 12, Table 12-29. Available at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2023/2023q3-som-pjm-sec12.pdf.

Q. What are the avoided distribution costs created by customer-generators?

A. Similarly, NM 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.

Unfortunately, utilities' forecasts are notorious for overestimating load growth, resulting in part from underestimating savings from resource displacement through solar rooftops and energy efficiency.[44] As a result, utilities build unneeded distribution infrastructure. For example, I have testified in California utility commission proceedings for more than three decades 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. DEK shows stagnant growth with its highest peak recorded almost seven years ago in 2017.[45]

DEK has calculated an **avoided cost for distribution of $0.015393 per kilowatt-hour** that is consistent with that calculated for other utilities.[46] That value should be included when determining the compensation for NM customers.

Q. What is the benefit in avoided carbon costs created by customer-generators?

A. The Commission recognizes that Kentucky utilities are at least implicitly including a cost of carbon emissions when developing integrated resource plans with specified zero net carbon targets, such as DEK's 2040 objective.[47] DEK asserts that the entire cost of

[44] Note that large data centers that may come to low-rate utilities interconnect at transmission and subtransmission voltage because of their high power demand. They also avoid paying the costs of the distribution system. The utilities need not invest in new distribution to serve these types of customers.

[45] DEK Response to Confidential KSES-DR-02-014.

[46] See for example Kentucky Power as well at the filings for California and Washington utilities.

[47] Sailers at p. 21. This includes line losses.

achieving its 2040 goal of zero carbon emissions from generation is reflected in the electricity system dispatch model results that incorporates the tax incentives from the federal government's 2022 Inflation Reduction Act (IRA).[48] This approach ignores that DEK must replace its current fossil-fueled generation fleet (or add extremely expensive carbon capture[49] or use unproven and likely expensive "green" hydrogen fuel) to actually achieve its 2040 objective. Furthermore, the IRA will not finance sufficient investment for the U.S. power grid to achieve zero emissions—further investments will be required.[50] DEK's presumption is not sufficient and a cost of carbon is necessary to reflect the value of further GHG emission reductions derived from rooftop solar.

Instead, the Commission should apply the recently adopted valuation standard by the U.S. Environmental Protection Agency that will drive the emission standards established for both natural gas production and electricity generation. The US EPA sets a value of avoided carbon emissions that it uses in establishing environmental regulations such as the Clean Power Plan and Affordable Clean Energy Rule as well as motor vehicle and stationary source regulations.[51] For 2030, that value ranges from \$140 to \$380 per metric ton of carbon dioxide (CO_2) depending the assumption about the discount rate.[52]

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[48] Sailers, p. 17. A contradiction in this assertion arises in that DEK claims it can rely on resources in the PJM area outside of its service territory and ownership, yet claims that it cannot use PJM's NetCONE calculations to set a capacity value because it must own those capacity resources.

[49] Direct Testimony of Andrew McDonald on Behalf of Joint Intervenors, Louisville Gas & Electric, Case No. 2023-00404, February 29, 2024, p. 12.

[50] Congressional Research Service, "U.S. Greenhouse Gas Emissions Trends and Projections from the Inflation Reduction Act," https://crsreports.congress.gov/product/pdf/R/R47385, January 12, 2023.

[51] US EPA, *Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review": EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, Docket ID No. EPA-HQ-OAR-2021-0317, https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf, November 2023.

[52] US EPA, p. 4.

Again assuming a thermal efficiency or "heat rate" for the marginal use of gas in the electricity market of 7,000 BTU per kWh, and applying the mid-range value for the 2% discount rate case of $230 per metric ton of CO_2, the cost of carbon is $0.0850 per kilowatt-hour.

McDonald proposed a cost of carbon on behalf of the Joint Intervenors in the recent LG&E case ranging between $58 and $188 per ton to reflect the current projected cost of carbon capture. The combined midpoint of the estimates for natural gas and coal generators is $126 per ton.[53] Based on the market heat rate, this translates to **$0.0466 per kilowatt-hour.**

Q. What is the line loss adjustment to be made to the avoided cost calculation?

Since the rooftop solar generator is located proximate to the primary consumer and all exported energy is consumed within the neighborhood, this resource avoids line losses. DEK uses line losses of 6.264%.[54] That adjustment adds **0.90 cents per kilowatt-hour** to the avoided cost.

VI. JOBS AND ECONOMIC BENEFITS TO KENTUCKY FROM ROOFTOP SOLAR

Q. What are the net economic benefits of adding rooftop solar over relying on grid-scale solar?

A. Among the directives from the Commission in determining NM rates is the consideration of net economic gains and added jobs from rooftop solar. DEK has not included such an analysis in its present filing. I present such an analysis here.

[53] McDonald at p. 12.

[54] Sailers, Attachment BLS-2.

Q. What analysis did you conduct to estimate the benefits of rooftop solar to the Kentucky economy?

A. Kentucky has lagged behind other states in installing rooftop photovoltaics (PV) with the total number of grid-connected residential PV installations ranking 40th of all states, comprising just 0.28% of homes. In 2022, small-scale solar accounted for 0.1% of the state's total electricity mix and all solar accounted for 0.22% of the state's electricity. Kentucky solar price declines of 47% over ten years combined with other incentives leads the Solar Energy Industry Association (SEIA) to forecast that the state will see 2,846 MW of solar growth within the next five years – 18th amongst all states.[55] Cutting back net metering or other incentives will deal a significant blow to a burgeoning green industry just as it begins to firmly establish itself.

This report examines the benefits to the state's economy caused by a thriving rooftop solar industry. A 15 MW per year solar growth scenario over eight years from 2022 to 2030 is modeled using two different methods.[56] This level of solar growth is only possible through continued incentives such as NEM.

This growth scenario was analyzed using the Jobs and Economic Development Impact modeling (JEDI) tool created by the National Renewable Energy Laboratory (NREL).[57] JEDI modeling impacts are state and type of development – in our case residential or utility specific. The US IREC+JEDI model used US solar jobs data from the Interstate Renewable

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[55] SEIA State Solar Spotlight, Kentucky, https://www.seia.org/sites/default/files/2024-03/Kentucky.pdf.

[56] 2022 was the initial year because of data availability.

[57] NREL, "Jobs & Economic Development Impact Models," https://www.nrel.gov/analysis/jedi/, retrieved December 2023. (The JEDI model is based on the widely-used IMPLAN Regional Economic Impacts Model.)

Energy Council (IREC) and merges that with JEDI economic multipliers.[58] US solar MW data was taken from the Solar Energy Industries Association (SEIA).

Q. What are your findings on the economic benefits?

A. The economic benefits of achieving high rooftop PV adoption levels are substantially greater than relying on utility-scale solar to supply the same amount of capacity. Direct jobs are those created directly in the industry. Indirect jobs are those created by solar industry purchases within the supply chain, for example jobs created by purchasing electrical equipment from the local supplier. Induced jobs are those stemming from household spending of labor income, for example a solar installation employee utilizing their paycheck to purchase groceries. Based on the analysis presented here, rooftop solar creates **4.8 to 11.4 times more jobs** per installed MW than utility-scale solar. As a result, an additional 15 MW of growth from rooftop solar will sustain as many as **444 jobs** compared to **89 jobs** associated with utility-scale solar, as shown in Figure JI-4.

[58] IREC, "National Solar Jobs Census 2022," https://irecusa.org/census-solar-job-trends/, July 2023.

