BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF NET METERING	**)**	
AND THE IMPLEMENTATION OF	**)**	**DOCKET NO. 16-027-R**
ACT 827 OF 2015	**)**	

JOINT REPORT AND RECOMMENDATIONS OF THE NET-METERING WORKING GROUP

Come now, the General Staff (Staff) of the Arkansas Public Service Commission (Commission); Arkansas Advanced Energy Association, Inc.; Arkansas Electric Energy Consumers, Inc.; the Attorney General of Arkansas; Francis M. Kelly; Luis Contreras; National Audubon Society, Inc.; Pat Costner; Pulaski County, Arkansas; Sierra Club; Solar Energy Arkansas, Inc.; The Alliance for Solar Choice; Scenic Hill Solar LLC; William R. Ball; Wal-Mart Stores Arkansas LLC/Sam's West, Inc.; Arkansas Electric Cooperative Corporation; Arkansas Valley Electric Cooperative Corporation; Ashley-Chicot Electric Cooperative, Inc.; C & L Electric Cooperative Corporation; Carroll Electric Cooperative Corporation; Clay County Electric Cooperative Corporation; Craighead Electric Cooperative Corporation; Entergy Arkansas, Inc.; Farmers Electric Cooperative Corporation; First Electric Cooperative Corporation; Mississippi County Electric Cooperative, Inc.; North Arkansas Electric Cooperative, Inc.; Oklahoma Gas and Electric Company; Ouachita Electric Cooperative Corporation; Ozarks Electric Cooperative Corporation; Petit Jean Electric Cooperative Corporation; Rich Mountain Electric Cooperative, Inc.; South Central Arkansas Electric Cooperative, Inc.; Southwest Arkansas Electric Cooperative Corporation; Southwestern Electric Power Company; The Empire District Electric Company; and Woodruff Electric Cooperative Corporation

(collectively the Joint Parties), and for their *Joint Report and Recommendations of the Net-Metering Working Group*, state as follows:

Introduction

In its Order No. 4, the Commission established a Net-Metering Working Group (NMWG) to address the rate issues in this docket which include the establishment of the appropriate rates, terms, and conditions for net-metering contracts under the provisions of Ark. Code Ann. § 23-18-604(b), as amended by Act 827 of 2015. The Commission established the NMWG to identify potential issues; seek the greatest level of consensus possible; identify areas of agreement and disagreement; attempt to achieve the maximum level of agreement and minimum level of disagreement; and present the recommendation or recommendations of the NMWG to the Commission for its consideration.

The NMWG held 6 (six) in-person meetings with phone participation to discuss the rate issues and related matters. Consistent with the provisions of the parties' unanimous Joint Motion that was approved by the Commission in Order No. 4, Staff led the NMWG, and the NMWG generally followed procedures consistent with those approved by the Commission for the PWC in the Commission's Energy Efficiency proceedings. This process provided an opportunity for parties with divergent points of view to work cooperatively toward finding common ground. The Parties had an opportunity to present their positions before the group and to engage in meaningful discussions. The meetings generally focused on identifying the quantifiable costs and benefits of net-metering, potential rate structure options, and pros and cons associated with various options. Two broad schools of thought currently exist within the NMWG.

As a result, two sub-groups were formed to develop detailed recommendations for the NMWG to consider.

Summary of Sub-Group 1[1]

Sub-Group 1 advocates a continuation of the current net-metering rate design until a full assessment of the costs and benefits of net-metering has been conducted and has been approved by the Commission. Since the inception of the NMWG, the members of Sub-Group 1 have consistently taken the position that analysis of the cost to serve net-metering customers and of the additional, quantifiable costs and benefits of distributed generation must precede the design of new rates for these customers. In the initial meeting, Sub-Group 1 requested a neutral facilitator, the adoption of rules to guide the NMWG in its conduct and decision-making, and recommended that the group pursue a comprehensive cost-benefit analysis of distributed generation by an independent, outside party. Although the NMWG was unable to reach consensus on these recommendations, Sub-Group 1 has continued to advocate for the parties to gather data and undertake analysis of costs and benefits, rather than proceeding directly to the question of rate design. As part of its recommendations, Sub-Group 1 presents an analysis of the costs and benefits of distributed generation for Entergy Arkansas, Inc., which was conducted by Crossborder Energy, Inc., a consulting firm with extensive expertise in distribution generation valuation. Throughout the NMWG process, Sub-Group 1 expressed both legal and policy concerns with the 2-Channel Billing approach advocated by members of Sub-Group 2.

[1] Sub-Group 1 includes the following parties: Arkansas Advanced Energy Association; Audubon Arkansas, Inc.; Francis M. Kelly; Luis Contreras; Pat Costner; Scenic Hill Solar LLC; Solar Energy Arkansas;; and Sierra Club.

Summary of Sub-Group 2[2]

Sub-Group 2 advocates an embedded cost of service approach to determine the costs and benefits associated with net-metering. This approach supports a change to the credit rate applied to the excess kilowatt hours (kWh) exported to the grid from the net-metering facility for prospective net-metering customers. A different excess generation credit rate based on an embedded cost of service approach is required in order to comply with the provisions of Act 827 of 2015, which is codified as Ark. Code Ann. § 23-18-604(b).

Currently, net-metering customers are credited at the full retail rate for excess kWhs that are exported to the grid. A credit equivalent to the full retail rate for excess generation results in a credit for utility-provided services and programs that are not avoided by net-metering customers. Crediting net-metering customers for costs that are not avoided means that the electric utility does not recover its entire cost of providing service to each net-metering customer, net of quantifiable benefits as required by Act 827 of 2015. Therefore the current net-metering policy that credits excess generation at the full retail rate must be changed for new net-metering customers.

In order to comprehend quantifiable benefits, Sub-Group 2 submits that quantifiable benefits are those that can be determined primarily through consideration of

[2] Sub-Group 2 includes the following parties: Arkansas Electric Energy Consumers, Inc.; Attorney General Leslie Rutledge; Arkansas Electric Cooperative Corporation; Arkansas Valley Electric Cooperative Corporation; Ashley Chicot Electric Cooperative, Inc.; C&L Electric Cooperative Corporation; Carroll Electric Cooperative Corporation; Clay County Electric Cooperative Corporation; Craighead Electric Cooperative Corporation; Entergy Arkansas, Inc.; Farmers Electric Cooperative Corporation; First Electric Cooperative Corporation; The General Staff of the Arkansas Public Service Commission; Mississippi County Electric Cooperative, Inc.; North Arkansas Electric Cooperative, Inc.; Oklahoma Gas and Electric Company; Ouachita Electric Cooperative Corporation; Ozarks Electric Cooperative Corporation; Petit Jean Electric Cooperative Corporation; Rich Mountain Electric Cooperative, Inc.; South Central Arkansas Electric Cooperative, Inc.; Southwest Arkansas Electric Cooperative Corporation; Southwestern Electric Power Company; The Empire District Electric Company; and Woodruff Electric Cooperative Corporation.

an individual utility's embedded cost of service. Sub-Group 2 submits that using an embedded cost of service approach for quantifying costs and benefits is consistent with how electric utility rates are set in Arkansas and with the requirements of Ark. Code Ann. § 23-18-604(b). Sub-Group 2 developed its net-metering policy recommendation within a 2-Channel Billing framework that credits net-metering customers for net excess generation (kWh) at a rate that is more appropriate than the retail rate, ensuring that net-metering customers pay rates more accurately reflecting the utility's cost of providing service.

Summary of Other Party Comments/Recommendations

Additionally, some NMWG participants provided differing perspectives from those advocated by either Sub-Group 1 or Sub-Group 2.

Pulaski County, Arkansas

Pulaski County believes that there is no legal presumption, pursuant to Act 827 of 2015 ("Act 827"), requiring the Arkansas Public Service Commission ("the Commission") to impose a different rate structure than already exists for net-metering customers. Further, there has been no factual basis presented to change the existing net-metering compensation structure that currently exists. This is because the existing universe of net-metering customers does not provide enough relevant data to quantifiably demonstrate that there are either costs to the electric utilities associated with net-metering or tangible benefits to the grid. Thus, a long-term, ongoing independent study of Arkansas specific data should be conducted, to approach Act 827 conservatively, ensuring that ratepayers and the electric utilities are protected, and that the demands of Act 827 are met.

Any proposal that changes the existing net-metering compensation model is likely overly complicated and will hinder the intent of the Arkansas Renewable Energy Development Act of 2001 ("AREDA"), which the Commission should avoid. A simple and straightforward net-metering rate structure can accomplish AREDA's intent, leading to additional distributed generation, thus, creating new tax revenue, which in turn will support local governments and schools.

The Alliance for Solar Choice

The Alliance for Solar Choice (TASC) has not actively participated in this phase of the proceeding and wishes to abstain from formally joining any party's recommendation at this time.

Because the NMWG participants have not reached consensus on a comprehensive recommendation to the Commission, the NMWG participants present the recommendations of Sub-Group 1, Sub-Group 2, William Ball, and Pulaski County, Arkansas for Commission consideration as attachments to this Report.

WHEREFORE, the Joint Parties submit this Report and attached Recommendations.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I certify that a copy of the foregoing has been delivered to all Parties of Record by electronic mail via the Electronic Filing System, this 15th day of September 2017.

/s/ Dawn R. Kelliher
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Attachments Table of Contents

Attachment A: Sub-Group 1 Recommendations

Attachment A, Sub-Group 1 Recommendations[3]

I. Overview of Sub-Group 1 Position

In this docket, the Commission is faced with a decision that will have significant consequences for Arkansas's growing distributed solar energy industry. As this Commission has found numerous times in a variety of contexts,[4] the Arkansas Renewable Energy Development Act (AREDA) aims to drive growth of distributed renewable generation in the state, through the mechanism of net metering, to bring about economic and environmental benefits, as well as benefits to electric utility systems. Recent amendments to AREDA call upon the Commission to reevaluate whether its rules for net metering customers are just and reasonable. In doing so, the Commission should base its decision on a thorough analysis of the benefits and costs of net metering, as required by the statute,[5] and informed by best practices from an extensive literature on distributed generation valuation.[6] A comprehensive study of these benefits and costs should cover the average lifetime of solar systems and should

[3] Sub-Group 1 members include Sierra Club, Audubon Arkansas, Arkansas Advanced Energy Association, Inc., Scenic Hill Solar, LLC, Solar Energy Arkansas, Inc., Pat Costner, Luis Contreras, and Frank Kelly.

[4] *See infra*, Section II.1.b.

[5] As discussed further below, Sub-Group 1 contends that Ark. Code Ann. § 23-18-604(b)(1)(A), calls for full analysis of the costs and benefits of net metering as a predicate to any change in rate design or contract terms.

[6] *See, e.g.*, Lori Bird, et al., National Renewable Energy Laboratory, *Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar* (Nov. 2013), available at http://www.nrel.gov/docs/fy14osti/60613.pdf, at Figure 3 (summarizing cost-benefit studies conducted between 2009 and 2013); Lindsey Hallock and Rob Sargent, Shining Rewards: The Value of Rooftop Solar Power for Consumers and Society (Summer 2015), available at http://www.environmentamerica.org/sites/environment/files/reports/EA_shiningrewards_print.pdf (summarizing eleven additional cost-benefit studies); *See* Electricity Innovation Lab, Rocky Mountain Institute, *A Review of Solar PV Benefit and Cost Studies* (2nd ed. Sept. 2013) (reviews 16 distributed solar benefit/cost studies completed between 2005 and 2013 by utilities, national labs, and other organizations), available at www.rmi.org/elab_emPower; Energy+Environmental Economics, The Benefits and Costs of Net Energy Metering in New York, Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service (Dec. 11, 2015), at 25, Fig. 11 (summarizing benefits and costs considered in 20 studies done between 2012 and 2015), available at https://www.ethree.com/wp-content/uploads/2017/01/E3-NY-Legislative-NEM-Study-Report-121115-FINAL-SENT.pdf.

not be limited to data in the utility's embedded cost of service study. As this Commission has previously noted, distributed solar penetration in Arkansas is low, and Act 827 "does not . . . specifically require an increase in rates; nor does it establish a timeline for implementation." Order No. 10 at 143.[7] The Commission therefore has ample time to gather data and review comprehensive studies prior to taking action. Precipitous action taken without full information would be unduly disruptive to the solar industry and stymie much-needed job growth in Arkansas.

Throughout the Net Metering Working Group (NMWG) process, Sub-Group 1 members advocated for a broad, collaborative study of costs and benefits to inform the Commission's decision. In part due to the NMWG's decision not to undertake such a study, Sierra Club contracted for a study that focuses on Entergy Arkansas, the state's largest utility.[8] This study done by Crossborder Energy, a firm with extensive experience in distributed solar valuation and utility economics, is attached hereto as Attachment A-1. The Crossborder study shows that the value of distributed solar generation for Entergy Arkansas exceeds the residential retail rate under either of two scenarios: (1) a conservative scenario employing several of Entergy's own estimates from its latest Integrated Resource Plan and energy efficiency filings, or (2) an expanded scenario including a wider range of benefits. The Crossborder study also finds that compensating net metering customers for exports at the full retail rate is cost-effective from the perspective of the utility and other ratepayers, using the tests commonly employed in evaluating energy efficiency programs.

[7] All references to orders are for Docket No. 16-027-R, unless otherwise noted.
[8] Due to budget limitations, the Crossborder study focuses on Entergy Arkansas, though Sub-Group 1 believes that a broader study, with utility participation, would greatly assist the Commission's decision in this matter.

In short, the Crossborder study shows that distributed solar helps the utility avoid direct costs that add up to more than the retail rate for residential customers, and therefore, net metering is a fair compensation scheme from the perspective of both the self-generating customer and other customers. In short, net metering does not shift costs to customers without solar. As such, the Commission should conclude that the existing net metering tariffs comply with Arkansas Code Section 23-18-604(b)(1). However, should the Commission believe that further action must be taken to ensure compliance with AREDA, we recommend that the Commission contract for an independent and comprehensive statewide study of the benefits and costs associated with distributed generation.

Sub-Group 1's comments are organized as follows. First, we present the relevant legal background. Second, we offer principles for the Commission to apply when interpreting and applying Act 827. Third, we summarize the findings of Crossborder study. Finally, we offer some procedural recommendations for future the working group processes in matters before the Commission. In addition, we offer specific responses to the Commission's questions posed in Section A of Order No. 1 in this matter, in Attachment A-3.

II. Legal Background

1. The Arkansas Renewable Energy Development Act Supports a Net Metering Policy that Promotes Distributed Generation Development.

As past orders by this Commission reflect, the Legislature's clear purpose in AREDA was to establish a net metering policy that promotes distributed generation development. The Legislature has provided a specific definition of net metering that is

based on a billing period, which is monthly for residential customers, and has required utilities to facilitate meter aggregation in order to expand distributed generation. In order to conform to the Legislature's intent, the Commission must establish rules for distributed generation that preserve the basic net metering construct, reflect all of the benefits and costs of distributed generation, and enable meter aggregation.

a. The Text of AREDA Demonstrates Clear Legislative Intent to Support Distributed Generation Development through Net Metering.

The purpose of AREDA, as laid out in the text of the statute itself, demonstrates a clear legislative focus on promoting the use of renewable energy resources and supporting investment in distributed generation development. Moreover, the Legislature clearly recognized net metering as the billing arrangement that would promote distributed generation, which would be in "Arkansas's long-term interest." Ark. Code Ann. § 23-18-602(c).

> *Net energy metering encourages the use of renewable energy resources and renewable energy technologies* by reducing utility interconnection and administrative costs for small consumers of electricity… Increasing the consumption of renewable resources promotes the wise use of Arkansas's natural energy resources to meet a growing energy demand, increases Arkansas's use of indigenous energy fuels while reducing dependence on imported fossil fuels, *fosters investments in emerging renewable technologies* to stimulate economic development and job creation in the state, including the agricultural sectors, reduces environmental stresses from energy production, and provides greater consumer choices.

Id. § 23-18-602(a) (emphasis supplied). Moreover, in the next section of AREDA, the legislature states that net metering would "help to further attract energy technology manufacturers, to provide a foothold for these technologies in the Arkansas economy, and to make it easier for customer access to these technologies."

Id. § 23-18-602(b). Thus, the Arkansas Legislature has made manifest its direction that net metering is intended to promote the use and development of renewable technologies.

b. Past Commission Orders Have Consistently Recognized and Pursued the Legislature's Intent to Support Distributed Generation Development.

The Commission has supported the clear interpretation of AREDA's text as promoting net metering, stating that "[v]arious provisions of AREDA indicate that its purpose is to promote net metering. The title is the Arkansas Renewable Energy *Development* Act of 2001." Docket No. 16-027-R, Order No. 13 at 15; ARK. CODE ANN. § 23-18-601 (emphasis in original) (internal quotation marks omitted). Additionally, the Commission has interpreted the purpose of Act 827, which amended AREDA in 2015, as "[requiring] the Commission to examine the balance of costs and benefits of net metering, within the framework of a statutory subchapter *aimed at promoting customer-owned, distributed renewable energy production*." Order No. 1 at 2 (emphasis added).

In Order No. 13, the Commission observed that it "has consistently held that the purpose of AREDA is to promote net metering." Order No. 13 at 15. The Commission went on to describe a steady stream of previous orders in which it had been guided by this legislative purpose:[9]

- "In the rulemaking which first adopted the Net Metering Rules, the Commission noted that AREDA 'authorizes the Commission to expand the scope of net metering to include facilities that do not use a renewable energy resource or may increase the peak limits for individual net metering facilities, if so doing results in desirable

[9] Docket No. 16-027-R, Order No. 13 at 15–16 (bullets added for emphasis).

distribution system, environmental, or public benefits.' Docket No. 02-046-R, Order No. 3 at 2.

- In Docket No. 06-105-U, the Commission pointed out that the General Assembly had retained in Act 1026 of 2007 the provision that gave the Commission the authority to further encourage net metering and interconnection. Order No. 4 at 4.

- In Docket No. 12-001-R, Order No. 6 stated that AREDA 'generally grants authority to the Commission to establish [net metering rules] to promote the development of renewable energy, and to expand the scope of net metering for certain purposes.'

- The Commission acknowledged in Docket No. 12-060-R that 'the General Assembly has generally directed the Commission to promote net metering.' Order No. 1 at 5. Order No. 4 notes that 'the findings and purposes of AREDA indicate general legislative support for net metering' and that 'reasonable promotion of net metering, rather than further limitation, is the appropriate approach [concerning aggregate limits on net metering facilities] in order to fulfill the purposes of the Act.' Order No. 4 at 11, 38. . . .

- Order No. 7 (at 12), recognized 'the statutory directive to promote the growth of net metering and the public policy benefits thereof.'"

Thus, the Commission has consistently interpreted AREDA as promoting renewable energy through net metering policies in order to realize public benefits, both to the utility's system and to society at large.

2. Act 827 Amendments to AREDA

a. Tariffs for Net Metering Customers to Reflect Cost of Service Net of Quantifiable Costs and Benefits of Distributed Generation

In Act 827, the Legislature modified Ark. Code Ann. § 23-18-604 to require the Commission to, "[f]ollowing notice and opportunity for public comment . . . establish appropriate rates, terms, and conditions for net-metering contracts, including:

> (A)(i) A requirement that the rates charged to each net-metering customer recover the electric utility's entire cost of providing service to each net-metering customer within each of the electric utility's class of customers.
>
> (ii) The electric utility's entire cost of providing service to each net-metering customer within each of the electric utility's class of customers under subdivision (b)(1)(A)(i) of this section:
>
> (a) Includes without limitation any quantifiable additional cost associated with the net-metering customer's use of the electric utility's capacity, distribution system, or transmission system and any effect on the electric utility's reliability; and
>
> (b) Is net of any quantifiable benefits associated with the interconnection with and providing service to the net metering customer, including without limitation benefits to the electric utility's capacity, reliability, distribution system, or transmission system . . . ."

The statute requires that rates charged to net-metering customers recover the entire cost of providing service to those customers, and that this "cost of providing service" must include quantifiable *additional* costs associated with net metering, and be net of any quantifiable benefits associated with net metering. Thus, the statute evinces the Legislature's understanding that ascertaining the cost of providing service to net metering customers requires evaluation of quantifiable, additional costs and benefits that do not apply to customers that do not self-generate. The statute calls upon the Commission to ensure that the rates charged to net metering customers reflect these additional costs and benefits, and specifically asks the Commission to evaluate costs and benefits related to generation capacity, transmission and distribution, and reliability.

b. Meter Aggregation

Act 827 also added provisions to require electric utilities to allow self-generating customers to apply excess generation credits from one meter to another under common

ownership, a concept commonly known as meter aggregation. Ark. Code Ann. § 23-18-604(d)(2). This statutory change follows on the heels of this Commission's order in 2013 that utilities must allow meter aggregation. *See* Docket No. 12-060-R, Order Nos. 4 and 7. In that docket, the Commission considered whether it had authority to require utilities to offer meter aggregation (now a moot point), and whether aggregation would be in the public interest. In Order No. 4, the Commission proposed amendments to the net metering rules to facilitate meter aggregation after concluding that to do so was consistent with "AREDA's findings that net metering is in the public interest," and that "*meter aggregation will further the purposes of AREDA, promote distributed generation* during periods of higher-than-average energy costs, *and promote customer investment in capacity* to meet system demand." *Id.* at 36. The Commission further noted that "the ability to site renewable generation at the most advantageous location is essential to AREDA's purpose of promoting renewable energy, and that this core purpose should outweigh the difficulties that may be involved in developing administrative procedures to provide aggregate billing for net metering customers." *Id.* at 37–38. In the 12-060-R docket, the Commission declined to adopt aggregate limits on a customer's net metering facilities, noting the absence of statutory size limits for aggregated facilities and that "given the track record of minimal net metering achievement in Arkansas so far, *reasonable promotion of net metering, rather than further limitation, is the appropriate approach in order to fulfill the purposes of the Act*." *Id.* at 38 (emphasis added).

Based on this Commission's acknowledgement that meter aggregation is essential to achieving the Legislature's purpose in advancing net metering and the

Legislature's subsequent endorsement of meter aggregation, it is clear that any changes to the net metering rules, contracts or rates approved by the Commission should not hamper the effectiveness of meter aggregation.

III. Principles for implementation of Act 827

Act 827 made significant changes to AREDA by providing additional instruction for how the Commission should determine whether the rates charged to net metering customers and the rules governing are fair, just and reasonable. As the Commission proceeds with Phase 2 of the docket, we urge the Commission to continue the careful approach demonstrated in Phase 1 and to consider the following principles.

A. AREDA Requires the Commission to Consider the Impact of the Net Metering Rules on the State's Growing Solar Energy Industry

When fulfilling its statutory obligation to "establish appropriate rates, terms, and conditions for net-metering contracts," Ark. Code Ann. §23-16-604(b)(1), the Commission should be guided first and foremost by the statutory purpose to promote development of distributed renewable energy resources, *id.* §23-18-602. The Commission's prior orders have consistently reflected this statutory purpose, up to and including orders in this docket, indicating that Act 827 in no way changed the fundamental driver behind AREDA—the legislature's intention to promote the development of distributed generation for the utility system, environmental, and economic benefits that it provides. *See supra*.

There is little doubt that renewable energy is a growing industry in the State of Arkansas. Since a 2014 jobs census commissioned by the Arkansas Advanced Energy Foundation (AAEF) found more than 25,300 workers in the advanced energy industry

and a $2.8 billion impact on the state's economy, there have been several significant developments especially within the renewable energy sector.

In the years since this 2014 economic impact analysis was conducted, advanced energy companies report that consumer awareness regarding renewable energy's affordable price and short-term payback has grown, expanding from more urban areas to rural and agricultural communities with farmers now installing solar systems to reduce energy costs. As a result, advanced energy companies continue to add new positions to meet growing consumer demand. Solar is an increasingly affordable option for Arkansans seeking to generate their own electricity; Arkansas firms report positive trends in the Arkansas solar marketplace for middle- and lower-income property owners. This has led to several new and existing companies entering into the Arkansas solar market place, including Community Solar Partners, Entegrity Energy Partners, Scenic Hill Solar, Seal Energy Solutions, Shine Solar, Silicon Ranch Corporation, and Today's Power, Inc., to name a few.

Advanced energy sources create opportunities for businesses to capture savings and hedge against energy price volatility. Recently, large corporations with operations in Arkansas have made significant renewable energy commitments explicitly to continue to deliver goods and services at reduced costs to customers. Wal-Mart Stores, Inc. is one of the 102 "RE100" companies committed to sourcing 100 percent of its electricity from renewable energy. Aerojet Rocketdyne installed a 12-megawatt solar farm in 2015 in Camden, Ark., adding 250 jobs in South Arkansas during construction. L'Oréal's 1.2-megawatt solar facility at the company's North Little Rock, Ark., plant went online in

April 2017. These developments are part of a larger trend of renewable energy generation expansion and constitute significant benefits for the State.

Arkansas's electric utilities also have recognized the value of renewable energy. Entergy Arkansas, Inc. broke ground on its 81-megawatt solar facility near Stuttgart in May 2017, creating 250 construction jobs in Arkansas County and powering 13,000 homes. Over its life, the Stuttgart Solar Energy Center will generate nearly $8 million in added revenue for Arkansas County, mostly for public schools. In seeking Commission approval for the Stuttgart Solar Energy Center, Entergy touted the positive economic impacts of local employment and increased tax revenue, along with consumers' reduced exposure to volatile fuel prices.[10]

Ouachita Electric Cooperative, a partner in the Aerojet project, has installed a 93-kilowatt system to power its Camden office building and a 1-megawatt solar array for its members' benefit. Ozarks Electric Cooperative offers members shares in its 1-megawatt array located in Springdale, Ark. SWEPCO announced in July 2017 it is investing in renewable energy and bringing cost savings to customers through the proposed Wind Catcher Energy Connection Project.

These residential and commercial renewable energy projects are creating jobs and spurring lasting economic investments across Arkansas. When AAEF performed its job census in 2014, the average annual salary of an advanced energy skilled worker was $52,000, which ranked higher than oil and gas workers and most other skilled trades in Arkansas, according to an analysis by the UALR Arkansas Economic Development Institute.

[10] In the Matter of the Petition of Entergy Arkansas, Inc., for a Declaratory Order Regarding a Purchase Power Agreement for a Renewable Resource, Docket No. 15-014-U, Direct Testimony of Kurtis W. Castleberry, at 15-16 & 20-21.

Tremendous potential to expand renewable energy generation exists in Arkansas, which would significantly benefit the state's economy by creating jobs and lowering energy costs for households and businesses. We urge the Commission to allow the market to continue to grow unfettered by unnecessary policy barriers. Policy barriers enacted in Nevada provide a cautionary tale for the Commission as it considers changes to net metering. A 2015 net-metering rate change undercut the deployment of renewable energy, resulting in thousands of lost jobs was solar companies left the state.[11] The economic fallout caused the Nevada legislature to restore equitable rates for net-metering customers, making the state once again open for renewable energy generation business with jobs returning to Nevada.

The Commission must of course balance the legislative direction to promote the distributed solar industry with its responsibility to ensure that rates recover the full, adjusted cost of providing service to net metering customers. Fortunately, the Crossborder study shows that the Commission can fulfill its statutory obligation to ensure that rates charged to net metering customers are reasonable without curtailing the compensation offered for exports from net-metered systems.

B. The Commission Must Look Beyond the Conventional Embedded Cost of Service Framework when Implementing Act 827.

The Legislature's new instruction in Section 23-18-604(b)(1)(A), calls for "appropriate rates, terms and conditions for net-metering contracts, including a requirement that the rates charged to each net-metering customer recover the electric

[11] Benjamin Storrow, *Nev. restored net metering. Is it a national model?*, E&E News (June 16, 2017), reprinted and publicly available at https://www.scientificamerican.com/article/nevada-boosts-solar-power-reversing-course/.

utility's entire cost of providing service to each net-metering customer within each of the electric utility's class of customers." The statute goes on to explain that the "electric utility's entire cost of providing service to each net-metering customer" includes quantifiable, additional costs and benefits associated with the net metering system, specifically referring to those associated with the utility's capacity, transmission, distribution, and reliability functions.

The Legislature thus provided a specific approach to understanding the cost to provide service to a net metering customer that is distinct from the conventional cost of service approach employed for jurisdictional and class cost allocation. The costs and benefits of the net metering customer's system interconnection and operation to "the electric utility's capacity, reliability, distribution system, or transmission system," Ark. Code Ann. §23-18-604(b)(A)(ii)(b), cannot be determined solely by reference to data within the four corners of the utility's embedded, historical cost of service analysis.

Cost of service studies do not evaluate the defining characteristic of net metering customers—their export of power to the utility's grid. Quite simply, these studies assign the embedded costs of the utility's plant and its ongoing service costs to various classes based on that class' responsibility for those costs, as determined by the class' usage during various hours of the year that the utility deems determinative of those costs. There is no mechanism in the cost of service study to capture the full benefits or costs of serving a net metering customer, especially when many of the benefits specified by the Legislature involve avoiding future utility costs. Fully capturing costs and benefits associated with net metering, including those "to the electric utility's capacity, reliability, distribution system, or transmission system" requires a study of these costs and benefits

over the system planning horizon. Most studies that have been done of the costs and benefits of net metering have looked at cost and benefit categories over the lifetime of the net-metered system, rather than taking a snapshot of their value.[12] In other words, reputable studies of net metering costs and benefits tend to evaluate distributed generation systems as system resources, expected to provide value over many years.[13]

Conventional cost of service analysis could be useful to the Commission's inquiry in one narrow sense. If the utility were to conduct load research on its net metering customers and then evaluate how allocation of costs to net metering customers might differ from others in their class, such an analysis would provide a better picture of the cost of serving net metering customers, but would still not be sufficient to meet AREDA's requirements because it would ignore costs or benefits associated with the generation exported by net metering customers (i.e., it would consider only how those customers' different usage and load profiles affects their responsibility for embedded utility costs). Moreover, as this Commission is aware, there are very few distributed solar customers in Arkansas—many utilities have fewer than a dozen such customers. Therefore, it is questionable whether valid load research could even be conducted on such a limited number of customers. The Commission may wish to consider the 2015 general rate case filed by Oklahoma Gas & Electric Company in Oklahoma. For that case, the company completed a cost of service study that, for analytical purposes only, treated residential distributed generation customers as a separate rate class—an analysis intended to inform an inquiry required by state law into whether there were any

[12] Attachment A-2 provides a survey of the time frames utilized in dozens of recent distributed generation valuation studies.
[13] In Order No. 10, the Commission noted evidence supporting a "20-year life for NMFs and a common warranty period of 25 years." Order No. 10 at 147.

intra-class subsidies of distributed generation customers. That analysis revealed that residential distributed generation customers were actually less costly to serve than other residential customers due to their reduced peak load, and paid a higher percentage of their cost of service than any other subset of the residential class.[14] Of course, results may differ for Arkansas's utilities, assuming valid data were available to support a cost of service analysis, which only highlights the importance of gathering data and evaluating evidence before assuming that changes to net metering are necessary.

Fortunately, simple net metering provides an excellent model for ensuring that the utility's cost of service is "covered" by net metering customers. Since net metering charges a customer for 100% of his or her consumption, it is only necessary to evaluate whether the offsetting and export credit rates fairly reflect the value that customer-sited generation provides in the form of benefits and avoided costs. If the value of customer-sited generation exceeds the retail rate, net metering customers are actually providing system wide benefits to all customers. Sub-Group 1 offers the Crossborder study, Attachment A-1, for the Commission's consideration in making this assessment.

C. Any Changes to Net Metering Should be Based on Data Rather than a Presumption that Cross-Subsidies Exist

Another principle that Sub-Group 1 advocates is that the Commission's decision should be driven by data and evidence-based. By allowing the NMWG nearly a year to discuss these issues, the Commission has already made clear that there is no statutory

[14] *See* Responsive Rate Design Testimony of Kathy J. Champion on behalf of the Oklahoma Corporation Commission Public Utility Division, Oklahoma Corporation Commission Cause No. PUD 201500273, Mar. 31, 2016, at 32-34 ("The COSS shows that DG customers cost less to serve their load shape and shows that DG customers, through a combination of load management and load additions (from their renewable generation), avoid peaks and cause less costs to be allocated to them.").

imperative to immediately make changes to the net metering rules. Sub-Group 1 urges the Commission to continue this sound course of action and promote the development of the quality data and analysis needed to implement Act 827.

The Commission should not eliminate net metering absent evidence that net metering customers are not paying their full, adjusted cost of service.[15] Under traditional ratemaking principles, the Commission must make decisions based on substantial evidence, there must be a cost basis to make a change to existing tariffs. Ark. Code Ann. § 23-2-423(c)(3). Any time rates are changed for customers, or a subclass of customers, it must be supported by data to demonstrate that those customers are not being unduly discriminated against.

Understanding the cost to serve net metering customers reasonably requires, at a bare minimum, an understanding of how the load profile of those customers compares to others in their class. For example, by generating electricity at the same time that sunshine is driving peak demand, net metering customers likely provide valuable load diversification and improved asset utilization benefits to the utility and the entire grid. As another example, to understand how net metering may result in additional, quantifiable benefits and costs to the net metering system, the Commission might wish to have data on the available capacity on a utility's distribution system components and its protocols for upgrading or replacing those components. By reducing peak demand, distributed generation can reduce wear and tear on distribution system components, extend their useful life, and reduced future fixed cost investments.

[15] During Phase 1 of this docket, Commission Staff noted that "[t]he record doesn't contain any evidence that net-metering customers are not currently paying the entire cost of serving them." Surreply Comments of General Staff (Doc. 89, filed Sept.9, 2017), at 51: 8-10.

The fundamental issue on which the Commission must consider evidence is whether net metering customers pay their full, adjusted cost of service under the current net metering tariffs. We strongly disagree with the notion, advocated by some, that net metering customers are inherently subsidized simply because they receive bill credits at the retail rate. Sub-Group 1 contends that a "subsidy" can only be ascertained through analysis of the costs and benefits associated with net metering, in the detailed terms provided by AREDA. As described in the attached report by Crossborder Energy, for Entergy Arkansas, the direct benefits of net metering exceed the costs under nearly all scenarios, as measured by common cost-effectiveness tests employed in Arkansas for energy efficiency resources. Attachment A-1, at 35-37. In addition, given the very different levels of customer charges and retail rates across the state, whether or not a net metering customer is paying the cost of providing service to him or her may depend in part on the particular rate structure. Although a uniform statewide methodology for evaluating the costs and benefits of distributed generation is important, that evaluation may also take into account utility- and location-specific factors.

Other states have taken measured, data-driven approaches prior to making changes to existing net metering policies, including the completion of cost-benefit studies prior to making changes or to evaluate whether new policies were needed.[16] Although the commissions listed below did not always take action consistent with the recommendations of the consultants hired or stakeholders engaged, all sought to gather data and solicit expert opinions before making decisions.

- Montana: In response to legislation requiring the state's primary utility to conduct a study on the costs and benefits of customer self-generation, the

[16] Further discussion of recent state policy developments is provided in Attachment A-3.

Montana Public Service Commission issued a solicitation and hired a consultant to establish minimum information requirements for that study, and sought public comment on the set of costs and benefits that the Commission proposed to be considered for inclusion in the study.[17]

- Iowa: After a lengthy exploratory docket in which stakeholders responded to several rounds of questions, the Iowa Utilities Board determined that penetration of distributed generation in that state was too low to justify a full cost-benefit study, much less immediate changes to the state's net metering rules.[18] The Iowa Utilities Board instead opted to order utilities to propose pilots to test variations on details of net metering policy to gather data prior to any significant or permanent changes in net metering policy.

- Rhode Island: The Rhode Island Public Utility Commission opened up Docket 4600 to develop a report to guide the Commission's review of the National Grid's rate structure, including for distributed generation resources. Raab Associates, Ltd., Paul Centolella & Associates, and Tabors Caramanis Rudkevich were hired to facilitate stakeholder discussions and consult on the project. The project developed a comprehensive cost-benefit evaluation matrix that could serve as a starting point for useful evaluation in Arkansas.[19]

- Mississippi: The Mississippi Public Service Commission hired Synapse Energy Economics to complete a study of long-term costs and benefits prior to developing its rule for compensating distributed generation.[20]
- Maine: The Maine Public Utility Commission hired Clean Power Research to prepare a report in response to a legislative directive to determine the value of distributed solar energy generation in the state and make recommendations.[21]

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[17] Montana Public Service Commission, In the Matter of Establishing Minimum Information Requirements for NorthWestern Energy's Study of the Costs and Benefits of Customer Generators, Regulatory Division Docket No. D2017.6.49, Notice of Opportunity to Comment (filed June 16, 2017), available at http://www.psc.mt.gov/Docs/ElectronicDocuments/pdfFiles/D2017649NOC.pdf.

[18] Iowa Utilities Board, In Re: Distributed Generation, Docket No. NOI-2014-0001, Order Regarding Policy Statement, Rate Design Presentations, and Net-Metering Generation Pilots (issued Oct. 30, 2015), available at https://efs.iowa.gov/cs/groups/external/documents/docket/mdax/mtqx/~edisp/1141884.pdf.

[19] *See* Rhode Island Public Utility Commission, Docket No. 4600 - Investigation Into the Changing Electric Distribution System); and Docket No. 4600-A - PUC Guidance Document, available at http://www.ripuc.org/eventsactions/docket/4600page.html.

[20] See Stanton et al., Synapse Energy Economics, Net Metering in Mississippi: Costs, Benefits, and Policy Considerations, Prepared for the Public Service Commission of Mississippi (Sept. 19, 2014), available at Prepared for the Public Service Commission of Mississippi September 19, 2014, available at http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf.

[21] Maine Public Utilities Commission, Maine Distributed Solar Valuation Study (Mar. 1, 2015), available at https://www.nrcm.org/wp-content/uploads/2015/03/MPUCValueofSolarReport.pdf. The Maine study was prepared by several outside experts working in conjunction with the Commission's staff, and presented to Maine Legislature's Joint Standing Committee on Energy, Utilities and Technology.

- Nevada: Public Utility Commission hired Energy + Environmental Economics (E3) to help it evaluate the costs and benefits of net metering in response to a legislative directive.[22]

As this Commission is aware, a wide range of modifications and alternatives to net metering have been discussed, evaluated, and in some cases adopted, either on a permanent or transitional basis. An increasing number of these approaches include a transparent, stakeholder-driven evaluation of the full costs and benefits of distributed generation, just as AREDA requires.

D. Consideration of Alternatives to Net Metering

The principles described above should guide the Commission in deciding whether changes to net metering are necessary and in judging the reasonableness and lawfulness of any proposed alternative billing structure. The Commission must carefully assess the implications of any alternative for the continued growth of distributed generation, as it has in the past when considering changes to the net metering rules or authorizing net metering of particular systems. Any proposed alternative billing structure must be consistent with the specific terms of AREDA and its overarching purpose. For example, AREDA requires, as the Commission recognized even prior to Act 827, that meter aggregation be available to customers. Any alternative to net metering must allow for meaningful meter aggregation that improves the economics of and expands access to distributed generation resources.

[22] Energy+Environmental Economics, Nevada Net Energy Metering Impacts Evaluation, Prepared for the Public Utility Commission of Nevada (July 2014), available at http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study.

Early in the NMWG process, Staff and other Sub-Group 2 participants expressed their view that changes to net metering were necessary and proposed to replace it with a two-channel billing rate design. This approach eliminates one-to-one kilowatt-hour netting of solar production against consumption within the monthly billing period, and replaces it with a scheme in which any self-generation not immediately consumed behind the meter is compensated at a rate closer to the wholesale rate. Sub-Group 1 believes that two-channel billing, sometimes referred to as instantaneous netting, is inconsistent with the Arkansas statutory definition of net metering and Arkansas's objective of encouraging distributed generation. It is an untested, complicated, and resource-intensive scheme that poses numerous troubling policy consequences, which Sub-Group 1 plans to address in its rebuttal comments.

IV. Analysis of Benefits and Costs of Net Metering for Entergy Arkansas

Sub-Group 1 maintains that this Commission's implementation of Act 827 should be informed by an analysis of the costs and benefits of net metering for Arkansas, conducted by an expert and with the collaboration of the utilities and key stakeholders. Such a study would include different scenarios and sensitivities that would allow the Commission to understand the impact of different assumptions advocated by parties on an apples-to-apples basis. In response to Staff's May 17 request that each Sub-Group present a calculation of the avoided costs associated with distributed generation at the following NMWG meeting, Sierra Club contracted with Crossborder Energy to undertake a comprehensive study for Entergy Arkansas.[23] An initial version of Crossborder's

[23] Crossborder Energy has extensive expertise evaluating the costs and benefits of distributed generation. *See* Attachment A-4, Curriculum Vitae of R. Thomas Beach.

analysis was presented at the July 18, 2017 NMWG meeting, with workpapers provided to NMWG one week later.[24] The final Crossborder study, entitled The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc., is provided at Attachment A-1.

By submitting this study, Sub-Group 1 does not contend that further analysis, especially of other utilities, is unnecessary. Instead, we submit this study to show that for Entergy Arkansas, the largest utility in the state, a comprehensive analysis of costs and benefits shows that net metering is a net benefit to the utility and all its customers. As such, we believe that maintaining net metering is consistent with AREDA and the Act 827 amendments thereto.

The Crossborder study considers the benefits and costs of distributed generation over a 25-year period, consistent with the common practice of looking at distributed generation systems and energy efficiency resources over the lifetime of the resource. Attachment A-1 at 50. Crossborder quantifies several benefits following methodologies employed in similar studies that have been completed across the country, including direct benefits such as energy, generation capacity, transmission and distribution capacity and line losses, avoided market and fuel price risk, and carbon emission regulatory costs. *Id.* at 55-78. Crossborder presents two scenarios for these direct benefits, including one that hews closely to Entergy Arkansas' own assumptions in evaluating its energy efficiency programs (the "Base Case"), and one that expands upon

[24] Following initial presentation of the Crossborder study at the July 18 meeting and again upon distribution of the workpapers on July 26th, Sub-Group 1 invited feedback on the methods and data employed. The final study does reflect the one substantive critique offered by Sub-Group 2 during the intervening time, which related to the time zone in which MISO locational marginal prices are reported.

those assumptions to include a larger set of benefits (the "Expanded Case"). *Id.* at 77, Table 14.

Crossborder also quantifies indirect, societal benefits that the Arkansas Legislature cited as motivation for requiring net metering, such as avoided environmental harms (in the form of greenhouse gas and criteria pollutant emissions), local economic development and avoided land and water use impacts. *Id.* at 78-86. Finally, Crossborder examines the reliability implications of distributed generation, which the Legislature specifically listed in Section 23-18-604(b)(1)(A). Although this benefit eludes quantification at this time, Crossborder concludes that emerging technologies such as behind-the-meter storage will help to realize the significant potential reliability and resiliency benefits offered by distributed solar. *Id.* at 86-87.

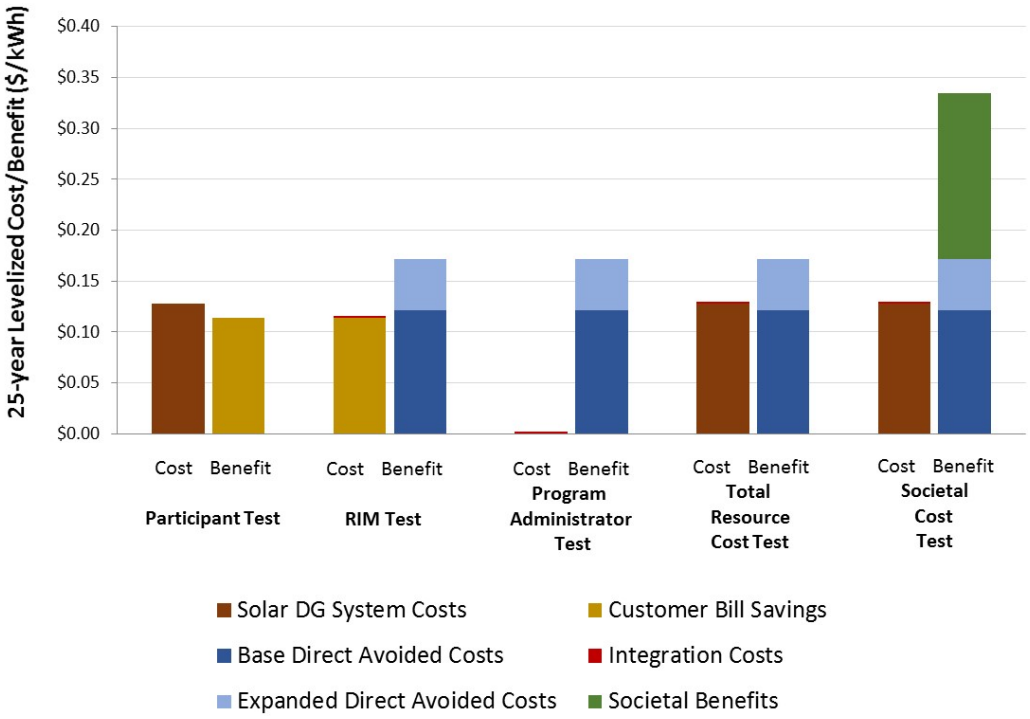
The Crossborder study shows that, for Entergy, the direct benefits of distributed generation under the Base Case add up to 12.9 cents per kilowatt-hour, and 19.2 cents per kilowatt-hour under the Expanded Case. *Id.* at Table 14 & Fig. 9. Neither of these figures includes the quantifiable societal benefits associated with distributed generation, and yet both exceed Entergy Arkansas' residential energy rates.[25] This result indicates that crediting self-generating customers on a kilowatt-hour basis (i.e., at the retail rate) for all energy they export to the grid is a good deal from the perspective of other ratepayers.

As in many other evaluations of the costs and benefits of distributed generation, Crossborder's analytical framework is drawn from the cost-effectiveness tests

[25] Under Entergy's General Purpose Residential Service Tariff, customers are charged between 5.2 and 9.6 cents per kilowatt-hour used, depending on the time of year and quantity of electricity used during the billing period, for an average of about 7.3 cents. *See* http://www.entergy-arkansas.com/content/price/tariffs/eai_rs.pdf. Residential customers are also assessed another approximately 2 cents in fuel charges and riders assessed on a per-kilowatt-hour basis.

commonly used to evaluate the merits of energy efficiency programs. Employing these tests allows Crossborder to assess the costs and benefits of distributed generation from a range of perspectives relevant to the Commission's decision.

Figure 1: *Cost-effectiveness Results for Net Metered Solar DG on the EAI System*[26]



Full retail net metering also passes the program administrator (utility) cost test and the ratepayer impact measure (RIM) test using both the Base and Expanded benefit cases. The RIM test result is especially significant because it indicates that net metering does not result in costs being shifted to non-participating customers (i.e., those without distributed solar systems). Relevant to AREDA's objective of promoting distributed renewable energy development, the Participant test shows that the payoff for Entergy residential customers installing distributed generation systems tends to be

[26] Reproduced from Attachment A-1, Figure ES-1.

negative, meaning that for most customers, the current net metering compensation scheme does not inadequately incent the development of distributed generation, consistent with data showing relatively slow rates of distributed solar adoption in the state. Thus, any reduction in the compensation for distributed generation exports will significantly reduce the payoff of what is already a marginal investment for customers, and therefore substantially discourage the adoption of distributed generation in the state.

The Commission may wish to expand the Crossborder analysis to include other utilities, or to include additional data points to be provided by utilities for this specific purpose. If the Commission chooses to undertake further analysis, we recommend that the study process (1) be open to stakeholder participation, input, and evaluation, (2) allow time for utilities to gather necessary data (load research on net metering customers, distributions system planning costs, etc.), and (3) be professionally facilitated by a neutral party.

V. Net Metering Working Group Process

Each member of Sub-Group 1 supported Staff's suggestion to initiate a working group process to be facilitated by Staff in the manner of the ongoing energy efficiency collaborative (the Parties Working Collaboratively, or PWC). We feel that these NMWG meetings were often very helpful in better understanding the perspective of other stakeholders, but also observed that the sense of common purpose characterizing the PWC was absent from the Net Metering Working Group. For example, Sub-Group 1 members advocated a cost-benefit study of net metering to answer the basic question

posed by Act 827, while members of Sub-Group 2, including Staff, preferred to move directly to a discussion of what rate design changes should be made based on a premise that net metering customers were not paying their full cost of service. Because of these very fundamental differences, the Net Metering Working Group was unable to reach agreement on critical issues.

As such, we offer several suggestions for the Commission's consideration. First, professional, neutral facilitation would greatly assist any working group in making progress towards the Commission's desired objectives, especially on a divisive issue like distributed generation. During the critical, initial period of the PWC, the Commission engaged a professional facilitator from the Regulatory Assistance Project.[27] After the initial series of orders established a common baseline from which to work and narrowed the gulfs of disagreement considerably, a Staff / IEM -led working group has been effective in the context of energy efficiency programs. The involvement of a neutral facilitator would permit Staff to take a position on the issues under discussion without compromising the value of a neutral arbiter on key tasks, such as setting agendas and assignments for meetings and moderating discussions among stakeholders. A professional facilitator might also have greater resources to undertake tasks such as providing minutes, meeting notes that synthesize stakeholder perspectives, or providing independent research that would give parties with a common factual basis for discussion. The Independent Evaluation Monitor has largely served these functions in the PWC, which in the view of those Sub-Group 1 members who participate in the PWC, has been helpful to the work of that group.

[27] In the Matter of a Notice of Inquiry Regarding a Rulemaking for the Developing and Implementing Energy Efficiency Programs, Docket No. 06-004-R, Order No. 4 , at 1.

Second, for likely contentious issues, the Commission may prefer to set more detailed guidelines for the deliverables the working group should produce, such as specific methodological questions on which the Commission would like recommendations. The open-ended assignment for this particular working group, on such a contentious issue, contributed to the challenges in focusing stakeholders on a series of narrow issues on which there could have been a meeting of the minds. For example, early in the working group process, Staff announced that it had determined that changes were necessary in the way that net metering operates in Arkansas, contrary to the belief of many stakeholders, which shifted the focus of the working group meetings away from evaluating the question of whether any changes were needed. A specific instruction from the Commission to evaluate that question, if indeed that is a question of interest to the Commission, would have made the tasks at hand clear to the entire working group.

VI. Conclusion

As this Commission has noted, Act 827 did not predetermine that changes to net metering are required, Order No. 10 at 143-44, but instead delegated to the Commission the task of ensuring that rates charged to net metering customers recover the full cost of service including any additional costs associated with distributed generation and net of quantifiable benefits. That work remains, and the Sub-Group 1 members are committed to supporting the Commission's efforts to meet the requirements of the statute.

Crossborder Energy

Comprehensive Consulting for the North American Energy Industry

The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc.

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September 15, 2017

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The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc.

This report provides a benefit-cost analysis of the impacts on ratepayers of the net metering of solar distributed generation (DG) in the service territory of Entergy Arkansas, Inc. (EAI). The Arkansas Public Service Commission (PSC) has initiated an investigation in Docket No. 16-027-R to review net metering issues in response to recent legislation directing the PSC to evaluate the rates, terms, and conditions of net metering in Arkansas.[28] Key provisions of this legislation state that the rates charged to net metering customers should recover the utility's costs, and must consider both the benefits and the costs of net metering to the electric utility and its ratepayers. Further, the PSC's analysis of net metering should consider all elements of utility service – generating capacity, reliability, and the transmission and distribution (T&D) system to deliver electricity.

This report contributes to the Commission's review by presenting a study of the benefits and costs of solar DG in the service territory of Entergy Arkansas, Inc. (EAI) the state's largest investor-owned utility. Crossborder Energy presented the initial results of this study at a workshop in Little Rock on July 18, 2017.

Our study provides a comprehensive benefit-cost analysis of demand-side solar in EAI's service territory. This analysis has the following key attributes:

1. **Multiple perspectives.** We examine the benefits and costs of solar DG from the perspectives of all of the key stakeholders – DG customers, other ratepayers, and the utility system and society as a whole. Together, these stakeholders constitute the public interest implicated by DG development. To capture all of these

[28] See A.C.A. § 23-18-604.

perspectives, we examine the benefits and costs of solar DG using the full set of cost-effectiveness tests for demand-side resources that commonly are used in the utility industry.

2. Consider a **comprehensive list of benefits and costs**.

3. Use **a long-term, life-cycle analysis** that covers the useful life of a solar DG system, which is at least 25 years. This treats solar DG on the same basis as other utility resources, both demand- and supply-side.

To calculate the benefits of net-metered solar DG, this report begins with the same avoided costs that EAI employs to evaluate the benefits of its other demand-side programs. We have supplemented these avoided costs with data from EAI's FERC Form 1 and with market data from the regional gas and electric markets in which EAI operates. Our approach to valuing solar DG also considers an expanded set of avoided costs and draws upon relevant analyses that have been conducted in other states, including the "public tools" for evaluating net-metered DG that have been developed in Nevada and California.[29]

We also evaluated costs of solar DG, including system costs, lost revenues, and integration costs, as appropriate under each of the standard cost-effectiveness tests. The cost of solar DG as a resource for the utility system and for participating ratepayers is the levelized cost of energy (LCOE) from solar DG installations. We calculate the LCOE for residential solar using a current installed cost of $3 per watt-DC, plus typical operating

[29] See the Public Utilities Commission of Nevada's (PUCN) 2014 net metering study at http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study. The California Public Utilities Commission's Public Tool is described and is available at http://www.cpuc.ca.gov/General.aspx?id=3934.

and financing assumptions for such systems. The costs of solar DG for EAI's non-participating ratepayers are principally the revenues that the utility loses from solar DG customers who use their on-site solar generation to serve their own loads and who export excess output back into the grid, thus running the meter backward using net metering. To determine these costs, we calculate the 25-year levelized lost revenues from residential customers who install solar DG under net metering. In this calculation we assume that EAI's retail rates escalate at 2% per year in the long run. Finally, as the cost of integration, we include an estimate of $2 per MWh as the cost of additional ancillary services that may be needed to integrate solar DG into the grid.

Our work concludes that the benefits of residential DG on the EAI system exceed the costs, such that residential DG customers do not impose a burden on EAI's other ratepayers. The following **Figure ES-1** and **Table ES-1** summarize the results of our application of the primary cost-effectiveness tests to residential solar DG on the EAI system.

Figure ES-1: *Cost-effectiveness Results for Net Metered Solar DG on the EAI System*

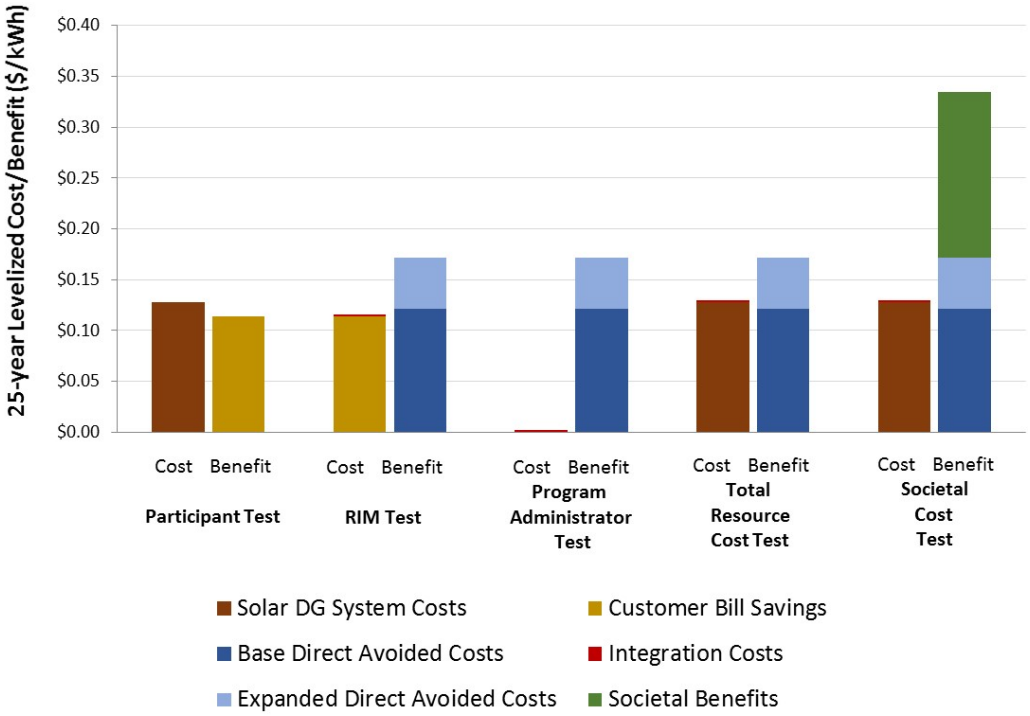


Table ES-1: *Benefits and Costs of Solar DG for EAI (25-yr levelized cents/kWh)*

Benefit-Cost Test	**Participant**		**RIM / PAC**		**TRC**		**Societal**	
Category	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit
Base Direct Avoided Costs – *EE Assumptions*				12.1		12.1		12.1
Expanded Direct Avoided Costs				17.2		17.2		17.2
Lost Revenues / Bill Savings (RIM / PCT)		11.4	11.4					
Integration (RIM/TRC/SCT)			0.2		0.2		0.2	
Solar DG LCOE	12.8				12.8		12.8	
Societal Benefits								16.4
Totals	12.8	11.4	11.6	12.1 – 17.2	13.0	12.1 – 17.2	13.0	28.5– 33.6
Benefit-Cost Ratios	**0.89**		**1.04 -1.48 (RIM) >> 1 (PAC)**		**0.93 – 1.32**		**2.19 – 2.58**	

The principal conclusions of our analysis are as follows:

1. **Solar DG is a cost-effective resource** for EAI, as the benefits equal or exceed the costs in the Total Resource Cost, Program Administrator, and Societal tests. The results of these tests are well above 1.0 when a broad range of benefits are considered. As a result, in the long-run, deployment of solar DG will reduce the utility's cost of service.

2. **Net metering does not cause a cost shift to non-participating ratepayers**, as shown by the result for the Ratepayer Impact Measure test.

3. **Modifications to net metering are not needed** to recover the utility's full cost of service over time from net metering customers. Major rate design changes for residential DG customers, such as increased fixed charges, the use of demand charges, or two-channel billing to set different compensation rates for imported and exported power, are not needed to recover the utility's full cost of service over time from net metering customers.

4. **The economics of solar DG are marginal** for EAI's residential customers, as shown by the Participant test results below 0.9 and the modest amount of solar adoption to date. This means that any reduction in the compensation provided to

solar DG customers is likely to be detrimental to the growth of this resource, although these economics may improve as solar costs continue to fall.

5. There are **significant, quantifiable societal benefits from solar DG**, including local economic benefits and public health improvements from reduced air pollution.

6. Solar DG also provides other important benefits that are difficult to quantify. These include the **enhanced reliability and resiliency** of customers' electric service, because solar DG is a foundational element for backup power systems and micro-grids that can provide uninterrupted power when the utility grid is down. Distributed generation also **enhances customers' freedom**, allowing them to choose the source of their electricity, and results in **customers who are more engaged and better informed** about how their electricity is supplied. The choice of using private capital to install solar DG on a customer's private premises **leverages a new source of capital to expand Arkansas's clean energy infrastructure and allows Arkansas to take advantage of federal tax incentives for solar that will begin to phase out in 2020**.

1. Background: Net Metering in Arkansas

Net metering is the billing arrangement used in most states in the U.S. to compensate customers who install renewable distributed generation (DG) on their premises, such as solar photovoltaic (PV) systems.[30] The output of a PV array first serves the DG customer's onsite load, reducing the amount of power which the customer purchases from the serving utility. When the DG output exceeds the onsite load, the excess generation is exported to the utility grid, where the utility uses that generation to serve neighboring loads. Under net metering, the DG customer receives a credit for these exports at the same volumetric rate that the customer pays when it imports power from the utility. Thus, the essence of net metering is the ability of a customer with a solar PV system to "run the meter backwards" when the customer exports power and serves as a generation source for the utility. In the accounting used to calculate the DG customer's bill, the customer can use the credits (when the meter runs backward) to offset the cost of usage from the grid (when the meter runs forward). The customer simply pays the net bill each month. The simplicity of net metering for the DG customer is a major factor in its widespread use and popularity.

Thus, DG located behind the meter both reduces the DG customer's use of power from the utility, and, at times, allows the DG customer to provide a service to the utility, thus becoming a producer (i.e., a generator). Some have applied a new label – "prosumers" – to DG customers in recognition of this dual role as both a customer of the utility and as a supplier providing a service (generation) to the utility.

[30] Today, 47 states offer some type of net metering. See http://programs.dsireusa.org/system/program/maps. This includes Arizona, California, Nevada, New Hampshire, and Hawaii, states which have large numbers of existing DG customers on traditional net metering, but which have adopted new compensation rules for new DG customers that make changes in the compensation for excess generation exported to the grid.

As generators, renewable DG customers typically have legal status as qualifying facilities (QFs) under the Public Utilities Regulatory Policies Act of 1978 (PURPA). Under this federal law, a utility in whose territory a QF is located is required to do the following:

- interconnect with a customer's renewable DG system,
- allow a DG customer to use the output of his system to offset his on-site load, and
- purchase excess power exported from such systems at a state-regulated price.[31]

These provisions of federal law are independent of whether a state has adopted net metering; thus, the adoption of net metering only impacts the accounting credits which the customer-generator receives for the power exports to the grid.[32]

The Arkansas Public Service Commission (PSC) has initiated a generic investigation in Docket No. 16-027-R to review net metering issues in response to recent legislation directing the PSC to evaluate the rates, terms, and conditions of net metering in Arkansas.[33] Key provisions of this legislation state that the rates charged to net metering customers should recover the utility's costs, and must consider both the benefits and the costs of net metering to the electric utility and its ratepayers. The legislation further states that the PSC's analysis of net metering should consider all elements of utility service – generating capacity, reliability, and the delivery (T&D) system.

The statute that established net metering in Arkansas cites the following purposes for a net metering program:

- Promote wise use of Arkansas's natural energy resources,
- Independence from imported fossil fuels,
- Invest in emerging energy technologies,

[31] The PURPA requirements can be found in 18 C.F.R. §292.303.
[32] Although behind-the-meter DG systems meet the requirements for a qualifying facility, FERC has held that a state requirement that utilities credit customers for exports at the retail rate does not run afoul of PURPA's avoided cost requirement. See MidAmerican Energy Co., 94 FERC ¶ 61,340 (2001).
[33] *See* A.C.A. § 23-18-604.

- Economic development / job creation,
- Reduce environmental stress, and
- Provide greater customer choice.[34]

These represent important societal benefits of the clean, renewable, local distributed generation installed under the net metering program.

2. Methodology

Solar DG is a long-term generation resource for Arkansas. New solar DG systems will provide benefits for the next 25 to 30 years. Thus, our analysis develops 25-year levelized benefits and costs for solar DG on the EAI system, the largest investor-owned utility in Arkansas. This approach is consistent with the statute's focus on assessing the impacts of net metering on the utility's cost of service, because the assessment of benefits and costs measures the impact of net metered DG on the utility's long-term cost of service. As the law recognizes, both the benefits and costs must be estimated, in order to capture factors that either reduce the cost of service (i.e. benefits) or increase them (i.e. costs).

The issues raised by the growth of behind-the-meter DG are not new. Issues of impacts on the utilities, on non-participating ratepayers, and on society as a whole also arose when state regulators and utilities began to manage demand growth through energy efficiency ("EE") and demand response ("DR") programs. To provide a framework to analyze these issues in a comprehensive fashion, the utility industry developed a set of standard cost-effectiveness tests for demand-side programs. These tests examine the cost-effectiveness of demand-side programs from a variety of perspectives, including from the viewpoints of the program participant, other ratepayers, the utility, and society as a whole.

[34] See A.C.A. § 23-18-602.

This framework for evaluating demand-side resources is widely accepted, and state regulators have years of experience overseeing this type of cost-effectiveness analysis, with each state customizing how each test is applied and the weight which policymakers place on the various test results. This suite of cost-effectiveness tests is now being adapted to analyses of net metering and behind-the-meter DG, as state commissions recognize that evaluating the costs and benefits of all demand-side resources – EE, DR, and DG – using the same cost-effectiveness framework will help to ensure that all of these resource options are evaluated in a fair and consistent manner.

Accordingly, we have evaluated the long-term benefits and costs of net-metered solar DG from multiple perspectives, using each of the major cost-effectiveness tests widely used in the utility industry.[35] Each of the principal demand-side cost-effectiveness tests uses a set of costs and benefits appropriate to the perspective under consideration. These are summarized in **Table 1** below ("+" denotes a benefit; "-" a cost).

Table 1: *Demand-side Benefit (+) / Cost (-) Tests*

Category	Total Resource Cost (TRC) and Societal	Ratepayer Impact (RIM)	Program Administrator - Utility (PAC)	Participant (PCT)
Capital and O&M Costs of the DG Resource	–			–
Utility Lost Revenues (same as Customer Bill Savings)		–		+
Costs for Incentives (if available)	–	–	–	+
Integration and Program Administration Costs	–	–	–	

[35] See the *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* (October 2001), available at http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF. We understand that these tests are used in Arkansas, with the Total Resource Cost test being the primary test for assessing the cost-effectiveness of energy efficiency portfolios.

Avoided Costs -- Energy -- Generation Capacity -- T&D, including losses -- Risk / Hedging / Market -- Environmental Compliance -- RPS (not applicable in AR) -- Societal (Societal Test only)	+	+	+	
Federal Tax Benefits	+			+

The key goal for regulators is to implement demand-side programs that produce balanced, reasonable results when the programs are tested from each of these perspectives. In this case, full retail net metering is the program under evaluation. First, the program should provide a resource that is a net benefit to the utility system or to society – thus, the Total Resource Cost (TRC) and Societal Tests compare the costs of solar DG systems to their benefits to the utility system and society as a whole. Second, the DG program will need to pass the Participant test if it is to attract customers to make long-term investments in DG systems. Finally, the Ratepayer Impact Measure (RIM) test gauges the impact on other, non-participating ratepayers. The RIM test sometimes is called the "no regrets" test because, if a program passes the RIM test, then all ratepayers are likely to benefit from the program. However, it is important to keep in mind that the RIM test measures equity among ratepayers, not whether the program provides an overall net benefit as a resource (which is measured by the TRC and Societal tests).

Data. Our starting point for the data needed to perform a full 25-year benefit-cost assessment is the set of publicly-available "key assumptions" for the avoided costs that EAI uses to evaluate its other demand-side programs, as filed most recently on May 1, 2017 in Docket No. 07-085-TF (the "*EE Assumptions*").[36] These avoided cost assumptions are included as **Attachment 1**. We have supplemented these avoided costs with data from EAI's *2015*

[36] See *Direct Testimony of Kandice Fielder* for EAI filed May 1, 2017 in Docket No. 07-085-TF

Integrated Resource Plan (*2015 IRP*), data on loads and market prices on the Midcontinent Independent System Operator's (MISO) system in Arkansas, FERC Form 1 data for EAI, and with information from analyses of the impacts of solar DG on utilities in other states. Our analysis is based entirely on public data sources without the use of confidential data.

Benefits. In deciding what benefits to include in this analysis, we were guided by A.C.A. §23-18-604(b)(1)(A), which specifically calls for consideration of energy, generation capacity, transmission, distribution and reliability benefits, by the societal benefits cited by the Legislature in A.C.A. §23-18-602, and by our knowledge of the benefits recognized and quantified in numerous other distributed generation studies.

The largest quantifiable direct benefits of DG are avoided energy, avoided generation capacity, avoided transmission and distribution capacity, and avoided line losses. Our methodologies for quantifying these benefits are discussed in detail below. Several of the most important (and beneficial) characteristics of DG are the shorter lead times and smaller, scalable increments in which DG is deployed, compared to large-scale generation resources. In this respect, DG should be treated like energy efficiency and demand response, which also are small-scale, short-lead-time resources. The small amount of DG included in EAI's *2015 IRP* combines with EE and DR to help to defer the need for larger-scale resources in the long-run. The *2015 IRP* finds that EAI will need new resources as early as 2018, and shows that EAI is depending on the continued growth of demand-side resources to meet its future energy and capacity needs. Our Base set of direct benefits of solar DG use the avoided costs included in the *EE Assumptions*, which EAI also uses to assess the benefits of its other demand-side programs.

We also consider an Expanded set of avoided costs that includes a number of additional direct benefits of DG that also will reduce ratepayer costs, including:

- **Fuel hedging benefits.** Renewable generation, including solar DG, reduces a utility's exposure to volatility in fossil fuel prices.

- **Price mitigation benefits.** Solar DG reduces market demand both for electricity and for the natural gas used to produce the marginal kWh of power. These reductions have the broad benefit of lowering prices across the gas and electric markets in which EAI operates.

- **Long-term avoided T&D costs.** Our Expanded set of avoided costs includes a detailed calculation of long-term avoided T&D costs, based on FERC Form 1 data.

In addition, solar DG also provides quantifiable societal benefits to the citizens of Arkansas. These include important environmental benefits, such as reduced emissions of greenhouse gases and criteria air pollutants, and lower use of scarce water resources. We have assembled the data needed to quantify the reduced emissions of these pollutants as well as the water savings, drawing upon recent quantifications of these societal benefits. We also quantify the additional societal benefits of stimulating local economic activity. Finally, we discuss but do not quantify the benefits of enabling customers to enhance the reliability and resiliency of their electric service and of expanding competition and customer choice.

Costs. The relevant costs of solar DG vary across the benefit-cost tests.

The Total Resource Cost, Societal, and Participant Tests use the capital, financing, and operating costs for solar DG systems, as incurred by the participating customers who install solar. These include the installation costs for the systems (offset by the federal investment tax credit), plus the costs for financing, maintenance, and periodic inverter replacement. The cost of DG systems per kilowatt-hour of output can vary based on size, installation costs, financing terms, and output. For those tests in which utility costs are relevant, we add an estimate of the solar integration costs which the utility will incur to incorporate these resources into its system, based on solar integration studies performed by other utilities with larger amounts of solar generation on their systems.

In the RIM Test, the costs of solar DG for non-participating ratepayers are principally the revenues which the utility loses from customers serving their own load with DG. To these lost revenues we add the estimate of solar integration costs.

The following sections discuss each of the benefits and costs of solar DG for EAI. Solar DG is a long-term resource with an expected useful life of at least 25 years. Accordingly, we calculate the benefits and costs of DG over a 25-year period in order to capture the value of these long-term resources, and we express the results as 25-year levelized costs using the same 6.1% per year discount rate that EAI assumes in evaluating its other demand-side programs.[37]

3. Direct Benefits of Solar DG

a. Energy

Solar DG on the EAI system avoids marginal generation, principally gas-fired generation in the MISO South market area. The methodology for calculating the avoided energy costs associated with demand-side resources is well-established. To estimate these avoided costs, we have used recent MISO locational marginal prices (LMPs) for the Arkansas Hub, weighted by a standard output profile for a solar array in Little Rock, and escalated these LMPs using the long-term forecast of natural gas prices from the Energy Information Administration's (EIA) *Annual Energy Outlook 2017 (AEO 2017)*.

Specifically, we looked at hourly day-ahead market prices reported by the MISO for the Arkansas Hub over the period June 2016 to May 2017. These prices averaged $27.38 per MWh for a 24x7 baseload profile. Using an hourly solar output profile for Little Rock from the National Renewable Energy Laboratory's (NREL) PVWATTS calculator, the solar-weighted average price for the June 2016 to May 2017 period was 16% higher, or $31.74 per MWh. The

[37] This discount rate is EAI's after-tax weighted average cost of capital.

higher average price when hours are weighted by typical solar output is due to the fact that MISO prices are higher during the hours when solar DG produces energy, as illustrated in the following two heat maps. **Table 2** shows average solar output by month and daylight hour (in Eastern Standard Time, the format reported by the MISO). **Table 3** indicates the level of June 2016 to May 2017 average MISO prices at the Arkansas Hub in these hours.

Table 2: *PV-Watts Output Profile for Solar PV in Little Rock*

Month	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	0%	0%	3%	17%	31%	42%	49%	48%	46%	37%	24%	11%	1%	0%
2	0%	0%	5%	19%	32%	42%	47%	52%	46%	36%	28%	15%	2%	0%
3	0%	1%	10%	24%	39%	52%	57%	59%	57%	49%	36%	21%	6%	0%
4	0%	7%	21%	33%	45%	54%	63%	69%	60%	54%	40%	24%	9%	0%
5	1%	9%	23%	35%	49%	57%	60%	63%	61%	50%	40%	24%	11%	2%
6	2%	10%	24%	36%	51%	58%	61%	64%	62%	55%	44%	28%	14%	3%
7	1%	8%	23%	39%	52%	62%	65%	68%	63%	54%	42%	29%	14%	3%
8	0%	6%	21%	38%	53%	61%	67%	67%	63%	56%	44%	28%	12%	2%
9	0%	4%	17%	34%	47%	56%	58%	60%	59%	50%	35%	19%	5%	0%
10	0%	2%	16%	32%	47%	56%	61%	63%	55%	45%	29%	13%	1%	0%
11	0%	0%	9%	23%	36%	44%	47%	48%	45%	32%	21%	6%	0%	0%
12	0%	0%	4%	17%	29%	41%	44%	50%	43%	34%	20%	6%	0%	0%

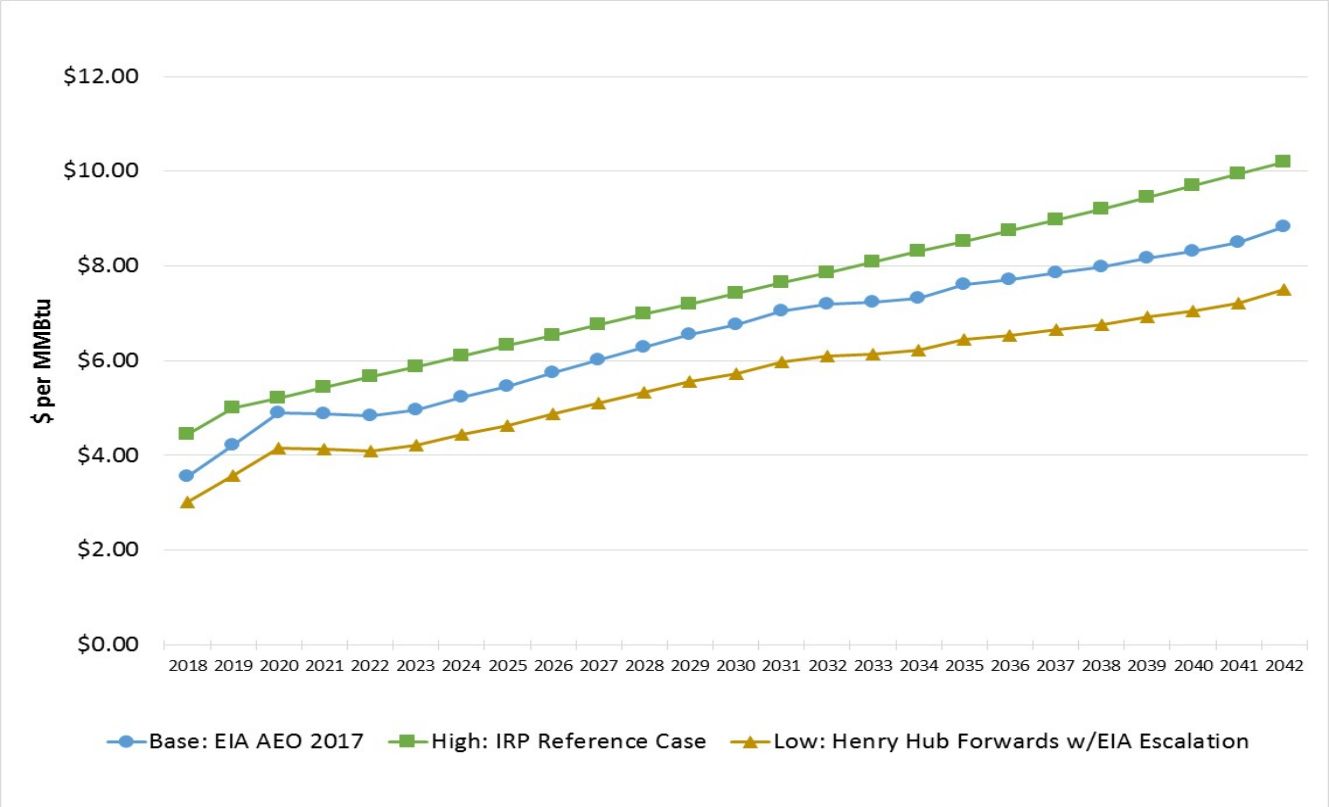
Table 3: *Average June 2016 to May 2017 MISO Arkansas Hub Prices ($/MWh)*

Month	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	22.9	26.5	32.8	30.8	30.2	29.7	28.5	27.6	26.5	25.7	25.0	25.7	30.6	34.2
2	20.4	23.7	26.9	25.6	25.3	24.8	24.4	23.9	23.4	22.9	22.5	22.6	23.7	26.7
3	24.8	31.3	31.5	30.2	29.9	29.1	27.9	27.1	26.4	26.2	26.5	26.8	26.9	29.5
4	27.7	30.5	29.9	30.7	32.4	33.2	33.7	34.8	36.9	38.2	39.2	40.0	37.1	35.1
5	23.1	25.5	26.7	27.8	29.1	30.1	31.4	33.3	35.6	37.5	39.7	40.9	37.6	34.0
6	17.5	18.9	20.3	21.8	23.3	25.1	27.0	29.5	33.5	36.7	37.7	37.5	32.5	28.8
7	19.7	20.3	22.0	23.7	25.3	27.0	29.0	31.9	35.4	39.0	41.7	40.9	35.9	31.3
8	19.4	20.5	21.8	23.4	25.5	28.0	30.7	33.7	37.2	39.7	41.9	39.7	34.8	31.4
9	21.2	22.8	23.2	24.3	25.9	27.1	29.1	32.7	35.8	39.0	39.5	37.2	32.3	30.0
10	25.0	28.0	27.1	27.2	28.6	29.8	31.6	34.4	39.9	47.8	52.1	51.0	40.9	39.2
11	20.4	23.3	25.5	24.5	24.6	24.8	24.6	24.3	24.3	24.5	24.4	24.8	28.1	29.2
12	25.9	30.7	37.2	35.2	33.6	33.2	31.6	30.5	29.4	28.5	28.1	29.1	35.3	37.3

After determining the solar-weighted average price for the Arkansas Hub, we escalate that value, based on the expected growth in natural gas prices at the Henry Hub, Louisiana, relative to historical Henry Hub prices for the base period of June 2016 to May 2017. Our base case natural gas forecast is EIA's *AEO 2017* forecast of prices at the Henry Hub. We also develop low and high scenario forecasts. Our low forecast uses June 1, 2017 Henry Hub forward market prices for 2018, escalated in subsequent years based on EIA's *AEO 2017* forecast. Our

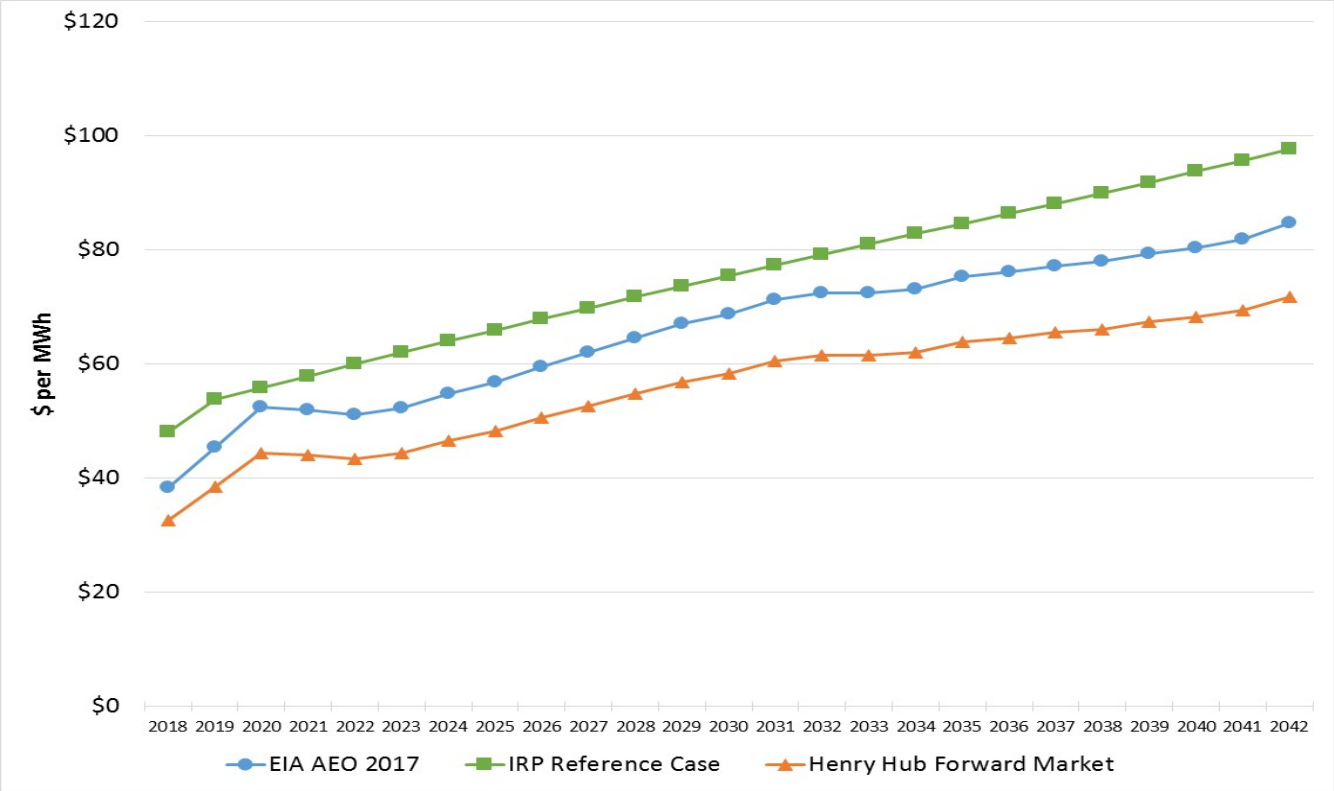
high case forecast employs Entergy's *2015 IRP* reference case gas price forecast.[38] The following two figures show the resulting projections of natural gas prices and solar-weighted avoided energy costs.

Figure 1: *Natural Gas Price Forecasts*



[38] See *2015 IRP*, at p. 32.

Figure 2: *Solar-weighted Avoided Energy Costs*



We have levelized these prices over the 25-year period from 2018 to 2042 using Entergy's 6.1% discount rate. The levelized avoided cost also assumes that solar output declines by 0.5% per year, based on the industry-standard assumption for the degradation over time in solar panel output.

With these inputs, our base forecast of EAI's avoided energy costs for solar DG is a 25-year levelized value of 6.35 cents per kWh, in 2018 dollars, as shown in **Table 4**.

Table 4: *EAI Avoided Energy Costs (25-year levelized 2018 $/MWh)*

Scenario	Base Case	Sensitivities	
		Low Gas	High Case
Gas Price Forecast	EIA *AEO 2017*	Henry Hub Forwards	*2015 IRP*
Avoided Energy ($/MWh)	**63.50**	**53.90**	**72.40**

b. Generation capacity

The *2015 IRP* finds that EAI has a need for new generating capacity as early as 2017.[39] Combustion turbines ("CTs") are the least-cost source of new utility-scale capacity. The avoided capacity cost of $77.98 per kW-year (in 2016 $) stated in the *EE Assumptions* is the annualized cost for CT capacity.

The capacity value of solar resources is only a fraction of its nameplate capacity, because solar will not be producing at full nameplate during the afternoon hours when demand peaks. MISO has adopted rules to determine the accredited capacity value of solar resources, as a percentage of nameplate capacity. MISO solar capacity value for resource adequacy is the capacity factor of solar facilities from hour ending (HE) 3 p.m. to 5 p.m. Eastern Standard Time in June, July, and August, with a default of 50% of nameplate until actual output is available.[40] Based on PVWATTS simulated solar output for Little Rock for a south-facing fixed array, the capacity value of solar according to the MISO accreditation formula is 54% of nameplate, with total annual solar production of 1,530 kWh per kW-AC of solar capacity.[41]

The capacity value of distributed solar PV is based on its ability to reduce the peak demand for power on the grid. This reduced peak demand also lowers the reserve capacity that the utility must maintain to serve that peak. EAI's current reserve margin is 12%. Accordingly, we increase avoided capacity costs by 12% to reflect the benefit of the lower required reserves.

Table 5 presents the complete calculation of avoided generation capacity costs.

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[39] See *2015 IRP*, at p. 16.
[40] See MISO Business Practice Manual BPM-011-r16, Section 4.2.3.4.1.
[41] The MISO capacity criteria is based on solar output during a defined set of hours. To estimate average solar output during these hours, we use hourly output from PVWATTS because it calculates solar output using solar insolation data from a typical meteorological year (TMY).

Table 5: *Avoided Generation Capacity Costs ($ per MWh in 2018$)*

Line	Parameter	Value	Notes
1	Avoided Capacity Cost (2016 $)	77.98 / kW-year	from *EE Assumptions*
2	Avoided Capacity Cost (2018 $)	81.13 / kW-year	2% per year inflation
3	MISO Solar RA Capacity Value	54%	MISO BPM-011
4	Solar Output	1,530 kWh / kW	NREL PVWATTS
5	EAI Avoided Reserves	12%	EAI reserve margin
6	**Solar Avoided Capacity Cost**	**0.0321 / kWh**	[(2 x 3) / 4] x 1.12
		32.10 per MWh	

c. Line losses

The avoided energy and capacity costs calculated above are at the generation level, and need to be increased to reflect the marginal line losses on both the transmission and distribution systems that are avoided by customer-sited solar DG, which is located behind the customer's meter at the point of end use. We understand that the line loses included in the *EE Assumptions* are average losses.[42] We have increased these losses by 50% to capture the higher marginal losses avoided by new DG resources, based on a study from the Regulatory Assistance Project on the relationship between average and marginal line losses.[43] The resulting loss factors are still conservative, in that they may not reflect the higher losses experienced during the peak demand hours in summer afternoons when solar output is high. Finally, we assume that the 2.0% transmission losses included in the *EE Assumptions* already are included in the MISO LMP prices used to determine avoided energy costs. **Table 6** shows our calculations of avoided line losses for both energy and capacity.

[42] This is notwithstanding our understanding that EAI is required to use marginal losses in its EE cost effectiveness calculations. See Order No. 7 in Docket 13-002-U, at page 39 of 91: "The Commission adopts the use of marginal, rather than average line losses, which is unopposed by any party, to quantify EE's incremental effects."

[43] Regulatory Assistance Project, *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements* (August 2011), at p. 5. See http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf.

Table 6: *Avoided Line Losses ($ per MWh in 2018$)*

Avoided Cost	Value *($ per MWh)*	Loss Factor	Convert to Marginal Losses	Avoided Losses *($ per MWh)*
Energy	63.50	7.44%	1.5	7.10
Capacity	32.10	9.44%	1.5	4.50
Total				11.60

d. Transmission and distribution capacity

A significant share of the output of solar DG serves on-site loads. This share typically ranges from 40% to 60%, and depends on the size of the solar system and the load profile of the customer. The DG output used onsite never touches the grid, and thus clearly reduces loads on the utility's T&D system. Even for the remaining power that a solar DG unit exports to the grid, these exports are likely to be entirely consumed on the distribution system by the solar customer's neighbors, unloading the upstream portions of the distribution system and the transmission system. Thus, much like energy-efficiency and demand response resources, solar DG displaces traditional generation sources which must use the utility T&D system to be delivered to customers.

Solar DG avoids transmission and distribution capacity costs to the extent that solar production occurs at times of peak demand on the T&D system. Solar DG helps the utility to manage and to reduce current loads and load growth, thus avoiding and deferring the need for load-related T&D investments. Solar DG also can defer the need for new transmission to access utility-scale renewables, if DG provides an alternative to larger-scale renewable projects to supply needed capacity or to meet renewable energy goals. These T&D benefits can be quantified by calculating the utility's marginal cost of load-related transmission and distribution capacity.

As DG penetration grows, and a deeper understanding is gained of the impacts of DG on the delivery circuits, utility T&D planners will integrate existing and expected DG capacity into their planning. A comparable evolution has occurred over the last several decades, as the long-term impacts of EE and DR programs are now incorporated into utilities' capacity expansion plans for generation, transmission, and distribution, and it is generally recognized that these demand-side programs can help to manage demand growth and to avoid capacity-related costs for T&D as well as generation.

In this study, we have developed two separate estimates of avoided T&D costs for EAI. The first is the avoided T&D capacity costs included in the *EE Assumptions*, which we use in the Base avoided costs. The second is an alternative calculation of long-term avoided T&D capacity costs which we use with the Expanded set of avoided costs.

i. Avoided T&D in the *EE Assumptions*

We first use the avoided T&D capacity costs of $23.86 per kW-year in 2016 that are included in EAI's *EE Assumptions*. Escalating that value by 2% per year over a 25-year period results in a levelized price of $29.80 per kW-year for 2018-2042, including standard degradation of 0.5% per year in solar output.

The next step is to convert a portion of this marginal T&D capacity value into an equivalent price per kilowatt-hour that considers the extent to which solar DG avoids investments in marginal T&D capacity. Distributed generation can avoid transmission investments by reducing peak loads on the EAI transmission system. We determined that the capacity contribution of solar PV to reducing peak transmission loads is 52.2% of the solar nameplate. This is based on a Peak Capacity Allocation Factor (PCAF) analysis of solar output at the time of Entergy's peak loads over the five-year period 2009-2013. The peak load data for these years is from FERC Form 714. In each of these years, we calculated an hourly set of peak

capacity allocation factors for those hours in which Entergy's loads were within 10% of the maximum hourly load for the year. In this allocation, the hours with loads in the range of 90% to 100% of the maximum hourly load for the year are weighted according to the amount by which they exceed the threshold of 90% of maximum load. The following heat map, **Table 7**, shows the resulting PCAF distribution for 2009-2013 of the hours with loads within 10% of the annual peak hour loads. As the heat map shows, this allocation focuses on the mid-afternoon hours in the months of June to August.

Table 7: *PCAF Heat Map – 2009 to 2013 Loads*

Month\Hour	10	11	12	13	14	15	16	17	18	19	20	21
1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	0.0%	0.1%	1.1%	3.4%	5.8%	7.3%	7.0%	4.7%	2.3%	0.5%	0.1%	0.0%
7	0.0%	0.0%	0.2%	2.0%	3.9%	5.2%	5.1%	3.1%	1.1%	0.2%	0.1%	0.0%
8	0.0%	0.1%	1.4%	4.3%	7.8%	10.0%	9.7%	6.6%	3.1%	1.0%	0.5%	0.0%
9	0.0%	0.0%	0.0%	0.1%	0.5%	0.8%	0.8%	0.2%	0.0%	0.0%	0.0%	0.0%
10	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
11	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

This PCAF allocation then was applied to solar output based on actual solar insolation in Little Rock in 2009-2013 from Clean Power Research's *Solar Anywhere* tool, with the NREL Solar Advisor Model used to convert the actual insolation to solar PV generation. We used actual solar insolation data in order to capture the correlation between solar output and the hot summer weather that drives periods of high demand. In other words, when it is hot and electric demand is high, it also tends to be sunny.[44] This correlation would be lost if solar output were based on typical meteorological year ("TMY") data, as it is in the PVWATTS tool. The result is that solar DG will reduce EAI's peak loads by an average of 52.2% of the solar nameplate

[44] EAI's 2015 testimony in support of its Stuttgart solar power purchase agreement recognizes this correlation. EAI witness Mr. Castleberry observed that solar output and peak electric demand are correlated, because it is the same resource (the sun) that produces both. See *Direct Testimony of Kurtis W. Castleberry, Director, Resource Planning and Market Operations on Behalf of EAI*, Docket No. 15-014-U, dated April 15, 2015, at pp. 19-20, hereafter "EAI's Stuttgart Testimony."

capacity. This is the solar contribution to reducing the system peak loads that drive load-related transmission investments.

The product of the levelized cost of T&D capacity and the 52.2% solar capacity contribution measures the transmission capacity cost avoided by a solar PV resource. We divide this product by the expected solar generation per kW of AC capacity to produce a volumetric ($/MWh) rate, as shown in the following table:

Table 8: *25-year Levelized Avoided T&D Marginal Capacity Cost for Solar DG*

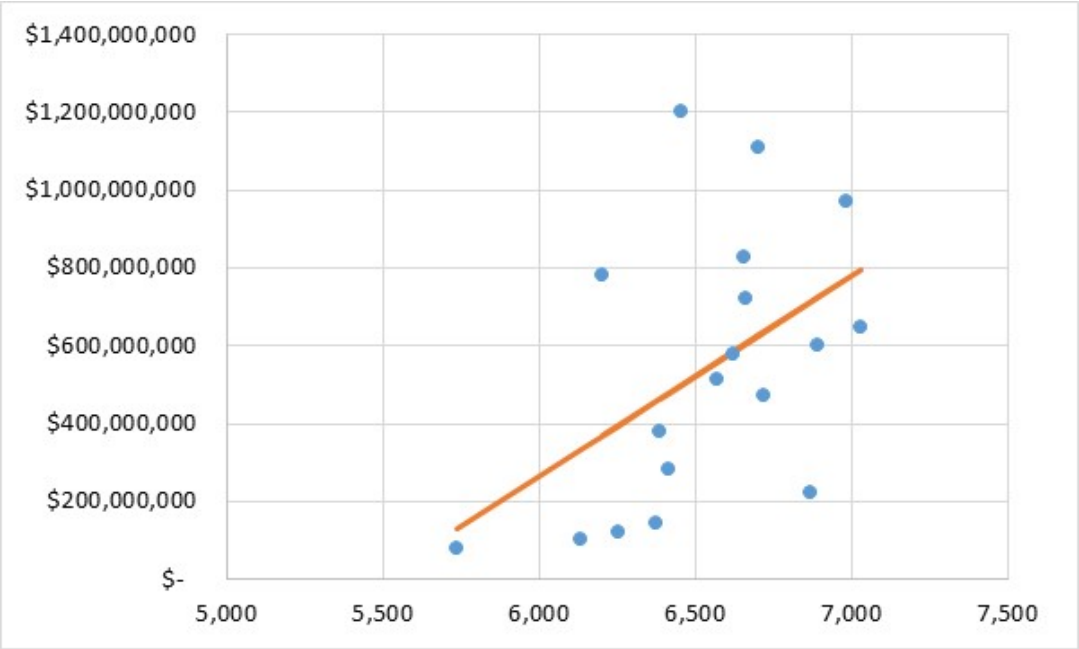
Parameter	Value	Notes
Avoided T&D Capacity Cost	$23.86 per kW-year	EE value, in 2016 $
Annual Escalation Rate	2.0%	
25-year Levelized Cost (2018 $)	$29.80 per kW-year	6.1% discount rate
Solar Contribution to MISO South Peak Load	52.2%	PCAF calculation
Solar Output – Annual kWh per kW-AC	1,530 kWh	NREL PVWATTS
Solar Avoided T&D Capacity Cost	**$10.20 per MWh**	$29.80 x 0.522 / 1.53 MWh

ii Long-term avoided T&D

As an alternative calculation of long-term avoided T&D investment costs for use in the Expanded set of avoided costs, we have used the well-accepted National Economic Research Associates (NERA) regression method. This approach is used by many utilities to determine their marginal transmission and distribution capacity costs that vary with changes in load. The NERA regression model fits incremental T&D investment costs to peak load growth. The slope of the resulting regression line provides an estimate of the marginal cost of T&D investments associated with changes in peak demand. The NERA methodology typically uses 10-15 years of historical expenditures on T&D investments and peak transmission system loads, as reported in FERC Form 1, and, if available, a five-year forecast of future expenditures and expected load growth.