Figure JI- 4

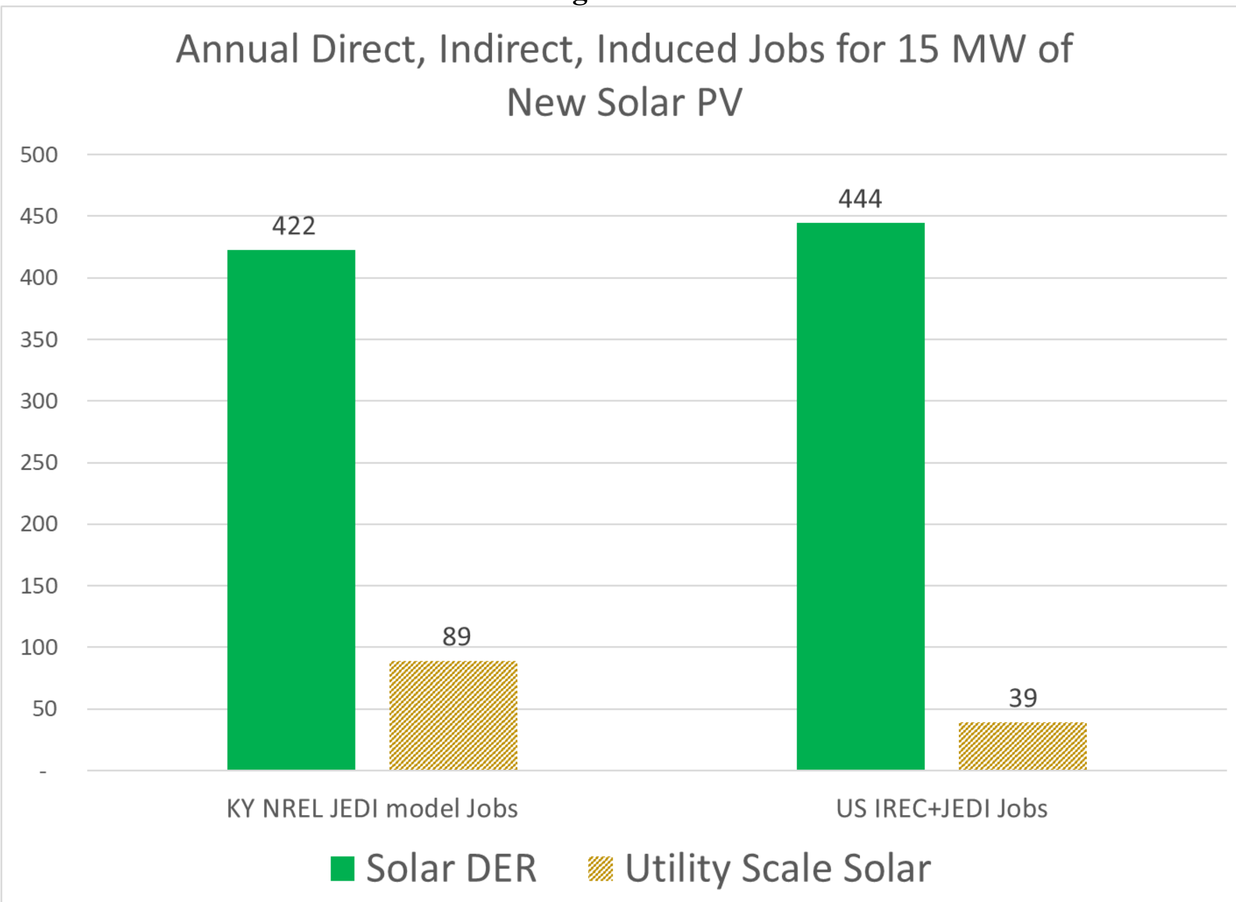

Figure JI-5 shows that rooftop solar creates **4.5 to 10.9 times greater total earnings** as compared to utility solar. Rooftop solar also supports more locally owned businesses and personal income[59] because it relies on neighborhood businesses to install the panels.

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[59] Direct economic benefits are the sum of business profits and employees' income. Purchased goods (e.g., solar panels or steel from China) are simply a passed through cost to buyers as no value is added by businesses. Other economic benefits not addressed and quantified here include environmental, risk mitigation and social transformation.

Figure JI- 5

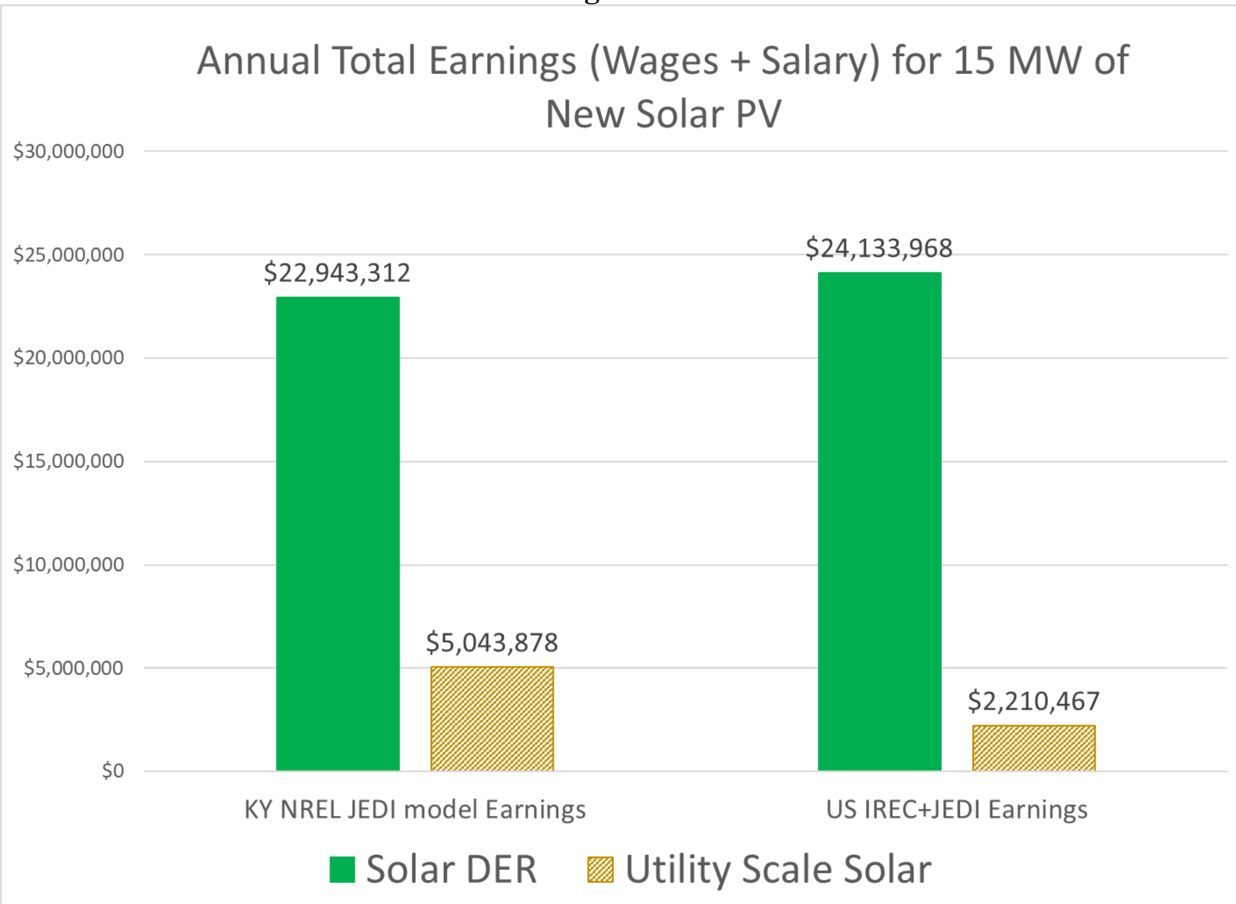

Figure JI-6 shows the **total output is 5.6 to 13.4 times greater** for rooftop solar compared to utility solar**.** Output is often referred to as the value to the regional economy and is a measure of the sum of sales to final users in the economy (GDP) plus sales to other industries (Intermediate Inputs) plus inventory change.[60]

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[60] IMPLAN, "Output, Value Added, & Double-Counting," https://support.implan.com/hc/en-us/articles/360025171053-Output-Value-Added-Double-Counting, June 19, 2019.

Figure JI-6

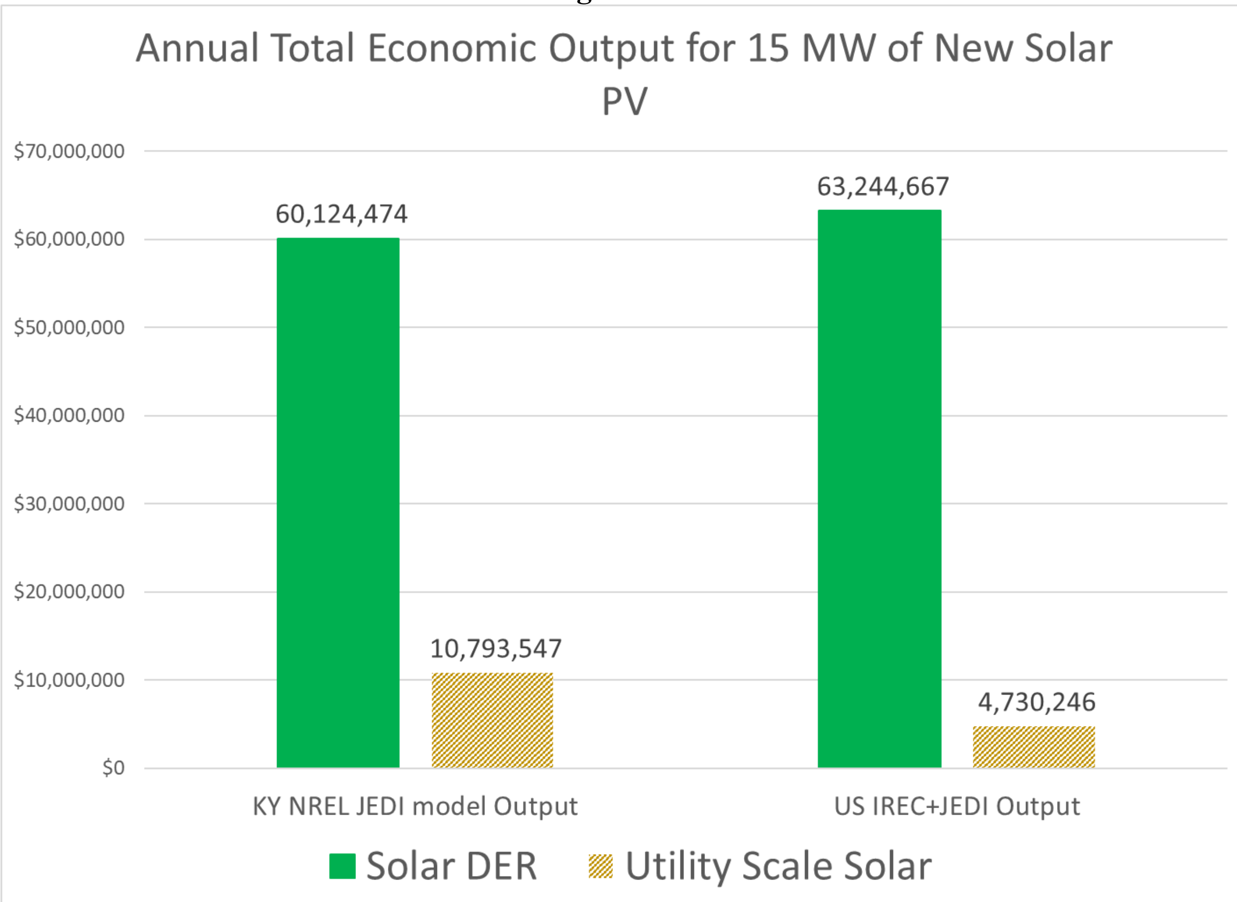
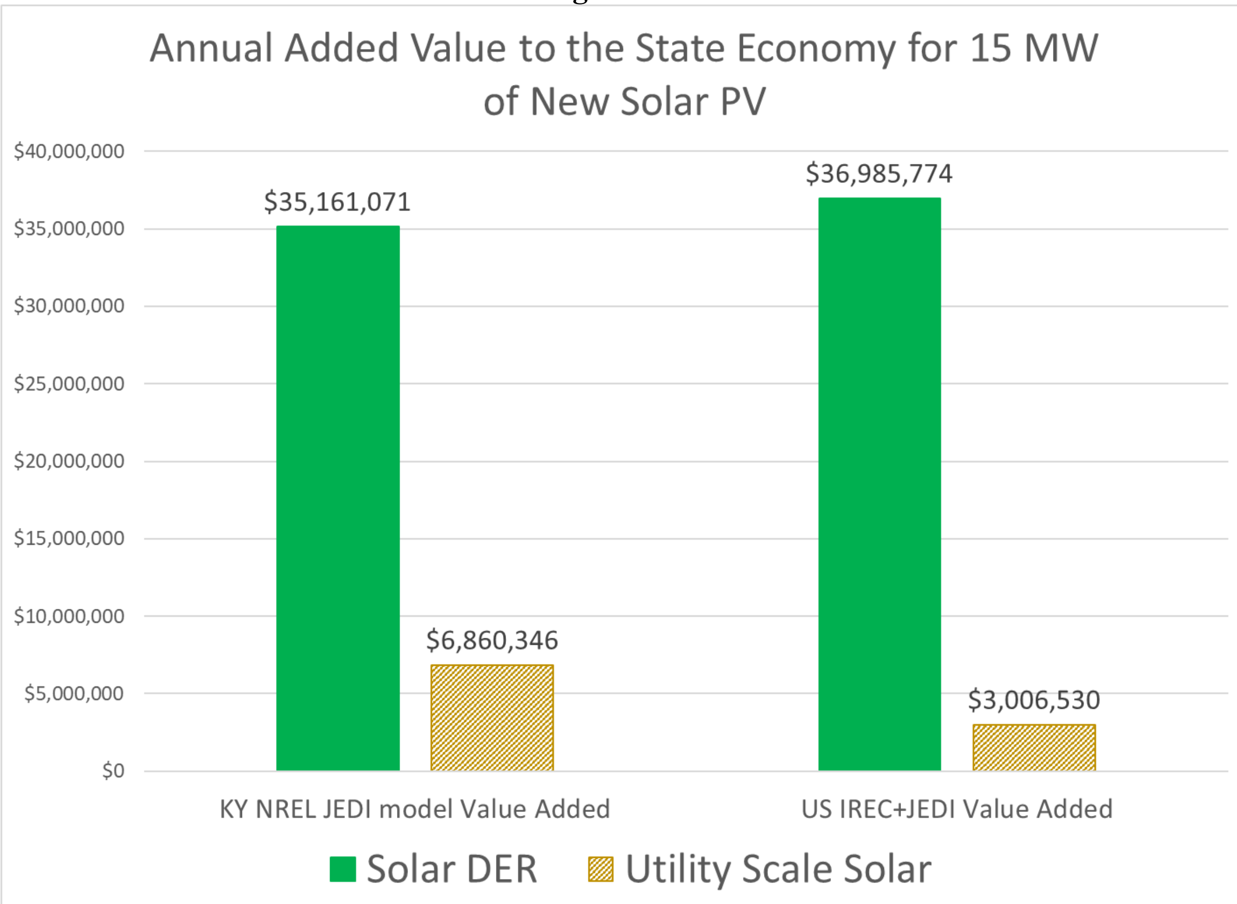


Figure JI-7 shows the **total value added is 5.1 to 12.3 times greater for rooftop solar** compared to utility solar. Value Added is defined as the total market value of all final goods and services produced within a region. To measure only final goods, all intermediate inputs are subtracted. In other words, value added is the wealth created by industry activity[61].