Transmission. We have utilized a NERA regression based on Entergy's historical peak load growth and transmission expenditures, over an 18-year period from 1996 to 2013. Our analysis of marginal transmission costs uses Entergy's FERC Form 1 data for this period. **Figure 3** shows the regression fit of cumulative transmission capital additions as a function of incremental demand growth on the Entergy system.

Figure 3: *Regression of Cumulative Entergy Transmission Costs vs. Peak Demand*



The regression slope resulting from this analysis is $517 per kW. We add 2.6% to this amount as a general plant loader, convert the total to an annualized marginal transmission cost using a real economic carrying charge (RECC) of 6.5%,[45] and include $4.29 per kW-year for transmission O&M costs. Our estimate of general plant and transmission O&M costs are also based on EAI's FERC Form 1 data. The resulting avoided cost for transmission capacity for Entergy is $38.76 per kW-year.

[45] Based on EAI's currently-authorized capital structure and cost of capital.

We use the same capacity contribution of 52.2% discussed above, using the PCAF method based on Entergy loads and actual solar insolation from 2008-2013. We convert the marginal transmission cost in $ per kW-year into a $ per MWh value using an annual solar output of 1,530 kWh per kW-AC. **Tables 9 and 10** show our calculations of this alternative avoided cost of transmission capacity for EAI. The result is that solar DG avoids transmission capacity costs of $13.20 per MWh.

Table 9: *EAI Marginal Transmission Cost*

Parameter	Value
Slope ($/kW)	517
General Plant Loader (%)	2.6%
General Plant Loader ($/kW)	13
Total Marginal Transmission ($/kW)	530
RECC Factor	6.50%
Annualized Transmission ($/kW-yr)	34.5
Transmission O&M ($/kW-yr)	4.29
Total Annual Marginal Cost ($/kW-yr)	**38.80**

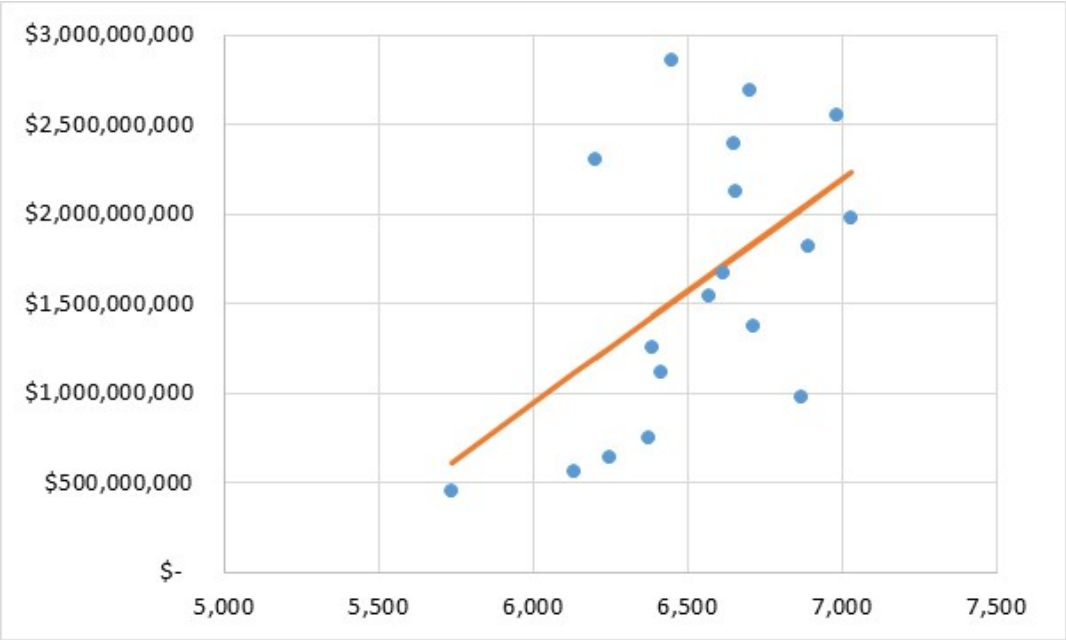
Table 10: *25-year Levelized Avoided Transmission Costs for EAI*

Parameter	Value	Notes
Avoided Transmission Capacity Cost	$38.80 per kW-year	From Table 9
Solar Contribution to MISO South Peak Load	52.2%	PCAF calculation
Solar Output – Annual kWh per kW	1,530 kWh	NREL PVWATTS
Solar Avoided Transmission Capacity Cost	**$13.20 per MWh**	$38.80 x 0.522 / 1.53 MWh

Distribution. The extent to which solar generation avoids distribution capacity costs is a more complex question than for transmission, for various reasons. Distribution substations and circuits can peak at different times than the system as a whole, which complicates the calculation of the avoided distribution costs that result from solar DG reducing distribution system loads. It is clear, however, that the significant share of solar DG output which serves on-site loads will reduce demand on the distribution system, because that power is consumed behind the mater, never touches the grid, and will reduce the loads that must be served from the grid. Further, the remaining DG output that is exported to the distribution system will serve nearby loads, and thus will unload upstream portions of the local distribution system. As a result, solar DG will reduce distribution system loads, avoiding the cost of distribution system expansions or upgrades, and extending the life of existing equipment.

To calculate EAI's marginal distribution costs, we use the same NERA regression method discussed above, using historical peak load growth and distribution expenditures, from FERC Form 1, over the 18 years 1996 to 2013. **Figure 4** shows the regression fit of cumulative distribution capital additions as a function of incremental demand growth on the Entergy system.

Figure 4: *Linear Regression of Cumulative Distribution Costs vs. Peak Demand*



Converting the regression slope of $1,249 per kW to an annual cost using a RECC of 6.5%, plus loaders for general plant and O&M from FERC Form 1 data, results in an annualized marginal distribution cost of $93.98 per kW-year.

Table 11: *EAI Marginal Distribution Cost*

Parameter	Value
Slope ($/kW)	1,249
General Plant Loader (%)	2.6%
General Plant Loader ($/kW)	32
Total Marginal Distribution Cost ($/kW)	1,281
RECC Factor	6.50%
Annualized Transmission ($/kW-yr)	83.30
Transmission O&M ($/kW-yr)	10.71
Total Annual Marginal Cost ($/kW-yr)	**94.00**

For the solar capacity contribution to reducing distribution costs, we used the hourly profile of EAI's residential loads to determine a PCAF allocation of residential demand. We then applied this PCAF allocation to the typical meteorological year profile of hourly solar output in Little Rock. The result is a capacity contribution of 13.5% of solar nameplate to reducing the highest residential class loads. We note that this is a conservative calculation given that we do not have data on actual residential class loads, so this contribution does not reflect the correlation between high loads and high solar output. If we had data on actual residential class loads, we would use a PCAF analysis of these loads applied to actual solar output data from the same period. **Table 12** shows the resulting calculation of avoided distribution costs on a $ per MWh basis.

Table 12: *25-year Levelized Avoided Distribution Costs for EAI*

Parameter	Value	Notes
Avoided Distribution Capacity Cost	$94.00 per kW-year	From Table 11
Solar Contribution to MISO South Peak Load	13.5%	Solar contribution to reducing residential class peaks
Solar Output – Annual kW per kW	1,530 kWh	NREL PVWATTS
Solar Avoided Distribution Capacity Cost	**$8.30 per MWh**	$94.00 x 0.135 / 1.53 MWh

We note that this regression analysis considers only the historical relationship between distribution capital additions and load growth. Moving forward, with the advent of smart inverters and other technologies, PV systems will be able to provide additional services and avoid new categories of costs in addition to those attributable to capacity expansion alone. Such services include voltage regulation, power quality, and conservation voltage reduction. For these reasons, this estimate of avoided distribution costs should be considered conservative.

This alternative **long-term calculation of marginal transmission and distribution capacity costs yields a combined avoided T&D value of $21.50 per MWh.**

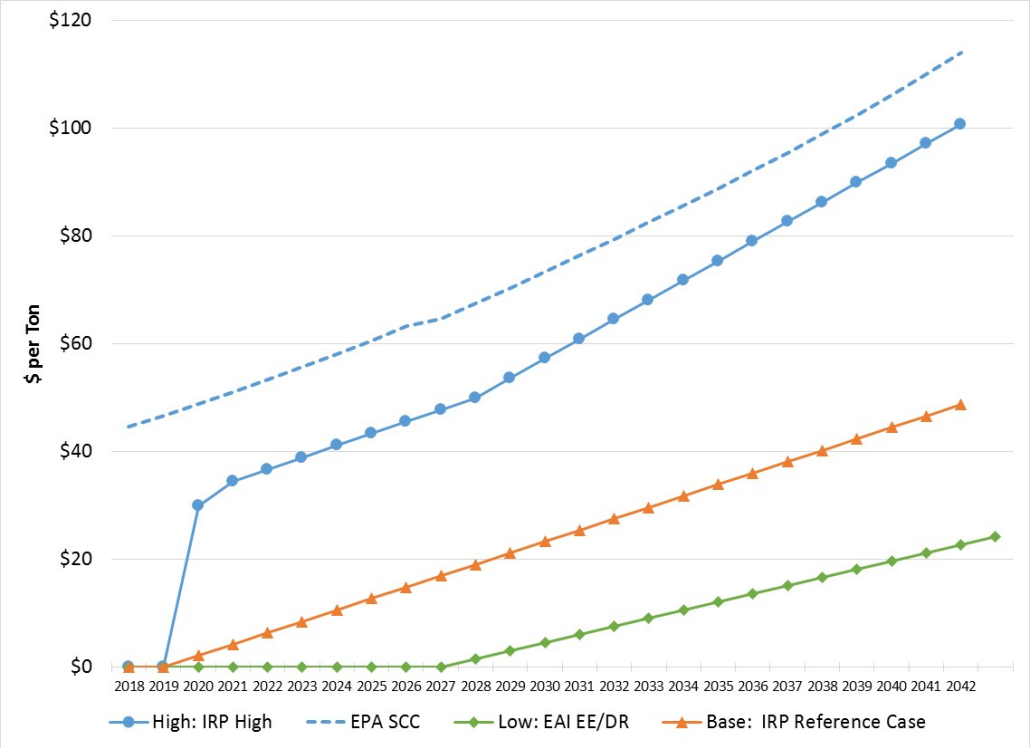
e. Avoided carbon emission compliance costs

Solar PV will avoid carbon emissions from traditional fossil-fueled power plants, and thus avoid the anticipated compliance costs associated with those emissions. Our analysis uses the Environmental Protection Agency's ("EPA") "AVoided Emissions and geneRation Tool" (AVERT) to calculate the avoided carbon emissions due to solar DG installations in Arkansas. AVERT calculates hourly avoided emissions based on a given hourly profile for energy efficiency savings or renewable energy production. Our model assumes 3 MW of DG solar in the state, uses a PV profile for Little Rock, and the Southeast AVERT regional data file to calculate the avoided carbon emissions in Arkansas. The avoided carbon emissions are 1.44 lbs per kWh of DG output, which is similar to the utility's assumed carbon emission reductions from its energy efficiency programs.[46]

Figure 5 shows the range of carbon emission compliance costs (in $ per short ton) that we have used to evaluate this benefit for EAI. For a base case forecast of carbon compliance costs, we make use of EAI's reference case forecast from the *2015 IRP*. For a high case we use EAI's *2015 IRP* high case. As a low case, we include the carbon prices assumed in EAI's *EE Assumptions*, which start at $1.51 per ton in 2027, and which we assume to escalate with the same trajectory as EAI's *2015 IRP* reference case. The figure also shows the U.S. Environmental Protection Agency's (EPA) social cost of carbon (SCC), which is a measure of carbon costs based on the societal damages from unmitigated climate change. We use the SCC later in this report to value the societal benefits from reduced carbon emissions.

[46] See EAI's *Energy Efficiency Program Portfolio Annual Report for the 2015 Program Year*, filed May 2, 2016 in Docket No. 07-085-TF, at page 44, reporting 887 metric tons of reduced carbon dioxide emissions from 1,312,305 kWh net energy savings, or 1.49 lbs per kWh saved.

Figure 5: *Carbon Cost Forecasts*



Based on the carbon compliance costs in Figure 5 and assumed avoided carbon emissions of 1.44 lbs per kWh, we calculate 25-year levelized avoided costs for carbon compliance, assuming a 6.1% discount rate and 0.5% annual solar output degradation. This calculation results in the following avoided costs.

Table 13: *EAI Marginal Carbon Costs*

Scenario:	Base	High Cases		Low Case
Carbon cost forecast	*2015 IRP* Reference Case	*2015 IRP* High Case	EPA SCC*	*EE Assumptions*
Avoided Carbon ($/MWh)	**12.00**	**33.20**	**47.90***	**3.50**

* The EPA SCC forecast is <u>not</u> used to calculate carbon compliance costs. It is only used to calculate societal benefits.

f. Reducing fuel price uncertainty

Renewable generation, including solar DG, reduces a utility's use of natural gas, and thus decreases the exposure of ratepayers to the volatility in natural gas prices, as exemplified by the

periodic spikes in natural gas prices. Such spikes have occurred regularly over the last several decades, as shown in the plot of historical benchmark Henry Hub gas prices in **Figure 6** below.[47]

Renewable generation also hedges against market dislocations or generation scarcity such as was experienced throughout the West during the California energy crisis of 2000-2001 or as has occurred periodically during drought conditions in the U.S. that reduce hydroelectric output and curtail generation due to the lack of water for cooling. For example, in 2014, the rapidly increasing output of solar projects in California made up for 83% of the reduction in hydroelectric output due to the multi-year drought in that state.[48]

EAI recognized this fuel hedging benefit in its testimony requesting Commission approval of cost recovery for the power purchase agreement for the Stuttgart solar project. The company argued that the project would diversify its resource portfolio and that "a diverse generation portfolio mitigates risk by helping protect customers from fluctuations in the cost and availability of the fuel needed to produce electricity."[49]

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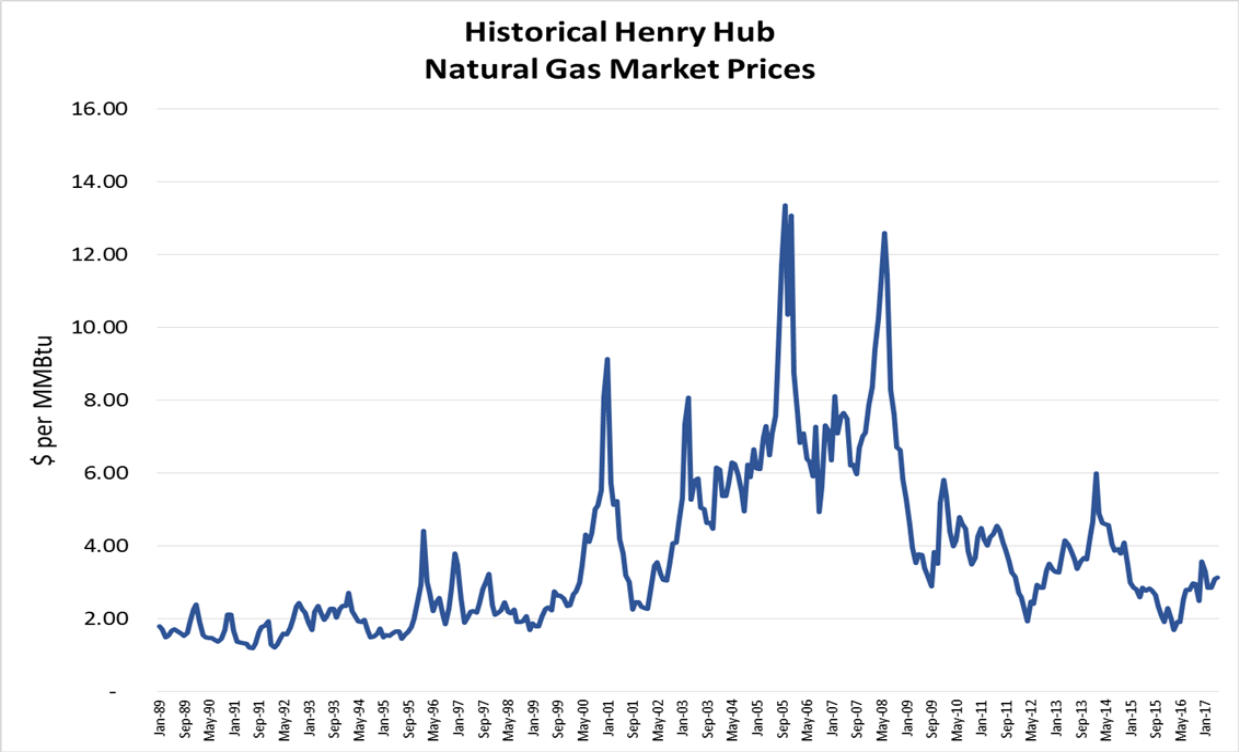
[47] Source for Figure 3: Chicago Mercantile Exchange data.

[48] Based on Energy Information Administration data for 2014, as reported in Stephen Lacey, *As California Loses Hydro Resources to Drought, Large-Scale Solar Fills in the Gap: New solar generation made up for four-fifths of California's lost hydro production in 2014* (Greentech Media, March 31, 2015). Available at http://www.greentechmedia.com/articles/read/solar-becomes-the-second-biggest-renewable-energy-provider-in-california.

[49] See EAI's Stuttgart Testimony, at p. 15.

Figure 6:



To calculate this benefit, we follow the methodology used in the *Maine Distributed Solar Valuation Study (Maine Study)*, a 2015 study commissioned by the Maine Public Utilities Commission and authored by Clean Power Research.[50] This approach recognizes that one could contract for future natural gas supplies today, and then set aside in risk-free investments the money needed to buy that gas in the future. This would eliminate the uncertainty in future gas costs. The additional cost of this approach compared to purchasing gas on an "as you go" basis (and using the money saved for alternative investments) is the benefit of reducing the uncertainty in the costs for the fuel that solar DG displaces.

[50] See Maine Public Utilities Commission, *Maine Distributed Solar Valuation Study* (March 1, 2015). Available at http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf.

We have performed this calculation for EAI, assuming our base gas cost forecast (the EIA *AEO 2017* forecast), U.S. Treasuries (at current yields) as the risk-free investments, and a marginal heat rate of 7,500 Btu per kWh. The result is **a value of $28.60 per MWh** as the 25-year levelized benefit of reducing fuel price uncertainty.

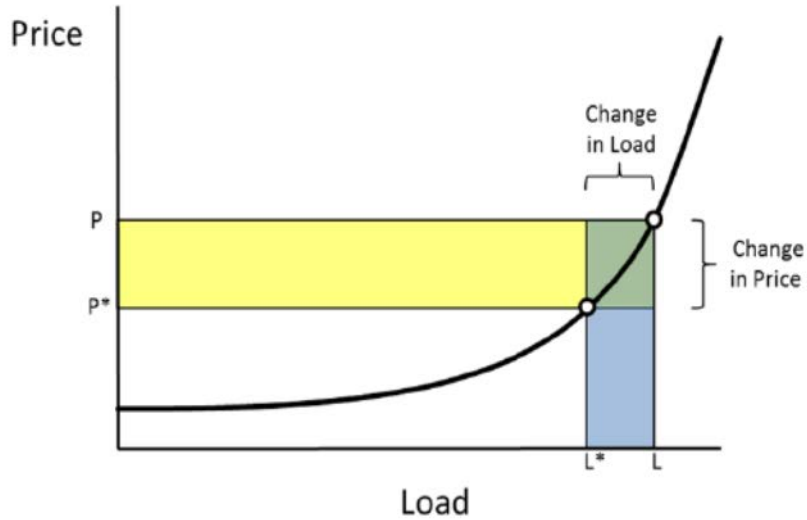
g. Market price mitigation

The increasing penetration of new renewable generation in Arkansas will place downward pressure on the region's energy market prices. New renewable generation, including solar DG, will reduce demand in the MISO South market. Because this generation is must-take (and has zero variable costs), it will displace the most expensive power that utilities such as EAI would otherwise have generated or purchased, which typically is natural gas-fired generation.[51] Thus, the addition of this local generation in EAI's service territory will reduce the demand which EAI places on the regional markets for both electricity and natural gas. With this reduction in demand, there is a corresponding reduction in the prices in these markets, which benefits EAI across the full volumes of its purchases in these markets. This "market price mitigation" benefit of renewable generation is widely acknowledged, and has become highly visible in markets that now have high penetrations of wind and solar resources.[52] The benefit is illustrated schematically in the yellow-shaded section of **Figure 7**.

[51] MISO reports the hourly marginal source of generation on its system. For our base period of June 2016 to May 2017, the MISO South marginal resource has been natural gas in 73% of hours and coal in 27% of hours.

[52] The market price mitigation benefit is not the same as the fuel hedging benefit discussed above. Both benefits involve energy market prices for electricity and natural gas. However, the fuel hedging benefit for consumers results from a reduction in the volatility of these market prices – in other words, in a reduced risk of periodic price spikes in these commodity markets, whereas the market price mitigation benefit is from an overall reduction in the levels of these market prices. Thus, these benefits are related but do not overlap and are not duplicative.

Figure 7: *Reduced Demand in the Energy Market Lowers the Price*



The magnitude of this benefit will depend on the overall amount of renewables on the grid. From 2010-2014, the National Renewable Energy Laboratory (NREL) and GE Consulting released the multi-phase Western Wind and Solar Integration Study (WWSIS), a major modeling effort to analyze much higher penetrations of wind and solar resources in the western U.S.[53] This work focused on the West Connect area (basically, Arizona, Colorado, New Mexico, Nevada, and Wyoming), but also modeled the entire WECC grid in the U.S. This modeling included analysis of the impact of increasing solar penetration on market prices in the West; the results for spot prices in Arizona are shown in the figure below.[54] Generally, the high penetration solar cases (15% to 25% penetration) result in 10% to 20% reductions in spot market prices. Note that the largest reductions in market prices occur from the initial 5% penetration of solar, which Arkansas is still well within.

[53] All reports from the WWSIS, are available on the NREL website at http://www.nrel.gov/electricity/transmission/western_wind.html.

[54] The results from the WWSIS for high penetrations of solar are reported in *Impact of High Solar Penetration in the Western Interconnection* (NREL and GE Consulting, December 2010), with the impact on spot market prices in Arizona reported at p. 8 and Figure 19.

Figure 8:

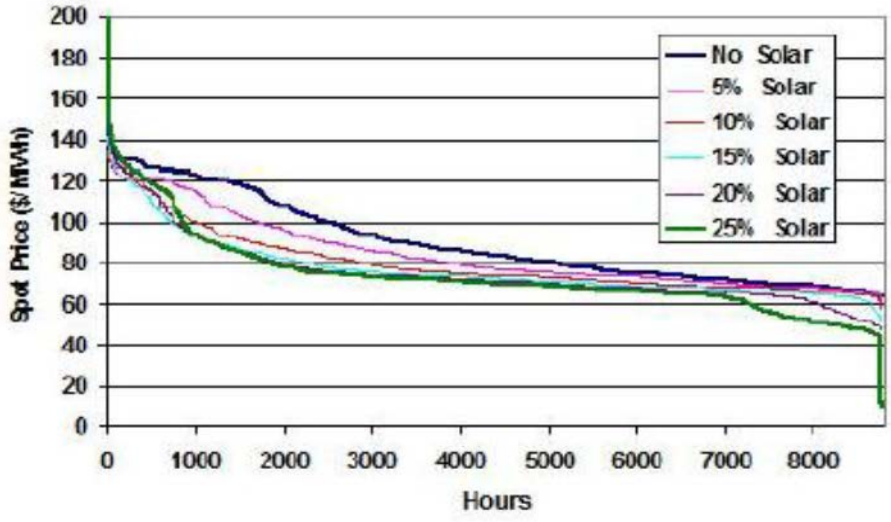


Figure 19 – Arizona Spot Price Duration Curves.

The same market mitigation benefit exists on the natural gas side. Renewable generation reduces marginal gas-fired generation, thus lowering the demand for natural gas. A study by Lawrence Berkeley National Lab (LBNL) has estimated that the gas-related market mitigation benefits of renewable energy range from $7.50 to $20 per MWh of renewable output.[55]

The New England states have done the most extensive work to calculate this market benefit, which they have labelled the Demand Reduction Induced Price Effect (DRIPE). DRIPE is included in the region's biennial forecast of avoided costs used for demand-side programs, *Avoided Energy Supply Costs in New England (AESC)*.[56] We have reviewed the DRIPE calculations in the *2013 and 2015 AESC* reports. There is a significant difference in the DRIPE impacts between the *2013* and *2015 AESC* reports, as a result of changes in the methodology for the DRIPE calculations in the *2015 AESC*.[57] For example, the *2015 AESC* assumes (1) a much shorter duration for energy DRIPE impacts (three years) and (2) zero capacity DRIPE as a result

[55] See Wiser, Ryan; Bolinger, Mark; and St. Clair, Matt, "Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency" (LBNL, January 2005), at p. ix, available at http://eetd.lbl.gov/EA/EMP.

[56] See *2015 AESC*, at Appendix B., Tables One and Two. This report is available at https://www9.nationalgridus.com/non_html/eer/ne/AESC2015%20merged%20report.pdf.

[57] See *2015 AESC*, at pages 1-5 and 1-16 to 1-17.

of an assumed near-term need for new capacity in New England. We have not attempted to resolve these differences, but for the purposes of this study have used the average of the energy DRIPE impacts between the two studies – a 4% reduction in avoided energy costs. We do not assume any capacity DRIPE, given the near-term need for new capacity in Arkansas. **Thus, the energy market price mitigation benefit is 4% of our avoided energy costs, plus associated losses, or $2.80 per MWh**.

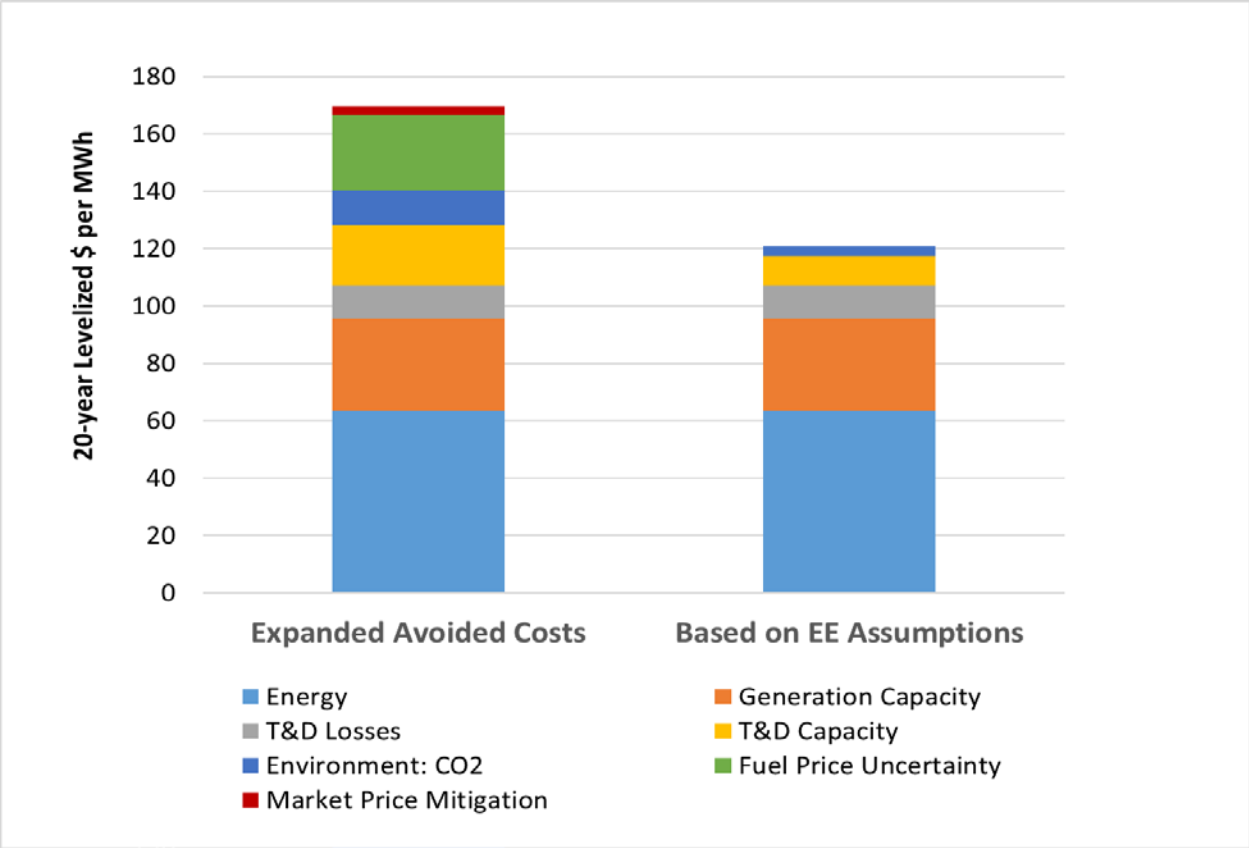
h. Total Direct Benefits

The following **Table 14** and **Figure 9** summarize the direct benefits of solar DG for EAI's ratepayers, for two sets of avoided costs – first, avoided costs limited to the *EE Assumptions*, and second, a broader set of avoided costs that includes the full set of long-term direct benefits discussed above. **The direct benefits range from 12.1 to 17.2 cents per kWh.**

Table 14: *Summary of Direct Benefits (25-year levelized $ per MWh)*

Benefit	**Base Case:** Avoided Costs from *EE Assumptions* ($ per MWh)	**Expanded Case:** Broader Set of Benefits ($ per MWh)
Energy	63.50	63.50
Generation Capacity	32.10	32.10
T&D Losses	11.60	11.60
T&D Capacity	10.20	21.50
Environment: CO_2	3.50	12.00
Fuel Price Uncertainty		28.60
Market Price Mitigation		2.80
Total Benefits	120.90	172.10
	12.1 cents per kWh	**17.2 cents per kWh**

Figure 9: *Summary of Direct Benefits*



4. Societal Benefits of Solar DG

Renewable DG has benefits to society that do not directly impact utility rates, many of which were expressly recognized by the Arkansas legislature when it enacted the Arkansas Renewable Energy Development Act of 2001 (AREDA).[58] When renewable generation takes the place of conventional fossil fuel generation, all members of society benefit from reductions in air pollutants that harm human health and exacerbate climate change. Demands on existing water supplies are reduced, avoiding the potential need to acquire new sources of supply. Distributed generation uses already-built sites, preserving land for other uses or as natural habitat. Distributed generation makes the power system more reliable and resilient, and

[58] A.C.A. § 23-18-601.

stimulates the local economy. Many of these benefits can be quantified, as discussed below. We use a lower, societal discount rate of 5% (3% real) in calculating these benefits, rather than the 6.1% EAI discount rate used for the direct benefits.

a. Carbon

The **social cost of carbon** (SCC) is "a measure of the seriousness of climate change."[59] It is a way of quantifying the value of actions to reduce greenhouse gas emissions, by estimating the potential damages if carbon emissions are not reduced. The carbon costs which we have included in the direct benefits of solar DG above are limited to the anticipated costs to comply with future regulation of carbon emissions. These compliance costs are assumed to be lower than the true costs that carbon pollution imposes on society, which are the damages estimated by the SCC. As a result, the additional costs in the SCC, above the compliance costs of mitigating carbon emissions, represent the societal benefits of avoided carbon emissions.

The most prominent and well-developed source for estimates of the social cost of carbon is the federal government's Interagency Working Group on the Social Cost of Carbon.[60] These values have been vetted by numerous government agencies, research institutes, and other stakeholders. The cost values were derived by combining results from the three most prominent integrated assessment models, each run under five different reference scenarios.[61] The group gave equal weight to each model and averaged the results across each scenario to obtain a range of values depending on the discount rate, given in the table below.

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[59] Anthoff, D. and Toll, R.S.J. 2013. The uncertainty about the social cost of carbon: a decomposition analysis using FUND. *Climactic Change* 117: 515-530.

[60] Interagency Working Group on Social Cost of Carbon, *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (May 2013, Revised July 2015). Available at: https://www3.epa.gov/climatechange/Downloads/EPAactivities/social-cost-carbon.pdf.

[61] *Id.* The three models are the Dynamic Integrated Climate-Economy (DICE) model, the Climate Framework for Uncertainty, Negotiation and Distribution (FUND) model, and the Policy Analysis of the Greenhouse Effect (PAGE) model.

Table 15: *Social Cost of Carbon*[62] *(2007 $ per metric tonne of CO_2)*

	Discount Rate		
	5%	**3%**	**2.5%**
Social Cost of Carbon	11	36	56

We recommend a base case SCC using the mid-range value of $36 per tonne based on a 3% discount rate. We escalate these benefits by 5% per year, recognizing that "future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climate change."[63]

While estimating the social cost of carbon contains many inherent uncertainties, we believe these values are appropriate. The mid-range real discount rate of 3% is a typical societal discount rate often used in long-term benefit/cost analyses. It is also a conservative assumption, when considering the diminished prosperity future generations will face in a world heavily impacted by climate disruption. Because "the choices we make today greatly influence the climate our children and grandchildren inherit," future benefits should not be significantly discounted relative to current costs.[64] As Pope Francis wrote in his encyclical calling for "all people of goodwill" to take action on climate change: "The climate is a common good, belonging to all and meant for all."[65]

We calculate the societal benefits for the years 2018 – 2042 of reducing carbon emissions as (1) the mid-range value of the SCC less (2) the base case for the compliance carbon costs used in our direct benefits, discussed above. The 25-year levelized difference is $35.90 per MWh.

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[62] *Id.*, p. 13.

[63] *Id*, pp. 13-14. 5% annual escalation in carbon costs has been used in both California and Arizona. See the CPUC Final Public Tool referenced in Footnote 2, at tab "Key Driver Inputs," at Cell D33. 5% is also midway between the two escalation rates (2.5% and 7.5% per year) used in the carbon cost scenarios in Arizona Public Service's *2014 Integrated Resource Plan*.

[64] California Climate Change Center, Our Changing Climate: Assessing the Risks to California (2006) at p. 2. http://www.energy.ca.gov/2006publications/CEC-500-2006-077/CEC-500-2006-077.pdf.

[65] Encyclical Letter *Laudato Si'* of the Holy Father Francis on Care for Our Common Home. June 18, 2015.

Reduced methane leakage. In addition, we also determine the total greenhouse gas emissions that will result from methane leakage in the natural gas infrastructure that serves marginal gas-fired power plants. We attach to this report as **Attachment 2** a recent white paper calculating the additional greenhouse gas emissions associated with methane leaked in providing the fuel to gas-fired power plants. This issue has received significant attention recently as a result of the major methane leak from the Aliso Canyon gas storage field in southern California. The bottom line is that the CO_2 emission factors of gas-fired power plants should be increased by 50% to account for these directly-related methane emissions from the production and pipeline infrastructure that serves gas-fired electric generation. This additional societal benefit amounts to $8.00 per MWh.

b. Health benefits of reducing criteria air pollutants

Reductions in criteria pollutant emissions improve human health. Exposure to particulate matter (PM) causes asthma and other respiratory illnesses, cancer, and premature death.[66] Nitrous oxides (NO_X) react with volatile organic compounds in the atmosphere to form ozone, which causes similar health problems.[67]

We use AVERT to calculate the avoided emissions of SO_2 and NO_x assuming 20 MW of solar DG development. To calculate the avoided fine particulate matter ($PM_{2.5}$) emissions, we assume an emissions factor of 0.0077 lbs/MMBtu for $PM_{2.5}$ emissions from the combustion of natural gas. This factor is from "AP 42," the EPA's compilation of air pollutant emissions factors.[68]

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[66] EPA, Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014), p. 4-17 ("CPP Technical Analysis"). Available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf.

[67] *Ibid.*

[68] U.S. EPA, "Emissions Factors & AP 42, *Compilation of Air Pollutant Emission Factors*," http://www.epa.gov/ttn/chief/ap42/index.html. See also Section 1.4 (*Natural Gas Combustion*), Table 1.4-2, "PM emission factors presented here may be used to estimate PM10, PM2.5 or PM1 emissions."

For quantifying the health benefits, we recommend using the health co-benefits from reductions in criteria pollutants that EPA developed in conjunction with the Clean Power Plan. These benefit estimates were developed in 2014 as part of the technical analysis for the proposed rule.

Table 16: *Avoided Emissions of Criteria Pollutants*

Pollutant	Avoided Emissions lbs/MWh
SO_2	1.68
NOx	1.01
$PM_{2.5}$	0.067

The value of these avoided emissions is calculated as follows:

1. Determine the amount of avoided emissions using AVERT as described above.

2. Calculate the social cost of the avoided emissions and subtract the compliance cost or emissions market value of those emissions.

SO_2. The analysis for SO_2 follows the same steps as the analysis for carbon. The total social cost of SO_2 is taken from the EPA's *Regulatory Impact Analysis for the Final Clean Power Plan (CPP Impact Analysis).*[69] The EPA calculated social cost values for 2020, 2025, and 2030. This analysis uses the values given for these three years assuming a 3% discount rate. Values for intermediate years are interpolated between the five-year values. The market value of SO_2 is taken from the EPA's 2016 SO_2 allowance auctions. However, the final clearing price of the latest spot auction was just $0.06 per ton.[70] This is low enough compared to the social cost that it is negligible for our calculations. The societal benefit of avoided SO_2 emissions is $71.90 per MWh.

[69] *Regulatory Impact Analysis for the Final Clean Power Plan*. Found at: https://www.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule-ria.pdf.
[70] EPA 2016 SO2 Allowance Auction. Found at: https://www.epa.gov/airmarkets/2016-so2-allowance-auction.

NOx. Heath damages from exposure to nitrous oxides come from the compound's role in creating secondary pollutants: nitrous oxides react with volatile organic compounds to form ozone, and are also precursors to the formation of particulate matter.[71] The social cost of NOx is taken from the EPA's CPP Impact Analysis.[72] We use a recent 2017 NO_x market price of $750 per ton for compliance with the Cross State Pollution Rule as the compliance cost for NOx.[73] The benefit of avoiding NOx emissions is $8.80 per MWh.

Fine Particulates ($PM_{2.5}$). We use the emissions factor and damage costs for $PM_{2.5}$, because $PM_{2.5}$ are the small particulates with the most adverse impacts on health. The EPA health co-benefit figures distinguish between types of PM, and calculate two separate benefit-per-ton estimates for PM: for PM emitted as elemental and organic carbon, and for PM emitted as crustal particulate matter.[74] The EPA estimates that approximately 70% of primary $PM_{2.5}$ emitted in Arkansas is crustal material, with the bulk of the remainder being elemental or organic carbon.[75] The emissions factor of 0.0077 lbs per MMBtu for total primary $PM_{2.5}$ does not differentiate among particle types.[76] As a result, we weigh the mid-point of each of the two benefit-per-ton estimates according to EPA's assumptions for Arkansas emissions. The health benefits of reducing $PM_{2.5}$ emissions are $3.70 per MWh on a 25-year levelized basis.

c. Water

Thermal generation consumes water, principally for cooling. Reducing water use in the electric sector through the use of renewable generation lowers the vulnerability of the electricity supply to the availability of water, and reduces the possibility that new water supplies will have

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[71] CPP Technical Analysis, p. 4-14.
[72] *CPP Impact Analysis*, at Table 4-7.
[73] See the EPA Cross State Air Pollution Rule. Found at: https://www.epa.gov/csapr. Recent NOx emission allowance prices can be found at http://www.evomarkets.com/content/news/reports_23_report_file.pdf.
[74] CPP Technical Analysis, p. 4-26, Table 4-7.
[75] *Ibid*., p. 4A-8, Figure 4A-5.
[76] AP 42, Table 1.4-2, Footnote (c).

to be developed to meet growing demand. However, water consumption by efficient gas-fired generation is relatively low, and the cost of incremental water supplies varies widely depending on the local abundance of water resources. As a result, the value of avoided water use is relatively modest. We have used $1.20 per MWh for the value of avoided water use, based on several sources.[77]

d. Local economic benefits

AREDA specifically notes the economic development benefits associated with distributed renewable energy.[78] Indeed, while distributed generation has higher costs per kW than central station renewable or gas-fired generation, a portion of the higher costs – principally for installation labor, permitting, permit fees, and customer acquisition (marketing) – are spent in the local economy, and thus provide a local economic benefit in close proximity to where the DG is located. These local costs are an appreciable portion of the "soft" costs of DG. Central station power plants have significantly lower soft costs, per kW installed, and often are not located in the local area where the power is consumed.

There have been a number of recent studies of the soft costs of solar DG, as the industry has focused on reducing these costs, which are significantly higher in the U.S. than in other major international markets for solar PV. The following **Table 17** presents data on the soft costs for residential PV systems that are likely to be spent in the local area where the DG customer

[77] This figure is based on the American Wind Energy Association's estimate that, in 2016, operating wind projects produced 226 million MWh and avoided the consumption of 87 billion gallons of water, with a cost of new water resources of about $1,000 per acre-foot. This is similar to the mid-point of cost estimates for the cost of water savings at gas-fired power plants by implementing dry cooling technologies. See Maulbetsch, J.S.; DiFilippo, M.N. *Cost and Value of Water Use at Combined-Cycle Power Plants*. CEC-500-2006-034. Sacramento: California Energy Commission, PIER Energy-Related Environmental Research, 2006, available at http://www.energy.ca.gov/2006publications/CEC-500-2006-034/.

[78] A.C.A. § 23-18-602(a) ("Increasing the consumption of renewable energy . . . fosters investments in emerging renewable technologies to stimulate economic development and job creation in the state.").

resides, from detailed surveys of solar installers that were conducted by two national labs (LBNL and NREL) in 2013.

Table 17: *Residential Local Soft Costs*

Local Costs	LBNL – J. Seel *et al.*[79]		NREL – B. Friedman *et al.*[80]	
	$/watt	%	$/watt	%
Total System Cost	6.19	100%	5.22	100%
Local Soft Costs				
Customer acquisition	0.58	9%	0.48	9%
Installation labor	0.59	10%	0.55	11%
Permitting & interconnection	0.15	2%	0.10	2%
Permit fees	0.09	1%	0.09	2%
Total local soft costs	**1.41**	**22%**	**1.22**	**23%**

Based on these studies, we assume that 22% of residential solar PV costs are spent in the local economy where the systems are located. These economic benefits occur in the year when the DG capacity is initially built, which for the purpose of this study is 2018. We have converted these benefits into a $ per kWh benefit over the expected DG lifetime that has the same net present value in 2018 dollars. We also use more current DG capital costs than the system costs used in the LBNL and NREL studies. The result is a societal benefit of $33.60 per MWh of DG output for residential systems.

e. Land use

Distributed generation makes use of the built environment in the load center – typically roofs and parking lots – without disturbing the existing use for the property. In contrast, central station fossil or renewable plants require large single parcels of land, and tend to be more remotely located where the land has agricultural or habitat uses. Unless the site is already being used for power generation, the land must be removed from its prior use when it becomes a solar

[79] J. Seel, G. Barbose, and R. Wiser, *Why Are Residential PV Prices So Much Lower in Germany than in the U.S.: A Scoping Analysis* (Lawrenece Berkeley National Lab, February 2013), at pp. 26 and 37.

[80] B. Friedman et al., *Benchmarking Non-Hardware Balance-of-System (Soft) Costs for U.S. Photovoltaic Systems, Using a Bottom-Up Approach and Installer Survey – Second Edition* (National Renewable Energy Lab, October 13, 2013), at Table 2.

farm or a fossil power plant. Central-station solar photovoltaic plants with fixed arrays or single-axis tracking typically require 7.5 to 9.0 acres per MW-AC, or 3.3 to 4.4 acres per GWh per year. The lost value of the land can vary over a wide range, depending on the alternative use to which it could be put. Based on the 2017 U.S. Department of Agricultural rental value for irrigated croplands in Arkansas ($132 per acre),[81] and 4 acres per GWh, the land use value avoided by DG is about $0.5 per MWh. This value will be lower if the land has an alternative use of lower value than irrigated land for farming.

f. Reliability and resiliency

AREDA specifically calls for the Commission to consider impacts to reliability as part of the "cost of providing service" to net metering customers and the benefits associated with distributed generation.[82] Renewable distributed generation resources are installed as thousands of small, widely distributed systems and thus are highly unlikely to experience outages at the same time. Furthermore, the impact of any individual outage at a DG unit will be far less consequential than an outage at a major central station power plant. In addition, the DG customer, not the ratepayers, will pay for the repairs. DG is located at the point of end use, and thus also reduces the risk of outages due to transmission or distribution system failures.

One study of the benefits of solar DG has estimated the reliability benefits of DG from a national perspective.[83] The study assumed that a solar DG penetration of 15% would reduce loadings on the grid during peak periods, mitigating the 5% of outages that result from such high-stress conditions. Based on a study which calculated that power outages cost the U.S. economy about $100 billion per year in lost economic output, the levelized, long-term benefits of

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[81] See USDA, National Agricultural Statistics Service, Survey of 2017 Cash Rents, available at https://quickstats.nass.usda.gov/results/58B27A06-F574-315B-A854-9BF568F17652#7878272B-A9F3-3BC2-960D-5F03B7DF4826.

[82] See A.C.A. § 604(b)(1)(A)(ii).

[83] Hoff, Norris and Perez, *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania* (November 2012), at Table ES-2 and pages 18-19.

this risk reduction were calculated to be $20 per MWh ($0.02 per kWh) of DG output. This calculation does not necessarily assume that the DG is located behind the customer's meter, so this reliability benefit also might result from widely distributed DG at the wholesale level.

However, most electric system interruptions do not result from high demand on the system, but from weather-related transmission and distribution system outages. In these more frequent events, renewable DG paired with on-site storage can provide customers with an assured back-up supply of electricity for critical applications should the grid suffer an outage of any kind. This benefit of enhanced reliability and resiliency has broad societal benefits as a result of the increased ability to maintain government, institutional, and economic functions related to safety and human welfare during grid outages.