[61] Ibid.

Figure JI- 7



Q. What is the difference in federal tax benefits flowing to Kentucky between rooftop versus utility-scale solar?

A. Small-scale systems also bring in more federal dollars to Kentucky. Rooftop solar systems could garner **$12 million in tax rebates through the** Inflation Reduction Act (IRA) **in 2024** and **$97 million by 2030.** Utility-scale projects are likely to secure just **$3 million in 2024** and **$28 million by 2030**, roughly 30% of what can be harvested from the smaller systems.[62]

[62] This forecast is detailed in the attachment, "The Economic Benefits of Rooftop and Utility Solar in Kentucky."

Both rooftop and utility solar generate clean electricity, but rooftop solar creates far greater beneficial economic impacts for Kentucky. These findings point to the need for a closer examination of the preferred path for adding more renewables. Further, action should be taken to ensure that the rooftop solar industry is sufficiently robust to deliver the capacity that will be required.

VII. CONCLUSION

Q. Could you please summarize your recommendations in this proceeding?

A. DEK is proposing that residential customer-generators be credited 5.71 cents per kilowatt-hour and commercial/non-residential receive a credit of 5.75 cents per kilowatt-hour. I recommend instead that **residential generator-customers receive a credit of $0.1627 kilowatt-hour** and **commercial/non-residential a credit of $0.1630 per kilowatt-hour**. Table JI-2 summarizes the recommended values for each component as discussed previously.

Table JI-2

Total Avoided Costs for Customer-Generators Category	Residential $/kWh	Commercial $/kWh	Source
Generation Energy	$0.0415	$0.0419	DEK Testimony, Sailers, p.16
Ancillary Services	$0.0006	$0.0005	DEK Testimony, Sailers, p.18
Generation Capacity	$0.0216	$0.0216	PJM NetCONE CT adjusted for solar
Risk Hedge Value	$0.0140	$0.0140	RMI
Transmission	$0.0173	$0.0173	PJM/DEOK data
Distribution	$0.0146	$0.0146	DEK Testimony, Sailers, p.21
Cost of Carbon	$0.0466	$0.0466	McDonald Testimony
Line Losses	$0.0066	$0.0066	
Transmission	0.785%	0.785%	
Distribution	5.436%	5.436%	
Total losses	6.264%	6.264%	Sailers Workpapers, Attachment BLS-2
Total Avoided Costs	**$0.1627**	**$0.1630**	
Without cost of carbon	$0.1190	$0.1194	

When acting on how to modify DEK's NM rate, the Commission should move in a considerate and deliberate manner. Given the low penetration of NM customers so far—less than 1%--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 NM 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, not just rooftop solar, in the future.

To do so, the Commission should give NM 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.

In any case, any transition should be done gradually. Rapid shifts have too often resulted in unanticipated economic displacement and adverse consequences.

Exhibit 1
The Economic Benefits of Rooftop and Utility Solar in Kentucky

The Economic Benefits of Rooftop and Utility Solar in Kentucky

M.Cubed

March 2024

EXECUTIVE SUMMARY

Kentucky has lagged behind other states in installing rooftop photovoltaics (PV) with the total number of grid-connected residential PV installations ranking 40th of all states, comprising just 0.28% of homes. In 2022, small-scale solar accounted for 0.1% of the state's total electricity mix and all solar accounted for 0.22% of the state's electricity. Kentucky solar price declines of 47% over ten years combined with other incentives leads the Solar Energy Industry Association (SEIA) to forecast that the state will see 2,846 MW of solar growth within the next five years – 18th amongst all states.[1] Cutting back net metering or other incentives will deal a significant blow to a burgeoning green industry just as it begins to firmly establish itself.

This report examines the benefits to the state's economy caused by a thriving rooftop solar industry. A 15MW per year solar growth scenario over eight years from 2022 to 2030 is modeled using two different methods.[2] This level of solar growth is only possible through continued incentives such as NEM.

This growth scenario was analyzed using the Jobs and Economic Development Impact modeling (JEDI) tool created by the National Renewable Energy Laboratory (NREL). [3] JEDI modeling impacts are state and type of development – in our case residential or utility specific. The US IREC+JEDI model used US solar jobs data from the Interstate Renewable Energy Council (IREC) and merges that with JEDI economic multipliers.[4] US solar MW data was taken from the Solar Energy Industries Association (SEIA).

The economic benefits of achieving high rooftop PV adoption levels are substantially greater than relying on utility-scale solar to supply the same amount of capacity. Direct jobs are those created directly in the industry. Indirect jobs are those created by solar industry purchases within the supply chain, for example jobs created by purchasing electrical equipment from the local supplier. Induced jobs are those stemming from household spending of labor income, for example a solar installation employee utilizing their paycheck to purchase groceries. Based on the analysis presented here, rooftop solar creates **4.8 to 11.4 times more jobs** per installed MW than utility-scale solar. As a result, an additional 15 MW of growth from rooftop solar will sustain as many as **444 jobs** compared to **89 jobs** associated with utility-scale solar, as shown in Figure 1.

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[1] SEIA State Solar Spotlight, Kentucky, https://www.seia.org/sites/default/files/2024-03/Kentucky.pdf

[2] 2022 was the initial year because of data availability.

[3] NREL, "Jobs & Economic Development Impact Models," https://www.nrel.gov/analysis/jedi/, retrieved December 2023. (The JEDI model is based on the widely-used IMPLAN Regional Economic Impacts Model.)

[4] IREC, "National Solar Jobs Census 2022," https://irecusa.org/census-solar-job-trends/, July 2023.

Figure 1

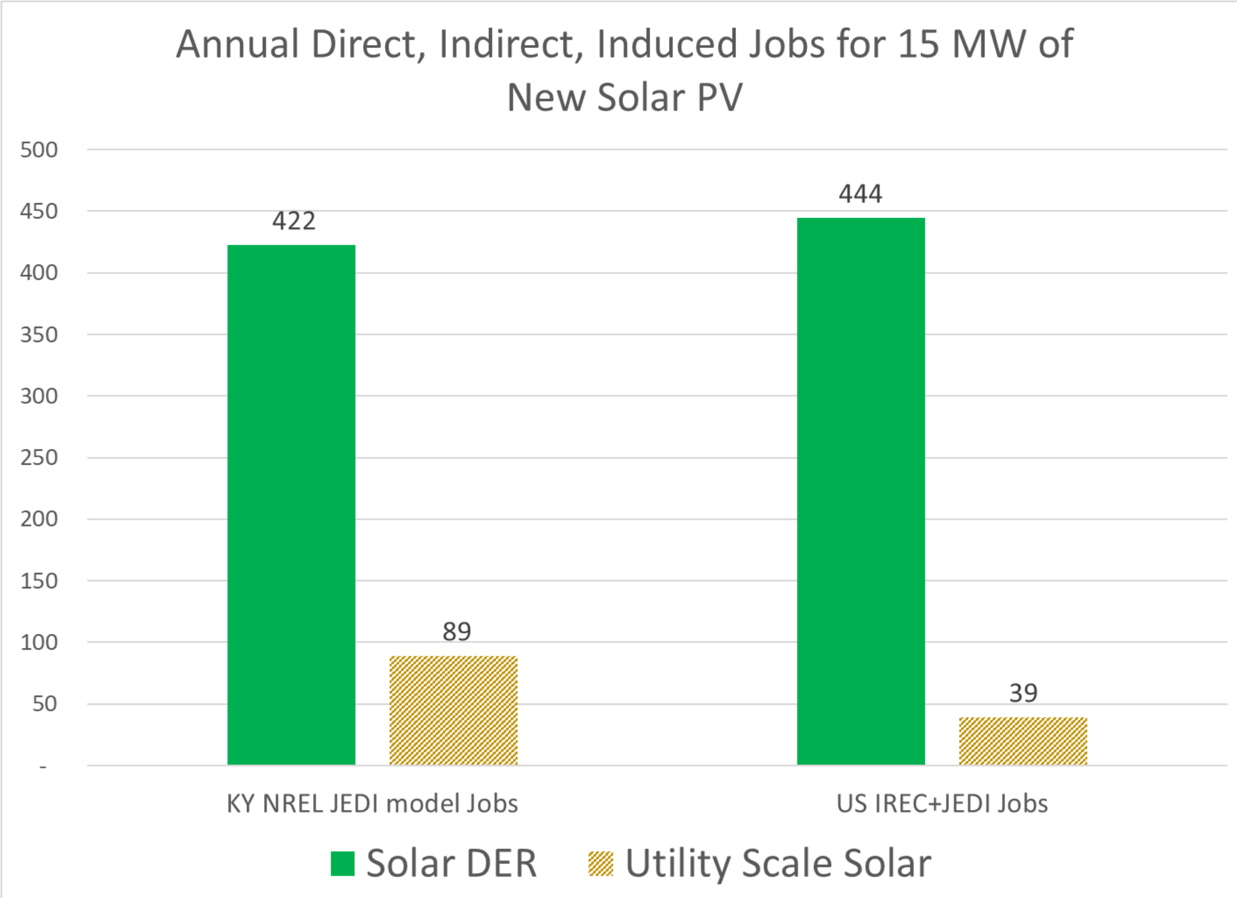

Figure 2 shows that rooftop solar creates **4.5 to 10.9 times greater total earnings** as compared to utility solar. Rooftop solar also supports more locally owned businesses and personal income[5] because it relies on neighborhood businesses to install the panels.

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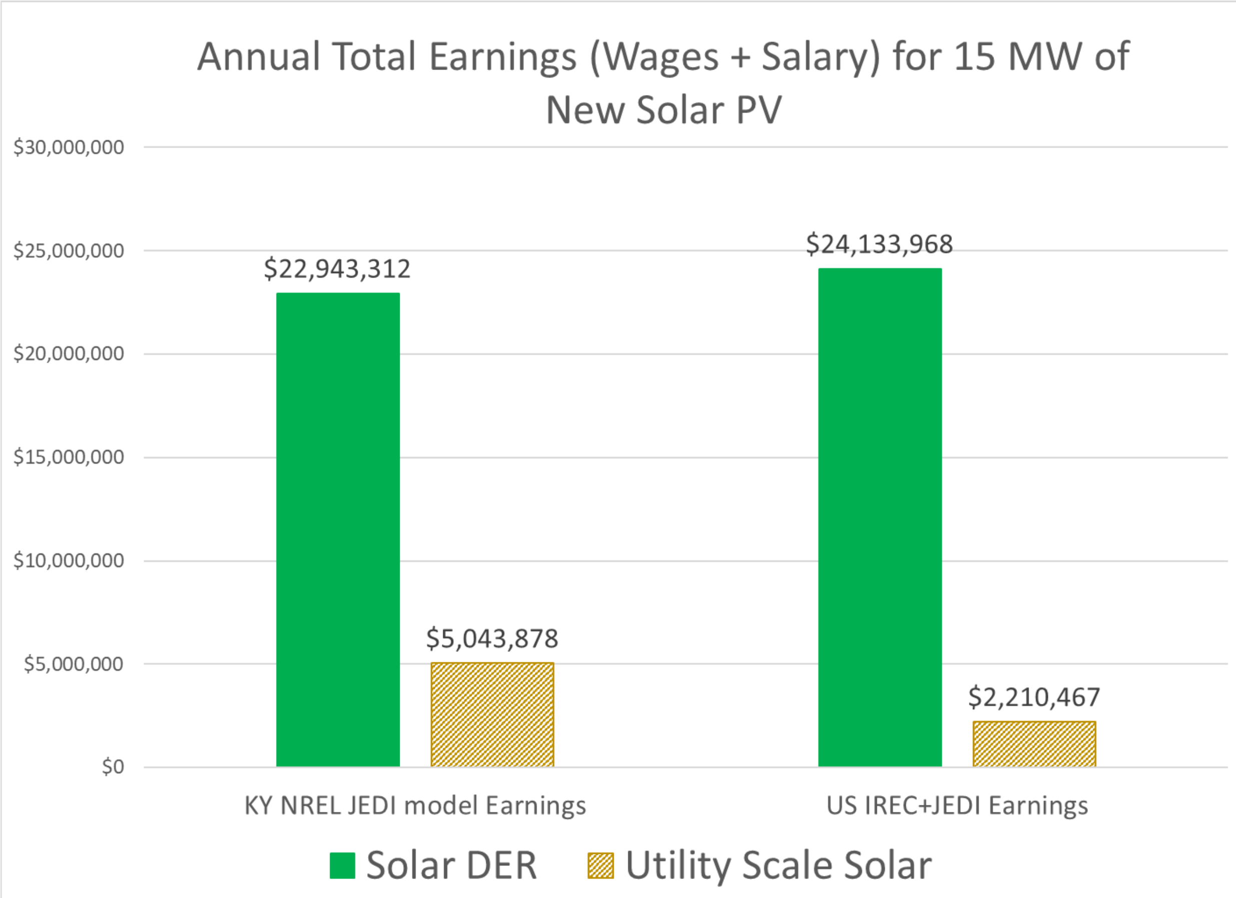
[5] Direct economic benefits are the sum of business profits and employees' income. Purchased goods (e.g., solar panels or steel from China) are simply a passed through cost to buyers as no value is added by businesses. Other economic benefits not addressed and quantified here include environmental, risk mitigation and social transformation.

Figure 2



Rooftop solar also generates far greater total output (**5.6 to 13.4 times**) and additional value (**5.1 to 12.3 times**) to Kentucky's economy as shown in Figures 3 and 4. Both rooftop and utility solar generate clean electricity, but rooftop solar creates far greater beneficial economic impacts for Kentucky.

Figure 3 shows the **total output is 5.6 to 13.4 times greater** for rooftop solar compared to utility solar**.** Output is often referred to as the value to the regional economy and is a measure of the sum of sales to final users in the economy (GDP) plus sales to other industries (Intermediate Inputs) plus inventory change.[6]

[6] IMPLAN https://support.implan.com/hc/en-us/articles/360025171053-Output-Value-Added-Double-Counting