Both DG and storage are essential in order to provide the reliability enhancements that are needed to eliminate or substantially reduce weather-related interruptions in electric service. The DG unit ensures that the storage is full or can be re-filled promptly in the absence of grid power, and the storage provides the alternative source of power when the grid goes down. DG also can supply some or all of the on-site generation necessary to develop a micro-grid that can operate independently of the broader electric system. It is challenging to quantify this benefit, which will be realized over time as storage technology is added to renewable DG systems.[84] Nonetheless, solar DG is a foundational element necessary to realize this benefit – in much the same way that smart meters are necessary infrastructure to realize the benefits of time-of-use rates, dynamic pricing, and demand response programs that will be developed in the future – and

[84] It is also important to recognize that adding storage may be cost-effective even without considering its reliability benefits when paired with DG. Distributed storage can reduce demand charges, allow TOU rate arbitrage, and provide power quality and capacity-related benefits to the utility or grid operator. Indeed, distributed storage may be economic as a result of the benefits in these other use cases, without considering the reliability benefits for the customer.

thus the reliability and resiliency benefits of wider solar DG deployment should be recognized as a broad societal benefit.

g. Customer choice

AREDA also cites "greater consumer choices" as a benefit of renewable generation that justifies the adoption of net metering.[85] There are important public policy reasons to ensure that the customers who invest in DG are treated equitably in assessments of the merits of net metering and renewable DG, so that consumers continue to have the freedom to exercise a competitive choice, to become more engaged and self-reliant in providing for their energy needs, and to encourage others to invest private capital in Arkansas's clean energy infrsatructure.

There are many dimensions to the customer choice benefits of DG technologies, including:

- **New Capital.** Customer-owned or customer-sited generation brings new sources of capital for clean energy infrastructure. Given the magnitude and urgency of the task of moving to clean sources of energy, expanding the pool of capital devoted to this task is essential.

- **New Competition.** Rooftop solar provides a competitive alternative to the utility's delivered retail power. This competition can spur the utility to cut costs and to innovate in its product offerings. With the widespread availability of rooftop solar, energy efficient appliances, and load management technologies, plus – in the near future – customer-sited storage, this competition will only intensify. In the now-foreseeable future, the combination of solar, storage, and load management may offer an electric supply whose quality and reliability is comparable to utility service.

- **High-tech Synergies.** Rooftop solar appeals to those who embrace the latest in technology. Solar has been described as the "gateway drug" to a host of other energy-saving and clean energy technologies. Studies have shown that solar customers adopt more energy efficiency measures than other utility customers, which is logical given that it makes the most economic sense to add solar only after making other lower-cost energy efficiency improvements to your premises.[86]

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[85] See A.C.A. § 23-18-602(a).

[86] See the *2009 Impact Evaluation Final Report on the California Solar Initiative*, prepared by Itron and KEMA and submitted in June 2010 to Southern California Edison and the Energy Division of the California Public Utilities Commission. See pages ES-22 to ES-32 and Chapter 10. Also available at the following link:

Further, with net metering, customers retain the same incentives to save energy that they had before installing solar. These synergies will only grow as the need to make deep cuts in carbon pollution drives the increasing electrification of other sectors of the economy, such as transportation.

- **Customer Engagement.** Customers who have gone through the process to make the long-term investment to install solar learn much about their energy use, about utility rate structures, and about producing their own energy. Given their long-term investment, they will remain engaged going forward. There is a long-term benefit to the utility and to society from a more informed and engaged customer base, but only if these customers remain connected to the grid. As we have seen recently in Nevada, this positive customer engagement can turn to customer "enragement" if the utility and regulators do not accord the same respect and equitable treatment to customers' long-term investments in clean energy infrastructure that is provided to the utility's investments and contracts. Emerging storage and energy management technologies may allow customers in the future to "cut the cord" with their electric utility in the same way that consumers have moved away from the use of traditional infrastructure for landline telephones and cable TV. Given the important long-term benefits that renewable DG can provide to the grid if customer-generators remain connected and engaged, it is critical for regulators and utilities to avoid alienating their most engaged and concerned customers.

- **Self-reliance.** The idea of becoming independent and self-reliant in the production of an essential commodity such as electricity, on your own property using your own capital, has deep appeal to Americans, with roots in the Jeffersonian ideal of the citizen (solar) farmer.

These benefits of customer choice are difficult to express in dollar terms; however, all are strong policy reasons for ensuring that the development of clean energy infrastructure includes policies which sustain a robust market for rooftop solar, as the Arkansas legislature has acknowledged.

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http://www.cpuc.ca.gov/workarea/downloadasset.aspx?id=7677. Also see Center for Sustainable Energy, *Energy Efficiency Motivations and Actions of California Solar Homeowners* (August 2014), at p. 6, finding that more than 87% of solar customers responding to a survey had installed or upgraded one or more energy efficiency technologies in their homes. Available at https://energycenter.org/sites/default/files/docs/nav/policy/research-and-reports/Energy%20Efficiency%20Motivations%20and%20Actions%20of%20California%20Solar%20Homeowners.pdf.

h. Summary of societal benefits

Table 18 below summarizes the societal benefits of solar DG that we have quantified and discussed. **The societal benefits total 16.3 cents per kWh.**

AREDA cites many of the societal benefits discussed above as the reasons why the state should implement net metering, reflecting the Legislature's clear judgment that these benefits have significant value for the residents of the state.[87] As discussed above, many of these benefits can be quantified, and indeed they do have significant value. Accordingly, these benefits cannot and should not be ignored by policymakers, because ignoring them implicitly values them at zero.

[87] See A.C.A. § 23-18-602.

Table 18: *Societal Benefits*

Benefit	Value ($ per MWh)	Method Used
Carbon: avoid societal damages from climate change	35.90	Use the difference between *the 2015 IRP* carbon cost and the EPA's social cost of carbon value measuring societal damages from climate change.
Carbon: reduce methane leaks from natural gas infrastructure	8.50	Assumes 2% leakage, per 2015 National Academy of Sciences paper.
Reduce SO_2 emissions	71.90	EPA AVERT model for avoided SO2 emissions. EPA estimates of health benefits.
Reduce NO_x emissions	8.80	EPA AVERT model for avoided NOx emissions. EPA estimates of health benefits.
Reduce $PM_{2.5}$ emissions	3.70	EPA Clean Power Plan technical appendices and EPA AP 42 for emissions factors.
Avoid consumptive water use	1.20	Several estimates of avoided water use from renewable generation.
Local economic benefit	33.60	22% of residential system cost is incremental expenses in the local economy, compared to a central station plant.
Land use	Small and positive, but varies	Highly variable based on alternative uses of land at which large power plants are sited.
Reliability	Significant and positive	Significant reliability and resiliency benefits from the pairing of solar DG and on-site storage.
Customer choice	Significant and positive	
Total	**163.60**	Use in the Societal Test

5. Costs of Solar DG for Participants

We use a pro forma cash flow analysis to project the lifecycle levelized cost of energy (LCOE) from a solar DG system based on 2015 solar system costs surveyed and reported by Lawrence Berkeley National Laboratory (LBNL) in their annual *Tracking the Sun* report. Due to the small penetration of solar in Arkansas, we adopt the solar costs that LBNL reported for Texas. The other major assumptions we use are summarized in **Table 19**.

Table 19: *Key Assumptions for the Residential Participant Cost of Solar*

Assumption	Value
Median Cost	$3.00 per watt DC
Range of Costs	$2.70 - $3.50 per watt DC
Federal ITC	30%
Financing Cost	5%
Participant discount rate	5%
Financing Term	15 years
Inverter Replacement	$500/kW in Year 15
Maintenance Cost	$10 per kW-year

The resulting **levelized cost of solar for residential customers is 12.8 cents per kWh.** This cost drops to 11.7 cents per kWh at the low end of the range of costs ($2.70 per watt DC).

6. Costs of Solar DG for the Utility and Non-Participating Ratepayers

We evaluated two additional costs from the perspective of the utility and non-participating ratepayers or the utility system as a whole: solar customer bill savings (lost revenues) and solar integration costs. The primary costs of solar DG for non-participating ratepayers are the retail bill savings provided to solar customers through net metering, i.e., the revenues that the utility loses as a result of DG customers serving their own load and that may be recovered from other ratepayers after rates are readjusted in a subsequent rate case.

We calculate this amount assuming that a residential customer using 15,000 kWh per year installs a solar PV system with annual generation equal to 80% of the customer's annual load prior to any degradation. Thus, the customer's solar PV system produces 12,000 kWh per year, and this output degrades by 0.5% per year thereafter.

We model hourly customer load based on NREL data for a typical load profile for a residential customer in Little Rock.[88] An hourly solar PV generation profile for a rooftop PV system in Little Rock is taken from the NREL PVWATTS model. We scale the customer load to 15,000 kWh per year, and scale the PV output to 12,000 kWh per year (the estimated output for a 7.8 kW-AC system). The hourly differences between these series are, when positive, the customer's net demand for delivered power from the utility, and, when negative, the customer's net exports to the utility grid. We then add up the hourly amounts in order to compute the monthly net usage which determines the customer's bill under net metering.

Bill calculations assume EAI's General Purpose Residential Service (RS) rates, as approved in Docket No. 15-015-U. We estimate that the modeled customer's bill would decrease from $127 per month without solar to $33 per month with solar PV. The $95 per month bill savings associated with our modeled 7.8 kW-AC solar PV system indicate that the customer is able to save 9.5 cents per kWh of solar PV generation in the first year (i.e. $95/1000 kWh = $0.095 per kWh). Assuming 2% annual rate escalation and 0.5% solar PV degradation, **the 25-year levelized value of the customer's bill savings (the utility's lost revenues) are 11.4 cents per kWh**.

Next, we add an estimate of solar integration costs derived from solar integration studies of other utilities with much higher solar penetrations.[89] These integration costs are the cost of the additional ancillary services needed to accommodate the increased variability that intermittent solar output adds to the utility system. Xcel Energy in Colorado calculated solar

[88] See the data file at https://openei.org/datasets/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states for Little Rock.

[89] It is also possible that the utility may incur costs to administer the net metering program. It is speculative to estimate these costs without specific information from the utility. However, we expect that such costs are minimal at the current penetration of net metered systems in Arkansas.

integration costs as $1.80 per MWh on a 20-year levelized basis.[90] A March 2014 study by Duke Energy estimated solar integration costs on its system in North Carolina ranging from $1.43 to $9.82 per MWh, depending on the level of PV penetration.[91] Based on the penetration level in Arkansas, the lower end of the range in the Duke study would apply. Arizona Public Service did a 2012 integration study that estimated integration costs on its system of $2 per MWh in 2020.[92] Based on this body of work, we assume that **$2 per MWh represents a reasonable assumption for a 25-year levelized solar integration cost in Arkansas**.

Thus, the utility costs associated with **reduced customer bills and solar integration combine to equal 11.6 cents per kWh** (i.e. 11.4 cents per kWh in lost retail revenues plus 0.2 cents per kWh in solar integration costs).

7. Results and Key Conclusions of this Benefit / Cost Analysis

The following **Table 20** and **Figure 10** incorporate the results of the above analyses into each of the primary cost-effectiveness tests for residential solar DG on the EAI system. These tests of the cost-effectiveness of solar DG consider benefits and costs from multiple perspectives. Other demand-side programs typically are evaluated from these multiple perspectives, and policymakers should take a similarly broad view in assessing solar DG.

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[90] Xcel Energy Services for Public Service Company of Colorado, "Cost and Benefit Study of Distributed Solar Generation on the Public Service Company of Colorado System" (May 23, 2013), at Table 1, pages v and 41-42. Available at http://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/Costs%20and%20Benefits%20of%20Distributed%20Solar%20Generation%20on%20the%20Public%20Service%20Company%20of%20Colorado%20System%20Xcel%20Energy.pdf

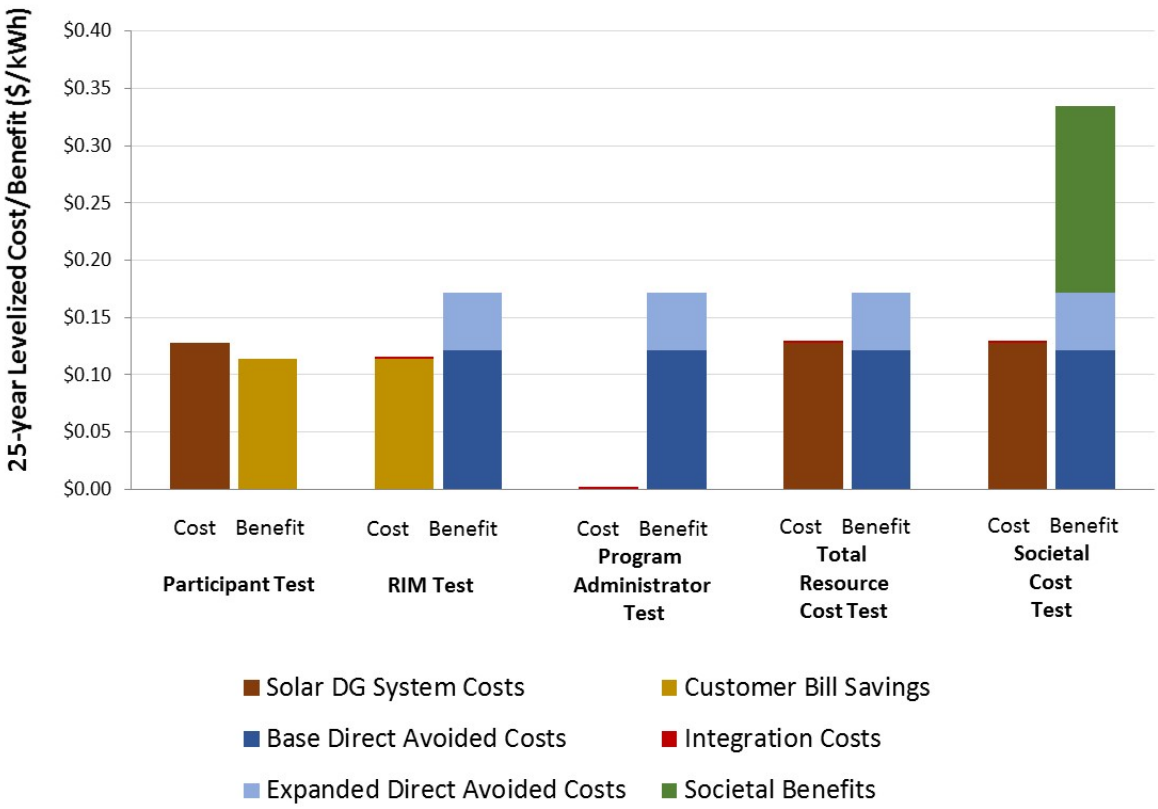
[91] See http://www.pnucc.org/sites/default/files/Duke%20Energy%20PV%20Integration%20Study%20201404.pdf

[92] See Arizona Public Service, *2014 Integrated Resource Plan*, at p. 43, citing Black & Veatch, "Solar Photovoltaic (PV) Integration Cost Study" (B&V Project No. 174880, November 2012).

Table 20: *Benefits and Costs of Solar DG for EAI (25-yr levelized cents/kWh)*

Benefit-Cost Test	**Participant**		**RIM / PAC**		**TRC**		**Societal**	
Category	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit
Base Direct Avoided Costs – *EE Assumptions*				12.1		12.1		12.1
Expanded Direct Avoided Costs				17.2		17.2		17.2
Lost Revenues / Bill Savings (RIM / PCT)		11.4	11.4					
Integration (RIM / TRC)			0.2		0.2		0.2	
Solar DG LCOE	12.8				12.8		12.8	
Societal Benefits								16.4
Totals	12.8	11.4	11.6	12.1 – 17.2	13.0	12.1 – 17.2	13.0	28.5 – 33.6
Benefit / Cost Ratios	**0.89**		**1.04 -1.48 (RIM) >> 1 (PAC)**		**0.93 – 1.32**		**2.19 – 2.58**	

Figure 10: *Cost-effectiveness Results for Net Metered Solar DG on the EAI System*



The principal conclusions of our analysis are as follows:

1. **Solar DG is a cost-effective resource** for EAI, as the benefits equal or exceed the costs in the Total Resource Cost, Program Administrator, and Societal Tests. The results of these tests are well above 1.0 when a broad range of benefits are considered. As a result, in the long-run, deployment of solar DG will reduce the utility's cost of service.

2. **Net metering does not cause a cost shift to non-participating ratepayers**, as shown by the result for the Ratepayer Impact Measure test.

3. **Modifications to net metering are not needed** to recover the utility's full cost of service over time from net metering customers. Major rate design changes for residential DG customers, such as increased fixed charges, the use of demand charges, or two-channel billing to set different compensation rates for imported and exported power, are not needed.

4. **The economics of solar DG are marginal** for EAI's residential customers, as shown by the Participant Test results below 0.9 and the modest amount of solar adoption in Arkansas to date. This means that any reduction to the compensation provided to solar

DG customers is likely to be detrimental to the growth of this resource, although these economics may improve as solar costs continue to fall.

5. There are **significant, quantifiable societal benefits from solar DG**, including local economic benefits and public health improvements from reduced air pollution.

6. Solar DG also provides other important benefits that are difficult to quantify. This includes **enhanced reliability and resiliency** of customers' electric service, because solar DG is a foundational element for backup power systems and micro-grids that can provide uninterrupted power when the utility grid is down. Distributed generation also **enhances customers' freedom**, allowing them to choose the source of their electricity, and results in **customers who are more engaged and better informed** about how their electricity is supplied. The choice of using private capital to install solar DG on a customer's private premises **leverages a new source of capital to expand Arkansas's clean energy infrastructure and allows Arkansas to take advantage of federal tax incentives for solar that will begin to phase out in 2020.**

EAI's *Key Assumptions* for Demand-side Resources

Back

Key Assumptions

Discount Rate 6.10%

Methodology for calculating the TRC Benefit Cost Results

The California Manual was followed in computing the benefit cost results.

Avoided Cost

1. Natural Gas price starting R $2.96 per MMBtu in 2010
2. Price on Carbon Dioxide (CO2) starting at $1.51/ton in 2027
3. Avoided Capacity Costs based on the following inputs
   - (a) Baseline Capital Cost (2016$ of $744 per kW)
   - (b) Levelized Fixed Charge Rate of $77.98
   - (c) Line Losses

Customer Class Inputs	T Line Loss (2016)	D Line Loss (2016)	Total Line Loss
Residential Service	2.17%	7.27%	9.44%
Small General Service	2.16%	7.03%	9.19%
Large General Service	3.30%	4.33%	7.63%
Large Industrial Power Service	3.30%	4.33%	7.63%
Agricultural Pumping	2.17%	7.27%	9.44%

   - (d) 12.0% in 2016 and in forward years
   - (e) Avoided Transmission & Distribution cost of $23.86 per kW-yr in 2016

The avoided costs for natural gas is based on Energy Information Administration of the Department of Energy.

Methane Leaks from Natural Gas Infrastructure Serving Gas-fired Power Plants

Andrew B. Peterson
R. Thomas Beach
Crossborder Energy
February 19, 2016

1. Summary

Natural gas has been commonly depicted as a "bridge" fuel between coal and renewable energy for the generation of electricity. Natural gas is considered more environmentally friendly because burning natural gas produces less CO_2 than coal on a per unit of energy basis. Most analyses of the greenhouse gas (GHG) emissions associated with burning natural gas to produce electricity use an emission factor of 117 lbs of CO_2 per MMBtu of natural gas burned. However, this number does not include methane leaked to the atmosphere during the production, processing, and transmission of natural gas from the wellhead to the power plant. Methane is both the primary constituent of natural gas and a potent greenhouse gas (GHG), so quantifying the methane leakage is important in assessing the impact of natural gas systems on global warming.

Methane is emitted to the atmosphere from natural gas systems in both normal operating conditions and in low frequency, high emitting incidents. The Environmental Protection Agency's (EPA) "Inventory of U.S. Greenhouse Gas Emissions and Sinks" attempts to calculate methane emissions from natural gas systems using a "Bottom Up" accounting method, which essentially adds up methane emissions from production, processing, transmission, storage, and distribution. This method sets a reasonable baseline for methane emissions during normal operating conditions, but does not account for low frequency high emitting situations.

Low frequency high emitting situations happen when some part of the production, processing, or transmission systems fail, leaking large amounts of methane into the atmosphere. The recent Aliso Canyon leak from a major Southern California Gas storage field in Parker Ranch, California is probably the best-known example of a low frequency high emitting event. The Aliso Canyon leak has emitted 2.4 MMT CO2-eq., or roughly 1.5% of total yearly methane emissions from all U.S. natural gas Infrastructure, in a single event. Several studies have shown that low frequency high emitting events like Aliso Canyon contribute significantly to methane emissions from natural gas systems.

The following analysis and discussion lays out an argument for increasing the carbon emission factor for burning natural gas in power plants to include the carbon equivalent of the methane emitted in the production, processing, transmission, and storage of natural gas, leaving out the losses in local distribution that are downstream from power plants on the gas

system. A conservative starting point for the leakage from wellhead to power plant is that 2% of natural gas produced is lost to leakage in the form of methane. This estimate is based the IPCC Fifth Assessment Report, the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks," adjusted based on several studies quantifying how the EPA's method underestimates actual emissions.

Using the conservative estimates of 2% of total production emitted, and a global warming potential (GWP) of 25 (the low end of methane's GWP) increases the CO_2 emitted by burning methane to 175.5 lbs of CO_2-eq. per MMBtu of natural gas burned (a factor of 1.5). Using a GWP of 34 (high end) yields 196.6 lbs of CO_2 per MMBtu of natural gas burned (a factor of 1.68).

2. Measuring Natural Gas Leakage (Methods)

Determining methane leaks from natural gas systems is relatively new field of study. Until 2011 methane leaks were calculated almost exclusively using a Bottom Up accounting method based on data published in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks". Several issues with this method, including outdated Emission Factors and low frequency high emitting events, have led researchers to use "Top Down" aerial measurements of methane leakage.

Bottom Up. Bottom Up (BU) methods attempt to identify all sources of methane emissions in a typical production chain and assign an Emission Factor (EF) to each source. The total emissions are determined by adding up all of the EFs through the life cycle of natural gas. BU measurements are useful because they avoid measuring methane from biogenic sources (landfills, swamps, etc), anthropogenic sources in geographic proximity to natural gas systems (coal plants, oil wells, etc), and only require an engineering inventory of equipment and activity. However, BU measurements often rely on decades-old EFs. The EFs used in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks" are based on a report published in 1996, which in turn is based on data collected in 1992. The EPA has developed a series of correction factors based on technological improvements and new regulations.

BU studies have been shown to underestimate methane emissions from natural gas systems.[1]–[5] While outdated EFs can cause both under and overestimation of emissions, low frequency high emission events are responsible for consistent underestimation of emissions by BU calculations.[1], [5]–[7] A recent study in the Barnett Shale region of Texas found that 2% of facilities were responsible for 50% of the emissions and 10% were responsible for 90% of the emissions.[5] BU measurements do not accurately take into account these low frequency high emitters. First, most BU measurements either sample only a few facilities or rely on facility and equipment inventories rather than local measurements. Secondly, most BU data is self-reported. Finally, several studies have found that the low frequency high emitters were both spatially and temporally dynamic, with the high emission rates resulting from equipment breakdowns and failures, and not from design flaws in a few facilities.

Top Down. Top Down (TD) methane measurements have used aerial flyovers to measure the atmospheric methane content, then use mass balance and atmospheric transport models to determine methane emissions from a geographical region. A signature compound such as ethane is used to distinguish fossil methane from biogenic methane. Unlike BU measurements, TD measurements account for low frequency high emitter situations. TD studies consistently measure higher levels of methane emissions than do BU studies. Only recently have measurements TB and BU studies converged, and this convergence was only after additional low frequency high emission situations were characterized in BU studies.[5]

3. Methane Leak Calculations

The EPA divides methane emissions from natural gas systems into four categories: Field Production, Processing, Transmission and Storage, and Distribution. This analysis focuses on only the first three categories, leaving out local distribution networks. Detailed descriptions of these categories can be found in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks."

US Natural Gas Production 2005 - 2013

Expressed as BCF Natural Gas

Source	2005	2009	2010	2011	2012	2013
Withdrawals from Gas Wells	16,247	14,414	13,247	12,291	12,504	10,760
from Shale Shale Wells	0	3,958	5,817	8,501	10,533	11,933
Total Withdrawals from Natural Gas Systems	16,247	18,373	19,065	20,792	23,037	22,692

Emissions from US Natural Gas Systems 2005 - 2013

Expressed as % of Total Production

Stage	2005	2009	2010	2011	2012	2013
Field Production	0.91	0.66	0.58	0.48	0.42	0.41
Processing	0.20	0.20	0.18	0.20	0.19	0.20
Transmission and Storage	0.59	0.56	0.53	0.51	0.44	0.47

Total	1.70	1.43	1.30	1.19	1.05	1.07

Using the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks," methane emissions from natural gas infrastructure from the wellhead to a gas-fired power plant (excluding local distribution) are currently estimated to be 1.1% of production.[8] Given that EPA uses a BU method for calculating emissions, it is reasonable to assume that 1.1% is an underestimation. A 2015 study that combined seven different datasets from both TD and BU and included the most aerial measurements to date concluded that methane emissions were 1.9 (1.5 – 2.4) times the number reported in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks."[5] If the EPA's estimate is multiplied by 1.9 the result is 2.09%.

The IPCC Fifth Annual Report agrees, stating that: "Central emission estimates of recent analyses are 2% - 3% (+/– 1%) of the gas produced, where the emissions from conventional and unconventional gas are comparable." [9]

4. Global Warming Potential of Natural Gas

Global warming potentials (GWP) provide a method of comparing different GHGs. A GWP is: "a relative measure of how much heat a greenhouse gas traps in the atmosphere. It compares the amount of heat trapped by a certain mass of the gas in question to the amount of heat trapped by a similar mass of carbon dioxide." The Intergovernmental Panel on Climate Change (IPCC) regularly publishes updated GWPs based on the most current scientific knowledge. The most current value for methane (based on the 2013 IPCC AR5) is 34.[9] The previous value (based on the 2007 IPCC AR4) is 25. Policy makers continue to tend to use the values closer to 25.[9] For example, the EPA uses 25 in its "Inventory of U.S. Greenhouse Gas Emissions and Sinks," but 34 is more commonly used in the scientific literature.[10]

5. Conclusion

This report recommends the use of a 2% emissions rate for methane leakage from natural gas systems when calculating the GHG emissions associated with natural gas-fired electric generation. Current analyses use 117 lbs of CO2 per MMBtu as the emissions factor from burning natural gas, which essentially assumes zero leakage. Adopting a 2% emission rate would increase this number to 175.5 lbs of CO2 per MMBtu of natural gas burned, assuming a conservative GWP of 25.

6. Citations

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[7] R. Subramanian, L. L. Williams, T. L. Vaughn, D. Zimmerle, J. R. Roscioli, S. C. Herndon, T. I. Yacovitch, C. Floerchinger, D. S. Tkacik, A. L. Mitchell, M. R. Sullivan, T. R. Dallmann, and A. L. Robinson, "Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol," *Environ. Sci. Technol.*, vol. 49, no. 5, pp. 3252–3261, Mar. 2015.

[8] EPA, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013," *US Environ. Prot. Agency*, pp. ES1–ES26, 2014.

[9] IPCC, "IPCC Fifth Assessment Report (AR5)," *IPCC*, 2013.

[10] EPA, "Understanding Global Warming Potentials," *EPA Website*, 2016. [Online]. Available: http://www3.epa.gov/climatechange/ghgemissions/gwps.html.

Attachment A-2: Survey of Timeframes in Distributed Generation Valuation Studies

We surveyed over two dozen distributed generation valuation studies conducted in recent years. Studies were included in this survey only if the study period could clearly be discerned. Only 4 of the 28 studies that we examined employed analytical timeframes of less than 20 years, and the majority used a 25-year analysis period.

State Studies	Benefit-Cost Analysis Timeframe
Arizona	
Beach, R., McGuire, P., 2016. *Filing in the Matter of the Arizona Corporation Commission's Investigation of Value and Cost of Distributed Generation*. Crossborder Energy. Prepared for The Alliance for Solar Choice. http://images.edocket.azcc.gov/docketpdf/0000168554.pdf.	20 years (p. 3 of study, pdf p. 69)
SAIC Energy, Environment and Infrastructure, 2013. *2013 Updated Solar PV Value Report*. Prepared for Arizona Public Service. http://www.azenergyfuture.com/getmedia/77708c68-7ca6-45c1-a46f-84382531bae3/2013_updated_solar_pv_value_report.pdf/?ext=.pdf	12 years (Study period ends in 2025, p. 2-8)
California	
Beach, T., McGuire, P., 2013. *Evaluating the Benefits and Costs of Net Energy Metering in California*. Crossborder Energy. Prepared for The Vote Solar Initiative. https://www.growsolar.org/wp-content/uploads/2012/06/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf	20 years (p. 24)
Snuller, P., Horii, B., King, M., DeBenedictis, A., Kahn-Lang, J., Pickrell, K., Haley, B., Kadish, J., Jones, R., Sohnen, J., Bower, J., 2013. *California Net Energy Metering Ratepayer Impacts Evaluation*. Energy and Environmental Economics (E3). Prepared for California Public Utilities Commission. http://www.cpuc.ca.gov/NR/rdonlyres/C311FE8F-C262-45EE-9CD1-020556C41457/0/NEMReportWithAppendices.pdf	"Snapshot" and 20 year scenarios evaluated (p. 23)
Colorado	

Xcel Energy Services, 2013. *Benefits and Costs of Distributed Solar Generation on the Public Service Company of Colorado System*. Study Report in Response to Colorado Public Utilities Commission Decision No. C09-12. http://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/Costs%20and%20Benefits%20of%20Distributed%20Solar%20Generation%20on%20the%20Public%20Service%20Company%20of%20Colorado%20System%20Xcel%20Energy.pdf	20 years (p. 20)
Connecticut	
Acadia Center, 2015. *Value of Distributed Generation: Solar PV in Connecticut*. http://acadiacenter.org/wp-content/uploads/2015/03/AcadiaCenter_GridVOS_Connecticut_March_2015.pdf. Methodology at http://acadiacenter.org/wp-content/uploads/2015/04/AcadiaCenter_ValueofDistributedGeneration_StudyMethodology_FINAL_2015_0414.pdf	25 years (p. 1)
District of Columbia	
Whited, M., Horowitz, A., Vitolo, T., Ong, W., Woolf, T., 2017. *Distributed Solar in the District of Columbia: Policy Options, Potential, Value of Solar and Cost-Shifting*. Synapse Energy Economics. Prepared for Office of the People's Counsel for the District of Colombia. http://www.opc-dc.gov/images/pdf/solar/Synapse-DC-Solar-Report-April1217.pdf	24 years (p. 118, n.373)
Hawaii	
Energy and Environmental Economics (E3), 2014. *Evaluation of Hawaii's Renewable Energy Policy and Procurement-Final Report*. http://puc.hawaii.gov/wp-content/uploads/2013/04/HIPUC-Final-Report-January-2014-Revision.pdf	20 years (p. 24)

Louisiana	
Dismukes, D., 2015. *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers* (Draft). Acadian Consulting Group. Prepared for Louisiana Public Service Commission. http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=f2b9ba59-eaca-4d6f-ac0b-a22b4b0600d5	6 years (2014-2020 study period, p. 105)
Maine	
Norris, B., Gruenhagen, P., Grace, R., Yuen, P.-Y., Perez, R., Rabago, K., 2015. *Maine Distributed Solar Valuation Study*. Clean Power Research. Prepared for the Maine Public Utility Commission. http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-FullRevisedReport_4_15_15.pdf	25 years (p. 5)
Maryland	
Daymark Energy Advisors, 2017. *Value of Solar for Maryland's Electric Cooperatives*. Prepared for Maryland Public Service Commission. http://webapp.psc.state.md.us/newIntranet/Casenum/NewIndex3_VOpenFile.cfm?filepath=C:%5CAdminDocket%5CPublicConferences%5CPC48%5C1%5C%5CMD%20PSC%20VoS%20Report%20Final%20(1).pdf	20 years (p. 23, Table 3)
Massachusetts	
Acadia Center, 2015. *Value of Distributed Generation: Solar PV in Massachusetts*. http://acadiacenter.org/wp-content/uploads/2015/04/AcadiaCenter_GridVOS_Massachusetts_FINAL_2015_0414.pdf	25 years (Fig. 1)
Pereira, A., Grace, R., Zhang, M., 2013. *Task 3b Report: Analysis of Economic Costs and Benefits of Solar Program*. La Capra Associates and Sustainable Energy Advantage. Prepared for Massachusetts Department of Energy Resources. http://www.mass.gov/eea/docs/doer/rps-aps/solar-consultants-report-final-task-3b-093013.pdf	32 years (p. 7)
Minnesota	
Xcel Energy, 2015. *Value of Solar Calculation*. Submitted to Minnesota Public Service Commission: Docket No. E002-M-13-867. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={E8E3FEFC-5283-48BC-B712-468E583C28D7}&documentTitle=20153-107860-01	25 years (Fig. ES-1)

Norris, B., Putnam, M., Hoff, T., 2014. *Minnesota Value of Solar: Methodology*. Clean Power Research. Prepared for Minnesota Department of Commerce. http://mn.gov/commerce-stat/pdfs/vos-methodology.pdf (developing a methodology for value of solar studies to be completed by utilities)	26 years (p. iii.)
Mississippi	
Stanton, E., Daniel, J., Vitolo, T., Knight, P., White, D., Keith, G., 2014. *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations*. Synapse Energy Economics. Prepared for the Public Service Commission of Mississippi. https://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf	25 years (p. 21)
Nevada	
Price, S., Ming, Z, Ong, A., *et al*., 2016. *Nevada Net Energy Metering Impacts Evaluation 2016 Update*. Energy and Environmental Economics (E3). Prepared for the Public Utilities Commission of Nevada. http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-8/14179.pdf.	28 years
Price, S., Pickrell, K., Kahn-Lang, J., Ming, Z., Chait, M., 2014. *Nevada Net Energy Metering Impacts Evaluation*. Energy and Environmental Economics (E3). Prepared for Public Utilities Commission of Nevada. http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study	28 years (2014-2041, p. 22)
New Hampshire	
Acadia Center, 2015. *Value of Distributed Generation: Solar PV in New Hampshire*. http://acadiacenter.org/wp-content/uploads/2015/10/AcadiaCenter_GridVOS_NewHampshire_FINAL_2015_0904.pdf	25 years (p. 1)
New Jersey	
Perez, R., Norris, B., Hoff, T., 2012. *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania*. Clean Power Research. Prepared for Mid-Atlantic Solar Energy Industries Association & Pennsylvania Solar Energy Industries Association. http://michigan.gov/documents/mpsc/valuesolarnj_pa_448375_7.pdf	30 years (p. 15)

New York	
Patel, K., Ming, Z., Lavin, L., De Moor, G., Horii, B., Price, S., 2015. *The Benefits and Costs of Net Energy Metering in New York*. Energy and Environmental Economics (E3). Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BF4166D6E-CBFC-48A2-ADA1-D4858F519008%7D	35 years (p. 30)
North Carolina	
Beach, R., McGuire, P., 2013. *The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina*. Crossborder Energy. Prepared for North Carolina Sustainable Energy Association. https://assets.documentcloud.org/documents/1384666/north-carolina-benefits-and-costs-of-solar.pdf	15 years (p. 3)
Pennsylvania	
Perez, R., Norris, B., Hoff, T., 2012. *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania*. Clean Power Research. Prepared for Mid-Atlantic Solar Energy Industries Association & Pennsylvania Solar Energy Industries Association. http://michigan.gov/documents/mpsc/valuesolarnj_pa_448375_7.pdf	30 years (p. 15)
Rhode Island	
Acadia Center, 2015. *Value of Distributed Generation: Solar PV in Rhode Island*. http://acadiacenter.org/wp-content/uploads/2015/07/AcadiaCenter_GridVOS_RhodeIsland_Updated_2016_0119.pdf	25 years (p. 1)
Tennessee Valley Authority[93]	
Tennessee Valley Authority, 2015. *Distributed Generation - Integrated Value (DG-IV): A Methodology to Value DG on the Grid*. https://www.tva.gov/file_source/TVA/Site%20Content/Energy/Renewables/dgiv_document_october_2015-2.pdf	20 years (p. 13)

[93] [93] Tennessee Valley Authority is a federal entity that encompasses most of Tennessee and parts of Alabama, Georgia, Kentucky, Mississippi, North Carolina and Virginia.

Texas	
Clean Power Research, 2013. *2014 Value of Solar at Austin Energy*. Prepared for Austin Energy. http://www.cleanpower.com/wp-content/uploads/2014-VOS-at-Austin-Energy-Results-2013-10-21.pdf	25 years (Slide 21)
Vermont	
Acadia Center, 2015. *Value of Distributed Generation: Solar PV in Vermont*. http://acadiacenter.org/wp-content/uploads/2015/07/AcadiaCenter_GridVOS_Vermont_FINAL_2015_0730.pdf	25 years (p. 1)
Vermont Public Service Department, 2014. *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014, October 1, 2014, Revised November 7, 2014.* http://publicservice.vermont.gov/sites/dps/files/documents/Renewable_Energy/Net_Metering/Act%2099%20NM%20Study%20Revised%20v1.pdf	20 years (p. 10)

Attachment A-3. Comments of Sub-Group 1 in response to Order No. 1 Questions

Sub-Group 1 offers the following comments in response to questions posed in Part A of the Commission's Order No. 1 in 16-027-R.

Question A.1.

> ***With respect to an electric utility's entire cost of providing service to each net metering customer within each of the electric utility's class of customers, does a net-metering customer's use of the electric utility's capacity, distribution system, or transmission system impose additional costs?***
>
> ***a. If so, which, if any of the additional costs are quantifiable?***
>
> ***b. How should any such quantifiable, additional costs be valued, for the purpose of Act 827?***

Response: We note that this question (and the statute) is concerned with actual costs imposed on the utility system, not about utility lost revenue which shows up as a cost to other ratepayers under the Ratepayer Impact Measure (RIM) test (and is accounted for accordingly in the Crossborder study, see Attachment A-1). However, the net-metering customer's use of the utility's system may impose additional direct costs in certain circumstances, namely administrative and integration costs.

- Administrative costs include those associated with customer service and billing of net metering customers. These costs are not, strictly speaking, associated with the "net-metering customer's use of the electric utility's capacity, distribution system, or transmission system," but are nevertheless part of the cost of serving net metering customers. These costs are quantifiable but minimal if the utility manually adjusts the bills of net metering customers. Depending on the utility's accounting practices and billing capabilities, solar-specific billing costs should be relatively easily segregated and allocated. In states with automated processes, the ongoing incremental costs of administering solar customer accounts should be nearly zero. This is one of many reasons in favor of upgrading customer information systems to allow for automatic billing. However, the cost of doing so should not be assigned solely to NM metering customers, since all customers will experience improved service as a result. Because the administrative costs of net

metering will vary by utility and we did not have access to the utilities' estimates of such costs, and because such costs are likely de minimis given the very low number of net-metering accounts in Arkansas the Crossborder study does not include administrative costs. Attachment A-1, at 34, n.62. If the utilities produce evidence establishing reasonable costs for administering their net metering program, these would be appropriate to include in an analysis of the cost of providing service to net metering customers.

- Integration costs. Under most circumstances (and we have not seen any Arkansas data to the contrary), there are no distribution system costs created by the level of exports exported from distributed generation systems. Because distribution systems are already sized to accommodate the coincident peak of that portion of the system, the distribution grid has considerable ability to accept power flows from customers without the need for incremental investment. The question is how much "hosting capacity" the existing infrastructure provides. How much reverse flow and intermittent generation can the system technically allow, and how much will be allowed by the next increment of investment in the engineering of the grid? This hosting capacity is not a finite amount, but rather an amount based on the current level of technology. Net metering customers' exports would affect the transmission system (potentially imposing additional costs) only under the extremely rare circumstances that the amount of energy exported by the net metering customers on that circuit exceeded the total demand on the circuit. The interconnection process should anticipate and address the potential for any such "backflow."

  However, at high levels of penetration on a particular feeder, exports from distributed generation systems can impose integration costs, i.e., the cost of maintaining the proper frequency and voltage of the distribution system given variable exports. Although the penetration of distributed solar in Arkansas is likely too low to impose such costs as this time, the Crossborder study quantifies integration costs based on studies done in other states. Attachment A-1 at 9394. Direct utility expenses incurred to integrate distributed generation (which are not paid by the customer upon interconnection), would be another way to quantify this particular cost.

Question A.2.

With respect to an electric utility's entire cost of providing service to each net metering customer within each of the electric utility's class of customers, are there any quantifiable benefits associated with the interconnection with and providing service to the net-metering customer, including without limitation benefits to the electric utility's capacity, reliability, distribution system, or transmission system?

a. If so, which, if any, of these benefits are quantifiable?

b. How should any such quantifiable, additional benefits be valued, for the purpose of Act 827?

Response: Sub-Group 1 maintains that there are quantifiable benefits associated with the interconnection and providing service to net metering customers, and offers the Crossborder study as our response to which of these benefits are quantifiable and proposed methodologies for valuing those benefits.

Question A.3.

As a matter of rate-making:

a. How should the Commission take into account immediate, or short term cost or benefit causation, versus projected or expected longer term cost or benefit causation?

Response: Short-run evaluation of the benefits and costs of distributed generation will fail to accurately assess the full benefits that distributed generation offers the utility's capacity, transmission, and distribution systems, as AREDA calls for this Commission to evaluate. Major utility plant costs cannot be avoided in the short term, regardless of how much energy distributed generation systems provide or how much peak is reduced. Distributed generation is, and therefore should be evaluated as, a system resource, rather than a revenue-loss problem for utilities to manage. In Attachment A-2, Sub-Group 1 has compiled a list of over two dozen recent DG cost-benefit studies, only a handful of which employ study periods of less than 20 years. The majority employ study periods that more closely reflect the expected useful life of solar photovoltaic systems, typically 25 years or more. We therefore recommend that the Commission apply the same thinking it does for general resource planning, which takes a long-run view of

costs and benefits of operating the system. Costs that will be incurred and benefits that will be realized over the longer term are amortized and factored into shorter term analyses (like costs of service). Utilities have long used levelized cost calculations to enable comparison of different alternative futures, and to justify long-lived investments.

b. Does evidence demonstrate that net-metering customers are materially different in terms of cost causation from other customers in their customer class (i.e., are net-metering customers their own class)?

Response: We have not seen any such evidence to date for Arkansas customers. Pursuant to Act 827, such evidence would need to encompass not only traditional cost of service study data regarding cost causation, but also the adjustments regarding additional, quantifiable costs and benefits. This would require gathering load research data on net metering customers, and a utility-by-utility examination of the issues and would involve an extraordinary level of effort that is not justified given the extremely low penetration of distributed generation on all utility systems.

Traditionally, utilities have not subdivided residential customers into separate classes based on differing costs of service, and likewise, there is typically a single default commercial class. For example, retail stores and bars have very different load profiles, but they are billed under the same rate structure, and both customer types are far more frequent in Arkansas than commercial customers with solar modules. While customers with solar modules are such a small portion of the customer base, it seems unnecessary to consider creating a separate subclass for them within the residential or commercial classes.

Evaluating net metering customers as a separate class—for analytical purposes only—can allow an assessment of whether the load profile of net metering customers results in different contributions to system costs when compared to other customers in their class. As noted in Sub-Group 1's Recommendations (Attachment A), when Oklahoma Gas & Electric Company undertook such an analysis of its Oklahoma residential net metering customers, it demonstrated that these customers actually paid a higher percentage of their cost of service than other residential customers. Because OG&E has advanced metering technology installed for its residential customers in Oklahoma, it had the load data needed to understand net metering customers' load profiles and evaluate this group on conventional cost of service factors. Given the extremely low rates of net metering penetration in Arkansas (only 0.04% of ratepayers averaged across 2015 and 2016 Annual Reports submitted by the utilities), it is unlikely that such load research would produce valid, statistically significant data to support treating net metering customers as a separate class.

c. Should rates incorporate time-differentiated rates for net-metering customers (either residential or commercial)?

Response: Time-differentiated rates, if properly designed, can more accurately capture the costs of serving customers and encourage customers to shift consumption to times that impose less cost on the system. However, this is no more true for net metering customers (residential or commercial) than it is for all customers. Because solar is non-dispatchable, a net metering customer can only adjust his or her consumption to respond to such rates, just like a customer without generation.

As such, any proposal to subject *only* net metering customers to time-differentiated rates must be carefully examined to ensure that it is not discriminatory. For example, the time periods and differential between peak and off-peak periods must accurately reflect underlying costs, and not be manipulated to undermine the value proposition of distributed generation.

Time-differentiated rates can more accurately reflect the value of solar generation, which tends to occur during system peak periods. Indeed, a quality solar valuation analysis already reflects the different values that solar generation has throughout the day, as reflected in the Crossborder Study (Attachment A-1 at 56-58). Exports from solar systems during these peak hours would therefore receive the higher peak price that is appropriate, rather than a price that reflects the average of costs over all hours of the day and year. However, if exports can only offset generation during the same time period (as is the case for some other jurisdictions with time-differentiated rates for net metering customers), the value of the net metering customer's investment to the system is not properly accounted for. That is, the net metered system will generate outside the period that may be set for time of use pricing. That generation should also earn credit for the net metering customer.

In sum, because time-differentiated rates can flatten utility demand, thereby reducing overall costs, we would support such rates for net metering and non-net metering customers alike.

Question A.4.

What role might net-metered generation play in assisting with compliance with the Clean Power Plan or other environmental regulations?

Response: Net-metered generation will make it easier for Arkansas utilities to comply with environmental regulations by allowing reduced generation at those utilities' central stations which would result in the need to acquire emission permits. Reduced operation at these facilities also reduces the amount of water used, wastewater that needs to be treated, and solid or hazardous waste materials that must be disposed of consistent with federal and state environmental regulations. An estimated avoided carbon emission compliance cost is included in the Crossborder study. Attachment A-1 at 70. Net-metered generation also reduces the utility's peak load, which can allow the utility to accelerate retirement of fossil-fuel generating stations nearing their end of service life and avoid capital costs for environmental compliance at those facilities.

Question A.5.

How should the Commission consider or take into account economic costs or benefits beyond the utility's entire cost of providing service, including:

a. Any public interest associated with economic development or job creation in the distributed energy sector, including the potential impact of federal tax benefits?

Response: AREDA demonstrates that the Legislature considered renewable energy, including that incentivized by net metering, as providing benefits beyond the utility's cost of service. *See* Ark. Code Ann. § 23-18-602(a) ("Increasing the consumption of renewable resources promotes the wise use of Arkansas's natural energy resources to meet a growing energy demand, increases Arkansas's use of indigenous energy fuels while reducing dependence on imported fossil fuels, fosters investments in emerging renewable technologies to stimulate economic development and job creation in the state, including the agricultural sectors, reduces environmental stresses from energy production, and provides greater consumer choices.")

Thus, we believe that societal benefits such as economic development and job creation should be considered by the Commission as part of determining fair, just and reasonable rates for net metering customers. Distributed generation also mobilizes private capital and federal tax benefits that cost much less than having the utility grow their rate base. The Crossborder study quantifies local economic benefits of distributed generation as part of the Societal Cost test, Attachment A-1 at 84-85.

b. Any public interest, beyond the direct costs and risks associated with compliance with environmental regulation, associated with environmental impacts?