Figure 3

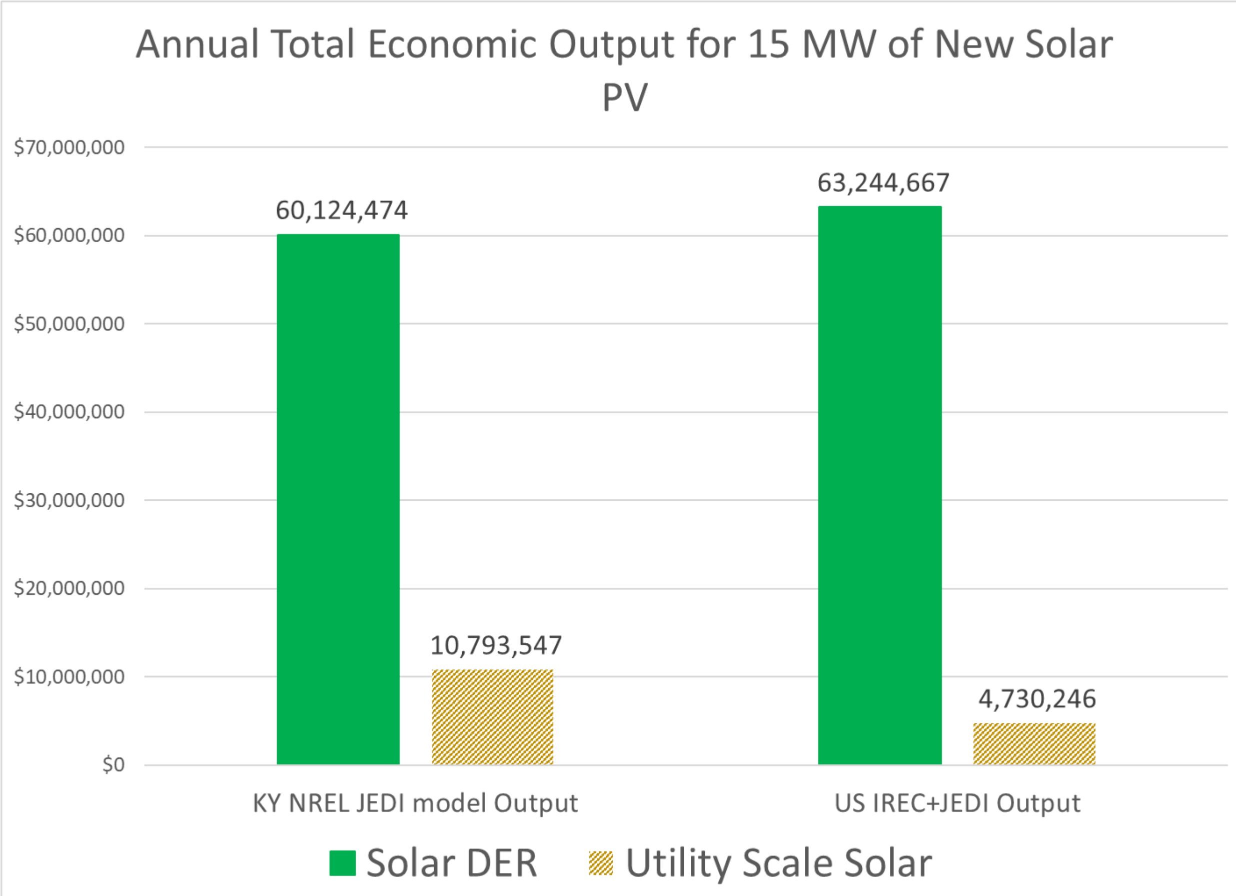
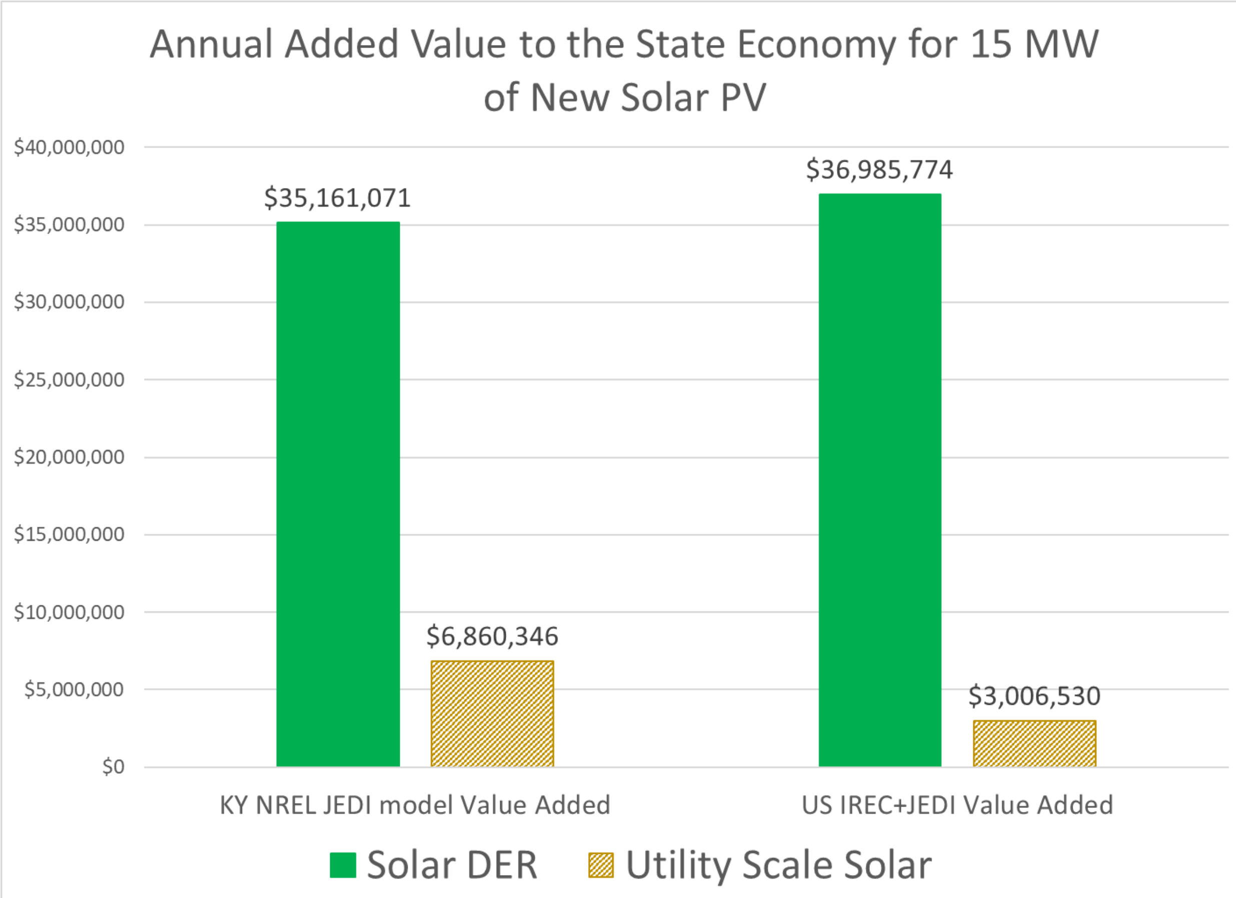


Figure 4 shows the **total value added is 5.1 to 12.3 times greater for rooftop solar** compared to utility solar. Value Added is defined as the total market value of all final goods and services produced within a region. To measure only final goods, all intermediate inputs are subtracted. In other words, value added is the wealth created by industry activity[7].

[7] ibid

Figure 4



Small-scale systems also bring in more federal dollars to Kentucky. Rooftop solar systems could garner **$12 million in tax rebates through the** Inflation Reduction Act (IRA) **in 2024** and **$97 million by 2030.** Utility-scale projects are likely to secure just **$3 million in 2024** and **$28 million by 2030**, roughly 30% of what can be harvested from the smaller systems.

These findings point to the need for a closer examination of the preferred path for adding more renewable generation. Further, action should be taken to ensure that the rooftop solar industry is sufficiently robust to deliver the capacity that will be required.

INTRODUCTION

Kentucky's low amount of distributed energy resources (DER) – also known as rooftop – PV penetration is due to its generally low electric rates. Kentucky's solar industry is in its infancy compared to other states, representing a so-far missed opportunity to secure federal tax credits and bolster jobs well-suited to fill-in the gaps caused by declining employment in other industries, such as mining and coal.

Changes to Duke Energy Kentucky's (DEK) net energy metering (NM) tariff could undermine progress in adding the renewable generation. With no significant wind generation capacity, utility solar is the only other viable option for greening the grid. The amount of large utility-scale solar currently supplies even less than rooftop solar.[8] Even though several large utility solar projects are posed to come online in 2024, rooftop solar[9] is still an important element in reducing carbon emissions because it can be built much more quickly than utility-scale renewables that require substantial additional transmission investment.

This report examines the benefits to the state's economy caused by a thriving rooftop solar industry. A 15 MW per year solar growth scenario over eight years from 2022 to 2030 is modeled using two different methods.[10] This level of solar growth is only possible through continued incentives such as NEM.

This growth scenario was analyzed using the Jobs and Economic Development Impact modeling (JEDI) tool created by the National Renewable Energy Laboratory (NREL).[11] JEDI modeling impacts are state and type of development – in our case residential or utility specific. The US IREC+JEDI model used US solar jobs data from the Interstate Renewable Energy Council (IREC) and merges that with JEDI economic multipliers.[12] US solar MW data was taken from the Solar Energy Industries Association (SEIA).

MORE JOBS CREATED BY ROOFTOP VERSUS UTILITY-SCALE SOLAR

The rooftop solar industry is a significant source of well-paid jobs in Kentucky. Solar installers earn 11% more than the average construction wage, with more benefits.[13] The National Solar Jobs Census 2022 shows nationally that rooftop solar creates 8.4 times as many jobs per MW as utility-scale solar.[14] The National Renewable Energy Laboratory *JEDI* economic model estimates that **4.8 times as many jobs** are

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[8] U.S. EIA, "Kentucky State Energy Profile", https://www.eia.gov/state/?sid=KY.

[9] As part of the broader portfolio of small-scale "distributed energy resources" (DERs) such as biomass and biogas generators, energy storage batteries and demand response technologies.

[10] 2022 was the initial year because of data availability.

[11] NREL, "Jobs & Economic Development Impact Models," https://www.nrel.gov/analysis/jedi/, retrieved December 2023. (The JEDI model is based on the widely-used IMPLAN Regional Economic Impacts Model.)

[12] IREC, "National Solar Jobs Census 2022," https://irecusa.org/census-solar-job-trends/, July 2023.

[13] E2, *Clean Jobs, Better Jobs*, https://e2.org/wp-content/uploads/2020/10/Clean-Jobs-Better-Jobs.-October-2020.-E2-ACORE-CELI.pdf, October 2020.

[14] IREC (2023).

generated from installing rooftop solar compared to utility-scale in Kentucky.[15] Adding IREC national data to the JEDI model shows **11.4 times more jobs** created by DER solar. These findings are detailed in Figure 1. **For every 15 MW installed, rooftop solar creates 334 to 405 additional jobs when compared to utility-scale solar.**

Rooftop solar jobs are much more likely to be filled by locals than large utility-scale projects, which are often designed and constructed by international companies that bring in labor from out of state. Rooftop PV is usually installed by local companies that have ongoing relationships within the communities in which they work. The 4.5 to 10.9 times greater earnings of rooftop solar compared to utility solar is shown in Figure 2.

Distributed solar creates a far greater economic impact in Kentucky. The annual total output of rooftop solar is 5.6 to 13.4 times greater, as shown in Figure 3. The annual value added is 5.1 to 12.3 times greater as shown in Figure 4. All exact numbers are shown below in Table 1.

Table 1 – Modeled Job, Earnings, Output, and Value Added Impacts

Impact	KY JEDI DER	KY JEDI Utility	US IREC MIX DER	US IREC MIX Utility
Annual Jobs	422	89	444	39
22-30 Jobs	3,376	712	3,552	312
Annual Earnings	22,943,312	5,043,878	24,133,968	2,210,467
22-30 Earnings	183,546,496	40,351,022	193,071,745	17,683,738
Annual Output	60,124,474	10,793,547	63,244,667	4,730,246
22-30 Output	480,995,791	86,348,373	505,957,335	37,841,966
Annual Value Added	35,161,071	6,860,346	36,985,774	3,006,530
22-30 Value Added	281,288,567	54,882,767	295,886,193	24,052,240

LOSS OF POTENTIAL FEDERAL MONEY IF ROOFTOP SOLAR IS STYMIED

Along with bringing more jobs and added economic value, rooftop solar also increases the flow of federal tax credits compared to utility-scale solar, thus keeping more funds in state rather than flowing to Washington D.C.

Residential Solar Rooftop Tax Credits

The federal Inflation Reduction Act (IRA) significantly increased the income investment tax credit (ITC), from 26% to 30%, with a phaseout starting in 2033, reducing to 0% in 2036.[16] To be ITC eligible, a rooftop system must be owned by the customer or building owner; leased systems do not qualify.

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[15] NREL (2023).

[16] U.S. DOE, " Homeowner's Guide to the Federal Tax Credit for Solar Photovoltaics," https://www.energy.gov/eere/solar/homeowners-guide-federal-tax-credit-solar-photovoltaics, March 2023.

Assuming an average installed cost of $2,682 per kilowatt (kW),[17] the typical ITC will be $885 per kilowatt. If 120 MW is installed – 15MW annually from 2022 (last available data year) to 2030 -- the **total tax credit to Kentucky would be $12.1 million annually or $96.5 million total. These funds represent a net flow of income from outside the state directly into the pockets of citizens, making rooftop PV a valuable economic development mechanism.**

Utility-scale Solar Tax Credits

While the IRA also increased the tax write-off and expanded the ITC's scope for utility-scale projects, it made securing the credit more complex, with a series of threshold conditions, including environmental justice standards, required to achieve maximum credits. Reaching the same 30% level ITC as residential solar will be a more difficult task for utility-scale projects. The credit follows the same schedule as applied for residential solar, with a phasedown beginning in 2033.

For utility-scale projects, labor standards must be met to receive the full ITC; otherwise the incentive is reduced to a base rate of 6%. Construction wages must be at or above the prevailing rates of that location as determined by the Secretary of Labor. Wage rates vary by several factors, including location, type of construction job, hours worked, and more. Prevailing wage requirements can be retroactively met by paying the difference to the affected employees plus a fine. Additionally, a percentage of total construction hours must be performed by an apprentice, a requirement- that can be lifted if a good faith effort is made to comply or if a penalty is paid. Achieving labor conditions qualifies a project for the full rate ITC.

To qualify for the 10% domestic content bonus, all steel must be produced, and a percentage of other manufactured products need to be mined, produced, or manufactured, in the United States. The 10% energy community bonus can be claimed by building on a brownfield site or in an area with high unemployment or that is historically or currently reliant on fossil fuel production. These bonuses can be stacked together.

In Kentucky, unless the projects are built on Native American tribal land or in an energy community, most utility-scale projects will qualify for an ITC of 10% to 20% rather than a full 30%.[18] Based on a reported average cost of $1,161 per kW, and assuming an average of a 20% ITC, 120 MW of utility-scale solar would generate **$27.8 million in tax credits -- $3.5 million annually** -- for Kentucky projects or about 29% of the amount for residential projects discussed above.