Response: Given the Legislature's recognition that renewable energy could "reduce environmental stresses from energy production," Sub-Group 1 believes that it is appropriate for the Commission to consider the public interest and environmental impacts associated with fossil fuel combustion that distributed solar generation would displace. Environmental regulations reduce, but certainly do not eliminate, the public health and environmental harms associated with air and water pollution. As part of the Societal test analysis, Crossborder estimates the benefits associated with avoided greenhouse gas emissions, avoided SO_2, $PM_{2.5}$ and NO_x emissions, and avoided water and land use. Attachment A-1 at 78-85.

Question A.6.

> ***Should policies related to net metering in Arkansas take into account developments in smart grid, demand response, storage, or other technologies?***

Response: Because self-generating customers are often early adopters of technologies like electric vehicles and storage, the rate structure and compensation levels established for customers with rooftop solar systems will have a significant impact on adoption of emerging behind-the-meter technologies. For example, if the Commission were to consider increasing fixed charges for net metering customers, as has been advocated in other jurisdictions, this would undermine the economic benefit that solar customers might gain from installing storage or technologies to enable load-shifting (demand response). At the same time, very high fixed charges might motivate solar customers to disconnect from the grid once distributed storage costs drop sufficiently to make disconnection an economically viable option. Conversely, time of

use rates for all customers (not just solar customers) would create incentives for adoption of these technologies.

Distributed energy resources like storage and demand response provide distinct values to the electric system, which has led some states, notably New York and California to pursue more comprehensive "value of DER" proceedings in order to establish consistent and integrated approaches to distributed energy resource rate treatment.[94]

Smart grid technologies, such as advanced metering infrastructure, can allow utilities to collect more comprehensive data on the timing and level of solar customers' usage from the grid and exports. As discussed in Sub-Group 1's Recommendations, the absence of load research data for net metering customers diminishes the Commission's ability to understand how those customers' load profiles differ from others in their class, though sophisticated techniques are available to allow reasonable approximation. The Commission may want to consider how data available through smart grid technologies could inform analysis of distributed generation customers as penetration of those technologies increases.

Question A.7.

> *What can be learned from the recent consideration of these net-metering valuation issues in other states?*

[94] See, e.g., New York Department of Public Service, Case 15-E-0751: Value of Distributed Energy Resources (VDER), at http://www3.dps.ny.gov/W/PSCWeb.nsf/All/8A5F3592472A270C8525808800517BDD?OpenDocument; California Public Utility Commission, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769, Rulemaking 14-08-013 (Aug. 14, 2014).

Response: Dozens of net metering valuation studies have been done in other states in the last decade, see Attachment A-2, which together show that it is commonplace to quantify a wide range of net metering costs and benefits, albeit using methodologies that vary to reflect the jurisdiction's unique circumstances, available data, and specific statutory guidance, where available. The most recent meta-analysis of which we are aware found, after looking at more than 30 studies, that[95]

> [A] preponderance of these studies - whether by public utility commissions, utilities, national laboratories, or firms specializing in energy accounting – conclude that the value of solar is higher than NEM rates. This indicates that the economic benefits of NEM outweigh the costs to the utility and that, rather than imposing a net cost, NEM is in most cases a net benefit.

Thus, with a few exceptions, primarily in states with much higher levels of solar penetration, comprehensive cost-benefit studies conclude that benefits of distributed solar exceed its costs. This was also the recent conclusion of the Brookings Institute upon reviewing a wide range of distributed solar valuation studies.[96]

The Iowa Utilities Board determined in 2015, after an extensive exploratory docket, that penetration of distributed generation in that state was too low to justify a full cost-benefit study, much less immediate changes to the state's net metering rules.[97] The Board instead ordered utilities to propose pilots to test variations on details of net metering policy to gather data prior to any significant or permanent changes in net

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[95] Pruss, S., Sherman, L., Scripps, E., 2017., Solar Energy in Michigan: The Economic Impact of Distributed Generation on Non-Solar Customers (June 2017) at 8-9, available at https://docs.wixstatic.com/ugd/371a41_1838db18923e4eb3a48712bbef91fef7.pdf.

[96] Mark Muro and Devashree Saha, Rooftop solar: Net metering is a net benefit (May 23, 2016), at https://www.brookings.edu/research/rooftop-solar-net-metering-is-a-net-benefit/.

[97] Iowa Utilities Board, In Re: Distributed Generation, Docket No. NOI-2014-0001, Order Regarding Policy Statement, Rate Design Presentations, and Net-Metering Generation Pilots (issued Oct. 30, 2015) at 7 ("One option would be to conduct a study on DG in Iowa, including quantification of costs and benefits. However, it appears such a study would be premature because of the relatively low DG penetration levels in Iowa"), available at https://efs.iowa.gov/cs/groups/external/documents/docket/mdax/mtqx/~edisp/1141884.pdf.

metering policy. The Iowa Utility Board's decision reflects a pragmatic assessment that for states with very low penetration of distributed solar, the costs of a comprehensive valuation study simply may not be justified by the scale of the issue, nor may adequate data be available to conduct such a study. Indeed, at the October 4, 2016 hearing in Docket 16-027-R, it became clear that a number of the utilities who had expressed grave concerns about the impact of net metering had no more than a handful of net metering customers.

Lawrence Berkeley National Laboratory (LBNL) forecasts that rates of distributed generation penetration in Arkansas will still be among the lowest in the nation in 2030.[98] In one report, LBNL considers low solar penetration rates an indicator that distributed generation compensation policies will have a very small impact on retail rates compared to other factors, and finds that rate impacts of net metered solar PV are miniscule compared to the impacts of other issues confronting utilities.[99] As such, the Commission should, in the view of Sub-Group 1, calibrate the resources it expends on this issue to reflect the very small significance that net metering has for rates,[100] as did the Iowa Utilities Board.

An important lesson from other states is that public and comprehensive analysis of the costs and benefits of net metering is a prerequisite to policy changes that are accepted by key constituencies. In June of this year, the New Hampshire Public Utilities Commission resolved a docket on the future of net metering by implementing a

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[98] Galen Barbose, *Putting the Potential Rate Impacts of Distributed Solar into Context* (LBNL-1007060) (Jan. 2017), at Fig. 10 (showing Arkansas rooftop solar penetration as the fifth lowest in the nation and scarcely registering as a percentage of retail sales), at https://emp.lbl.gov/sites/all/files/lbnl-1007060.pdf.
[99] *Id.*
[100] That impact is not only small, but very likely downward (i.e., lower rates), as shown in the Crossborder study.

temporary rate for compensation of distributed generation exports, to be in place "while further data is collected and analyzed, pilot programs are implemented, and a distributed energy resource (DER) valuation study is conducted."[101] The temporary rate represents a compromise between competing settlement proposals that disagreed on what percentage of distribution system costs should be credited to exporting solar customers. Because the New Hampshire Commission was operating on a limited time frame allowed by the state legislature, it was not possible to gather data and do these studies prior to implementing new tariffs.

Finally, the extended battle over net metering in Nevada clearly presents a cautionary tale for regulators in other states. In late 2015, the Public Utility Commission of Nevada (PUCN) issued an order approving tariffs proposed by NV Energy that drastically altered the compensation framework for distributed generation, by placing DG customers in a separate class, increasing the fixed monthly service charge, and reducing the rate paid for all generation exported to the grid to the utility's avoided wholesale cost.[102] These rate changes were to be phased in over five years (later extended to twelve years), and applied to existing as well as new net-metering customers. In that 2015 order, the PUCN disregarded the 2014 benefit-cost analysis conducted by E3 Consulting as relevant to policy but not ratemaking decisions, and instead relied on a marginal cost of service study presented by NV Energy[103] that

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[101] New Hampshire Public Utilities Commission Order Accepting Settlement Provisions, Resolving Settlement Issues, and Adopting a New Alternative Net Metering Tariff, Order 26,029 (June 23, 2017), available at https://s3.amazonaws.com/dive_static/paychek/26-029_1.pdf.

[102] See PUCN Net Metering Rates & Rules Fact Sheet (undated), at http://puc.nv.gov/uploadedFiles/pucnvgov/Content/Consumers/Be_Informed/Fact_Sheet_Net_Metering.pdf.

[103] *Id.*

quantified only two of the eleven distributed generation benefits that the Commission had previously acknowledged.[104]

These changes resulted in an exodus of the rooftop solar industry from Nevada, resulting in the loss of around 2,600 jobs, along with significant public backlash.[105] In response, Governor Brian Sandoval brought together a task force to examine ways to revive the solar industry and eventually, in June 2017, signed legislation largely restoring compensation to distributed generation customers.[106] As a result of the legislation, numerous companies have announced plans to resume business in Nevada.[107] Tom Beach, the primary author of the Crossborder study, was a member of that task force and has for many years been involved in evaluation of and litigation over Nevada's net metering policies, and therefore would be able to answer any questions the Commission might have about those proceedings at the November 30 hearing in this docket.

The Nevada saga illustrates how significant the Commission's decision in this matter is for the rooftop solar industry in Arkansas, and how important it is to get the decision right the first time around. Distributed generation rates derived solely from cost of service analysis, rather than a benefit-cost analysis, have the potential to bring distributed solar development to a halt and would be extremely unpopular with Arkansans who wish to go solar. Fortunately, in Order No. 10, this Commission has

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[104] SolarCity and Natural Resources Defense Council, *Distributed Energy Resources in Nevada: Quantifying the net benefits of distributed energy resources*, at 6 (undated), available at http://www.solarcity.com/sites/default/files/SolarCity-Distributed_Energy_Resources_in_Nevada.pdf.

[105] Benjamin Storrow, *Nev. restored net metering. Is it a national model?*, E&E News (June 16, 2017), reprinted and publicly available at https://www.scientificamerican.com/article/nevada-boosts-solar-power-reversing-course/.

[106] Reuters, *Nevada reinstates key solar energy policy* (June 15, 2017), at http://www.reuters.com/article/us-usa-solar-nevada/nevada-reinstates-key-solar-energy-policy-idUSKBN1962IZ.

[107] *Id.*

recognized that grandfathering of existing solar customers would be fair if any changes are made to net metering tariffs, avoiding one of the most controversial and unjustified aspects of the PUCN's 2015 Order.

Question A.8.

What other issues, if any, should be addressed in implementation of Act 827?

In requiring wide-ranging analysis of the cost to serve net metering customers, Act 827 highlights the need for better understanding of existing distribution system capabilities and what drives long-term distribution system costs. Without a detailed understanding of long-term distribution system costs and the drivers of those costs, utilities cannot identify and take advantage of cost savings provided by net metering and energy efficiency. We believe that the Commission could initiate a process that encourages utilities to study their distribution systems with an eye to increasing efficiency, improving the transparency of distribution system planning, and understanding how emerging distributed energy resources can be leveraged for the benefit of all customers.

For example, utilities should perform extensive monitoring and metering of distribution systems to discern marginal distribution capacity costs; the potential for avoidable and deferrable capacity investments over the near, medium, and long term; hosting capacity at feeder level resolution; and other information that would allow better distribution system planning and more clear identification of the potential for integration of distributed generation. Fortunately, most integration costs only arise at levels of

penetration much higher than observed anywhere in Arkansas. There is therefore no need to impose new constraints on integration prior to the gathering and study of real operations data.

More broadly, we observe that many utilities may have financial disincentives to capturing the benefits of distributed generation because their shareholder returns are based in large part on the amount of infrastructure the utility builds. Under this model, "utilities see a negative financial impact from procuring grid services from resources that they do not own – which includes the vast majority of [distributed energy resources] – even if those assets provide reliable service at a lower cost."[108] The Commission may want to revisit certain elements of how utilities are compensated for providing service to ensure that the avoided costs offered by solar are realized by utilities as they forecast load and plan distribution, transmission and generation capacity expansions.

[108] SolarCity and Natural Resources Defense Council, Distributed Energy Resources in Nevada: Quantifying the net benefits of distributed energy resources, at 2, 15-16 (May 2016), http://www.solarcity.com/sites/default/files/SolarCity-Distributed_Energy_Resources_in_Nevada.pdf.

R. THOMAS BEACH
Principal Consultant Page 1

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the U.S., and Canada.

Since 1989, Mr. Beach has had an active consulting practice on policy, economic, and ratemaking issues concerning renewable energy development, the restructuring of the gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning independent power generation. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of the Public Utilities Regulatory Policies Act of 1978.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning Renewable Portfolio Standard programs, including program structure and rate impacts. He has also worked for the solar industry on rate design and net energy metering issues, on the creation of the California Solar Initiative, as well as on a wide range of solar issues in many other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, standby rates, greenhouse gas emission regulations, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

   - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

   - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

   - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

   - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

   - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar thermal power plants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

    - *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
   b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

    - *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
    b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

    - *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

    - *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

    - *Natural gas rate design issues; rate parity for solar thermal power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

    - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

    - *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

    - *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

    - *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

    - *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

    - *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

    - *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

    - *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

    - *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

    - *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

    - *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

    - *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

    - *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

    - *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

63. a. Phase II Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

    - *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

    - *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

    - *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

67. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

    - *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    - *Local reliability benefits of a new natural gas storage facility.*

69. Prepared Direct Testimony of R. Thomas Beach on behalf of **The Vote Solar Initiative** (A. 10-11-015—June 1, 2011)

    - *Distributed generation policies; utility distribution planning.*

70. Prepared Reply Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014—August 5, 2011)

    - *Electric rate design for commercial & industrial solar customers.*

71. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-06-007—February 6, 2012)

    - *Electric rate design for solar customers; marginal costs.*

72. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R.11-02-019—January 31, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R. 11-02-019—February 28, 2012)

    - *Natural gas pipeline safety policies and costs*

73. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-10-002—June 12, 2012)

    - *Electric rate design for solar customers; marginal costs.*

74. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002—June 19, 2012)

    - *Natural gas pipeline safety policies and costs*

75. a. Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—June 25, 2012)
    b. Reply Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—July 23, 2012)

    - *Ability of combined heat and power resources to serve local reliability needs in southern California.*

76. a. Prepared Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—November 16, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—December 14, 2012)

    - *Allocation and recovery of natural gas pipeline safety costs.*

77. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 12-12-002—May 10, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

78. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 13-04-012—December 13, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

79. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 13-12-015—June 30, 2014)

    - *Electric rate design for commercial & industrial solar customers; residential time-of-use rate design issues.*

80. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation** and the **Indicated Shippers** (A. 13-12-012—August 11, 2014)
    b. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—August 11, 2014)
    c. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation** (A. 13-12-012—September 15, 2014)
    d. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—September 15, 2014)

    - *Rate design, cost allocation, and revenue requirement issues for the gas transmission system of a major natural gas utility.*

81. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (R. 12-06-013—September 15, 2014)

    - *Comprehensive review of policies for rate design for residential electric customers in California.*

82. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 14-06-014—March 13, 2015)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

83. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A.14-11-014—May 1, 2015)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 14-11-014—May 26, 2015)

    - *Time-of-use periods for residential TOU rates.*

84. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Joint Solar Parties** (R. 14-07-002—September 30, 2015)

    - *Electric rate design issues concerning proposals for the net energy metering successor tariff in California.*

85. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 15-04-012—July 5, 2016)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

EXPERT WITNESS TESTIMONY BEFORE THE ARIZONA CORPORATION COMMISSION

1. Prepared Direct, Rebuttal, and Supplemental Testimony of R. Thomas Beach on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. E-00000J-14-0023, February 27, April 7, and June 22, 2016).

   - *Development of a benefit-cost methodology for distributed, net metered solar resources in Arizona.*

2. Prepared Surrebuttal and Responsive Testimony of R. Thomas Beach on behalf of the **Energy Freedom Coalition of America** (Docket No. E-01933A-15-0239 – March 10 and September 15, 2016).

   - *Critique of a utility-owned solar program; comments on a fixed rate credit to replace net energy metering.*

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the **Colorado Solar Energy Industries Association** and the **Solar Alliance**, (Docket No. 09AL-299E – October 2, 2009).
   https://www.dora.state.co.us/pls/efi/DDMS_Public.Display_Document?p_section=PUC&p_source=EFI_PRIVATE&p_doc_id=3470190&p_doc_key=0CD8F7FCDB673F1043928849D9D8CAB1&p_handle_not_found=Y

   - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the **Vote Solar Initiative** and the **Interstate Renewable Energy Council**, (Docket No. 11A-418E – September 21, 2011).

   - *Development of a community solar program for Xcel Energy.*

3. Answer Testimony and Exhibits, plus Opening Testimony on Settlement, of R. Thomas Beach on behalf of the **Solar Energy Industries Association**, (Docket No. 16AL-0048E [Phase II] – June 6 and September 2, 2016).

   - *Rate design issues related to residential customers and solar distributed generation in a Public Service of Colorado general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

1. Direct Testimony of R. Thomas Beach on behalf of **Georgia Interfaith Power & Light and Southface Energy Institute, Inc.** (Docket No. 40161 – May 3, 2016).

   - *Development of a cost-effectiveness methodology for solar resources in Georgia.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League** (Case No. IPC-E-12-27—May 10, 2013)

   - *Costs and benefits of net energy metering in Idaho.*

2. a. Direct Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — April 23, 2015)
   b. Rebuttal Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — May 14, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE MASSACHUSETTS DEPARTMENT OF PUBLIC UTILITIES

1. Direct and Rebuttal Testimony of R. Thomas Beach on behalf of **Northeast Clean Energy Council, Inc.** (Docket D.P.U. 15-155, March 18 and April 28, 2016)

   - *Residential rate design and access fee proposals related to distributed generation in a National Grid general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony of R. Thomas Beach on Behalf of **Geronimo Energy, LLC**. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])

   - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

EXPERT WITNESS TESTIMONY BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

1. Pre-filed Direct and Supplemental Testimony of R. Thomas Beach on Behalf of **Vote Solar and the Montana Environmental Information Center** (Docket No. D2016.5.39, October 14 and November 9, 2016).

   - *Avoided cost pricing issues for solar QFs in Montana.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

   - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

   - *QF pricing issues in Nevada.*

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

   - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

4. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **The Alliance for Solar Choice (TASC)**, (Docket Nos. 15-07041 and 15-07042 –October 27, 2015).
   b. Prepared Direct Testimony of R. Thomas Beach on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 1, 2016).
   c. Prepared Rebuttal Testimony of R. Thomas Beach on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 5, 2016).

   - *Net energy metering and rate design issues in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

1. Prepared Direct and Rebuttal Testimony of R. Thomas Beach on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. DE 16-576, October 24 and December 21, 2016).

   - *Net energy metering and rate design issues in New Hampshire.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony of R. Thomas Beach on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)
   http://164.64.85.108/infodocs/2011/3/PRS20156810DOC.PDF

   - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)

   - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony of R. Thomas Beach on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)

   - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

April 25, 2014:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=89f3b50f-17cb-4218-87bd-c743e1238bc1
May 30, 2014:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=19e0b58d-a7f6-4d0d-9f4a-08260e561443
June 20, 2104:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=bd549755-d1b8-4c9b-b4a1-fc6e0bd2f9a2

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

   - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of **The Alliance for Solar Choice** (Docket No. 2014-246-E – December 11, 2014) https://dms.psc.sc.gov/attachments/matter/B7BACF7A-155D-141F-236BC437749BEF85

   - *Methodology for evaluating the cost-effectiveness of net energy metering*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF TEXAS

1. Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (SEIA) (Docket No. 44941 – December 11, 2015)

   - *Rate design issues concerning net metering and renewable distributed generation in an El Paso Electric general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

1. Direct Testimony of R. Thomas Beach on behalf of the **Sierra Club** (Docket No. 15-035-53—September 15, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE VERMONT PUBLIC SERVICE BOARD

1. Pre-filed Testimony of R. Thomas Beach and Patrick McGuire on Behalf of **Allco Renewable Energy Limited** (Docket No. 8010 — September 26, 2014)

   - *Avoided cost pricing issues in Vermont*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

Direct Testimony and Exhibits of R. Thomas Beach on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011) http://www.scc.virginia.gov/docketsearch/DOCS/2gx%2501!.PDF

   - *Cost-effectiveness of, and standby rates for, net-metered solar customers.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

Attachment B: Sub-Group 2 Recommendations

NET-METERING WORKING GROUP
SUB-GROUP 2 RECOMMENDATIONS
SEPTEMBER 15, 2017

Ark. Code Ann. § 23-18-604(b)(1)(A) (most recently amended by Act 827 of 2015 (Act 827)) requires that the Commission establish rates, terms, and conditions for net-metering service that recover "the electric utility's entire cost of providing service to each net-metering customer within each of the electric utility's class of customers", including, but not limited to, quantifiable costs and benefits associated with the net-metering customer's use of the electric utility's capacity, reliability, distribution system, or transmission system.

Participants in Sub-Group 2 have concluded that the current rate structure for net-metering customers does not meet this statutory requirement. Crediting net-metering customers' excess generation kilowatt hours (kWhs) at the full retail rate results in the failure by utilities to recover the actual cost to provide service, net of quantifiable benefits. Accordingly, Sub-Group 2 recommends the Commission adopt a 2-Channel Billing approach to address the requirements of Act 827 of 2015. 2-Channel Billing is discussed in detail in the following sections.

Under current net-metering policy, customers are charged full retail rates (consisting of generation, distribution, transmission, and related costs) for the amount of energy they receive from the utility, net of the excess generation they provide to the electric grid. As a result, the net-metering customers' self-generation is valued at the full retail rate for both the unmetered generation used behind the meter and for the metered excess generation delivered to the electric grid. While Sub-Group 2 participants do not oppose customers using the unmetered generation to reduce their

bill, crediting net-metering customers' metered excess generation kWhs at the full retail rate, as described below, does not adhere to the requirements of Act 827 of 2015.

The current retail rate structure for each utility was developed using a utility-specific Cost of Service (COS) Study, which allocates the embedded cost for generation, transmission, and distribution. Most of these embedded costs do not change for the utility if a net-metering customer uses more or less energy than it did prior to installing a net-metering facility. Given that utility rates are designed to collect these embedded costs, crediting a net-metering customer at full retail rates for excess generation effectively credits the net-metering customer for investments in embedded costs and costs of providing utility services that the customer does not avoid due to the customer's reduced consumption. Therefore, utilities do not recover the entire cost of their investments in generation, transmission, and distribution to serve net-metering customers (including, for example, costs for billing, metering, reliability, efficiency programs, and other approved investments and ongoing costs essential to maintaining the distribution and transmission systems). The resulting shortfall is then spread out and ultimately recovered from non-net-metering customers through the normal ratemaking process.

The issue confronting the Commission is how it should change the current net-metering policy to ensure that utilities recover their entire cost of providing service, net of quantifiable benefits, from net-metering customers. Sub-Group 2 urges the Commission to change the current net-metering policy with respect to new net-metering customers, because there is currently a fundamental flaw in the mechanism for crediting excess generation.

Consequently, Sub-Group 2 recommends that the Commission adopt 2-Channel Billing. 2-Channel Billing represents a fair, balanced, and equitable approach to addressing the relevant provisions of Act 827 of 2015. 2-Channel Billing collects the utility's cost to serve the net-metering customer for energy delivered by the utility through Channel 1 and applies an excess generation credit that appropriately recognizes the utility costs that the net-metering customer avoids as well as the benefits the net-metering customer provides to the system for all self-generated energy exported to the grid through Channel 2.

NET-METERING RATE STRUCTURE OPTIONS

NMWG Sub-Group 2 identified five different options that potentially would address the quantifiable costs and benefits of a net-metering customer's ongoing use of the utility's generation, transmission, and distribution systems. The five options considered were:

1. *2-Channel Billing*
2. *3-Part Rate*
3. *Grid Usage Charge*
4. *Minimum Bill*
5. *Time-Of-Use (TOU) Rate*

Sub-Group 2 evaluated and discussed the relative strengths and weaknesses of the options, which included the exchange of relevant information and analyses, during multiple meetings, some involving all NMWG participants and some involving only the Sub-Group 2 participants, over the course of several months. A brief description of each evaluated option is discussed below.

1. 2-Channel Billing

2-Channel Billing is a billing framework for a net-metering customer that measures the energy delivered by the utility and consumed by a customer (as recorded on Channel 1 of the bi-directional meter) and the excess self-generated energy exported to the grid (as recorded on Channel 2). Under 2-Channel Billing, the customer is billed at the applicable retail rates, including fuel and riders for energy delivered by the utility and consumed by the customer (Channel 1). The customer receives a bill credit for any excess self-generated energy exported to the grid (Channel 2) during a billing cycle based upon a predetermined excess generation credit rate. Self-generated energy consumed directly by the net-metering customer behind the meter is not measured or recorded by the bi-directional meter, and to do so would require the installation of a separate meter to measure the output of the customer's generation facility.[109]

2. 3-Part Rate

A 3-Part Rate schedule uses a combination of a fixed monthly customer charge, a demand charge expressed in $/kW-month, and a volumetric charge expressed in cents/kWh. Under a typical 3-Part Rate structure, the monthly fixed charge is designed to recover some portion (or all) of the embedded customer costs such as metering, billing, and customer service; a demand charge is designed to recover a portion of embedded production, transmission, and distribution costs; and the volumetric energy charge(s) are designed to recover the remaining portion of the utility's costs. As is the

[109] Sub-Group 2 does not recommend installing a separate meter to measure the output of a net-metering customer's generator.

case under typical residential rate structures, the volumetric energy charges are based upon the total kWh usage for a given billing cycle, whereas a demand charge would typically be based on the customer's demand or kW profile in a given time interval. Under a demand or 3-Part Rate, the utility recovers a greater portion of its costs under the fixed or demand rate charges compared to a rate structure that relies more heavily on volumetric kWh charges. A net-metering customer billed under a 3-Part Rate would receive a kWh credit equivalent to the full retail rate for excess energy exported to the grid.

3. Grid Usage Charge

A Grid Usage Charge is an additional monthly fee that can take various forms. In one variation, the additional monthly fee is a fixed rate (e.g., expressed in $/kW-month like a demand charge) that is multiplied by the size of a net-metering customer's generator. Developing such a Grid Usage Charge would require the utility to derive a fixed $/kW-month charge to be applied each month based on the utility's underlying COS Study. A net-metering customer billed under a Grid Usage Charge would receive a kWh credit equivalent to the full retail rate for excess energy exported to the grid.

4. Minimum Bill

A Minimum Bill provision provides a specific threshold dollar value that a customer must pay for each billing period if the actual level of demand and/or energy yields a monthly bill below the threshold. Minimum Bill provisions are different than fixed monthly customer charges in that the Minimum Bill provision only applies in instances where the bill based on actual usage would have been below the specified

minimum bill threshold. Some existing utility rate schedules include a minimum bill provision.

A net-metering customer billed under a Minimum Bill would receive a kWh credit equivalent to the full retail rate for excess energy exported to the grid. The excess energy credit in a billing cycle can never result in a bill that would be less than the otherwise applicable minimum bill.

5. Time-of-Use (TOU) Rate

A TOU Rate involves time-varying pricing in which the volumetric charge(s) in a rate schedule are broken into pre-set rates that incorporate time of day and/or seasonality. Under this option, a net-metering customer billed under a TOU rate will receive a credit equivalent to the full retail rate that varies based on the TOU window in which the excess energy delivered to the grid occurs. Only a few Arkansas utilities offer TOU residential rates.

SUB-GROUP 2 RECOMMENDS 2-CHANNEL BILLING

Based upon several exchanges of information and analysis during multiple meetings, some involving all NMWG participants and some involving only the Sub-Group 2 participants, over the course of several months, Sub-Group 2 recommends that the Commission adopt 2-Channel Billing in order to address the relevant provisions of Act 827 of 2015. At this time, Sub-Group 2 recommends that the Commission apply the 2-Channel Billing methodology to new net-metering customers taking service under non-demand billed tariffs.

2-Channel Billing does not require a more sophisticated meter beyond the normal bi-directional digital meter that is used today. The bi-directional meter measures energy consumed by the customer directly from the utility on one channel and measures the energy exported to the grid on another channel.

2-Channel Billing does not require that the customer install a second meter, and thus does not measure or record self-generated energy directly consumed by the customer behind the meter. Under 2-Channel Billing, however, the net-metering customer fully retains the benefit of its reduced energy consumption (in other words, the energy it self-produces that is used behind the meter). This aspect of net-metering is similar to the impact of efficiency programs or actions undertaken by customers to invest in conservation and weatherization to reduce their usage.

2-Channel Billing collects the utility's cost to serve the net-metering customer for energy delivered by the utility through Channel 1 and applies an excess generation credit that appropriately recognizes the utility costs that the net-metering customer avoids as well as the benefits the net-metering customer provides to the system for all self-generated energy exported to the grid through Channel 2.

2-Channel Billing represents a fair, balanced, and equitable approach to addressing the relevant provisions of Act 827 of 2015.

2-CHANNEL BILLING IS NET-METERING AND IS CONSISTENT WITH THE REQUIREMENTS OF ACT 827

2-Channel Billing satisfies the statutory definition of net-metering and can work in tandem with current, Commission-approved billing practices of the jurisdictional electric utilities. Under 2-Channel Billing, the rate charged to Channel 1 for the service provided by the utility to the customer would be the Commission-approved tariffed rate for the net-metering customer's respective rate class, i.e. the retail rate inclusive of applicable riders. This rate is approved by the Commission and is based on the utility's embedded COS Study, which would reflect the entire cost of providing service for the kWhs measured through Channel 1, as required in Ark. Code Ann. § 23-18-604(b)(1).

The only change from the current net-metering rate structure under 2-Channel Billing is that a different excess generation credit rate would be assigned to the excess kWh exported to the grid from the net-metering facility measured through Channel 2. This differs from the current net-metering policy that credits excess generation at the full retail rate. By crediting the customer for the excess kWh exported to the grid at a rate that is more appropriate than the full retail rate, 2-Channel Billing ensures that the customer pays rates that reflect the utility's ongoing cost of providing service, net of quantifiable benefits, consistent with Ark. Code Ann. § 23-18-604(b)(1).

The reliance on 2-Channel Billing recommended by Sub-Group 2 avoids the necessity to invest in additional metering systems[110], relies on rates and rate design the Commission has already approved, and will reflect future changes in both the rates paid by the net-metering customer for consumption as measured on Channel 1 and in the

[110] While not all customers currently have bi-directional meters installed, all utilities have this technology and it will be provided at no-cost to the customer.

credit for excess generation exported to the grid by the net-metering customer as measured on Channel 2. Both the rates paid for consumption measured on Channel 1 and the credit for excess generation measured on Channel 2 will be based on the utility's actual embedded cost of serving net-metering customers, net of benefits. This approach reforms the current credit for excess generation to eliminate the kWh credit equivalent to the full retail rate. Failure to change the current practice of crediting the excess generation at the full retail rate will result in other customers ultimately picking up a portion of the costs of serving net-metering customers.

IMPLEMENTATION OF 2-CHANNEL BILLING

1. *Demand Billed Tariffs*
2. *Non-Demand Billed Tariffs*
3. *Aggregated Meters with a Generation Meter*
4. *Illustration of a Monthly Bill*

1. *Demand Billed Tariffs*

Sub-Group 2 recommends that 2-Channel Billing only apply to non-demand billed tariffs. Demand billed tariffs are generally designed to recover a portion of the utility's embedded operational costs including infrastructure costs through the demand component of the 3-part rate structure, as opposed to non-demand billed tariffs that collect all embedded costs through the volumetric charge. Therefore, Sub-Group 2 recommends that demand-billed tariffs continue to be billed as they are today. Sub-Group 2 recognizes that there may be limited exceptions to this recommendation based on utility-specific rate schedules that are not specifically recognized as demand or non-demand based rate schedules.

2. *Non-Demand Billed Tariffs*

As discussed above under 2-Channel Billing, the customer is billed at the applicable retail rates including fuel and riders for energy delivered by the utility and consumed by the customer (Channel 1). The customer receives a bill credit for any excess self-generated energy exported to the grid (Channel 2) during a billing cycle based upon a predetermined excess generation credit rate. The customer's resulting total bill will consist of usage-related charges, a separate credit for excess generation, and any otherwise applicable minimum, as well as Commission-designated non-bypassable riders, applicable franchise fees, local and/or state taxes, etc.

During any billing period, the excess self-generated kWhs will be credited up to the kWh supplied by the electric utility, as measured on Channel 1, at the Commission approved excess generation rate. Any accumulated net excess generation credits, measured in kWh, will be carried forward and applied in the next applicable billing period, just as the net excess generation, measured in kWh, is treated currently.

3. *Aggregated Meters with a Generation Meter*

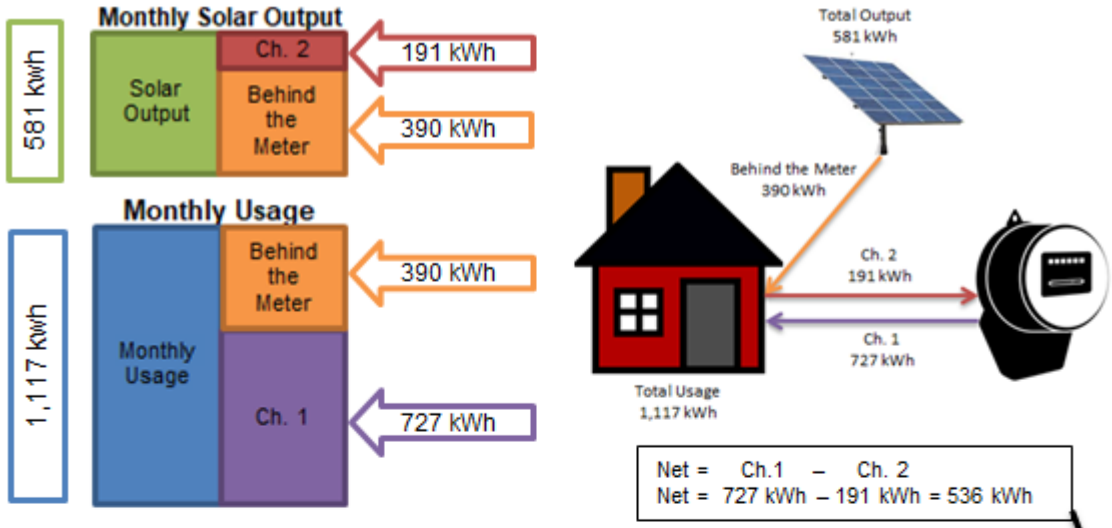
Any net excess generation, measured in kWh, after application to the generation meter shall be credited to each additional meter in rank order as specified by the customer. Monthly bills for non-demand billed tariffs shall be credited at the Commission-approved excess generation credit rate. Monthly bills for demand billed tariffs shall be credited as they are today. The customer will still be responsible for providing the utility with a list of the customer's accounts in the priority order that they desire.

4. *Illustration of a Monthly Bill*

An illustration of 2-Channel Billing in comparison to the current full retail kWh credit rate under the net-metering rules is shown below in Figure 1. In all three scenarios shown below, the customer consumes 1,117 kWh of energy across the entire monthly billing cycle. In two of the scenarios, the customer has installed a net-metering facility which reduces the energy that would otherwise have been supplied by the utility. In these scenarios, it is assumed that the customer's net-metering facility generates 581 kWh during the monthly billing cycle.

In the first scenario where the customer does not have a net-metering facility, the customer's monthly bill is $129. In the second scenario, which illustrates 2-Channel Billing, the net-metering customer is billed for Channel 1 usage (727 kWh) and separately credited for Channel 2 excess generation delivered to the grid (191 kWh) resulting in a $77 monthly bill. In the third scenario, which illustrates the Commission's current full retail rate credit framework, the Channel 1 value (727 kWh) and the Channel 2 value (191 kWh) are netted and the net-metering customer is billed for 536 kWh resulting in a $68 monthly bill.

Figure 1
Illustrative Billing Scenarios



Net = Ch.1 – Ch. 2
Net = 727 kWh – 191 kWh = 536 kWh

	Rate	Scenario 1 Typical Customer (without solar)	Scenario 2 2-Channel Billing	Scenario 3 1:1 Full Retail NM
Billed kWh:		1,117	727	536
Base Rates				
Customer:	$8.40/month	$8	$8	$8
Energy:	$0.0731/kWh	$82	$54	$40
Riders				
Fuel:	$0.0155/kWh	$17	$11	$8
Other Riders:	$0.0053/kWh	$6	$4	$3
Excess kWh:		–	191	--
Excess Energy:	($0.0551)/kWh	–	($11)	--
Taxes		$16	$10	$8
Total Bill		**$129**	**$77**	**$68**
Savings		**N/A**	**($53)**	**($61)**

Note: Dollar values may not add due to rounding.

FRAMEWORK FOR 2-CHANNEL BILLING RATE STRUCTURE

Embedded Cost of Service Study

In determining the appropriate rate structure for new net-metering customers, Sub-Group 2 recommends the Commission follow precedent with regard to historical ratemaking practices. Regulated rates are based on a utility's COS Study that underlies the rates approved by the Commission in the utility's most recent general rate case proceeding. Further, it is well-established that rates in Arkansas charged to retail customers are based on actual, embedded costs. Only real and directly quantifiable costs and benefits that exist within a utility's approved rates and the underlying COS Study should be considered in determining the net-metering rate. Cost causation and cost of service principles are fundamental to establishing the appropriate rate for all customers, including net-metering customers (i.e., that any quantified costs and benefits considered in the implementation of the Arkansas Renewable Energy Development Act must be based upon a utility's approved rates and the underlying COS Study).

Consistent with these principles, the costs and benefits considered to set an applicable net-metering rate should be:

- Well-defined, readily quantifiable, and transparently accounted for;
- Based on the appropriate valuation of the actual embedded cost of providing service; and
- Based on the individual utility's COS Study that establishes the underlying basis for the Commission-approved revenue requirements and rates.

The utility's cost of providing service reflected in rates, in the near term, is comprised of the utility's embedded infrastructure costs including generation, transmission, and distribution plant, as well as ongoing operational and maintenance

costs. Most of these costs are not avoided by the utility as the result of reduced energy consumption or excess energy exported to the distribution system associated with net-metering.

Any benefits related to the utilities' embedded costs including investments in generation, transmission, and distribution plant that may occur over the longer term as the result of providing service to net-metering customers will be captured in future updated utility COS Studies and approved revenue requirement and rates. Net-metering customers will receive the benefits of embedded costs when they are actually avoided. Over time, to the extent that the net-metering facilities provide benefits to the utilities' generation, transmission, and distribution costs, such benefits will be reflected within the revenue requirement and rates as approved by the Commission and reflected in the underlying COS Study.

Functionalization and Allocation of Costs

All customers pay for electric service at the applicable retail rate set out in a utility's tariff, which is designed to recover the utility's embedded cost to provide service. The excess generation credit rate should be developed using COS methodologies consistent with those used to allocate the utility's embedded costs from its most recent COS Study that is the basis for the utility's current rates.

The utility's total embedded costs are generally allocated to different customer classes based on some level of demand, energy, and the respective number of customers. The objective of the COS Study is to allocate all costs required to serve customers among each customer class in a fair and equitable manner. The first step in a COS Study is to functionalize the utility's embedded costs by its three major operating

functions of generation, transmission, and distribution. The second step is to classify the functionalized costs by demand, energy, and customer. The final step is to allocate the functionalized and classified costs among the customer classes based on cost causation principles. Sub-Group 2 recommends that the credit rate for excess generation under 2-Channel Billing reflect the findings and conclusions of the Commission for each utility's rates as reflected in the underlying COS Study from the most recent rate proceeding. In Arkansas, generation and transmission costs are generally allocated based on some level of coincident peak (CP) demand. CP demand is the demand of any class within a specific 12-month period that occurs at the same time as the utility's system peak. CP demands can be derived by a single peak or by averaging monthly peaks in a year (i.e., 1CP, 4CP, or 12CP). Generation costs for Arkansas utilities are generally allocated using the single CP or the average CP of the four summer months of June through September (4CP). Transmission costs for Arkansas utilities are generally allocated based on the average CP of each month of the year (12CP). As noted above, Sub-Group 2 recommends that the credit rate for excess generation measured on Channel 2 be developed using the CP values reflected in the COS Study underlying the utility's Commission-approved rates and charges.

Distribution costs are generally allocated based on a non-coincident peak (NCP) demand and number of customers. NCP demand is the maximum demand of any class within the specific 12-month period, but not necessarily occurring at the time of the utility's system peak.

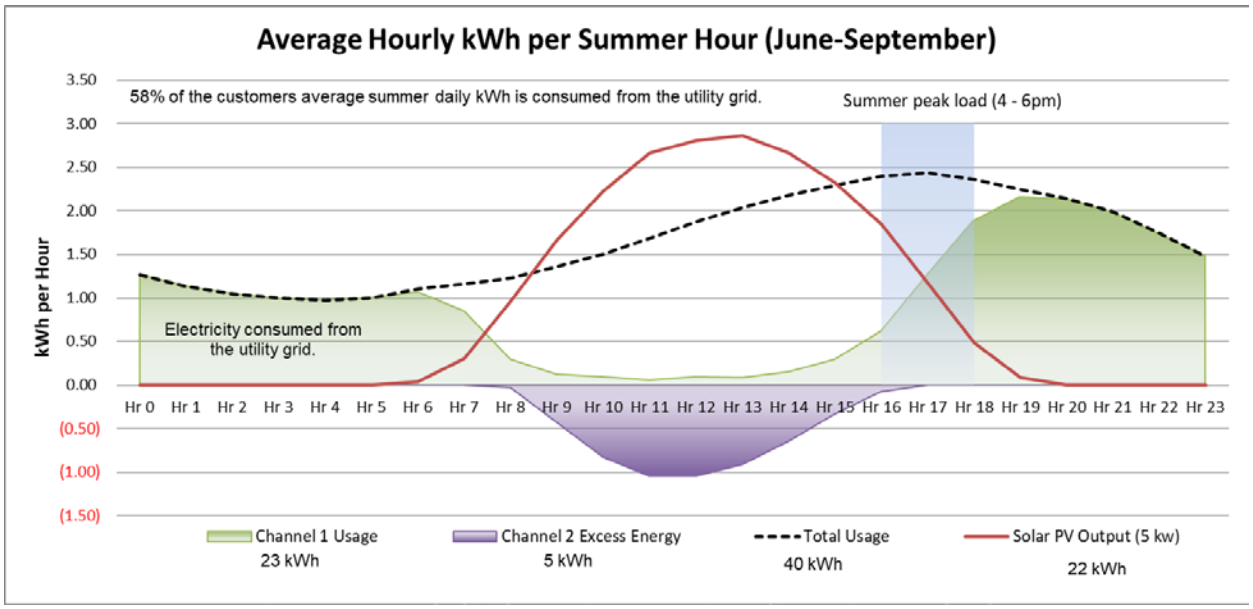
Net-Metering Customer's Load Profile

Net-metering customers' requirements for electric service are not that different from other customers. Net-metering customers take service from the electric utility and expect safe and reliable service. The utility uses the same metering and billing systems, customer care and customer service functions and programs, and other utility systems to serve its net-metering customers and non-net-metering customers. A net-metering customer does not differ from any other customer when it is taking service from the utility, which will be measured on Channel 1. The only difference in a net-metering customer is that the customer owns generation, consumes a portion of its own generation behind the meter, and, at times, exports excess energy to the grid, which will be measured on Channel 2.

Figure 2 below illustrates the average hourly electricity flows for the average summer day between June and September for a typical residential customer with a 5 kW DC rooftop Solar PV system located in Little Rock, Arkansas.[111] The red line depicts the operation of the rooftop solar PV system during the daylight hours. The purple shaded area depicts the period in which the customer produces more energy than the customer is actually using behind the utility's meter (dashed black line). During the other hours of the day, the customer's solar PV equipment is not operating and the customer is essentially a "full requirements" retail customer being served by the utility.

[111] Average PV output is based on NREL PVWatts™ modeling.

Figure 2
Illustrative Electricity Flows for the Average Summer Day



One can identify several important takeaways from this illustrative figure that demonstrate how a typical residential customer without self-generation differs from one that has installed a net-metered rooftop solar PV system. Sub-Group 2 considered these differences in the analysis of each utility's COS Study when developing its proposed excess generation credit methodology.

First, a fixed tilt solar PV system's (i.e., a very common technology configuration that does not track the sun) peak output occurs between the hours of noon and 1 p.m. (hours 12 -13) when the sun is at its zenith. For the summer period above, the typical 5 kW solar PV system produced approximately 2.9 kW, or about 63% of its rated nameplate capacity between noon and 1 p.m. Excess energy, depicted by the purple shaded area, is provided to the grid between 9 a.m. and 3 p.m. (hours 9-15), which generally falls outside of the utility's summer peak load hours of 4 p.m. to 7 p.m. (hours16 -19) and, thus, does not contribute to lowering the utility's peak load.

Second, during the utility's summer peak load hours the solar PV system is supplying energy, but not in excess of the net-metering customer's requirements. As the red line above illustrates, the output of the solar PV system drops precipitously from 4 p.m. to 6 p.m. when its output is approximately 0.5 kW or about 11% of its rated nameplate capacity. Conversely, the net-metering customer's load increases significantly during this period. The output of a typical solar PV system offsets some of the utility's peak load, but not 100%. Sub-Group 2's analysis focuses on the determination of the appropriate level of peak load offset by the output of a typical solar PV system.

The third important takeaway from this figure is to note the green shaded area where the utility is providing electricity to the net-metering customer. In the mid-afternoon (hour 15), the utility has to ramp up supply to meet the typical residential net-metering customer's increasing electric load. Despite the customer having installed a net-metered rooftop solar PV system with rated nameplate capacity that exceeds the net-metering customer's peak load, the utility must still have sufficient infrastructure in place to meet the net-metering customer's needs when the solar PV system output is declining and stops producing electricity in the late afternoon.

A final point regarding the above figure is to note the area shaded in purple. Between 9 a.m. and 3 p.m. (hours 9-15), the 5 kW solar PV system illustrated above produced more electricity on average than the customer was using, which results in a net export to the grid during those hours. Under the current Net-Metering Rules, the customer receives a credit equivalent to the full retail rate for this excess generation, yet the customer is not actually avoiding all of the embedded infrastructure costs

(generation plant, transmission lines, distribution poles, lines, and transformers, etc.) that allow the excess energy to be exported to the grid and to provide service to the net-metering customer. Between 4 p.m. and 6 p.m. (hours 16-18), the peak load hours during the summer months, most of the kWhs generated by a solar net-metering facility are used directly by the net-metering customer behind the meter.

Net-Metering Customers Are Not A Separate COS Rate Class

Sub-Group 2 does not recommend that net-metering customers be placed into a separate COS rate class. While a net-metering customer's energy usage profile will vary from the non-net-metering customer, that alone does not justify the need for a separate COS rate class. A net-metering customer's daily energy requirements from the utility measured through Channel 1 may be different than a non-net-metering customer with a similar energy requirement; however, the CP and NCP of the respective customers will not vary as significantly as the energy requirements.

Differences between customers within a class are generally addressed through rate design. For example, EAI has four separate COS rate classes with more than sixteen separate rate schedules. All rate classes within a COS Study have customers with varying usage profiles. Within a residential rate class, customers with summer vacation homes will have different profiles than those that live in their home all year long. Customers that heat and cool their home with electricity will differ from those who only cool their home with electricity and heat with natural gas or propane. Customers that live in small apartments will differ from customers that live in 5,000 square foot homes. It would not be appropriate, however, to put each of these type of customers into their own separate COS rate class.