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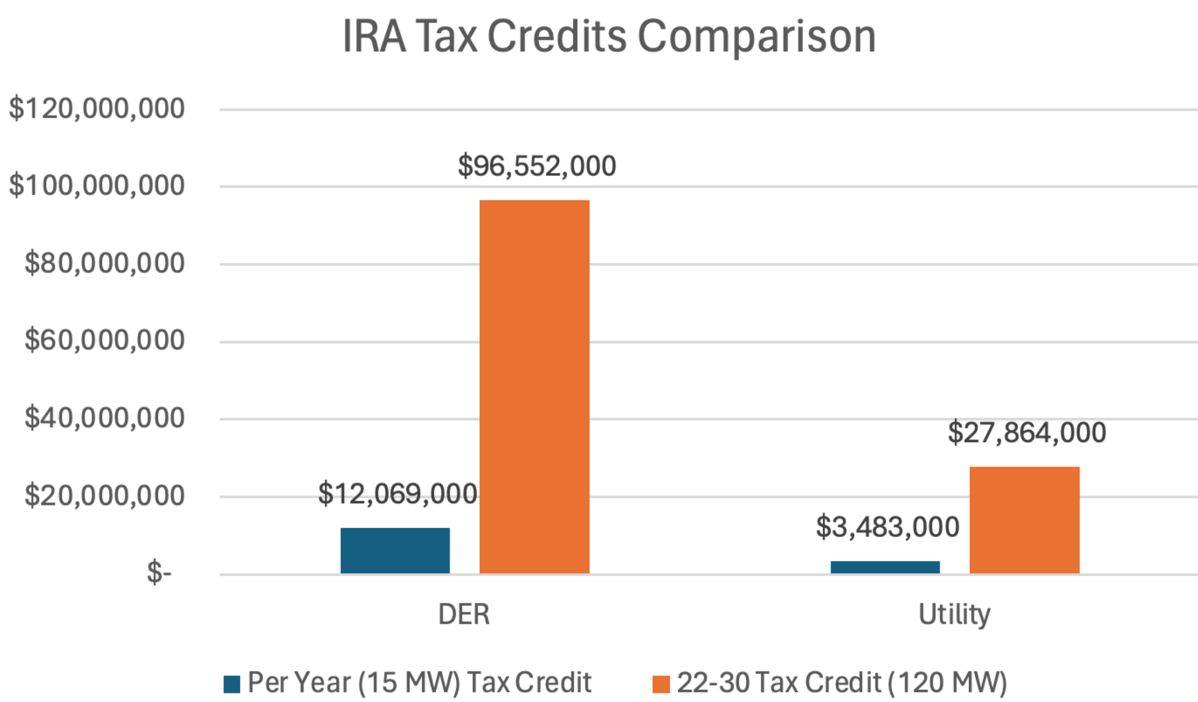
[17] NREL, *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2023*, 2023, p. vi.

[18] To further incentivize the Justice 40 principles, the ITC offers two low-income bonus tax credits beyond the full rate. An additional 10% tax credit is available for projects in LMI communities (capacity maximum 700 MW) or Indian land projects (capacity maximum 200 MW). An additional 20% tax credit is available for qualified low-income residential projects (capacity maximum 200 MW) and qualified low-income benefit projects (capacity maximum 700 MW). These two low-income bonuses can be stacked together with the other bonuses and the full ITC, creating a maximum tax credit of 80% (full rate 30% + domestic energy content bonus 10% + energy community bonus 10% + LMI/Indian bonus 10% + low income residential/benefit projects bonus 20%).

Importantly, most of those credits would accrue to the out-of-state renewable energy development companies that build those projects, **whereas the residential ITC goes directly to either homeowners or rental building owners who predominantly live locally.**

Figure 5 shows the expected federal IRA tax credit amounts from installing 15 MW annually or 120 MW total for DER versus utility-scale solar.

Figure 5



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. Richard McCann has testified over fifty times on electricity, air quality, water supply and other regulatory and planning matters. He can reached at mccann@mcubed-econ.com and 530.757.6363

Exhibit 2
Resume of Dr. Richard McCann, PhD

M.CUBED
POLICY ANALYSIS FOR THE PUBLIC AND PRIVATE SECTORS

DR. RICHARD MCCANN
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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

- **Utilities Cost of Capital Testimony, Environmental Defense Fund (2019-present).** Testified at the California Public Utilities Commission in the four 2020 and 2023 Cost of Capital applications and the 2022 Accelerated Cost of Capital Applications.
- **Review of *Benefits and Costs of Net Energy Metering in Washington*, Washington Solar Energy Industry Association (2023-present)**. Participated in workshops and prepared detailed assessment of "cost-shift" analysis. Prepared analyses of potential rooftop solar capacity in the state and the relative economic benefits of installing distributed energy resources over utility-scale renewables.
- **Testimony on AB 205 Income Graduated Fixed Charge, California Energy Storage Association (2023)**. Testified on the likely adverse consequences and the lack of supporting empirical evidence for imposing fixed charges ranging from $50 to $75 per month on average proposed by California's investor owned utilities.
- **Author and co-author, *The Future of Decentralized Electricity Distribution Networks* (2022-2023).** Wrote "Leveraging the rise of the prosumer to promote electrification," and co-authored (with Fereidoon Sioshansi) "Productive net metering reform: Where do the foundations of regulation, technological change, and good economics meet?"
- **Testimony on SDG&E 2024 General Rate Case, Small Business Utility Advocates. (2023).** Testified on using microgrids as a cost-effective alternative to undergrounding distribution lines.
- **Testimony on Sempra Utilities 2024 General Rate Case, Environmental Defense Fund. (2022-2023).** Testified on factors likely to decrease natural gas demand, thus reducing the need for requested infrastructure investment, and on changing the depreciation recovering mechanism to avoid stranded costs for future customers.

- **Net Energy Metering 3.0 Rulemaking Testimony, Agricultural Energy Consumers Association and California Farm Bureau (2021-2023**). Identified distinguishing aspects of aggregated NEM (NEMA) tariff that differ from residential NEM usage, and estimated the net value to utility customers.
- **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. Advising on CCA-related regulatory matters.
- **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.
- **Decarbonization Incentive Rate Proposal, Local Government Sustainable Energy Coalition (2022-present.)** Developed proposal for incentivizing building and transportation electrification by charging those uses only the marginal costs of service.
- **Pacific Gas & Electric 2023 General Rate Case Testimony, California Farm Bureau (2022**). Analyzed the comparative cost of using rural community and customer microgrids instead of undergrounding 10,000 miles of distribution lines to mitigate wildfire risk.
- **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.
- **Cincinnati Solar Project Techno-Economic Analysis, Placer County (2021).** Managed and directed the team preparing a financial analysis of the County's proposed 3 megawatt solar generation project to assess the benefits of participating in the RES-BCT utility tariff available to local governments.
- **Regulatory Analysis and Support, Joint Community Choice Aggregators (2018-2021)**. 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.
- **Master-Meter Rate Setting Testimony and Regulatory Support, Western Manufactured Housing Communities Association (1998-2019).** 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 (2017-2019)**. 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.
- **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, IBM (1985), Arco Refining (1986), Mobil Oil (1986), Sun Oil/Mission Energy (1987), Signal Energy (1988), Luz Engineering (1988).** Prepared testimony on need-for-power in Southern California Edison, Pacific Gas and Electric and San Diego Gas and Electric, for qualifying facility project siting applicants at the CEC.

Professional Affiliations

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

Civic Activities

- City of Davis 2020 Environmental Recognition Award
- Member, City of Davis Natural Resources Commission
- Past member, City of Davis Utilities Rates Advisory Commission
- Past member, City of Davis Community Choice Energy Advisory Committee
- Past Member, City of Davis Citizens Electricity Restructuring Task Force
- Past Member, Yolo County Housing Commission

VERIFICATION

The undersigned, Dr. Richard McCann, being first duly sworn, dposes 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

Subscribed and sworn to before me by Dr. Richard McCann this 13th day of March, 2024.

See California Notary wording below

____
Notary Public

My commission expires: 3/15/2026

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 13 day of March, 2024, by Richard McCann, proved to me on the basis of satisfactory evidence to be the person(s) who appeared before me.

Signature Laura (Seal)

LAURA CHRISTENSEN
Notary Public - California
Yolo County
Commission # 2394289
My Comm. Expires Mar 15, 2026