CURRENT NET-METERING POLICY AND UTILITY RATE DESIGN

A net-metering customer's investment in a generation facility allows the customer, at times, to export excess generation to the grid at the distribution system level. The net-metering customer does not invest in transmission or distribution services and does not avoid the costs embedded in rates to provide these services to all customers, including net-metering customers. The utility rates were developed using the underlying COS Study that allocated the utility's embedded cost for generation, transmission, and distribution. These embedded costs are approved by the Commission and included in rates paid by all customers and do not change for the utility if customers use more or less energy. In fact, for a net-metering customer, these embedded costs that support the utility infrastructure become even more important because, without the grid, they would have no way to export their excess generation to the utility. Given that utility rates are designed to collect all functionalized embedded costs, when a net-metering customer receives a kWh credit equivalent to the full retail rate for its excess generation, the customer is not paying the full cost of the utility's investment in generation, transmission, and distribution services. Table 1 below presents an illustrative example of EAI's functionalized residential base rate on a $/kWh basis from its last rate case.

Table 1
EAI's Functionalized Residential Base Rate

Function	Base Rate	Percent of Base Rate
Generation	$0.03836	56%
Transmission	$0.01038	15%
Distribution	$0.01967	29%
TOTAL	**$0.06481**	**100%**

Under the existing full retail rate credit framework, a net-metering customer that offsets all of its energy requirements with excess generation would be billed for zero (0) kWh of energy usage and avoid any contribution to generation, transmission, and distribution costs (not otherwise collected through a fixed customer charge) even though the customer used the utility infrastructure and other systems and services to purchase kWh's and to export excess generation to the grid. The only contribution the customer would make would be the fixed customer charge. Consequently, under the current rate structure that provides a credit equivalent to the full retail rate, the net-metering customer fails to pay the utility's entire cost of providing service, net of quantifiable benefits.

EXCESS GENERATION CREDIT METHODOLOGY

Retail rates are collected through three basic components: base rates, fuel rider, and other riders. Based on the structure of retail rates, Sub-Group 2 identified two potential benefit categories for developing the excess generation credit methodology: avoided incremental fuel which represents the fuel rider component of retail rates and

embedded capacity which represents the base rate component of retail rates. The excess generation credit rate applied to excess generation measured on Channel 2 is the dollar value of the avoided incremental fuel expressed in $/kWh plus the embedded capacity credit expressed in $/kWh.

Avoided Incremental Fuel Benefit

The avoided incremental fuel is represented by the historical annual hourly real-time Locational Marginal Price (LMPs), based on the previous calendar year from Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), or both, as applicable for each utility. An additional benefit of avoided incremental fuel is distribution line losses. This benefit is calculated by adjusting the LMP by the utility's distribution line loss factor to account for the fact that generation interconnected to the distribution system and used locally avoids line losses associated with delivering power from a central station generator. Further, LMP values already reflect transmission line losses and congestion. Table 2 below provides an illustrative example of EAI's 2016 LMP adjusted for solar production shape and distribution line losses.

Table 2
EAI's Avoided Increment Fuel

Component	Amount
Historical Hourly LMP	$0.02761
Distribution Line Losses	7.4%
TOTAL	$0.02966

Embedded Capacity Benefit

The embedded capacity benefit is a quantifiable percentage of each component of the functionalized base rate costs expressed in $/kWh. The capacity benefit represents the portion of the utility's embedded costs that may be avoided by the customer due to both the unmetered generation used behind the meter and for the metered excess generation, measured in kWh, delivered to the electric grid. Currently under net-metering the customer receives a full retail rate credit equivalent to 100% of the base rate for generation, transmission, and distribution for each self-generated kWh, including both the generation used behind the meter and the excess energy exported to the grid. To quantify an appropriate embedded capacity percentage to credit, Sub-Group 2 analyzed solar capacity for each hour of the year (i.e. 8,760 hours) using the PVWatts® Model and compared those values with the peak hours of the utility.

As shown in Table 1 above, 56% of EAI's cost collected through base rate energy charge is generation related which is allocated using 4CP, the average of the CP hour in each of the summer months of June through September. An appropriate adjustment to reflect the embedded capacity credit to apply to the excess generation would be to evaluate the solar capacity factor that coincides with the utility's peak hours as allocated within the COS Study. Figure 3 below shows the solar capacity factor by average hour (the daily average of each hour in a month for each month of the year) based on the PVWatts® hourly load profile. The solar capacity factor is a ratio of the solar facility's AC output to the AC installed capacity.

Figure 3
Solar Capacity Factor Average Hour

MONTH \ HOUR	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0%	0%	0%	0%	0%	0%	0%	0%	3%	17%	31%	41%	48%	48%	46%	37%	24%	11%	1%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	6%	20%	36%	44%	48%	56%	53%	46%	34%	18%	3%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	2%	12%	29%	42%	53%	60%	62%	59%	52%	39%	23%	6%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	5%	20%	35%	50%	59%	65%	66%	60%	51%	40%	26%	9%	1%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	1%	9%	23%	39%	51%	60%	64%	64%	63%	55%	44%	29%	12%	2%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	2%	10%	24%	39%	50%	59%	61%	64%	60%	52%	42%	29%	13%	3%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	1%	8%	23%	38%	50%	59%	61%	64%	59%	54%	43%	28%	13%	3%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	6%	21%	36%	51%	62%	65%	65%	62%	52%	42%	26%	11%	2%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	4%	16%	33%	46%	54%	61%	59%	54%	47%	35%	20%	5%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	2%	16%	33%	46%	54%	58%	60%	53%	42%	28%	11%	1%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	7%	21%	32%	41%	45%	47%	43%	33%	19%	5%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	4%	16%	29%	38%	44%	46%	42%	35%	21%	6%	0%	0%	0%	0%	0%	0%

As shown in the figure above the solar capacity factor will vary over each hour and each month of the year. When a net-metering customer's solar PV facility is operating, the customer's load that the utility must serve is reduced. The benefit of this reduced load and its underlying cost allocation may be valued and developed based on the utility's COS Study allocation methodology for generation and transmission. Sub-Group 2 recommends using the average monthly peak hour over the most recent five years for each utility to develop the appropriate credit. Additionally, given the peak hours will fluctuate from year to year, Sub-Group 2 recommends the use of a three-hour average. The three-hour average is the peak hour of the utility and the hour before and after the peak hour. Table 3 below illustrates the solar capacity factor by average hour by month using the three-hour average peak method that coincides with the five year average peak hours for EAI as shown in EAI's FERC Form No. 1. For example, EAI's January peak hour is hour 8, as shown in Figure 3 above at hour 8 the average capacity of solar is 3%. The hour before, hour 7, solar is at 0% capacity and at the hour after,

hour 9, solar is at 17% capacity. The three-hour average would result in an average capacity factor of 7%

Table 3
EAI's Peak and Solar Capacity Factor
Average Hour

Month	Peak Hour	Solar Capacity Factor
January	8	7%
February	8	8%
March	8	14%
April	17	25%
May	16	43%
June	16	41%
July	15	52%
August	16	40%
September	16	34%
October	16	27%
November	8	9%
December	8	7%
4CP		42%
12CP		26%

Development of the Embedded Capacity Credit

As shown in Table 3 above, based on the PVWatts® hourly load profile and the hourly peak demands of EAI, the net-metering customer that reduces load has an underlying generation capacity benefit of 42% during EAI's 4CP and a transmission capacity benefit of 26% during the 12CP on an average hourly basis. Sub-Group 2 recognizes that the generation capacity of solar will generally be higher than average during a utility's peak-load hours. To fully capture the full potential benefit that solar could provide during the utility's peak hours Sub-Group 2 recommends using the maximum hourly capacity factor of solar that coincides with the utility's peak hours. Figure 4 below shows the solar capacity factor by maximum hour (the maximum capacity factor of each hour in a month for each month of the year) based on the PVWatts® hourly load profile.

Figure 4
Solar Capacity Factor Maximum Hour

MONTH	HOUR 0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0%	0%	0%	0%	0%	0%	0%	0%	6%	31%	55%	71%	79%	82%	76%	65%	46%	22%	2%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	12%	36%	58%	74%	83%	94%	80%	72%	54%	30%	7%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	4%	24%	50%	70%	84%	92%	92%	85%	75%	56%	35%	10%	1%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	1%	9%	31%	53%	70%	80%	86%	87%	81%	71%	55%	35%	12%	2%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	2%	12%	31%	52%	69%	81%	86%	85%	81%	70%	55%	35%	14%	3%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	2%	12%	31%	50%	65%	75%	79%	80%	77%	67%	53%	36%	17%	4%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	2%	10%	28%	47%	63%	72%	78%	80%	75%	68%	54%	36%	17%	5%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	1%	8%	26%	47%	64%	73%	80%	78%	75%	65%	52%	35%	15%	3%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	6%	25%	47%	64%	76%	81%	82%	75%	66%	48%	27%	10%	1%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	4%	25%	48%	65%	77%	80%	79%	74%	62%	45%	23%	4%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	1%	18%	42%	61%	72%	79%	75%	68%	54%	34%	11%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	10%	33%	53%	65%	73%	74%	70%	56%	35%	12%	0%	0%	0%	0%	0%	0%

The recommended capacity factor gives credit for the maximum production capability of the generator and not just the excess generation exported to the grid. Table 4 below illustrates the solar capacity factor by maximum hour by month using the three-

hour average peak method that coincides with the five year average peak hours for EAI as shown in EAI's FERC Form No. 1. For example, EAI's January peak hour is hour 8, as shown in Figure 4 above at hour 8 the maximum capacity of solar is 6%. The hour before, hour 7, solar is at 0% capacity and at the hour after, hour 9, solar is at 31% capacity. The three-hour average would result in an average maximum capacity factor of 12%.

Table 4
EAI's Peak and Solar Capacity Factor Maximum Hour

Month	Peak Hour	Solar Capacity Factor
January	8	12%
February	8	16%
March	8	26%
April	17	34%
May	16	53%
June	16	52%
July	15	65%
August	16	51%
September	16	47%
October	16	43%
November	8	21%
December	8	14%
4CP		54%
12CP		36%

As shown in Table 4 above, based on the PVWatts® hourly load profile and the hourly peak demands of EAI the net-metering customer that reduces load has an underlying generation capacity benefit of 54% during EAI's 4CP and a transmission

capacity benefit of 36% during the 12CP on an maximum hourly basis. The benefit of the net-metering customer's reduced load to the distribution cost allocation is 0%. This is because distribution costs are allocated by number of customers and NCP in the COS Study underlying rates. The allocation factor associated with the number of customers does not change as a result of net-metering, and the NCP may not change. In addition, the net-metering customer needs the distribution system at minimum to both receive energy from the utility and export excess generation to the grid. Based on the typical net-metering customer's load profile presented above, the functionalized cost expressed in $/kWh was adjusted to reflect the capacity benefit of generation, transmission, and distribution. This embedded capacity credit, in $/kWh, represents the embedded capacity benefits attributable to the net-metering customer's self-generation that is to be credited to the net-metering customer's excess generation. Table 5 below, illustrates EAI's residential embedded capacity excess generation credit.

Table 5
EAI's Functionalized Residential Embedded Capacity Credit

Function	Base Rate[1]	Capacity Benefit	Embedded Capacity Credit
Generation	$0.04003	54%	$0.02153
Transmission	$0.01083	36%	$0.00392
Distribution	$0.02052	0%	$0.00000
TOTAL	**$0.07138**	**36%**	**$0.02545**

[1] adjusted for FRP Rate

RATE IMPACT

Adjusting EAI's functionalized base rates using the maximum solar capacity factor for generation and transmission as shown above in Table 5, the net-metering customer's embedded capacity credit for its excess generation is approximately 36% of the total base rate costs for generation, transmission, and distribution. The net-metering customer would also receive 100% of the avoided increment fuel costs adjusted for distribution line losses.

For example, EAI's excess generation credit rate would be the avoided incremental fuel credit of $0.02966 per kWh plus the embedded capacity credit of $0.02545 per kWh for a total excess generation credit of $0.05511 per kWh. The net-metering customer would continue to receive the benefit equivalent to the full retail rate for all self-generation consumed behind the meter.

Sub-Group 2's proposal provides an embedded COS Study approach that reflects directly quantifiable costs and benefits based upon the COS Study underlying each utility's Commission-approved rates. The COS Study is adjusted consistent with traditional cost allocation methodologies to recognize the load characteristics of a typical net-metering customer to determine the appropriate cost-based excess generation credit that reflects actual costs and benefits. In addition, Sub-Group 2 recommends that net-metering customers be credited with the full market value for the actual energy, including distribution losses, exported to the grid.

Table 6 below, shows an illustrative example of the monthly bill impact for a typical EAI residential customer with a 5 kW DC rooftop solar PV net-metering system under four different billing scenarios. The light green section is a customer's bill without

a solar PV net-metering system, $129 per month. The light brown section is the customer's bill if the customer paid retail rates for all energy delivered by the utility (no credit for excess energy), $89 per month. The yellow section is the customer's bill under the current full retail rate credit net-metering policy, $68 per month. The light blue section is the customer's bill under 2-Channel Billing pursuant to Sub-Groups 2's proposed excess generation credit rate, $77 per month.

The illustrative bill impact shows that under the current full retail rate credit net-metering policy a customer receives a bill reduction of $61 per month or 47% of the typical bill amount without a net-metering facility. Under Sub-Group 2's recommended 2- Channel Billing approach, the customer would receive an average net monthly bill of $77 which represents a bill reduction of $53 per month or 41% of the typical bill amount without a net-metering facility. Under Sub-Group 2's recommended approach, the typical net-metering customer would experience a reduction in average monthly savings of only $9 from the level under the current Net-Metering Rules. It is important to note that the Commission has already determined that existing net-metering customers will be grandfathered; as such, the relative difference in savings of $9 between the current Net-Metering Rules and what Sub-Group 2 is recommending the Commission adopt is only relevant to the extent that it illustrates the expected magnitude of the change. Based on the examples provided above, existing and future net-metering customers will both have the ability to significantly reduce their electric bills.

Based on the illustrative bill impact shown below, under the current Net-Metering Rules, an existing net-metering customer receives approximately 10.8 cents (which reflects avoided franchise fees and state and local taxes) for each self-generated kWh.

Under Sub-Group 2's recommended approach a future net-metering customer receives a credit of approximately 5.5 cents (which does not account for avoided franchise fees and state and local taxes) per excess kWh exported to the grid. In total, including the behind the meter usage and the kWh exported to the grid as measured on Ch. 2, the future net-metering customer is receives approximately 9.1 cents for each self-generated kWh (~84% of the full retail rate). A summary of the typical customer's monthly bill impact by utility is attached as Attachment B.4.

Table 6
EAI's Typical Customer Monthly Bill

Month	Total Usage (kWh)	Solar PV Output (kWh)	Ch. 1 Usage (kWh)	Ch. 2 Excess Energy (kWh)	Behind the Meter Usage (kWh)	Typical Bill w/o Solar	Typical Bill with Solar - 5 kW		
							Ch. 1 Delivered (On-Site)	Current NEM Rules	2 Channel Billing
Jan	1,511	432	1,168	89	343	$161	$131	$124	$126
Feb	1,295	464	944	113	351	$142	$111	$99	$104
Mar	1,070	619	716	264	354	$123	$87	$58	$70
Apr	754	666	436	348	318	$91	$57	$19	$35
May	874	727	469	322	404	$103	$60	$26	$40
Jun	1,180	694	652	166	528	$142	$83	$64	$72
Jul	1,235	710	695	170	540	$148	$88	$69	$77
Aug	1,385	704	815	134	571	$165	$101	$86	$93
Sep	1,039	590	629	180	411	$126	$80	$60	$69
Oct	778	570	484	275	294	$93	$62	$32	$45
Nov	1,068	400	795	126	274	$123	$95	$81	$87
Dec	1,214	396	925	107	289	$135	$109	$98	$102
	13,404	**6,973**	**8,728**	**2,296**	**4,677**	**$1,552**	**$1,063**	**$816**	**$920**
Monthly Average	**1,117**	**581**	**727**	**191**	**390**	**$129**	**$89**	**$68**	**$77**
					Monthly Bill Savings:		**$41**	**$61**	**$53**

CHANGES TO THE NET-METERING RULES TO IMPLEMENT 2-CHANNEL BILLING

The following is a summary of the changes proposed to the current Net-Metering Rules, attached as Attachment B-5 to Sub-Group 2 Recommendations: Net-Metering Rules – Red-Line Version to implement the 2-Channel Billing approach recommended by Sub-Group 2:

Definitions

To define and clarify the billing framework for the Net-Metering Customer which Sub- Group 2 is proposing, Sub-Group 2 added definitions for: “2-Channel Billing,” “Channel 1,” “Channel 2,” and “Channel 2 Excess Generation.”

Sub-Group 2 proposes to remove the following definitions as they are not referenced within the Rules: “Biomass Resource,” “Fuel Cell Resource,” “Geothermal Resource,” “Hydroelectric Resource,” “Micro Turbine Resource,” “Qualifying Facility,” “Solar Resource,” and “Wind Resource.”

For clarity purposes, Sub-Group 2 reflected in its redline version of the Net-Metering Rules, the new identification letters for each definition.

Rule 2.04

Subsections (A), (B), and (C) of Rule 2.04 remain the same. However, the name of the rule was modified to indicate that these billing requirements would apply to those Net-Metering Customers taking service pursuant to the Grandfathered Net-Metering Tariff.

Subsections (C) – (E) of Rule 2.04 were renumbered as standalone rules.

Rule 2.05

Rule 2.05 includes the billing requirements which would apply to those Net-Metering Customers taking service pursuant to the 2-Channel Billing approach as described in the Net-Metering Tariff in Appendix E.

Rule 2.06

Rule 2.06 includes the billing requirements which would apply to those Net-Metering Customers taking service pursuant to the Demand Billed Section of the Net-Metering Tariff in Appendix E.

Rule 2.07

The provisions of Rule 2.07 were previously contained within Rule 2.04. It was separated for clarity. Rule 2.07(A) was former Rule 2.04(C)(3) with the original, first sentence deleted. Rule 2.07(B) was former Rule 2.04(C)(3)(a). Rule 2.07(C) was former Rule 2.04(C)(3)(b). Rule 2.04(D) was former rule 2.04(C)(4).

Rule 2.08

Rule 2.08 was formerly Rule 2.04(E).

Rule 2.09

Rule 2.09 was formerly Rule 2.04(D), 2.04(C)(1), and 2.04(E). These sections were modified to clarify that Channel 2 Excess Generation would be applied to additional meters under Sub-Group 2's proposal, not Net Excess Generation as currently stated in the listed rules.

Rule 4.01

Rule 4.01 was updated consistent with the proposed appendix additions.

No further changes to the body of the rules, the Standard Interconnection Agreement, the Disclaimer, or the Preliminary Interconnection Site Review Request are proposed.

Changes Required to Tariffs to Implement 2-Channel Billing

The following is a summary of the changes proposed for the current Net-Metering Standard Tariffs, attached as Appendix D and E of the Net-Metering Rules:

Sub-Group 2 proposes two Tariffs, the standard Net-Metering Tariff which will apply to all Net-Metering Customers who sign a Standard Interconnection Agreement with the Electric Utility after to the date of the Order in Phase 2 pursuant to Order No. 10 as amended by Errata Order No. 14 and the Net-Metering Tariff – Grandfathered which will apply to all Net-Metering Customers who sign a Standard Interconnection Agreement with the Electric Utility prior to the date of the Order in Phase 2 pursuant to Order No. 10 as amended by Errata Order No. 14. Both tariffs were based on the approved Net-Metering Tariff included in Errata Order No. 14.

The Grandfathered Net-Metering Tariff revises the current Net-Metering Tariff. Changes to original language are struck through. Added language is in red font and underlined. Sub-Group 2 is also proposing some changes to the tariff to make it more consistent with the language contained in the rules. These changes are indicated in green font.

Sub-Group 2 proposes a new Excess Generation Credit Rider that sets out the annual determination of the Excess Generation Credit that would apply to the new Net-Metering Tariff.

Net-Metering Tariff – Grandfathered

Section X.1. – Availability

Changes to this section were made to clarify the effective dates of the tariff.

Language was added to clarify the attachment of the Standard Interconnection Agreement to the premises and the continuation of the term of the tariff pursuant to Order No. 10, in Docket No. 16-027-R. Language was also included to provide that the utility will provide a customer with notice that the Net-Metering Customer's Net-Metering Tariff was preparing to expire and that the customer's service would be subject to the applicable tariff. The notice must be provided 30 days before the expiration of the Net-Metering Tariff.

Section X.2 – Monthly Billing

Section X.2.3. was modified to clarify that the charges for the net kWhs supplied by the utility included not only the standard rate schedule, but also any appropriate rider schedules.

Section X.2.7 was added to clarify that the billing amount in a given Billing Period will never be less than the otherwise applicable minimum bill.

Section X.2.11 was removed as unnecessary as the provision is contained in the rules, but is unrelated to billing under the tariff.

The Grandfathered Tariff remains essentially the same as that previously approved by the Commission. Changes were made to clarify who qualifies for service under the tariff and when the schedule will expire. Clarifying language was added to the remainder of the tariff.

Net-Metering Tariff

The terms of the new Net-Metering Tariff are as consistent as possible with the Grandfathered Net-Metering Tariff. However, certain changes were required to capture the billing framework for Net-Metering Customers submitting a signed Standard

Interconnection Agreement after the date of the Order in Phase 2 of Docket No. 16-027-R.

Specifically, the new tariff includes billing provisions for Monthly 2-Channel Billing and Monthly Billing for Demand Billed Tariffs which are consistent with the changes proposed in the Net-Metering Rules.

SUB-GROUP 2 RESPONSES TO COMMISSION QUESTIONS

1. With respect to an electric utility's entire cost of providing service to each net-metering customer within each of the electric utility's class of customers, does a net-metering customer's use of the electric utility's capacity, distribution system, or transmission system impose additional costs?

RESPONSE: Yes. Net-metering imposes additional costs on the utility such as billing, customer service, interconnections, and operational impacts. The additional costs include:

- Application review and site inspections, distribution system studies for larger systems, billing system and associated processes to facilitate net-metering as well as ongoing billing-related costs on a monthly basis in order to process and accurately bill a net-metering account, which for most utilities, is done manually at this time due to the small number of net-metering customers.

- Growth in the number of net-metering customers would require utilities to consider more automated billing systems for such customers, the cost of which may or may not be limited to one-time programming and IT costs, but might also require more significant investments in current utility customer billing and customer care systems.

- Customer service costs to respond to billing questions, complaints, and other net-metering-specific inquiries. In jurisdictions with greater deployment of net-metering, utilities have dedicated employees that interface with solar installers, handle customer interconnection paperwork, check on the status of needed electrical and other permits, and help address the more complex billing and other issues that arise once a customer's generation system has been installed.

- Investment in distribution reliability projects, the need and location for which will depend on the level of penetration of customer-owned generation, particularly intermittently-operating solar PV systems, the utility may have to make to ensure on-going reliable service for all customers.

- Other market-related, ancillary service costs associated with maintaining reliability which are currently borne by the utility and passed through to all customers. An example would be charges imposed by an RTO from deviations from scheduled load due to being unable to accurately forecast customer self-generation output in a given hour.

a. If so, which, if any of the additional costs are quantifiable?

RESPONSE: Interconnection costs are quantifiable based on the interconnection studies conducted by the utility. The other additional costs above are quantified and captured within a utility's COS Study as they are incurred, including any additional costs associated with future growth of net-metering within the state of Arkansas.

b. How should any such quantifiable, additional costs be valued, for the purpose of Act 827?

RESPONSE: Quantifiable costs are those that are detailed in the books and financial records of the utility as shown in its embedded COS Study. For the purpose of Act 827, additional costs should be quantified for rate-making purposes in the same manner as other similar costs to provide utility service using well-established cost of service methodologies based on each electric utility's specific cost of service data. Cost of service methodologies are generally described in the National Association of Regulatory Utility Commissioners (hereinafter "NARUC") publication titled "Electric Utility Cost Allocation Manual," which was published in January 1992. These methodologies have been reviewed before the APSC for many years, and form the basis for establishing cost-based rates. Such an approach, which includes the recovery of costs attributable to specific activities required by individual customer's that cause the costs to be incurred, follows the long-standing and widely-accepted regulatory principle of cost causation.

c. Are there existing or emerging technologies or policies that could mitigate such costs?

RESPONSE: Yes, there are policies and technologies that could help mitigate both the additional costs imposed on the grid by net-metering customers, as well as to appropriately allocate the costs and benefits that are avoided by those customers. Sensors with communication capability can improve the quality of the information available to the utility. These can include additional meters that allow a utility to track use and generation over time, allowing a better understanding of the impacts of a net-metering customer on the system. Additionally, smart inverters (installed with net-metering systems) and condition-monitoring sensors installed on the grid can improve the utility's understanding of equipment operation and upset conditions that may lead to the premature failure of components. This can allow a utility to better plan for the addition and operation of net-metering systems, and better understand the cost impacts imposed on the grid as new generators are added. Energy storage technologies may also mitigate the costs imposed on the grid by net-metering customers by mitigating rapidly changing load patterns caused by net-metering intermittency, or by reducing the amount of excess generation sent to the grid when two-way power flows could be detrimental to system operation.

To the extent that emerging technologies could mitigate the incremental costs incurred by utilities to permit net-metering customers' to self-generate and export excess generation to the grid, those future policies or technologies can be considered by the Commission in future rate cases or rate reviews for each electric utility. Such developments, however, are likely to be beneficial to all customers and not unique to serving net-metering customers. To the extent that such technologies are deployed by

utilities and mitigate the costs to serve customers, including the net-metering customers, those costs and savings will be reflected in the utilities' COS Studies used to develop rates

2. With respect to an electric utility's entire cost of providing service to each net-metering customer within each of the electric utility's class of customers, are there any quantifiable benefits associated with the interconnection with and providing service to the net-metering customer, including without limitation benefits to the electric utility's capacity, reliability, distribution system, or transmission system?

RESPONSE: Yes. For the purpose of establishing rates for net-metering, the benefits of net-metering considered in the determination of such rates should be:

- Well-defined, readily quantifiable, and transparently accounted for;
- Based on the appropriate valuation of the actual embedded cost of providing service to a net-metering customer; and
- Based on the individual utility's COS Study that establishes the underlying basis for the utility's revenue requirements and rates.

a. If so, which, if any, of these benefits are quantifiable?

RESPONSE: Quantifiable benefits associated with providing service to net-metering customers could include:

- Embedded generation capacity
- Embedded transmission capacity
- Incremental energy, including adjustment for distribution line losses

Net-metering customers that reduce their contribution to peak load avoid responsibility for a portion of the utility's peak generation and transmission costs. Net-metering customers that export excess energy to the grid allow the utility to avoid incremental energy costs, including line losses.

b. How should any such quantifiable, additional benefits be valued, for the purpose of Act 827?

RESPONSE: For purposes of Act 827, benefits should be valued using traditional cost of service methodologies. The most recent COS Study identifies the costs by function (generation, transmission, distribution, and distribution customer) and should serve as the basis for a rate structure that allows for recovery of the cost to serve all customers including those billed under net-metering. To the extent that net-metering customers may reduce the utility's investments and expenses associated with its generation, transmission, distribution, and customer service functions, such future reductions will be comprehended within the utility's future COS Studies.

The above identified embedded generation and transmission benefits associated with the cost of providing service to each net-metering customer within each of the electric utility's classes of customers may be quantified, based on the utility's most recent COS Study and class cost allocation methodology underlying the rates currently approved by the Commission.

Avoided incremental energy benefits may be quantified based on the annual hourly real-time LMPs for the previous historical calendar year for Midcontinent Independent System Operator, Southwest Power Pool, or both, plus distribution line losses. The weighted average annual avoided incremental energy cost per kilowatt hour would be determined based on a simulation of the average net-metering customers' generator output for the rate class using the PV Watts® calculator.

c. Are there existing or emerging technologies or policies that could enhance such benefits?

RESPONSE: Yes. Many of the technologies discussed in response to 1c are equally applicable to enhancing the benefits of net-metering. Advanced inverters installed along with solar projects may be used to manage voltage issues and to better align solar output with peak system demand in the evenings and potentially benefit a utility's ratepayers, assuming that customers are willing or capable of sharing that inverter data on a real-time basis with the utility.

Similar to 1c, additional technologies to measure, store, and communicate with a net-metering customer allow a utility to better understand operation of the system, which allows for a clearer picture of any benefits that may be provided by a net-metering customer. But, any such benefits must be tied to quantifiable costs avoided by the utility.

However, the challenge is to incorporate these additional and new technologies alongside existing utility devices and make them work harmoniously. Further, these new technologies may bring additional regulatory challenges, including the concern that smart inverter features could reduce the amount of energy solar systems put onto the grid which could hurt the business case for rooftop solar and raise issues as to whether new rate structures should be introduced to mitigate their impacts.

3. As a matter of rate-making:

a. How should the Commission take into account immediate, or short term cost or benefit causation, versus projected or expected longer term cost or benefit causation?

RESPONSE: The Commission should take account of the actual costs or quantifiable benefits of providing service to net-metering customers based on the utility's most recent embedded cost of service study, updated for base rate adjustments including Formula Rate Plan, Docket No. U-2811, and Act 821 adjustments. As a matter of rate-making, the utility's COS Study, based on test-year data, serves as the framework for defining actual and directly quantifiable costs and benefits of providing service to each net-metering customer within each of the electric utility's class of customers. The rate-making process, regardless of the existence of net-metering, takes all changes to actual costs or benefits into account in determining rates whether those costs are long-term or short-term. As longer term costs and benefits materialize, the embedded cost of service study will, through periodic updates, reflect those costs and benefits as well. Thus, relying on the methodologies established in the embedded COS Study appropriately balances short- and long-term cost causation.

b. Does evidence demonstrate that net-metering customers are materially different in terms of cost causation from other customers in their customer class (i.e., are net-metering customers their own class)?

RESPONSE: At this time, there is no evidence demonstrating that net-metering customers, when they are energy consumers, are materially different from the other customers in their rate class. Thus, the costs of serving net-metering customers are not materially different than the costs of serving the other customers in their same rate class. Although rate classes have customers with varying load profiles the overall cost

of service, including the utility infrastructure and system distribution services required to serve that class of customers are homogenous for all customers in that class. When net-metering customers take service from the utility (e.g., using the distribution system poles and wires, metering and billing systems, reliability service programs and policies, customer service functions, transmission system, generation system, etc.), they are just like any other customer and incur the same cost of service as all other customers.

While there might be a wide range of load profiles within a particular rate class, net-metering customers are unique from other customers in their rate class due to the fact that, at times, many net-metering customers export power back onto the utility system. Differences between customers within a class are appropriately addressed through rate design. The Commission can establish a rate structure without creating a new customer class and that is what Sub-Group 2 recommends.

c. Should rates incorporate time-differentiated rates for net-metering customers (either residential or commercial)?

RESPONSE: The potential development of time-differentiated rates could be explored within the context of the utility's general rate case proceeding. Given the relatively small number of net-metering customers in Arkansas, mandatory time-differentiated rates are not necessary at this time. The availability of a rate choice should not be exclusive to or excluded from a customer's applicable options based on net-metering status.

4. What role might net-metered generation play in assisting with compliance with the Clean Power Plan or other environmental regulations?

RESPONSE: The Clean Power Plan is currently stayed by the Supreme Court of the United States and is under review by the Environmental Protection Agency. It is not

possible to know what the prospects for environmental regulations under the Clean Power Plan will be in the near-term and the role that net-metered generation may play. To the extent that net-metering customers reduce the utility's investments and expenses associated with environmental compliance costs, such future reductions will be reflected within the utility's future COS Studies or in the fuel and purchased energy recovery mechanisms.

5. How should the Commission consider or take into account economic costs or benefits beyond the utility's entire cost of providing service, including:

a. Any public interest associated with economic development or job creation in the distributed energy sector, including the potential impact of federal tax benefits?

RESPONSE: Societal benefits such as economic development and job creation in the distributed energy sector are not comprehended in utility costs or recoverable by a utility and, thus, should not be considered by the Commission as part of determining just and reasonable rates for net-metering customers. Furthermore, such benefits provided by net-metering customers can be difficult to quantify and speculative in nature.

b. Any public interest, beyond the direct costs and risks associated with compliance with environmental regulation, associated with environmental impacts?

RESPONSE: See response to question 5a.

6. Should policies related to net-metering in Arkansas take into account developments in smart-grid, demand response, storage or other technologies?

RESPONSE: Yes. Developments in smart-grid, demand response, storage or other technologies that affect the utility's actual cost of providing service to all customers including net-metering customers, should be taken into account. However, the impact

these technologies have on the utility's actual costs of providing service can only be taken into account at a time when the technologies have emerged to a point where they have a quantifiable impact**.**

7**.** **What can be learned from the recent consideration of these net-metering valuation issues in other states?**

RESPONSE: As detailed in the Appendix: Lessons Learned from Other States & Jurisdictions, attached to this Report, this Commission is wrestling with the same net-metering rate design and rate structure-related issues as other jurisdictions across the United States. However, many of those other jurisdictions have reached the same conclusion: namely, that net-metering rates which provide a kWh credit equivalent to the full retail rate for excess generation from net-metering facilities, fail to recover the cost of serving the net-metering customers from those customers. As a result, those costs are being borne by the non-net-metering customers through normal ratemaking procedures. To remedy this, many jurisdictions have had proposed, or have adopted, a 2-Channel Billing framework the same, or similar to, that proposed by Sub-Group-2.

While many jurisdictions have implemented 2-Channel Billing, although they may use a different term to describe the same billing framework, their valuation of the excess energy is varied. As described in detail in the Appendix, jurisdictions have credited the excess energy delivered to the utility as measured by Channel 2 for certain utilities on: a five-year weighted average price of utility-scale solar power purchase agreements (Arizona Public Service), which was subsequently modified to a fixed value below full retail in conjunction with a settlement; the initial excess credit

rate based on the market prices for solar power over the last five years (Tucson Electric Power); and on a percentage of retail, energy, transmission and distribution charges (New Hampshire). Other jurisdictions have added charges for net-metering customers (California) while other jurisdictions have made upward adjustment to avoided cost rates to reflect potential unquantifiable benefits (Mississippi). While the methods by which to value the excess energy may be as varied as the jurisdictions, the results are the same – more appropriate recovery of the costs necessary to serve net-metering customers.

8. What other issues, if any, should be addressed in implementation of Act 827?

RESPONSE: None at this time.

APPENDIX TO
NET METERING WORKING GROUP
SUB-GROUP 2
RECOMMENDATIONS
SEPTEMBER 15, 2017

LESSONS LEARNED FROM OTHER STATES AND JURISDICTIONS

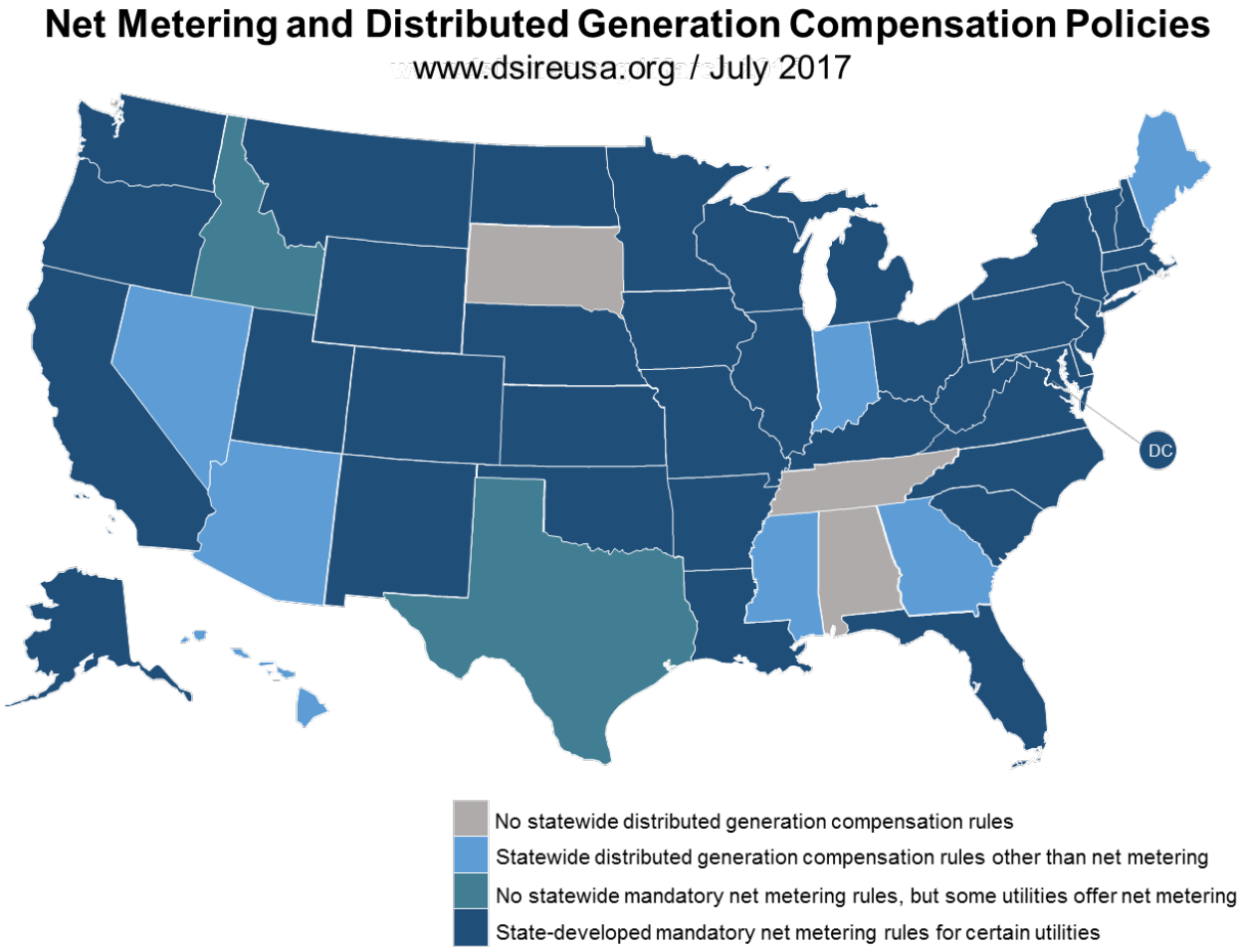
In Phase 2 of APSC Docket No. 16-027-R, the Commission will be addressing the same rate design and rate structure issues related to customers with net-metering facilities as defined in Ark. Code Ann. § 23-18-603(6) (net-metering facilities) and net-metering policy that have been addressed by, or are pending in front of, numerous other regulators around the United States[112]. Sub-Group 2 has compiled this Appendix to help provide background information and lessons learned from other jurisdictions with respect to: (1) ways other regulators are addressing net-metering policy and related rate structures, and (2) various cost-benefit analyses performed by other regulators related to net-metering. Consistent with Sub-Group 2's recommendations in this proceeding, other regulators have concluded that current net-metering policies and rate structures that credit excess generation from customers with net-metering facilities at the full retail rate, fail to appropriately recover the costs imposed on the utility for serving those customers. Consequently, those costs are ultimately recovered from non-net-metering customers through normal ratemaking procedures.

[112] Some states have addressed the issues directly as related to net-metering facilities and net-metering policy while other states have addressed the issues related to distributed generation systems including net-metering facilities.

Overview of Net-Metering Policy Changes

Active regulatory proceedings as well as legislative efforts that are seeking to correct the issues that arise from net-metering policy are taking place in many jurisdictions outside the State of Arkansas. Some of these proceedings were initiated by utilities, while others (such as APSC Docket No. 16-027-R) have been opened through actions of legislators and retail regulators. As discussed in this Appendix, a number of other jurisdictions have given specific attention to the impact on customers without net-metering facilities that result from net-metering customers not paying the full cost of the services they receive from the utility.

Among other research, the NC Clean Energy Technology Center's Database of State Incentives for Renewables & Efficiency issues a quarterly report that tracks net-metering policies and regulatory activity in the U.S. In addition to the information reflected in the legend for the map below, states shown in light blue now have rate structures that value excess energy exported to the grid by net-metering customers at a rate other than the full retail rate.



Hawaii

The state of Hawaii has among the highest electricity rates in the United States.[113] This high cost, coupled with net-metering policy, led to Hawaiian customers adding significant amounts of net-metering systems in recent years. These significant net-metering additions began to cause operational problems with the grid, and it became clear that addition of net-metering at the levels being seen was unsustainable for the utility and its customers.

[113] U.S. Department of Energy, EIA Form 826 data for May 2017.

In 2014, the Public Utilities Commission of the State of Hawaii (Hawaii PUC) issued an Order instituting a proceeding to investigate the technical, economic, and policy issues associated with distributed energy resources as they pertained to the electric operations of four Hawaiian utilities.[114] In an October 2015 Order in that proceeding, the Hawaii PUC issued an order closing its existing net-metering program to new customers, and instead put in place two options for customers installing new net-metering systems: a grid supply option and a self-supply option.[115] The grid-supply option allows a customer with net-metering to deliver excess generation to the grid, although they are credited at a rate less than the full retail rate. Under the self-supply option, customers are not credited for incidental amounts of excess energy delivered to the grid (this option would be advantageous when considering storage), but they are subject to a lower monthly fixed fee than a customer that elects to take service under the grid-supply option.

The following describes one of the two replacement programs adopted by the Hawaii PUC:

> *The grid-supply option is intended to provide customers with the option to export excess energy to the grid in exchange for energy credits against the customer's bill, to the extent such energy export provides benefits to the electric system. The grid-supply option is therefore functionally similar to the existing NM program (see, e.g., HECO's Tariff Rule 18), with the difference that the energy credit rate under the grid-supply option need not be tied to the retail electricity price, but rather can be set at a rate that approximates the relative value of such exported energy to the system.*[116]

In its October 2015 Order, the Hawaii PUC emphasized that "the interim options approved herein provide near-term balance, customer choice, and value to both

[114] Docket No. 2014-0192.
[115] Hawaii PUC Docket 2014-0192, Decision and Order No. 33258, issued October 12, 2015.
[116] *Id.* at 126.

participating and non-participating customers. This balance affords stakeholders the time to conduct more granular analysis and propose new policy designs during Phase 2."[117] Thus, Hawaii, as the state with the highest net-metering system penetration in the U.S., appears to be the first state to have offered an option to its residents similar to a 2-Channel Billing framework. However, Hawaii does not use the term "2-Channel Billing," instead, it refers to its successor policy as the "Customer Grid-Supply Option."[118] Availability of the Customer Grid-Supply option to Hawaiian customers is capped and, once the cap is reached, new customers would be required to take service under the Customer Self-Supply Option.

In the Hawaii Commission's October 2015 Order as described above, it approved the self-supply and grid-supply tariffs for HECO. The self-supply option, among other aspects, contains a minimum charge of $25 per month and no credit mechanism for incidental exports to the grid. The grid-supply option, which has some similarities to a 2-Channel Billing framework, has a minimum charge of $25 per month and credits exports to the grid at a rate below the full retail rate.

Similar to those considerations recognized by the Arkansas Commission in Order No. 10 of Docket No. 16-027-U, the Hawaii PUC did grant grandfathering of existing net-metered customers to avoid changing the economics of investments that already had been made by those customers. The aforementioned cap on the Customer Grid-Supply option (35 MW total across the three Hawaiian Electric Company (HECO) subsidiaries) was reached in mid-2016, less than a year after the October 2015 order.

[117] *Id.* at 168.
[118] *See* Hawaii PUC Docket 2014-0192, Decision and Order No. 33258, issued October 12, 2015.

However, in April 2017, the Hawaii PUC expanded the cap to allow over 40MW more to qualify over a six-month period, ending October 21, 2017.[119]

Mississippi

In December 2015, the Mississippi Public Service Commission (MPSC) issued a final order adopting new net-metering rules that are based on the 2-Channel Billing framework.[120] To address the issue of how to quantify and factor in certain types of additional benefits, a 2.5 cents per kWh adder was incorporated in addition to each utility's avoided costs that would be used to credit any excess energy the net-metering customer delivers to the grid as measured through Channel 2 of the meter. The 2.5 cents per kWh adder will remain in effect for the first three years of the program until such time as the MPSC can more appropriately quantify and address these potential additional benefits. The MPSC took the further step of creating an incentive mechanism to assist qualifying, low-income customers in Mississippi who are considering installing a net-metered system. In addition to the 2.5 cents per kWh adder discussed above and avoided costs, a qualifying low-income customer receives an additional 2.0 cents per kWh for any excess energy delivered to the grid as measured through Channel 2 of the meter, for a period of 15 years. Customers receiving the adder also have to transfer any Renewable Energy Credits to the electric utility.

[119] *See* HECO website: https://www.hawaiianelectric.com/clean-energy-hawaii/producing-clean-energy/customer-self-supply-and-grid-supply-programs.

[120] *See* Final Order dated December 3, 2015 adopting the Mississippi Renewable Energy Net Metering Rule and the Mississippi Distributed Generator Interconnection Rule, Docket No. 2011-AD-2. *See also* Final Order effective August 29, 2016 adopting Entergy Mississippi, Inc.'s Net Energy Metering Rider Schedule NEM-1 (Revised), Docket No. 2016-UN-32.

Nevada

Net-metering policy revisions in the state of Nevada resulted, in part, from two studies performed by Energy + Environmental Economics, Inc. (E3). An initial study performed by E3 in 2014 was updated in 2016 and the newer study found that Nevada customers with DG served under a net-metering tariff will impose an annual net cost on customers without net-metering systems of $36-$43 million from 2017 to 2046. This cost shift occurs because DG customers served under net metering tariffs do not pay the full cost for the services they obtain from the utility.[121]

The Public Utilities Commission of Nevada (PUCN) went further than simply adopting the 2-Channel Billing framework; it also took steps to make more fundamental rate design changes including increasing the fixed monthly charge while correspondingly decreasing the volumetric-based energy charges. Those additional changes were to be phased-in over 12 years. The PUCN did not initially "grandfather" pre-existing net-metering customers from the various changes, although that decision was eventually rescinded so that pre-existing net-metering customers in Nevada were ultimately grandfathered.

In June 2017, the Nevada state legislature voted to pass Assembly Bill 405 aimed at restoring the credit rate for excess energy closer to, but still less than, the full retail rate for new net-metering customers. The legislation made other changes to existing policy as well including mandating that net-metering customers not be put into a separate rate class and reversing the phased-in rate structure changes involving higher

[121] The major reasons for the reversal in net benefits to net costs between this study and a 2014 study in Nevada include natural gas price declines, utility-scale solar cost declines and their effect on Renewable Portfolio Standard requirements, and updated data from the two investor-owned utilities in Nevada: Nevada Power (covering southern Nevada) and Sierra Pacific Power (covering northern Nevada). *See* E3 *Nevada Net Energy Metering Impacts Evaluation 2016 Update*, August 17, 2016.

fixed and lower volumetric charges that were put in place earlier. The legislation also mandated that the credit residential customers receive for excess energy they export to the grid will be on a declining, sliding scale tied to the prevailing retail electricity rate.[122] In accordance with Assembly Bill 405, for the first 80 MW of new installations after the law takes effect, customers will be credited at 95% of the retail rate, decreasing in 7% steps tied to 80 MW "tiers" and eventually reaching 75% of the retail rate after the final tier of new DG capacity is added across Nevada.

NV Energy made a compliance filing regarding how their two electric utilities proposed to comply with Assembly Bill 405 that drew immediate criticism from solar advocates. Most recently, the PUCN issued a draft order on August 31, 2017, providing specific directions to NV Energy's two electric utilities to come into compliance with Assembly Bill 405.[123] Most notably, the PUCN draft order requires NV Energy to modify its net-metering billing to allow intra-month netting in lieu of the current practice which follows 2-Channel Billing. In other words, if a net-metering customer produces less electricity than they consume in a given billing period, the customer will receive a full retail rate credit for the kWhs delivered to the grid as recorded on Channel 2. It is only in the scenario where the net-metering customer produces more electricity than consumed on a monthly basis (Channel 2 is greater than Channel 1) that the customer receive a less than full retail rate credit.

[122] *See* AB405, https://www.leg.state.nv.us/App/NELIS/REL/79th2017/Bill/5487/Overview
[123] PUCN Docket No. 17-07026, Order Granting in Part and Denying in Part Joint Application by NV Energy on Assembly Bill 405, August 31, 2017.

Arizona

As another state with a high penetration of net-metering customers, Arizona has been working to address the issues that arise from net-metering policies for more than 5 years. Most recently, the Arizona Corporation Commission (ACC) undertook a rulemaking to set the framework for addressing the issues that arise from net-metering policy.[124] On January 3, 2017, the ACC issued an order that eliminated the 1:1 full retail credit policy for new net-metering systems and replaced it with a 2-Channel Billing framework where excess energy delivered to the utility would be credited based on a five-year weighted average price of utility-scale solar power purchase agreements (PPAs).[125] The order required the initial excess energy rate to be set in pending utility rate cases, and indicated an avoided cost-based methodology could provide the basis for the credit in the future.

In August 2017, a Settlement Agreement was approved by the ACC in Arizona Public Service Company's (APS') rate case that set the initial rate for new rooftop distributed net-metering customers at $0.129/kWh.[126] This credit rate for excess generation may decrease by up to 10% per year until such time that the credit rate is equal to the average cost of utility-scale PPAs into which APS has entered. This will ensure that, once that level is reached, DG customers will not be credited at rates such that it forces the utility to acquire power at costs above those for a similar resource (larger-scale solar). The Settlement Agreement also offers customers who add DG systems after a specific date a limited selection between time-of-use (TOU) and other

[124] ACC Docket No. E-00000J-14-0023, Initiated on January 24, 2014.
[125] *See* December 20, 2016 Amendment, ACC Docket No. E-00000J-14-0023.
[126] *See* March 1, 2017 Settlement Term Sheet, ACC Docket No. E-01345A-0036/ Docket No. E-01345A-0123.

demand-based rate options. The Settlement Agreement grandfathered existing solar customers for 20 years under the previous net-metering policy.[127]

Tucson Electric Power (TEP) has also proposed to change the value for excess energy sent to the grid by new net-metering customers.[128] In accordance with the ACC's decision described above, TEP will determine its credit rate for excess energy delivered to the utility and measured through Channel 2 of the meter within its pending rate case. TEP has proposed the initial excess energy credit rate for new rooftop solar net-metering customers be set at $0.0973/kWh based upon market prices for solar power over the last five years. TEP has also proposed that future net-metering customers choose between two new rate options that incorporate TOU energy pricing coupled with either a grid access charge or demand charge.

Phase 1 of TEP's rate case closed in February 2017, while Phase 2 is ongoing and will address the excess energy credit rate.[129] UniSource Energy Systems, a separate utility in Arizona that is operated by the same parent company as TEP, has proposed similar changes for new net-metering customers within an open rate case that is also still pending ACC approval.[130]

California

The California legislature passed a bill (AB 327) in 2013 requiring the California Public Utilities Commission (CPUC) to study "who benefits, and who bears the

[127] ACC Docket No. E-01345A-16-0036 AND E-01345A-16-0123, Recommendation of Assistant Chief ALJ Teena Jibilian, July 26, 2017; https://ofchq.snl.com/Cache/B0E4A340AE389633061.PDF?Y=&CachePath=%5c%5cdmzdoc1%5cwebcache%24%5c&O=PDF&D=&T=&reqFrom=SNL3

[128] ACC Docket No. E-01933A-15-0322, Application originally filed November 5, 2015. *See also*: https://www.tep.com/proposed-pricing-for-new-solar-customers/

[129] ACC Docket No. E-01933A-15-0239 AND Docket No. E-01933A-15-0322, Decision No. 75975 February 24, 2017; http://docket.images.azcc.gov/0000177572.pdf

[130] ACC Docket No. E-004204A-15-0142, Application originally filed May 5, 2015.

economic burden, if any, of the net energy metering program." The CPUC initiated a study, which was conducted by E3 on behalf of the CPUC. The E3 study estimated that because the current net-metering rates do not recover the costs of serving the net-metering customers from those customers, by 2020, approximately $1.1 billion would be shifted annually from net-metering customers to non-net-metering customers if California's current practices (and rate structures) remain unchanged.[131]

In conjunction with AB 327, in order to address the identified issues associated with their existing net-metering policy, Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) each proposed different successor policies in a CPUC Rulemaking (R. 14-07-002). The proposals from these three California investor-owned utilities varied, but each utility incorporated minimum bill charges, grid access charges, and changes to the credit for excess energy delivered to the grid from net-metering customers to help mitigate the subsidy that is imposed upon customers without DG systems. Other stakeholders including solar advocates, consumer advocates, etc. proposed alternative approaches and successor tariffs to the CPUC. The CPUC eventually adopted a net-metering successor tariff that continues the existing net-metering structure with some adjustments for new NEM customers (existing customers are grandfathered under previous net-metering rules). New elements to the successor tariff, referred to as Net Energy Metering (NEM) 2.0, relate to non-by-passable charges and time-of-use rates. Under the new tariff, net-metering customers must pay certain non-by-passable charges on each kilowatt-hour (kWh) of electricity they consume from the grid equivalent to approximately 2-3 cents

[131] Energy + Environmental Economics, Inc., *California Net Energy Metering Ratepayer Impacts Evaluation*, October 28, 2013.

per kWh.[132] In addition, pre-existing residential NEM customers are required to take service on a TOU rate once DG capacity caps are reached for each investor owned utility in California. As of June 1, 2017 all three major investor owned utilities had reached their prescribed cap.[133]

The new tariff did not impose any demand charges, grid access charges, installed capacity fees, standby fees, or similar fixed charges on residential net-metering customers, at least for the purposes of this version of the net-metering successor tariff, although the CPUC committed to revisit the issues again in 2019. At that time, the CPUC will consider further adjustments to its net-metering tariff, including an energy export credit rate for net-metering tariff customers, taking into account values differentiated by the time solar energy is produced and locations of solar net-metering systems from which the energy is exported onto the grid.[134]

The CPUC successor tariff decision was not unanimous, but rather a split 3-2 vote. One of the dissenting Commissioners (Michael Florio) included the following statement in his dissent:

> *I respectfully disagree with the majority of my colleagues on this decision adopting a Net Energy Metering Successor Tariff … My reasoning is as follows. First, I think there is sometimes a misconception that somehow the Investor Owned Utilities are paying whatever Net Energy Metering customers receive for their solar generation. This is not correct; the utilities are just a conduit. Other customers – the people who do not or even cannot have solar – pay the compensation that the Net Energy Metering customers receive … Going forward, I favor a compensation*

[132] In California, all utility customers, except grandfathered NEM customers, pay non-bypassable charges on all energy they consume from the grid. Grandfathered NEM customers only pay on usage from the grid after NEM exports are subtracted. For more information regarding the CPUC NEM successor tariff and proceeding, see here: http://www.cpuc.ca.gov/General.aspx?id=3934

[133] CPUC Net Energy Metering Informational page: http://www.cpuc.ca.gov/General.aspx?id=3800.

[134] *See* pgs. 60-61 of CPUC Decision 16-01-044, Decision Adopting Successor to Net Energy Metering Tariff, 2/5/2016. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf

> *structure that reflects the value of exported generation. Participating customers should be compensated at the retail rate for generation consumed on site. Exports should be compensated in a way that reflects their value, which should at minimum be differentiated by time and location…*[135]

The California utilities' NEM successor tariffs were approved with modification on June 23, 2016 and are currently in effect in SDG&E, PG&E, and SCE's service territories.[136]

Maine

Maine is a restructured state with unbundled generation (procured in the wholesale market pursuant to competitive contracts for default service customers) and transmission and distribution rates regulated by the Maine Public Utilities Commission (MPUC). In March 2017, the MPUC issued an order[137] that amended the current net-metering policy to reflect a "buy-all, sell-all" crediting structure, which is fundamentally different than 2-Channel Billing. The MPUC's rule requires the utility to install a separate meter at the customer's expense. In Maine, "nettable energy" is defined as the entire amount of energy generated by the customer's system, including the amount ordinarily consumed by the customer behind the meter, minus the amount of energy consumed by the customer from the utility. Each year until December 31, 2026, a new customer will receive a credit equal to 100% of the applicable generation supply charge and a decreasing credit for the transmission and distribution (T&D) charges. The T&D credit will decrease by 10% per year for a 10-year period. Customers are grandfathered for a 15-year period after they are connected. The gradual reduction in nettable energy will

[135] Dissent of Commissioner Michel P. Florio on CPUC Decision 16-01-044, Adopting a Net Energy Metering Successor Tariff, 2/3/2016.
[136] *See* Resolution E-4792, Decision 16-01-044, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K978/163978119.PDF
[137] March 1, 2017 Order, Maine PUC Docket No, 2016-00222.

begin for new customers with net-metering facility in-service dates beginning on January 1, 2018.[138]

New Hampshire

The New Hampshire Public Utilities Commission (NH PUC) recently established new net-metering rules that will become effective September 1, 2017.[139] As part of that process, the NH PUC denied utilities' (plus other stakeholders) proposal for a 2-Channel Billing framework when deciding that intra-month netting should be maintained. All new net-metering systems installed after the new rules begin must pay non-by-passable charges (e.g., system benefits, stranded cost recovery) based on the full amount of electricity the customer uses (Channel 1) without netting any excess energy delivered to the grid (Channel 2). Under the new rules, small net-metering systems ≤ 100 kW will receive a 1:1 intra-month credit. Any excess kWh balance remaining at the end of the month will receive a lower credit based on 100% of retail energy and transmission charges, but only 25% of applicable distribution charges.

It should be noted that New Hampshire is a restructured state with customer choice in which utility costs have been unbundled into generation, transmission, distribution, etc. Larger net-metering systems >100kW are still credited for monthly excess at the default energy rate. As applicable, a new net-metering customer will receive a monetary bill credit instead of a kWh credit (the new rules allow a cash payment if the customer moves and closes their account or the annual credit balance exceeds $100). The NH PUC decision also eliminated the existing statewide net-metering cap of 100 MW. Utilities will also have the opportunity to estimate and recover

[138] *See* http://programs.dsireusa.org/system/program/detail/280. It should be noted that the Maine Legislature's attempt to amend the MPUC's net metering rules was not adopted.
[139] New Hampshire June 23, 2017 Order 26,029, Docket # DE 16-576.

total lost revenues attributable to net-metering customers pursuant to the mechanism and process approved in Order No. 25,991 in Docket DE 15-147 dated February 21, 2017. Finally, existing net-metering systems will be grandfathered under the current full 1:1 retail credit framework through 2040, while any new net-metering systems installed after September 1, 2017, will be grandfathered under the new rate structure through 2040 as well.

Indiana

In May 2017, Indiana Governor Eric Holcomb signed Senate Bill (SB) 209 which phases out 1:1 full retail net-metering in the state effective July 1, 2017.[140] SB 309 allows residential customers and small businesses that have already installed solar panels or other renewable energy net-metering systems before the end of 2017 to be credited at the full retail rate for their excess energy for another 30 years. Customers who install net-metering facilities within the next five years will receive the full retail rate for any excess energy until 2032. Afterwards, a customer who installs distributed generation after 2022 will receive credit for excess energy at a lower rate that reflects a 25% premium above the prevailing wholesale value of energy. Finally, customer-owned net-metered systems are not allowed to be sized larger than 1 MW nameplate capacity.

Massachusetts

Massachusetts adopted a statutory mandate to reform net-metering that will reduce the full retail rate credit given to solar customers. On April 11, 2016, Governor Baker signed into law Chapter 75 of the Acts of 2016, An Act Relative to Solar Energy (Solar

[140] Indiana Senate Bill No. 309; March 31, 2017.

Act). Among other things, the Solar Act amended General Laws Chapter 164 by adding Section 139(j). The new statutory provision requires electric distribution companies to submit for Commission approval minimum charges that ensure that all distribution company customers contribute to the fixed costs of ensuring the reliability, proper maintenance and safety of the electric distribution system. The statute further requires the minimum charge to recover all reasonably and prudently incurred costs necessary to maintain the reliability, proper maintenance and safety of the electric distribution system. Since the law was passed, the Massachusetts Department of Public Utilities (DPU) determined that distribution companies could submit proposals for minimum charges, that DPU may choose to exempt or lower the threshold for minimum charges applicable to low income customers, and that the new minimum charges should be effective no later than December 31, 2018. [141] In addition, after further activity in the same proceeding, DPU has still not set a minimum charges threshold, but instead ordered each distribution company to individually file a proposal for new minimum charges in a base rate proceeding or revenue-neutral rate proceeding.[142]

Since Massachusetts has unbundled its generation from T&D rates, similar to Maine, the Massachusetts distribution utilities are in the process of submitting tariffs that will require that credit for excess generation from certain net-metering customers to be less than the full distribution service rate.

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[141] Massachusetts Department of Public Utilities, Docket No. 16-64, Order issued on May 11, 2016. *See:* http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=16-64%2f1664_Order_51116.pdf

[142] Massachusetts Department of Public Utilities, Docket No. 16-64, Orders issued on January 13, 2017 and September 8, 2017. *See*: http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=16-64%2f1664E_Order_11317.pdf and http://170.63.40.34/DPU/FileRoomAPI/api/Attachments/Get/?path=16-64%2f1664G_Order_9817.pdf

Vermont

The Vermont Public Service Board recently adopted reforms to its net-metering rule.[143] In this new rule, effective January 1, 2017, all net-metering customers must pay "non-bypassable charges" (and such charges cannot be included in credits for excess generation), which include the customer charge, energy efficiency charge, energy assistance program charge, any on-bill financing payment, and any equipment rental charge.

Review of Cost-Benefit Studies

A number of organizations have undertaken efforts in recent years to research and evaluate the appropriateness of net-metering policies. These efforts include studies that were commissioned or conducted by state regulators and other stakeholders as well as a number of scholarly articles. For example, the 2014 article in *Energy Law Journal* written by David Raskin addresses the failure of the existing structures to recover the costs of serving the net-metering customers from those customers will impose an annual net cost on other non-net-metering customers:

> *It is not necessarily the case . . . that distributed generation owners who remain connected to the grid use less of the other unbundled services. Utilities must be ready to serve the entire customer load whenever a distributed generator is not producing energy, such as during the evening peak and on rainy afternoons…In addition, the variability of solar energy (without adequate storage) may increase the utility's cost to supply balancing services because, as variable energy is added to the system, utilities must invest in or acquire a larger proportion of balancing resources relative to their total load.*
>
> *[T]he cost shifting associated with net-metering will, at some point, become so large that regulatory action will almost certainly be taken to redress the impacts on remaining utility customers. . . . [I]f policymakers wait too long*

[143] The Vermont's newly amended net metering rule is available at: http://psb.vermont.gov/sites/psbnew/files/doc_library/rulemaking-5100-attachment-a-on-reconsideration-08292016.pdf

> *to address the issue, they will face the politically uncomfortable fact that substantial investments in behind-the-meter generation were made in reliance on net-metering, and the politics of fixing the subsidy will be problematic. Existing net metered customers will claim that they relied on the prior rate practice and potential new customers will ask why their neighbors got a better deal than will be available to them."* [144]

As noted above, the failure of a 1:1 full retail credit to recover the costs of serving net-metering customers has been documented in other jurisdictions and in various scholarly articles and studies commissioned to find solutions to the problem. As noted above, E3 found, in a 2016 study, that the failure of the existing structures in Nevada to recover the costs of serving the net-metering customers from those customers will impose an annual net cost on other non-net-metering customers of $36-$43 million from 2017 to 2046.[145]

Similarly, pursuant to a Louisiana Public Service Commission's (LPSC) directive, the Acadian Consulting Group performed a study to quantify the impacts and implications of Louisiana's net-metering policy currently being utilized by the LPSC for smaller-scale residential and commercial solar energy installations.[146] The final report including a lengthy response to critiques of Acadian's February 2015 draft report was released by the LPSC in September 2015; the final report reiterated that the cost-of-service analysis estimated that over $2 million in typical year utility costs of serving net-metering customers were not being recovered from those customers and were being picked up by the non-net-metering customers. This failure to recover the costs of serving net-metering customers from those customers in typical year was estimated to

[144] *Getting Distributed Generation Right: A Response to "Does Disruptive Competition Mean A Death Spiral for Electric Utilities*," Energy Law Journal, December 2014 (Volume 35). See Appendix, Tab 1.
[145] E3 *Nevada Net Energy Metering Impacts Evaluation 2016 Update*, August 17, 2016.
[146] *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers*, Acadian Consulting Group, September 2015.

increase from between $5 million to $31 million in 2020, across all LPSC-jurisdictional utilities, pursuant to two respective solar net-metering installation forecasts. The final report also stated that solar net-metering installations, on average, are estimated to make a 64 percent contribution on average toward recovering the costs of serving those net-metering customers across all LPSC-jurisdictional utilities. Any level below 100 percent indicates that net-metering customers are estimated to pay less than 100 percent of their full cost of service. Under normal utility ratemaking, if the rates paid by the net-metering customers do not recover the cost of serving them, those costs will have to be recovered from other utility customers.

Other studies performed across the United States have yielded similar findings: net-metering customers are not paying rates that recover the costs to serve them as reflected in their respective utility's embedded cost of service.

In a recent proceeding, the staff of the Arizona Commerce Commission noted similar findings.[147] In New York, the NYSERDA 2011 Study estimated the rate impact of displaced distribution cost, and found that the net-metering program will create a direct cross-subsidy of participating net-metering customers by non-net-metering customers of nearly $400 million in 2038, which is the forecasted peak year for energy *production* before projects begin to reach the end of their useful lives.[148] In Massachusetts, the Department of Energy Resources published a 2013 report addressing the economic benefits and costs of the state's solar renewable portfolio

[147] Arizona Commerce Commission, Open Meeting re: Arizona Public Service Company-Application for Approval of Net Metering Cost Shift Solution (Docket No. E-0135A-13-0248). Sept. 30, 2013.
[148] NYSERDA 2011 Study, pgs. 7-4 through 7-5. (The Power New York Act of 2011 directed the New York State Energy Research and Development Authority ("NYSERDA") to conduct a study evaluating the costs and benefits of increasing the State's solar generation capacity to 5,000 MW by 2025.

standard set-aside that has implications for net-metering installations. That study estimated rate impacts of between $500 and $933 million over a 32-year period.[149]

Summary

The information presented in this Appendix demonstrates that numerous other regulators have concluded that the historical practice of crediting net-metering customers for their excess generation delivered to the grid at the full retail rate fails to recover the cost of providing service to those customers. Consequently, those costs will ultimately be recovered from the non-net-metering customers through normal ratemaking procedures. Numerous regulators across the United States are modifying policies for the crediting of excess generation to provide less than a full retail rate credit. To date, these activities have predominantly occurred in states with higher levels of net-metering penetration, as the magnitude of the costs recovered from non-net metering customers required that action be taken. However, while Arkansas does not yet exhibit such high rates of net-metering adoption, now is an appropriate time to adjust crediting mechanisms for excess generation to ensure that as technologies progress, the costs of such technologies are borne by the customers in proportion to the costs they impose on utility systems.

[149] Department of Energy Resources 2013 Study, pg. 17.

Summary of 2 Channel Billing Impact by Utility
(Average Residential Customer with a 5 kW DC Rooftop Solar PV System)

Investor Owned Utilities	Embedded Capacity		Historical Houly LMPs ($/kWh)	Excess Generation Credit ($/kWh)	Average Bill Per Month			Monthly Bill Savings			Effective Value of Solar Generation		
	Generation	Transmission			Typical Bill w/o Solar	Current NEM Rules	2 Channel Billing	Under Current NEM Rules	Under 2 Channel Billing	Difference between Current NEM Rules and 2 Ch. Billing	Under Current NEM Rules ($/kWh)	Under 2 Channel Billing ($/kWh)	Effective % of Retail Rates Compensated Under 2 Ch. Billing
Entergy	54%	36%	$0.028	$0.055	$129	$68	$77	$61	$53	$9	$0.108	$0.091	84%
SWEPCO	33%	26%	$0.023	$0.032	$115	$59	$71	$56	$45	$11	$0.096	$0.075	78%
OG&E	33%	26%	$0.023	$0.034	$117	$62	$73	$55	$44	$11	$0.096	$0.075	79%
Empire	38%	34%	$0.023	$0.044	$122	$65	$75	$57	$47	$11	$0.099	$0.081	82%
Average:	**40%**	**31%**	**$0.024**	**$0.041**	**$121**	**$63**	**$74**	**$57**	**$47**	**$10**	**$0.100**	**$0.081**	**81%**

Cooperatives	Embedded Capacity		Historical Houly LMPs ($/kWh)	Excess Generation Credit ($/kWh)	Average Bill Per Month			Monthly Bill Savings			Effective Value of Solar Generation		
	Generation	Transmission			Typical Bill w/o Solar	Current NEM Rules	2 Channel Billing	Under Current NEM Rules	Under 2 Channel Billing	Difference between Current NEM Rules and 2 Ch. Billing	Under Current NEM Rules ($/kWh)	Under 2 Channel Billing ($/kWh)	Effective % of Retail Rates Compensated Under 2 Ch. Billing
Arkansas Valley	33%	22%	$0.026	$0.036	$137	$79	$92	$58	$45	$13	$0.109	$0.085	78%
Ashley-Chicot	33%	33%	$0.026	$0.038	$146	$85	$99	$61	$47	$14	$0.116	$0.090	78%
C&L	33%	22%	$0.026	$0.038	$143	$79	$93	$64	$50	$14	$0.115	$0.090	78%
Carroll	33%	22%	$0.026	$0.037	$122	$66	$76	$56	$45	$11	$0.098	$0.078	80%
Clay County	33%	22%	$0.026	$0.038	$159	$87	$102	$72	$56	$16	$0.126	$0.097	77%
Craighead	33%	33%	$0.026	$0.036	$125	$70	$80	$55	$45	$10	$0.097	$0.077	79%
Farmers	33%	33%	$0.026	$0.038	$147	$78	$93	$69	$54	$15	$0.122	$0.094	77%
First Electric	33%	22%	$0.026	$0.036	$121	$69	$80	$52	$41	$11	$0.091	$0.073	80%
Mississippi County	33%	22%	$0.026	$0.036	$96	$53	$59	$44	$37	$7	$0.081	$0.066	82%
North Arkansas	33%	22%	$0.026	$0.037	$145	$82	$95	$62	$49	$13	$0.112	$0.087	78%
Ouachita	33%	22%	$0.026	$0.035	$126	$71	$83	$55	$44	$12	$0.095	$0.075	79%
Ozarks	33%	22%	$0.026	$0.034	$117	$67	$77	$49	$40	$10	$0.085	$0.068	80%
Petit Jean	33%	22%	$0.026	$0.038	$133	$73	$84	$60	$48	$12	$0.106	$0.084	79%
Rich Mountain	33%	22%	$0.026	$0.039	$143	$80	$93	$63	$50	$13	$0.115	$0.090	78%
South Central	33%	33%	$0.026	$0.037	$144	$80	$93	$64	$51	$13	$0.113	$0.088	78%
Southwest Arkansas	33%	22%	$0.026	$0.038	$137	$74	$87	$63	$49	$14	$0.115	$0.090	78%
Woodruff	33%	22%	$0.026	$0.036	$135	$75	$88	$59	$46	$13	$0.108	$0.084	78%
Average:	**33%**	**25%**	**$0.026**	**$0.037**	**$134**	**$75**	**$87**	**$59**	**$47**	**$12**	**$0.106**	**$0.083**	**79%**

Notes:
Excess Generation Credit: represents the credit rate per kWh applied to the kWh measured on channel 2.
Typical Bill w/o Solar: represents a customer's bill without a solar PV net-metering system.
Current NEM Rules: represents a solar customer's bill under the current full retail rate credit net-metering policy.
2 Channel Billing: represents a solar customer's bill under Sub-Groups 2's proposed excess generation credit rate methodology.

ARKANSAS
PUBLIC SERVICE COMMISSION

NET-METERING RULES

Last Revised: March xx, 2017
Order No. xx
Docket No. 16-027-R
Effective : xx-xx-2017

NET-METERING RULES
ADMINISTRATIVE HISTORY

Docket	Date	Order No.	Subject Matter of Docket/ Order
02-046-R	07/26/02	4	Adopted rules relating to the terms and conditions of – Net-Metering.
06-105-U	11/27/07	8	Amended definitions; Rules 1.02, 2.01, and 2.04; Section 1 of the Standard Interconnection Agreement, Appendix A; and X.1.1, X.2.3, and X.2.4 of the Net-Metering Tariff, Appendix B.
	11/29/07	10	Amended Rule 4.02 to delete reference to Docket No. 86-033-A.
	11/30/07	11	Amended the Standard Interconnection Agreement, Appendix A to add e-mail address lines to the signature block.
	12/19/07	12	Errata order correcting clerical errors in the amendments adopted in Order No. 8.
12-001-R	06/15/12	6	Amended Section 7 of the Standard Interconnection Agreement, Appendix A to exempt state governmental agencies and entities, local governmental entities, and federal entities from the indemnity requirement.
12-060-R	09/03/13	7	Amended Rule 2.04 to provide for meter aggregation, incorporated the provisions of Act 1221 of 2013 concerning the carryover of net-metering credits, and added a definition of Net-Metering Customer to track the definition in Ark. Code Ann. § 23-18-603.
	10/11/13	10	Updated the Net-Metering Tariff to reflect the amendments adopted in Order No. 7.
16-027-R	xx/xx/17	XX	Revised Rules to comply with Act 827 of 2015.

NET-METERING RULES

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SECTION 1. GENERAL PROVISIONS

Rule 1.01 Definitions

The following definitions shall apply throughout the Net-Metering Rules (NMRs) except as otherwise required by the context, and any references to the NMRs shall include these definitions:

(a) 2-Channel Billing

A billing framework for a Net-Metering Customer that measures the energy delivered by the utility and consumed by the customer (as recorded on Channel 1 of the meter) and the excess, self-generated energy exported to the electric grid (as recorded on Channel 2 of the meter).

(b) Additional Meter

A meter associated with the Net-Metering Customer's account that the Net-Metering Customer may credit with Net Excess Generation Credits from the Generation Meter. Additional Meter(s): 1) shall be under common ownership within a single Electric Utility's service area; 2) shall be used to measure the Net-Metering Customer's requirements for electricity; 3) may be in a different class of service than the Generation Meter; 4) shall be assigned to one, and only one, Generation Meter; 5) shall not be a Generation Meter; and 6) shall not be associated with unmetered service.

(c) Annual Billing Cycle

The normal annual fiscal accounting period used by the utility.

(d) Avoided Costs

As defined in Ark. Code Ann. § 23-18-604(c).

(e) Billing Period

The billing period for net-metering will be the same as the billing period under the customer's applicable standard rate schedule.

~~**(e) Biomass Resource**~~

~~A resource that may use one or more organic fuel sources that can either be processed into synthetic fuels or burned directly to produce steam or electricity, provided that the resources are renewable, environmentally sustainable in their production and use, and the process of conversion to electricity results in a net environmental benefit. This includes, but is not limited to, dedicated energy crops and trees, agricultural food and feed crops, agricultural crop wastes and residues, wood wastes and residues, aquatic plants, animal wastes, and other accepted organic, renewable waste materials.~~

(f) Channel 1

The channel of the meter which measures the energy in kWhs delivered to a Net-Metering Customer by the Electric Utility.

(g) Channel 2

The channel of the meter that measures the excess, self-generated energy in kWhs exported to the electric grid.

(h) Channel 2 Excess Generation

The excess, self-generated energy exported to the electric grid and measured in kWhs on Channel 2 during a Billing Period. Channel 2 Excess Generation during a Billing Period that is not credited to the Net-Metering Customer's Generation Meter account within that Billing Period is carried forward as Net Excess Generation Credits.

(i) Commission

The Arkansas Public Service Commission.

(j) Electric Utility

A public or investor-owned utility, an electric cooperative, municipal utility, or any private power supplier or marketer that is engaged in the business of supplying electric energy to the ultimate customer or any customer class within the state.

~~(h) Fuel Cell Resource~~

~~A resource that converts the chemical energy of a fuel directly to direct current electricity without intermediate combustion or thermal cycles.~~

(k) Generation Meter

The meter associated with the Net-Metering Customer's account to which the Net-Metering Facility is physically attached.

~~(j) Geothermal Resource~~

~~A resource in which the prime mover is a steam turbine. The steam is generated in the earth by heat from the earth's magma.~~

~~(k) Hydroelectric Resource~~

~~A resource in which the prime mover is a water wheel. The water wheel is driven by falling water.~~

~~(l) Micro Turbine Resource~~

~~A resource that uses a small combustion turbine to produce electricity.~~

(l) Net Excess Generation

As defined in Ark. Code Ann. § 23-18-603(3).

(m) Net Excess Generation Credits

Uncredited customer generated kilowatt hours remaining in a Net-Metering Customer's account at the close of a Billing Period to be credited, or, pursuant to Rule 2.0~~5~~7, purchased by the utility in a future billing period.

(n) Net-Metering

As defined in Ark. Code Ann. § 23-18-603(4).

(o) Net-Metering Customer

As defined in Ark. Code Ann. § 23-18-603(5).

(p) Net-Metering Facility

As defined in Ark. Code Ann. § 23-18-603(6).

(q) Parallel Operation

The operation of on-site generation by a customer while the customer is connected to the Electric Utility's distribution system.

~~(s) Qualifying Facility~~

~~As defined in Ark. Code Ann. § 23-3-702(4).~~

(r) Renewable Energy Credit
As defined in Ark. Code Ann. § 23-18-603(7).

(s) Residential Use
Service provided under an Electric Utility's standard rate schedules applicable to residential service.

~~**(v) Solar Resource**~~
~~A resource in which electricity is generated through the collection, transfer and/or storage of the sun's heat or light.~~

~~**(w) Wind Resource**~~
~~A resource in which an electric generator is powered by a wind-driven turbine.~~

Rule 1.02 Purpose

The purpose of these Net-Metering Rules is to establish rules for net energy metering and interconnection.

Rule 1.03 Statutory Provisions

A. These Rules are developed pursuant to the Arkansas Renewable Energy Development Act of 2001 (Ark. Code Ann. § 23-18-601 *et seq.* as amended.)

B. These Rules are promulgated pursuant to the Commission's authority under Ark. Code Ann. §§ 23-2-301, 23-2-304(a)(3), and 23-2-305.

C. Nothing in these Rules shall govern, limit, or restrict the Commission's authority under Ark. Code Ann. § 23-18-604.

Rule 1.04 Other Provisions

A. These Rules apply to all Electric Utilities, as defined in these Rules, that are jurisdictional to the Commission.

B. The Net-Metering Rules are not intended to, and do not affect or replace any Commission approved general service regulation, policy, procedure, rule, or service application of any utility which addresses items other than those covered in these Rules.

C. Net-Metering Customers taking service under the provisions of the Net-Metering Tariff may not simultaneously take service under the provisions of any other alternative source generation or cogeneration tariffs except as provided herein.

SECTION 2. NET-METERING REQUIREMENTS

Rule 2.01 Electric Utility Requirements

An Electric Utility shall allow Net-Metering Facilities to be interconnected using a standard meter capable of registering the flow of electricity in two (2) directions.

Rule 2.02 Metering Requirements

A. Metering equipment shall be installed to both accurately measure the electricity supplied by the Electric Utility to each Net-Metering Customer and also to accurately measure the electricity generated by each Net-Metering Customer that is fed back to the Electric Utility over the applicable Billing Period. If nonstandard metering equipment is required, the customer is responsible for the cost differential between the required metering equipment and the utility's standard metering equipment for the customer's current rate schedule.

B. Accuracy requirements for a meter operating in both forward and reverse registration modes shall be as defined in the Commission's Special Rules - Electric. A test to determine compliance with this accuracy requirement shall be made by the Electric Utility either before or at the time the Net-Metering Facility is placed in operation in accordance with these Rules.

Rule 2.03 New or Additional Charges

Any new or additional charge which would increase a Net-Metering Customer's costs beyond those of other customers in the rate class shall be filed by the Electric Utility with the Commission for approval. The filing shall be supported by the cost/benefit analysis described in Ark. Code Ann. § 23-18-604(b)(2).

Rule 2.04 Billing for Grandfathered Net-Metering Customers Pursuant to Appendix D

A. On a monthly basis, the Net-Metering Customer shall be billed the charges applicable under the currently effective standard rate schedule and any appropriate rider schedules. Under Net-Metering, only the kilowatt hour (kWh) units of a customer's bill are netted.

B. If the kWhs supplied by the Electric Utility exceeds the kWhs generated by the Net- Metering Facility and fed back to the Electric Utility during the Billing Period, the Net-Metering Customer shall be billed for the net kWhs supplied by the Electric Utility in accordance with the rates and charges under the customer's standard rate schedule and any appropriate rider schedules.

C. If the kWhs generated by the Net-Metering Facility and fed back to the Electric Utility exceed the kWhs supplied by the Electric Utility to the Net-Metering Customer during the applicable Billing Period, the utility shall credit the Net-Metering Customer with any accumulated Net Excess Generation in the next applicable Billing Period.

~~i. Net Excess Generation shall first be credited to the Net-Metering Customer's Generation Meter.~~

~~ii. After application of subdivision D.1. and upon request of the Net-Metering Customer pursuant to subsection E., any remaining Net Excess Generation shall be credited to one or more of the Net-Metering Customer's Additional Meters in the rank order provided by the customer.~~

~~iii. Net Excess Generation shall be credited as described in subdivisions (D)(1) and (D)(2) during subsequent Billing Periods. Net Excess Generation Credits remaining in a Net-Metering Customer's account at the close of a Billing Period shall not expire and shall be carried forward to subsequent Billing Periods indefinitely.~~

~~a. For Net Excess Generation Credits older than 24 months, a Net-Metering Customer may elect to have the Electric Utility purchase the Net Excess Generation Credits in the Net-Metering Customer's account at the Electric Utility's estimated annual average Avoided Cost rate for wholesale energy if the sum to be paid to the Net-Metering Customer is at least $100~~

~~b. An Electric Utility shall purchase at the Electric Utility's estimated annual average Avoided Cost rate for wholesale energy any Net Excess Generation Credits remaining in a Net-Metering Customer's account when the Net-Metering Customer:~~

~~i. ceases to be a customer of the Electric Utility;~~

~~ii. ceases to operate the Net-Metering Facility; or~~

~~iii. transfers the Net-Metering Facility to another person..~~

~~iv. When purchasing Net Excess Generation Credits from a Net-Metering Customer, the Electric Utility shall calculate the payment based on its~~

~~annual average avoided energy costs in the applicable Regional Transmission Organization for the current calendar year.~~

~~D. Upon request from a Net-Metering Customer, an Electric Utility must apply Net Excess Generation to the Net-Metering Customer's Additional Meters provided that:~~

~~1. The Net-Metering Customer must give at least 30 days' notice to the Electric Utility of its request to apply Net Excess Generation to the Additional Meter(s).~~

~~2. The Additional Meter(s) must be identified at the time of the request.~~

~~3. In the event that more than one of the Net-Metering Customer's Additional Meters is identified, the Net-Metering Customer must designate the rank order for the Additional Meters to which Net Excess Generation is to be applied. The Net-Metering Customer cannot designate the rank order more than once during the Annual Billing Cycle.~~

~~E. Any Renewable Energy Credit created as a result of electricity supplied by a Net-Metering Customer is the property of the Net-Metering Customer that generated the Renewable Energy Credit.~~

Rule 2.05 Billing for Net-Metering Customers Pursuant to Appendix E - X.2. Monthly 2-Channel Billing

A. On a monthly basis, the Net-Metering Customer shall be billed the charges applicable under the currently effective standard rate schedule and any appropriate rider schedules for all kWhs supplied to the Net-Metering Customer by the Electric Utility measured through Channel 1.

B. If the kWhs supplied by the Electric Utility as measured on Channel 1 exceed the customer's Channel 2 Excess Generation, including any Net Excess Generation Credits, all Channel 2 Excess Generation, including any Net Excess Generation Credits, shall be credited at the rate established by the Excess Generation Credit Rider.

C. If the customer's Channel 2 Excess Generation, including any Net Excess Generation Credits, exceeds the kWhs supplied by the Electric Utility as measured on Channel 1, then the Channel 2 Excess Generation, including any Net Excess Generation Credits, not to exceed the kWhs measured on Channel 1 during the Billing Period, shall be credited to the customer's account at the rate established by the Excess Generation Credit Rider.

Rule 2.06 Billing for Net-Metering Customers Pursuant to Appendix E - X.3. Monthly Billing for Demand Metered Tariffs

A. On a monthly basis, a Net-Metering Customer taking service under a Demand Metered Tariff shall be billed the charges applicable under the currently effective standard rate schedule and any appropriate rider schedules. For Demand Metered Tariffs, only the kWh units of a customer's bill are netted.

B. If the kWhs supplied by the Electric Utility exceed the kWhs generated by the Net-Metering Facility and fed back to the Electric Utility during the Billing Period, the Net-Metering Customer shall be billed for the net kWhs supplied by the Electric Utility in accordance with the rates and charges under the customer's standard rate schedule.

C. If the kWhs generated by the Net-Metering Facility and fed back to the Electric Utility exceed the kWhs supplied by the Electric Utility to the Net-Metering Customer during the applicable Billing Period, the utility shall credit the Net-Metering Customer with any accumulated Net Excess Generation in the next applicable Billing Period.

Rule 2.07 Net Excess Generation Credits

A. Net Excess Generation Credits remaining in a Net-Metering Customer's account at the close of a Billing Period shall not expire and shall be carried forward to subsequent Billing Periods indefinitely.

B. For Net Excess Generation Credits older than 24 months, a Net-Metering Customer may elect to have the Electric Utility purchase the Net Excess Generation Credits in the Net-Metering Customer's account at the Electric Utility's estimated annual average Avoided Cost rate for wholesale energy if the sum to be paid to the Net-Metering Customer is at least $100.

C. An Electric Utility shall purchase, at the Electric Utility's estimated annual average Avoided Cost rate for wholesale energy, any Net Excess Generation Credits remaining in a Net-Metering Customer's account when the Net-Metering Customer:

i. ceases to be a customer of the Electric Utility;

ii. ceases to operate the Net-Metering Facility; or

iii. transfers the Net-Metering Facility to another person.

D. When purchasing Net Excess Generation Credits from a Net-Metering Customer, the Electric Utility shall calculate the payment based on its annual average avoided energy costs in the applicable Regional Transmission Organization for the current calendar year.

Rule 2.08 Renewable Energy Credit

Any Renewable Energy Credit created as a result of electricity supplied by a Net-Metering Customer is the property of the Net-Metering Customer that generated the Renewable Energy Credit.

Rule 2.09 Additional Meters

A. Upon request from a Net-Metering Customer, an Electric Utility must apply Net Excess Generation Credits to the Net-Metering Customer's Additional Meters provided that:

1. The Net-Metering Customer must give at least 30 days' notice to the Electric Utility of its request to apply Channel 2 Excess Generation to the Additional Meter(s).

2. The Additional Meter(s) must be identified at the time of the request.

3. In the event that more than one of the Net-Metering Customer's Additional Meters is identified, the Net-Metering Customer must designate the rank order for the Additional Meters to which Net Excess Generation Credits are to be applied. The Net-Metering Customer cannot designate the rank order more than once during the Annual Billing Cycle.

B. Net Excess Generation Credits shall be credited to one or more of the Net-Metering Customer's Additional Meters in the rank order provided by the customer at the rate established by the applicable tariffs attached to these Rules.

Rule 2.~~5~~10 Application to Exceed Generating Capacity Limit

A. A Net-Metering Customer shall file an application with the Commission seeking approval to install a Net-Metering Facility with a generating capacity of more than 300 kW for non-residential use under Ark. Code Ann. §§ 23-18-604(b) (5) or (7) as appropriate.

B. The application shall be filed in conformance with Section 3 of the Commission's Rules of Practice and Procedure and shall, at a minimum, include:

1. Evidence that the Net-Metering Facility in excess of 300 kW satisfies the requirements of Ark. Code Ann. §§ 23-18-604(b)(5) or (7):

2. A description of the proposed Net-Metering Facility including:

   a. Project proposal;

   b. Project location (street address, town, utility service area);

   c. Generator type (wind, solar, hydro, etc.);

   d. Generator rating in kW (DC or AC);

   e. Capacity factor;

   f. Point of interconnection with the Electric Utility;

   g. Single Phase or Three Phase interconnection;

   h. Planned method of interconnection consistent with Rule 3.01.B.;

   i. Expected facility performance calculated using an industry recognized simulation model (PVWatts, etc.);

3. Evidence that the electrical energy produced by the Net-Metering Facility is not intended to exceed the amount necessary to offset part or all of the Net-Metering Customer requirements for electricity in the form of:

   a. The monthly electric bills for the 12 months prior to the application for the Generation Meter and Additional Meter(s), if any, to be credited with Channel 2 Excess Generation and Net Excess Generation, or

   b. In the absence of historical data reasonable estimates for the class and character of service may be made; and

4. A copy of the Preliminary Interconnection Review Request submitted to the Electric Utility and the results of the utility's interconnection site review conducted pursuant to Rule 3.03.

SECTION 3. INTERCONNECTION OF NET- METERING FACILITIES TO EXISTING ELECTRIC POWER SYSTEMS

Rule 3.01 Requirements for Initial Interconnection of a Net-Metering Facility

A. A Net-Metering customer shall execute a Standard Interconnection Agreement for Net-Metering Facilities (Appendix A) prior to interconnection with the utility's facilities.

B. A Net-Metering Facility shall be capable of operating in parallel and safely commencing the delivery of power into the utility system at a single point of interconnection. To prevent a Net-Metering Customer from back-feeding a de-energized line, a Net-Metering Facility shall have a visibly open, lockable, manual disconnect switch which is accessible by the Electric Utility and clearly labeled. This requirement for a manual disconnect switch shall be waived if the following three conditions are met: 1) The inverter equipment must be designed to shut down or disconnect and cannot be manually overridden by the customer upon loss of utility service; 2) The inverter must be warranted by the manufacturer to shut down or disconnect upon loss of utility service; and 3) The inverter must be properly installed and operated, and inspected and/or tested by utility personnel.

C. The customer shall submit a Standard Interconnection Agreement to the Electric Utility at least thirty (30) days prior to the date the customer intends to interconnect the Net-Metering Facilities to the utility's facilities. Part I, Standard Information, Sections 1 through 4 of the Standard Interconnection Agreement must be completed for the notification to be valid. The customer shall have all equipment necessary to complete the interconnection prior to such notification. If mailed, the date of notification shall be the third day following the mailing of the Standard Interconnection Agreement. The Electric Utility shall provide a copy of the Standard Interconnection Agreement to the customer upon request.

D. Following notification by the customer as specified in Rule 3.01.C., the utility shall review the plans of the facility and provide the results of its review to the customer, in writing, within 30 calendar days. Any items that would prevent Parallel Operation due to violation of safety standards and/or power generation limits shall be explained along with a description of the modifications necessary to remedy the violations.

E. The Net-Metering Facility, at the Net-Metering Customer's expense, shall meet safety and performance standards established by local and national electrical codes including the National Electrical Code (NEC), the Institute of Electrical and Electronics Engineers (IEEE), the National Electrical Safety Code (NESC), and Underwriters Laboratories (UL).

F. The Net-Metering Facility, at the Net-Metering Customer's expense, shall meet all safety and performance standards adopted by the Electric Utility and filed with and approved by the Commission pursuant to these Rules that are necessary to assure safe and reliable operation of the Net-Metering Facility to the Electric Utility's system.

G. If the Electric Utility's existing facilities are not adequate to interconnect with the Net-Metering Facility, the Net-Metering Customer shall pay the cost of additional or reconfigured facilities prior to the installation or reconfiguration of the facilities.

Rule 3.02 Requirements for Modifications or Changes to a Net-Metering Facility

A. Prior to being made, the Net-Metering Customer shall notify the Electric Utility of, and the Electric Utility shall evaluate, any modifications or changes to the Net-Metering Facility described in Part I, Standard Information, Section 2 of the Standard Interconnection Agreement for Net-Metering Facilities. The notice provided by the Net-Metering Customer shall provide detailed information describing the modifications or changes to the Electric Utility in writing, including a revised Standard Interconnection Agreement for Net-Metering Facilities that clearly identifies the changes to be made. The utility shall review the proposed changes to the facility and provide the results of its evaluation to the customer, in writing, within thirty (30) days of receipt of the customer's proposal. Any items that would prevent Parallel Operation due to violation of applicable safety standards and/or power generation limits shall be explained along with a description of the modifications necessary to remedy the violations.

B. If the Net-Metering Customer makes such modification without the Electric Utility's prior written authorization and the execution of a new Standard Interconnection Agreement, the Electric Utility shall have the right to suspend Net-Metering service pursuant to the procedures in Section 6 of the Commission's General Service Rules.

C. A Net-Metering Facility shall not be modified or changed to generate electrical energy in excess of the amount necessary to offset all of the Net-Metering Customer requirements for electricity.

Rule 3.03 Requirements for Preliminary Interconnection Site Review Request

A. For the purpose of requesting that the Electric Utility conduct a preliminary interconnection site review for a proposed Net-Metering Facility pursuant to Rule 2.05.B.4, or as otherwise requested by the customer, the customer shall notify the Electric Utility by submitting a completed Preliminary Interconnection Site Review Request. The customer shall submit a separate Preliminary Interconnection Site Review Request for each point of interconnection if information about multiple points of interconnection is requested. Part 1, Standard Information, Sections 1 through 4 of the Preliminary Interconnection Site Review Request must be completed for the notification to be valid. If mailed, the date of notification shall be the third day following the mailing of the Preliminary Interconnection Site Review Request. The Electric Utility shall provide a copy of the Preliminary Interconnection Site Review Request to the customer upon request.

B. Following notification by the customer as specified in Rule 3.03.A., the Electric Utility shall review the plans of the facility interconnection and provide the results of its review to the customer, in writing, within 30 calendar days. If the customer requests that multiple interconnection site reviews be conducted the Electric Utility shall make reasonable efforts to provide the customer with the results of the review within 30 calendar days. If the Electric Utility cannot meet the deadline it will provide the customer with an estimated date by which it will complete the review. Any items that would prevent Parallel Operation due to violation of safety standards and/or power generation limits shall be explained along with a description of the modifications necessary to remedy the violations.

C. The preliminary interconnection site review is non-binding and need only include existing data and does not require the Electric Utility to conduct a study or other analysis of the proposed interconnection site in the event that data is not readily available. The utility shall notify the customer if additional site screening may be required prior to interconnection of the facility. The customer shall be responsible for the actual costs of conducting the

preliminary interconnection site review and any subsequent costs associated with site screening that may be required.

D. The preliminary interconnection site review does not relieve the customer of the requirement to execute a Standard Interconnection Agreement prior to interconnection of the facility.

SECTION 4. STANDARD INTERCONNECTION AGREEMENT, PRELIMINARY INTERCONNECTION SITE REVIEW REQUEST, AND STANDARD NET-METERING TARIFF FOR NET-METERING FACILITIES

Rule 4.01 Standard Interconnection Agreement, Preliminary Interconnection Site Review Request, and Standard Net-Metering Tariff

Each Electric Utility shall file, for approval by the Commission, a Standard Interconnection Agreement for Net-Metering Facilities (Appendix A), Standard Interconnection Agreement for Net-Metering Facilities – Disclaimer (Appendix B); Preliminary Interconnection Site Review Request (Appendix C), a Net-Metering Tariff – Grandfathered (Appendix D), and a Net-Metering Tariff in standard tariff format (Appendix E).

Rule 4.02 Filing and Reporting Requirements

Each Electric Utility shall file in Docket No. 06-105-U by March 15 of each year, a report individually listing each Net-Metering Facility, the type of resource (Solar, Wind, etc.), its use (Residential or Other), generator capacity rating, inverter capacity rating, and if the Net-Metering Facility is associated with Additional Meters (Yes or No), as of the end of the previous calendar year. The annual report shall be provided in spreadsheet format.

APPENDIX A

STANDARD INTERCONNECTION AGREEMENT FOR NET-METERING FACILITIES

I. STANDARD INFORMATION

Section 1. Customer Information

Name:_____
Mailing Address:_____
City:_____ State: _____ Zip Code: _____
Facility Location (if different from above):_____
Daytime Phone: _____ Evening Phone: _____
Utility Customer Account Number (from electric bill) to which the Net-Metering Facility is physically attached: _____

Section 2. Generation Facility Information

System Type: Solar Wind Hydro Geothermal Biomass Fuel Cell Micro turbine (circle one)
Generator Rating (kW): _____ AC or DC (circle one)
Describe Location of Accessible and Lockable Disconnect (If required): _____
_____
Inverter Manufacturer: _____ Inverter Model: _____
Inverter Location:_____ Inverter Power Rating: _____
Expected Capacity Factor: _____
Expected annual production of electrical energy (kWh) calculated using industry recognized simulation model (PVWatts, etc.): _____

Section 3. Installation Information

Attach a detailed electrical diagram of the Net-Metering Facility.
Installed by: _____
Qualifications/Credentials: _____
Mailing Address:_____
City:_____State: _____ Zip Code:_____
Daytime Phone:_____ Installation Date:_____

Section 4. Certification

The system has been installed in compliance with the local Building/Electrical Code of
_____(City/County)
Signed (Inspector):_____ Date:_____
(In lieu of signature of inspector, a copy of the final inspection certificate may be attached.)

The system has been installed to my satisfaction and I have been given system warranty

information and an operation manual, and have been instructed in the operation of the system.
Signed (Owner):_____ Date:_____

Section 5. E-mail Addresses for parties
Customer's e-mail address: _____
Utility's e-mail address: _____ (To be provided by utility.)

Section 6. Utility Verification and Approval
Facility Interconnection Approved: _____ Date: _____
Metering Facility Verification by: _____ Verification Date: _____

II. INTERCONNECTION AGREEMENT TERMS AND CONDITIONS

This Interconnection Agreement for Net-Metering Facilities ("Agreement") is made and entered into this _____day of _____, 20_____, by _____ ("Electric Utility") and _____ ("Customer"), a_____(specify whether corporation or other), each hereinafter sometimes referred to individually as "Party" or collectively as the "Parties". In consideration of the mutual covenants set forth herein, the Parties agree as follows:

Section 1. The Net-Metering Facility
The Net-Metering Facility meets the requirements of Ark. Code Ann. § 23-18-603(6) and the Arkansas Public Service Commission's *Net-Metering Rules*.

Section 2. Governing Provisions
The Parties shall be subject to the provisions of Ark. Code Ann. § 23-18-604 and the terms and conditions set forth in this Agreement, the Commission's *Net-Metering Rules*, the Commission's *General Service Rules*, and the Electric Utility's applicable tariffs.

Section 3. Interruption or Reduction of Deliveries
The Electric Utility shall not be obligated to accept and may require Customer to interrupt or reduce deliveries when necessary in order to construct, install, repair, replace, remove, investigate, or inspect any of its equipment or part of its system; or if it reasonably determines that curtailment, interruption, or reduction is necessary because of emergencies, forced outages, force majeure, or compliance with prudent electrical practices. Whenever possible, the Utility shall give the Customer reasonable notice of the possibility that interruption or reduction of deliveries may be required. Notwithstanding any other provision of this Agreement, if at any time the Utility reasonably determines that either the facility may endanger the Electric Utility's personnel or other persons or property, or the continued operation of the Customer's facility may endanger the integrity or safety of the Utility's electric system, the Electric Utility shall have the right to disconnect and lock out the Customer's facility from the

Electric Utility's electric system. The Customer's facility shall remain disconnected until such time as the Electric Utility is reasonably satisfied that the conditions referenced in this Section have been corrected.

Section 4. Interconnection

Customer shall deliver the as-available energy to the Electric Utility at the Electric Utility's meter.

Electric Utility shall furnish and install a standard kilowatt hour meter. Customer shall provide and install a meter socket for the Electric Utility's meter and any related interconnection equipment per the Electric Utility's technical requirements, including safety and performance standards.

The customer shall submit a Standard Interconnection Agreement to the Electric Utility at least thirty (30) days prior to the date the customer intends to interconnect the Net-Metering Facilities to the utility's facilities. Part I, Standard Information, Sections 1 through 4 of the Standard Interconnection Agreement must be completed be valid. The customer shall have all equipment necessary to complete the interconnection prior to such notification. If mailed, the date of notification shall be the third day following the mailing of the Standard Interconnection Agreement. The Electric Utility shall provide a copy of the Standard Interconnection Agreement to the customer upon request.

Following submission of the Standard Interconnection Agreement by the customer, the utility shall review the plans of the facility and provide the results of its review to the customer, in writing, within 30 calendar days. Any items that would prevent Parallel Operation due to violation of applicable safety standards and/or power generation limits shall be explained along with a description of the modifications necessary to remedy the violations.

If the Electric Utility's existing facilities are not adequate to interconnect with the Net-Metering Facility, the Customer shall pay the cost of additional or reconfigured facilities prior to the installation or reconfiguration of the facilities.

To prevent a Net-Metering Customer from back-feeding a de-energized line, the customer shall install a manual disconnect switch with lockout capability that is accessible to utility personnel at all hours. This requirement for a manual disconnect switch will be waived if the following three conditions are met: 1) The inverter equipment must be designed to shut down or disconnect and cannot be manually overridden by the customer upon loss of utility service; 2) The inverter must be warranted by the manufacturer to shut down or disconnect upon loss of utility service; and 3) The inverter must be properly installed and operated, and inspected and/or tested by utility personnel.

Customer, at his own expense, shall meet all safety and performance standards established by local and national electrical codes including the National Electrical Code (NEC), the Institute of Electrical and Electronics Engineers (IEEE), the National

Electrical Safety Code (NESC), and Underwriters Laboratories (UL).

Customer, at his own expense, shall meet all safety and performance standards adopted by the utility and filed with and approved by the Commission that are necessary to assure safe and reliable operation of the Net Metering Facility to the utility's system.

Customer shall not commence Parallel Operation of the Net-Metering Facility until the Net Metering Facility has been inspected and approved by the Electric Utility. Such approval shall not be unreasonably withheld or delayed. Notwithstanding the foregoing, the Electric Utility's approval to operate the Customer's Net-Metering Facility in parallel with the Utility's electrical system should not be construed as an endorsement, confirmation, warranty, guarantee, or representation concerning the safety, operating characteristics, durability, or reliability of the Customer's Net-Metering Facility.

Section 5. Modifications or Changes to the Net-Metering Facility Described in Part 1, Section 2

Prior to being made, the Customer shall notify the Electric Utility of, and the Electric Utility shall evaluate, any modifications or changes to the Net-Metering Facility described in Part 1, Standard Information, Section 2 of the Standard Interconnection Agreement for Net-Metering Facilities. The notice provided by the Customer shall provide detailed information describing the modifications or changes to the Utility in writing, including a revised Standard Interconnection Agreement for Net-Metering Facilities that clearly identifies the changes to be made. The Electric Utility shall review the proposed changes to the facility and provide the results of its evaluation to the Customer, in writing, within thirty (30) calendar days of receipt of the Customer's proposal. Any items that would prevent Parallel Operation due to violation of applicable safety standards and/or power generation limits shall be explained along with a description of the modifications necessary to remedy the violations.

If the Customer makes such modification without the Electric Utility's prior written authorization and the execution of a new Standard Interconnection Agreement, the Electric Utility shall have the right to suspend Net-Metering service pursuant to the procedures in Section 6 of the Commission's General Service Rules.

A Net-Metering Facility shall not be modified or changed to generate electrical energy in excess of the amount necessary to offset all of the Net-Metering Customer requirements for electricity.

Section 6. Maintenance and Permits

The customer shall obtain any governmental authorizations and permits required for the construction and operation of the Net-Metering Facility and interconnection facilities. The Customer shall maintain the Net-Metering Facility and interconnection facilities in a safe and reliable manner and in conformance with all applicable laws and regulations.

Section 7. Access to Premises

The Electric Utility may enter the Customer's premises to inspect the Customer's protective devices and read or test the meter. The Electric Utility may disconnect the interconnection facilities without notice if the Electric Utility reasonably believes a hazardous condition exists and such immediate action is necessary to protect persons, or the Electric Utility's facilities, or property of others from damage or interference caused by the Customer's facilities, or lack of properly operating protective devices.

Section 8. Indemnity and Liability

The following is Applicable to Agreements between the Electric Utility and to all Customers except the State of Arkansas and any entities thereof, local governments and federal agencies:

Each Party shall indemnify the other Party, its directors, officers, agents, and employees against all loss, damages, expense and liability to third persons for injury to or death of persons or injury to property caused by the indemnifying party's engineering, design, construction, ownership, maintenance or operations of, or the making of replacements, additions or betterment to, or by failure of, any of such Party's works or facilities used in connection with this Agreement by reason of omission or negligence, whether active or passive. The indemnifying Party shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity. The indemnifying Party shall pay all costs that may be incurred by the other Party in enforcing this indemnity. It is the intent of the Parties hereto that, where negligence is determined to be contributory, principles of comparative negligence will be followed and each Party shall bear the proportionate cost of any loss, damage, expense and liability attributable to that Party's negligence. Nothing in this paragraph shall be applicable to the Parties in any agreement entered into with the State of Arkansas or any entities thereof, or with local governmental entities or federal agencies. Furthermore, nothing in this Agreement shall be construed to waive the sovereign immunity of the State of Arkansas or any entities thereof. The Arkansas State Claims Commission has exclusive jurisdiction over claims against the state.

Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to or any liability to any person not a Party to this Agreement. Neither the Electric Utility, its officers, agents or employees shall be liable for any claims, demands, costs, losses, causes of action, or any other liability of any nature or kind, arising out of the engineering, design, construction, ownership, maintenance or operation of, or the making of replacements, additions or betterment to, or by failure of, the Customer's facilities by the Customer or any other person or entity.

Section 9. Notices

The Net-Metering Customer shall notify the Electric Utility of any changes in the information provided herein.

All written notices shall be directed as follows:

Attention:
[Electric Utility Agent or Representative]
[Electric Utility Name and Address]

Attention:
[Customer]
Name:_____
Address: _____
City:_____
Customer notices to Electric Utility shall refer to the Customer's electric service account number set forth in Section 1 of this Agreement.

Section 10. Term of Agreement
The term of this Agreement shall be the same as the term of the otherwise applicable standard rate schedule. This Agreement shall remain in effect until modified or terminated in accordance with its terms or applicable regulations or laws.

Section 11. Assignment
This Agreement and all provisions hereof shall inure to and be binding upon the respective Parties hereto, their personal representatives, heirs, successors, and assigns. The Customer shall not assign this Agreement or any part hereof without the prior written consent of the Electric Utility, and such unauthorized assignment may result in termination of this Agreement.

Section 12. Net-Metering Customer Certification
I hereby certify that all of the information provided in this Agreement is true and correct, to the best of my knowledge, and that I have read and understand the Terms and Conditions of this Agreement.
Signature: _____ Date: _____
IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized representatives.

Dated this _____ day of _____, 20__.

Customer:	Electric Utility:
_____	_____
By: _____	By:_____
Title: _____	Title:_____
Mailing Address:	Mailing Address:
_____	_____
_____	_____

E-mail Address:

_____

E-mail Address:

_____

APPENDIX B

STANDARD INTERCONNECTION AGREEMENT FOR NET-METERING FACILITIES

Disclaimer

POSSIBLE FUTURE RULES OR RATE CHANGES, OR BOTH AFFECTING YOUR NET-METERING FACILITY

The following is a supplement to the Interconnection Agreement you signed with _____[Electric Utility].

1. Electricity rates, basic charges, and service fees, set by [Electric Utility] and approved by the Arkansas Public Service Commission (Commission), are subject to change.
2. I understand that I will be responsible for paying any future increases to my electricity rates, basic charges, or service fees from [Electric Utility].
3. My Net-Metering System is subject to the current rates of [Electric Utility], and the rules and regulations of the Commission. The [Electric Utility] may change its rates in the future with approval of the Commission or the Commission may alter its rules and regulations, or both may happen. If either or both occurs, my system will be subject to those changes.

By signing below, you acknowledge that you have read and understand the above disclaimer.

_____
Name (printed)

_____
Signature

_____
Date

APPENDIX C

PRELIMINARY INTERCONNECTION SITE REVIEW REQUEST

I. STANDARD INFORMATION

Section 1. Customer Information

Name:_____
Contact Person:_____
Mailing Address:_____
City:_____ State: _____ Zip Code: _____
Facility Location (if different from above):_____
Daytime Phone: _____ Evening Phone: _____
E-Mail Address:_____Fax:_____
If the requested point of interconnection is the same as an existing electric service, provide the electric service account number:_____
Additional Customer Accounts (from electric bill) to be credited with Net Excess Generation:_____
Annual Energy Requirements (kWh) in the previous twelve (12) months for the account physically attached to the Net-Metering Facility and for any additional accounts listed (in the absence of historical data reasonable estimates for the class and character of service may be made):_____

Section 2. Generation Facility Information

System Type: Solar Wind Hydro Geothermal Biomass Fuel Cell Micro Turbine (circle one)
Generator Rating (kW): _____ AC or DC (circle one)
Expected Capacity Factor: _____
Expected annual production of electrical energy (kWh) of the facility calculated using industry recognized simulation model (PVWatts, etc):_____

Section 3. Interconnection Information

Attach a detailed electrical diagram showing the configuration of all generating facility equipment, including protection and control schemes.
Requested Point of Interconnection:_____
Customer-Site Load (kW) at Net-Metering Facility location (if none, so state): _____
Interconnection Request: Single Phase:_____Three Phase:_____

Section 4. Signature

I hereby certify that, to the best of my knowledge, all the information provided in this

Preliminary Interconnection Site Review is true and correct.
Signature: _____ Date: _____

II. TERMS AND CONDITIONS

Section 1. Requirements for Request

For the purpose of requesting that the Electric Utility conduct a preliminary interconnection site review for a proposed Net-Metering Facility pursuant to the requirement of Rule 2.06.B.4, or as otherwise requested by the customer, the customer shall notify the Electric Utility by submitting a completed Preliminary Interconnection Site Review Request. The customer shall submit a separate Preliminary Interconnection Site Review Request for each point of interconnection if information about multiple points of interconnection is requested. Part 1, Standard Information, Sections 1 through 4 of the Preliminary Interconnection Site Review Request must be completed for the notification to be valid. If mailed, the date of notification shall be the third day following the mailing of the Preliminary Interconnection Site Review Request. The Electric Utility shall provide a copy of the Preliminary Interconnection Site Review Request to the customer upon request.

Section 2. Utility Review

Following submission of the Preliminary Interconnection Site Review Request by the customer the Electric Utility shall review the plans of the facility interconnection and provide the results of its review to the customer, in writing, within 30 calendar days. If the customer requests that multiple interconnection site reviews be conducted the Electric Utility shall make reasonable efforts to provide the customer with the results of the review within 30 calendar days. If the Electric Utility cannot meet the deadline it will provide the customer with an estimated date by which it will complete the review. Any items that would prevent Parallel Operation due to violation of safety standards and/or power generation limits shall be explained along with a description of the modifications necessary to remedy the violations.

The preliminary interconnection site review is non-binding and need only include existing data and does not require the Electric Utility to conduct a study or other analysis of the proposed interconnection site in the event that data is not readily available. The Electric Utility shall notify the customer if additional site screening may be required prior to interconnection of the facility. The customer shall be responsible for the actual costs for conducting the preliminary interconnection site review and any subsequent costs associated with site screening that may be required.

Section 3. Application to Exceed 300 kW Net-Metering Facility Size Limit

This Preliminary Interconnection Site Review Request and the results of the Electric Utility's review of the facility interconnection shall be filed with the Commission with the customer's application to exceed the 300 kW facility size limit pursuant to Net Metering Rule 2.05.B.4.

Section 4. Standard Interconnection Agreement

The preliminary interconnection site review does not relieve the customer of the requirement to execute a Standard Interconnection Agreement prior to interconnection of the facility.

APPENDIX D

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.	
Replacing:	Sheet No.	
Name of Company		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. X		
Title: NET-METERING TARIFF -GRANDFATHERED		PSC File Mark Only

X. GRANDFATHERED NET-METERING

AVAILABLE TO NET METERING FACILITIES WITH A SIGNED, STANDARD INTERCONNECTION AGREEMENT SUBMITTED BEFORE AAAA XX, 20XX

X.1. AVAILABILITY

X.1.1. To any residential or any other customer who takes service under standard rate schedule(s) _____ (list schedules) who is an owner of a Net-Metering Facility and has submitted a completed and signed Standard Interconnection Agreement for Net-Metering Facilities with the customer's Electric Utility prior to [date of Order in Phase 2]. This schedule will expire on [date of Order in Phase 2 + 20 years]. The generating capacity of Net-Metering Facilities may not exceed the greater of: 1) twenty-five kilowatts (25 kW) or 2) one hundred percent (100%) of the Net-Metering Customer's highest monthly usage in the previous twelve (12) months for Residential Use. The generating capacity of Net-Metering Facilities may not exceed three hundred kilowatts (300 kW) for non-residential use unless otherwise allowed by the Commission. Net-Metering is intended primarily to offset part or all of the customer's energy use.

If a customer sells premises with a Net-Metering Facility, the Standard Interconnection Agreement may be transferred to the new owner and this tariff shall continue in effect for the remainder of the term.

Thirty (30) days' notice prior to the expiration date of this schedule, the Electric Utility shall provide, notice to the customer that this tariff will expire and that the customer's service will be subject to an applicable tariff.

The provisions of the customer's standard rate schedule are modified as specified herein.

APPENDIX D

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.	
Replacing:	Sheet No.	
Name of Company		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. X		
Title: NET-METERING TARIFF -GRANDFATHERED		PSC File Mark Only

X.1.2. Net-Metering Customers taking service under the provisions of this tariff may not simultaneously take service under the provisions of any other alternative source generation or co-generation tariff except as provided in the Net-Metering Rules.

X.2. MONTHLY BILLING

X.2.1. The Electric Utility shall separately meter, bill, and credit each Net-Metering Facility even if one (1) or more Net-Metering Facilities are under common ownership.

X.2.2. On a monthly basis, the Net-Metering Customer shall be billed the charges applicable under the currently effective standard rate schedule and any appropriate rider schedules. Under Net-Metering, only the kilowatt hour (kWh) units of a customer's bill are netted.

X.2.3. If the kWhs supplied by the Electric Utility exceed~~s~~ the kWhs generated by the Net-Metering Facility and fed back to the Electric Utility during the Billing Period, the Net-Metering Customer shall be billed for the net ~~billable~~ kWhs supplied by the Electric Utility in accordance with the rates and charges under the ~~Net-Metering Customer's~~ customer's standard rate schedule and any appropriate rider schedules.

X.2.4. If the kWhs generated by the Net-Metering Facility and fed back to the Electric Utility ~~during the Billing Period~~ exceed the kWhs supplied by the Electric Utility to the Net-Metering Customer during the applicable Billing Period, the ~~Electric Utility~~ utility shall credit the Net-Metering Customer with any accumulated Net Excess Generation in the next applicable Billing Period.

X.2.5. Net Excess Generation shall first be credited to the Net-Metering Customer's ~~meter to which the Net-Metering Facility is physically attached (~~Generation Meter~~)~~.

APPENDIX D

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.	
Replacing:	Sheet No.	
Name of Company		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. X		
Title: NET-METERING TARIFF -GRANDFATHERED		PSC File Mark Only

X.2.6. After application of X.2.5 and upon request of the Net-Metering Customer pursuant to X.2.8, any remaining Net Excess Generation Credits shall be credited to one or more of the Net-Metering Customer's ~~meters (~~Additional Meters~~)~~ in the rank order provided by the ~~Net-Metering Customer~~ customer.

X.2.7 The billing amount in a given Billing Period will never be less than the otherwise applicable minimum bill or customer charge.

X.2.8. Net Excess Generation Credits shall be credited as described in X.2.5, ~~and~~ X.2.6, and X.2.7 during subsequent Billing Periods~~;~~. ~~the~~ Net Excess Generation Credits remaining in a Net-Metering Customer's account at the close of a ~~billing cycle~~ Billing Period shall not expire and shall be carried forward to subsequent ~~billing cycles~~ Billing Periods indefinitely.

X.2.9. For Net Excess Generation Credits older than ~~twenty-four (~~24~~)~~ months, a Net-Metering Customer may elect to have the Electric Utility purchase the Net Excess Generation Credits in the Net-Metering Customer's account at the Electric Utility's estimated annual average Avoided Cost ~~cost~~ rate for wholesale energy if the sum to be paid to the Net-Metering Customer is at least ~~one hundred dollars~~ $100.

X.2.10. An Electric Utility shall purchase at the Electric Utility's estimated annual average Avoided Cost rate for wholesale energy any Net Excess Generation Credits remaining in a Net-Metering Customer's account when the Net-Metering Customer: 1) ceases to be a customer of the Electric Utility; 2) ceases to operate the Net-Metering Facility; or 3) transfers the Net-Metering Facility to another person.

X.2.11. When purchasing Net Excess Generation Credits from a Net-Metering Customer, the Electric Utility shall calculate the payment based on its annual average avoided energy costs in the applicable Regional Transmission Organization for the current calendar year.

APPENDIX D

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.	
Replacing:	Sheet No.	
Name of Company		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. X		
Title: NET-METERING TARIFF -GRANDFATHERED		PSC File Mark Only

X.2.~~8~~12. Upon request from a Net-Metering Customer, an Electric Utility must apply Net Excess Generation Credits to the Net-Metering Customer's Additional Meters provided that:

(a) Additional Meter(s) shall be under common ownership within a single Electric Utility's service area; shall be used to measure the Net-Metering Customer's requirements for electricity; may be in a different class of service than the Generation Meter; shall be assigned to one and only one Generation Meter; shall not be a Generation Meter; and shall not be associated with unmetered service.

(b) The Net-Metering Customer must have given at least 30 days' notice to the Electric Utility of its request to apply Net Excess Generation Credits to the Additional Meter(s).

(c) The Additional Meter(s) must have been ~~be~~ identified at the time of the request. ~~Additional Meter(s) shall be under common ownership within a single Electric Utility's service area; shall be used to measure the Net-Metering Customer's requirements for electricity; may be in a different class of service than the Generation Meter; shall be assigned to one and only one Generation Meter; shall not be a Generation Meter; and shall not be associated with unmetered service.~~

(d) In the event that more than one of the Net-Metering Customer's Additional Meters ~~meters~~ is identified, the Net-Metering Customer must designate the rank order for the Additional Meters to which Net Excess Generation Credits are ~~is excess kWhs are~~ to be applied. The Net-Metering Customer cannot designate the rank order more than once during the Annual Billing Cycle.

~~X.2.11.Any Renewable Energy Credit created as the result of electricity supplied by a Net-Metering Customer is the property of the Net-Metering Customer that generated the Renewable Energy Credit.~~

APPENDIX E

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.	
Replacing:	Sheet No.	
Name of Company		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. X		
Title: NET-METERING TARIFF		PSC File Mark Only

X. NET-METERING

X.1. AVAILABILITY

X.1.1. To any residential or any other customer who takes service under standard rate schedule(s) _____ (list schedules) who is an owner of a Net-Metering Facility and has submitted a completed and signed ~~a~~ Standard Interconnection Agreement for Net-Metering Facilities with the customer's Electric Utility after [date of Order in Phase 2]. The generating capacity of Net-Metering Facilities may not exceed the greater of: 1) twenty-five kilowatts (25 kW) or 2) one hundred percent (100%) of the Net-Metering Customer's highest monthly usage in the previous twelve (12) months for Residential Use. The generating capacity of Net-Metering Facilities may not exceed three hundred kilowatts (300kW) for non-residential use unless otherwise allowed by the Commission. Net-Metering is intended primarily to offset some or all of the customer's energy use.

The provisions of the customer's standard rate schedule are modified as specified herein.

X.1.2. Net-Metering Customers taking service under the provisions of this tariff may not simultaneously take service under the provisions of any other alternative source generation or co-generation tariff except as provided in the Net-Metering Rules.

X.2. MONTHLY 2-CHANNEL BILLING

X.2.1. The provisions of X.2 are applicable to the following non-demand based rate schedules: [list utility specific schedules].

APPENDIX E

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.	
Replacing:	Sheet No.	
Name of Company		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. X		
Title: NET-METERING TARIFF		PSC File Mark Only

X.2.2. The Electric Utility shall separately meter, bill, and credit each Net-Metering Facility, even if one (1) or more Net-Metering Facilities are under common ownership.

X.2.3. On a monthly basis, the Net-Metering Customer shall be billed the charges applicable under the currently effective standard rate schedule and any appropriate rider schedules for all kWhs supplied to the Net-Metering Customer by the Electric Utility measured through Channel 1.

X.2.4. If the kWhs supplied by the Electric Utility as measured on Channel 1 exceed the customer's Channel 2 Excess Generation, including any Net Excess Generation Credits, all Channel 2 Excess Generation, including any Net Excess Generation Credits, shall be credited at the rate established by the Excess Generation Credit Rider.

X.2.5 If the customer's Channel 2 Excess Generation, including any Net Excess Generation Credits, exceeds the kWhs supplied by the Electric Utility as measured on Channel 1, then the Channel 2 Excess Generation, including any Net Excess Generation Credits, not to exceed the kWhs measured on Channel 1 during the Billing Period, shall be credited at the rate established by the Excess Generation Credit Rider.

X.2.6. The billing amount in a given Billing Period will never be less than the otherwise applicable minimum bill or customer charge, plus any non-by-passable charges as approved by the Commission.

X.2.7. Net Excess Generation Credits remaining in a Net-Metering Customer's account at the close of a Billing Period shall not expire, shall be carried forward to subsequent Billing Periods indefinitely, and shall be applied as described in X.2.4, X.2.5, and X.2.6 during subsequent Billing Periods.

APPENDIX E

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.	
Replacing:	Sheet No.	
Name of Company		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. X		
Title: NET-METERING TARIFF		PSC File Mark Only

X.2.8. For Net Excess Generation Credits older than 24 months, a Net-Metering Customer may elect to have the Electric Utility purchase the Net Excess Generation Credits in the Net-Metering Customer's account at the Electric Utility's estimated annual average Avoided Cost rate for wholesale energy if the sum to be paid to the Net-Metering Customer is at least $100.

X.2.9 An Electric Utility shall purchase at the Electric Utility's estimated annual average Avoided Cost rate for wholesale energy any Net Excess Generation Credits remaining in a Net-Metering Customer's account when the Net-Metering Customer: 1) ceases to be a customer of the Electric Utility; 2) ceases to operate the Net-Metering Facility; or 3) transfers the Net-Metering Facility to another person.

X.2.10 When purchasing Net Excess Generation Credits from a Net-Metering Customer, the Electric Utility shall calculate the payment based on its annual average avoided energy costs in the applicable Regional Transmission Organization for the current calendar year.

X.3. MONTHLY BILLING FOR DEMAND METERED TARIFFS

X.3.1. The provisions of X.3 are applicable to the following demand based rate schedules: [list utility specific schedules].

X.3.2. The Electric Utility shall separately meter, bill, and credit each Net-Metering Facility even if one (1) or more Net-Metering Facilities are under common ownership.

X.3.3. On a monthly basis, a Net-Metering Customer taking service under a Demand Metered Tariff pursuant to X. 3 of this rate schedule shall be billed the charges applicable under the currently effective standard rate schedule and any appropriate rider schedules. For Demand Metered Tariffs, only the kWh units of a customer's bill are netted.

APPENDIX E

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.	
Replacing:	Sheet No.	
Name of Company		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. X		
Title: NET-METERING TARIFF		PSC File Mark Only

X.3.4. If the kWhs supplied by the Electric Utility exceed the kWhs generated by the Net-Metering Facility and fed back to the Electric Utility during the Billing Period, the Net-Metering Customer shall be billed for the net kWhs supplied by the Electric Utility in accordance with the rates and charges under the customer's standard rate schedule.

X.3.5. If the kWhs generated by the Net-Metering Facility and fed back to the Electric Utility exceed the kWhs supplied by the Electric Utility to the Net-Metering Customer during the applicable Billing Period, the utility shall credit the Net-Metering Customer with any accumulated Net Excess Generation Credits in the next applicable Billing Period.

X.3.6. The billing amount in a given Billing Period will never be less than the otherwise applicable minimum bill or customer charge, plus any non-by-passable charges as approved by the Commission.

X.3.7. Net Excess Generation Credits shall be credited as described in X.3.5 and X.3.6 during subsequent Billing Periods. Any Net Excess Generation Credits remaining in a Net-Metering Customer's account at the close of a Billing Period shall not expire and shall be carried forward to subsequent Billing Periods indefinitely.

X.3.8. For Net Excess Generation Credits older than 24 months, a Net-Metering Customer may elect to have the Electric Utility purchase the Net Excess Generation Credits in the Net-Metering Customer's account at the Electric Utility's estimated annual average Avoided Cost rate for wholesale energy if the sum to be paid to the Net-Metering Customer is at least $100. An Electric Utility shall purchase at the Electric Utility's estimated annual average Avoided Cost rate for wholesale energy any Net Excess Generation Credits remaining in a Net-Metering Customer's account when the Net-Metering Customer: 1) ceases to be a customer of the Electric Utility; 2) ceases to operate the Net-Metering Facility; or 3) transfers the Net-Metering Facility to another person.

APPENDIX E

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.	
Replacing:	Sheet No.	
Name of Company		
Kind of Service: Electric	Class of Service: All	
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Title: NET-METERING TARIFF		PSC File Mark Only

When purchasing Net Excess Generation Credits from a Net-Metering Customer, the Electric Utility shall calculate the payment based on its annual average avoided energy costs in the applicable Regional Transmission Organization for the current calendar year.

X.4. MONTHLY BILLING FOR ADDITIONAL METERS

X.4.1. Upon request from a Net-Metering Customer, an Electric Utility shall apply Net Excess Generation Credits to the Net-Metering Customer's Additional Meter(s) provided that:

(a) Additional Meter(s) shall be under common ownership within a single Electric Utility's service area; shall be used to measure the Net-Metering Customer's requirements for electricity; may be in a different class of service than the Generation Meter; shall be assigned to one and only one Generation Meter; shall not be a Generation Meter; and shall not be associated with unmetered service.

(b) The Net-Metering Customer must give at least 30 days' notice to the Electric Utility of its request to apply Net Excess Generation Credits to the Additional Meter(s).

(c) The Additional Meter(s) must be identified at the time of the request.

(d) In the event that more than one of the Net-Metering Customer's Additional Meters is identified, the Net-Metering Customer must designate the rank order for the Additional Meters to which the Net Excess Generation Credits are to be applied. The Net-Metering Customer cannot designate the rank order more than once during the Annual Billing Cycle.

X.4.2. Net Excess Generation Credits shall be applied to one or more of the Net Metering Customer's Additional Meter(s) in the rank order provided by the Net Metering Customer. Net Excess Generation Credits applied to an Additional Meter during any

APPENDIX E

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Billing Period shall not exceed the kWhs supplied by the Electric Utility to the Additional Meter.

APPENDIX F

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.	
Replacing:	Sheet No.	
Name of Company		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. X		
Title: EXCESS GENERATION CREDIT RIDER		PSC File Mark Only

X. EXCESS GENERATION CREDIT RIDER

X.1. APPLICABILITY

This Excess Generation Credit Rider (EGC Rider) applies to all Net-Metering Customers taking service pursuant to Section X.2 - Monthly 2-Channel Billing of the Net-Metering Tariff.

X.2. PURPOSE

The purpose of this EGC Rider is to establish the credit rate that is to be applied to kWhs classified as Channel 2 Excess Generation and Net Excess Generation Credits.

X.3. EXCESS GENERATION CREDIT RATE

The Excess Generation Credit Rate (EGC Rate) shall be determined in the manner approved by the Arkansas Public Service Commission ("Commission") pursuant to Order No. {xx} in Docket No. 16-027-R and shall become effective upon the date established by the Commission. The EGC Rate listed in Attachment A to this EGC Rider shall be redetermined annually through filings made in accordance with the provisions of § X.4 of this EGC Rider.

X.4. ANNUAL RE-DETERMINATION

On or before March 1 of each year beginning in 2019, a re-determined EGC Rate shall be filed by the Company with the Commission. The re-determined EGC Rate shall be determined by application of the Formula set out in Attachment A to this EGC Rider. Each such revised EGC Rate filing shall be filed in Docket xx-xxx-TF and be accompanied by a set of workpapers sufficient to fully document the calculations of the revised EGC Rate.

APPENDIX F

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.	
Replacing:	Sheet No.	
Name of Company		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. X		
Title: EXCESS GENERATION CREDIT RIDER		PSC File Mark Only

The Commission General Staff (Staff) shall review the EGC Rate to verify that the Formula in Attachment A has been correctly applied and shall notify the Company of any necessary corrections. After the Staff completes its review of the EGC Rate calculation, the Company shall make appropriate changes to correct undisputed errors identified by the Staff in its review. Any disputed issues arising out of the Staff review are to be resolved by the Commission after notice and hearing.

The EGC Rate so re-determined shall be effective for bills rendered on and after the first billing cycle of April of the filing year.

X.5. TERM

This EGC Rider shall remain in effect until modified or terminated in accordance with applicable regulations or laws.

Appendix F

Appendix A to
Rate Schedule No. XX
Attachment Page X of X
Schedule Sheet X of X
Including Attachments

[Company Name]
Excess Generation Rider Credit Formula
(Residential Rate Class)

Embedded Capacity

Column	1	2	3
Function	Functionalized Embedded Capacity $/kWh	Capacity Benefit %	Embedded Capacity Credit $/kWh
Production	$ 0.04003	54 %	$ 0.002153
Transmission	$ 0.01083	36 %	$ 0.00392

Embedded Capacity Credit $/kWh **$ 0.02545**

Avoided Incremental Fuel

Column	4	5	6
	Average Hourly LMP $/kWh	Embedded Distribution Line Losses %	Avoided Incremental Energy $/kWh
Avoided RTO Energy $/kWh	$ 0.02761	7.4 %	**$ 0.02965**

Residential Excess Generation Rider Credit $ 0.05511

Appendix F
Attachment A to
Rate Schedule No. XX
Page X of X
Schedule Sheet X of X
Including Attachments

[Company Name]
Excess Generation Rider Credit Formula
(Non-Residential Rate Class)

Embedded Capacity

Column	1	2	3
Function	Functionalized Embedded Capacity $/kWh	Capacity Benefit %	Embedded Capacity Credit $/kWh
Production			
Transmission			

Embedded Capacity Credit $/kWh **$ 0.0xxxx**

Avoided Incremental Fuel

Column	4	5	6
	Average Hourly LMP $/kWh	Embedded Distribution Line Losses %	Avoided Incremental Energy $/kWh
Avoided RTO Energy $/kWh			

Non-Residential Excess Generation Rider Credit $ 0.0xxxx

Appendix F
Attachment A to
Rate Schedule No. XX
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Including Attachments

Embedded Capacity

The allocation of the embedded functionalized base-rate cost by applying the capacity benefit of the net-metering facility

Avoided Incremental Fuel

The calculation of the cost of the avoided incremental fuel

Column 1 – Functionalized Embedded Capacity $/kWh

The embedded functionalized base-rate cost of providing production and transmission service for the Residential or non-Residential Class of customers expressed as a $/kWh based on the utility's last approved Cost of Service Study, as adjusted for a Formula Rate Plan, U-2811, Act 821, or other Commission approved adjustments to base rates.

Column 2 – Capacity Benefit %

The benefit of a customer's self-generation provided to production and transmission service for the Residential or non-Residential Class of customers derived from the solar capacity factor determined by using a three hour average capacity factor produced by the PVWatts ® Model for a window either side of the utility's peak hour over the past five years averaged for either a 1 CP, 4 CP, or 12 CP, consistent with the utility's the cost allocation methodology underlying rates approved by the Commission in the utility's last general rate case.

Column 3 – Embedded Capacity Credit $/kWh

The multiplication of Column 1 and Column 2.

Column 4 – Avoided Incremental Fuel $/kWh

The average weighted avoided increment fuel is represented by the historical annual hourly real-time locational marginal price (LMP), based on the previous calendar year from MISO, SPP, or both, as applicable for the utility determined by summing the product of each hours solar AC output in kWh times the hourly LMP for the calendar year divided by the annual AC kWh generation of the solar facility as determined by the PVWatts ® Model.

Column 5 – Embedded Distribution Line Losses %

The average distribution line losses consistent with the cost allocation methodology underlying rates approved by the Commission in the utility's last general rate case.

Column 6 – Avoided Incremental Energy $/kWh

The Avoided Incremental Fuel in $/kWh increased for Embedded Distribution Losses by multiplying Avoided Incremental Fuel by one (1) plus Embedded Distribution Line Losses. (Column 4 x (1+ Column 5)).

Excess Generation Rider Credit

The sum of the Embedded Capacity Credit $/kWh and the Avoided Incremental Energy $/kWh.

ARKANSAS
PUBLIC SERVICE COMMISSION

NET-METERING RULES

Last Revised: March xx, 2017
Order No. xx
Docket No. 16-027-R
Effective : xx-xx-2017

NET-METERING RULES

ADMINISTRATIVE HISTORY

Docket	Date	Order No.	Subject Matter of Docket/ Order
02-046-R	07/26/02	4	Adopted rules relating to the terms and conditions of – Net-Metering.
06-105-U	11/27/07	8	Amended definitions; Rules 1.02, 2.01, and 2.04; Section 1 of the Standard Interconnection Agreement, Appendix A; and X.1.1, X.2.3, and X.2.4 of the Net-Metering Tariff, Appendix B.
	11/29/07	10	Amended Rule 4.02 to delete reference to Docket No. 86-033-A.
	11/30/07	11	Amended the Standard Interconnection Agreement, Appendix A to add e-mail address lines to the signature block.
	12/19/07	12	Errata order correcting clerical errors in the amendments adopted in Order No. 8.
12-001-R	06/15/12	6	Amended Section 7 of the Standard Interconnection Agreement, Appendix A to exempt state governmental agencies and entities, local governmental entities, and federal entities from the indemnity requirement.
12-060-R	09/03/13	7	Amended Rule 2.04 to provide for meter aggregation, incorporated the provisions of Act 1221 of 2013 concerning the carryover of net-metering credits, and added a definition of Net-Metering Customer to track the definition in Ark. Code Ann. § 23-18-603.
	10/11/13	10	Updated the Net-Metering Tariff to reflect the amendments adopted in Order No. 7.
16-027-R	xx/xx/17	XX	Revised Rules to comply with Act 827 of 2015.

NET-METERING RULES

TABLE OF CONTENTS

SECTION 1. GENERAL PROVISIONS

Rule 1.01 Definitions

The following definitions shall apply throughout the Net-Metering Rules (NMRs) except as otherwise required by the context, and any references to the NMRs shall include these definitions:

(a) 2-Channel Billing
A billing framework for a Net-Metering Customer that measures the energy delivered by the utility and consumed by the customer (as recorded on Channel 1 of the meter) and the excess, self-generated energy exported to the electric grid (as recorded on Channel 2 of the meter).

(b) Additional Meter
A meter associated with the Net-Metering Customer's account that the Net-Metering Customer may credit with Net Excess Generation Credits from the Generation Meter. Additional Meter(s): 1) shall be under common ownership within a single Electric Utility's service area; 2) shall be used to measure the Net-Metering Customer's requirements for electricity; 3) may be in a different class of service than the Generation Meter; 4) shall be assigned to one, and only one, Generation Meter; 5) shall not be a Generation Meter; and 6) shall not be associated with unmetered service.

(c) Annual Billing Cycle
The normal annual fiscal accounting period used by the utility.

(d) Avoided Costs
As defined in Ark. Code Ann. § 23-18-604(c).

(e) Billing Period
The billing period for net-metering will be the same as the billing period under the customer's applicable standard rate schedule.

(f) Channel 1
The channel of the meter which measures the energy in kWhs delivered to a Net-Metering Customer by the Electric Utility.

(g) Channel 2
The channel of the meter that measures the excess, self-generated energy in kWhs exported to the electric grid.

(h) Channel 2 Excess Generation
The excess, self-generated energy exported to the electric grid and measured in kWhs on Channel 2 during a Billing Period. Channel 2 Excess Generation during a Billing Period that is not credited to the Net-Metering Customer's Generation

Meter account within that Billing Period is carried forward as Net Excess Generation Credits.

(i) Commission
The Arkansas Public Service Commission.

(j) Electric Utility
A public or investor-owned utility, an electric cooperative, municipal utility, or any private power supplier or marketer that is engaged in the business of supplying electric energy to the ultimate customer or any customer class within the state.

(k) Generation Meter
The meter associated with the Net-Metering Customer's account to which the Net-Metering Facility is physically attached.

(l) Net Excess Generation
As defined in Ark. Code Ann. § 23-18-603(3).

(m) Net Excess Generation Credits
Uncredited customer generated kilowatt hours remaining in a Net-Metering Customer's account at the close of a Billing Period to be credited, or, pursuant to Rule 2.0~~5~~7, purchased by the utility in a future billing period.

(n) Net-Metering
As defined in Ark. Code Ann. § 23-18-603(4).

(o) Net-Metering Customer
As defined in Ark. Code Ann. § 23-18-603(5).

(p) Net-Metering Facility
As defined in Ark. Code Ann. § 23-18-603(6).

(q) Parallel Operation

The operation of on-site generation by a customer while the customer is connected to the Electric Utility's distribution system.

(r) Renewable Energy Credit
As defined in Ark. Code Ann. § 23-18-603(7).

(s) Residential Use
Service provided under an Electric Utility's standard rate schedules applicable to residential service.

Rule 1.02 Purpose

The purpose of these Net-Metering Rules is to establish rules for net energy metering and interconnection.

Rule 1.03 Statutory Provisions

D. These Rules are developed pursuant to the Arkansas Renewable Energy Development Act of 2001 (Ark. Code Ann. § 23-18-601 *et seq.* as amended.)

E. These Rules are promulgated pursuant to the Commission's authority under Ark. Code Ann. §§ 23-2-301, 23-2-304(a)(3), and 23-2-305.

F. Nothing in these Rules shall govern, limit, or restrict the Commission's authority under Ark. Code Ann. § 23-18-604.

Rule 1.04 Other Provisions

D. These Rules apply to all Electric Utilities, as defined in these Rules, that are jurisdictional to the Commission.

E. The Net-Metering Rules are not intended to, and do not affect or replace any Commission approved general service regulation, policy, procedure, rule, or service application of any utility which addresses items other than those covered in these Rules.

F. Net-Metering Customers taking service under the provisions of the Net-Metering Tariff may not simultaneously take service under the provisions of any other alternative source generation or cogeneration tariffs except as provided herein.

SECTION 2. NET-METERING REQUIREMENTS

Rule 2.01 Electric Utility Requirements

An Electric Utility shall allow Net-Metering Facilities to be interconnected using a standard meter capable of registering the flow of electricity in two (2) directions.

Rule 2.02 Metering Requirements

C. Metering equipment shall be installed to both accurately measure the electricity supplied by the Electric Utility to each Net-Metering Customer and also to accurately measure the electricity generated by each Net-Metering Customer that is fed back to the Electric Utility over the applicable Billing Period. If nonstandard metering equipment is required, the customer is responsible for the cost differential between the required metering equipment and the utility's standard metering equipment for the customer's current rate schedule.

D. Accuracy requirements for a meter operating in both forward and reverse registration modes shall be as defined in the Commission's Special Rules - Electric. A test to determine compliance with this accuracy requirement shall be made by the Electric Utility either before or at the time the Net-Metering Facility is placed in operation in accordance with these Rules.

Rule 2.03 New or Additional Charges

Any new or additional charge which would increase a Net-Metering Customer's costs beyond those of other customers in the rate class shall be filed by the Electric Utility with the Commission for approval. The filing shall be supported by the cost/benefit analysis described in Ark. Code Ann. § 23-18-604(b)(2).

Rule 2.04 Billing for Grandfathered Net-Metering Customers Pursuant to Appendix D

A. On a monthly basis, the Net-Metering Customer shall be billed the charges applicable under the currently effective standard rate schedule and any appropriate rider schedules. Under Net-Metering, only the kilowatt hour (kWh) units of a customer's bill are netted.

B. If the kWhs supplied by the Electric Utility exceeds the kWhs generated by the Net- Metering Facility and fed back to the Electric Utility during the Billing Period, the Net-Metering Customer shall be billed for the net kWhs supplied by the Electric Utility in accordance with the rates and charges under the customer's standard rate schedule and any appropriate rider schedules.

C. If the kWhs generated by the Net-Metering Facility and fed back to the Electric Utility exceed the kWhs supplied by the Electric Utility to the Net-Metering Customer during the applicable Billing Period, the utility shall credit the Net-Metering Customer with any accumulated Net Excess Generation in the next applicable Billing Period.

Rule 2.05 Billing for Net-Metering Customers Pursuant to Appendix E - X.2. Monthly 2-Channel Billing

A. On a monthly basis, the Net-Metering Customer shall be billed the charges applicable under the currently effective standard rate schedule and any appropriate rider schedules for all kWhs supplied to the Net-Metering Customer by the Electric Utility measured through Channel 1.

B. If the kWhs supplied by the Electric Utility as measured on Channel 1 exceed the customer's Channel 2 Excess Generation, including any Net Excess Generation Credits, all Channel 2 Excess Generation, including any Net Excess Generation Credits, shall be credited at the rate established by the Excess Generation Credit Rider.

C. If the customer's Channel 2 Excess Generation, including any Net Excess Generation Credits, exceeds the kWhs supplied by the Electric Utility as measured on Channel 1, then the Channel 2 Excess Generation, including any Net Excess Generation Credits, not to exceed the kWhs measured on Channel 1 during the Billing Period, shall be credited to the customer's account at the rate established by the Excess Generation Credit Rider.

Rule 2.06 Billing for Net-Metering Customers Pursuant to Appendix E - X.3. Monthly Billing for Demand Metered Tariffs

A. On a monthly basis, a Net-Metering Customer taking service under a Demand Metered Tariff shall be billed the charges applicable under the currently effective standard rate schedule and any appropriate rider schedules. For Demand Metered Tariffs, only the kWh units of a customer's bill are netted.

D. If the kWhs supplied by the Electric Utility exceed the kWhs generated by the Net-Metering Facility and fed back to the Electric Utility during the Billing Period, the Net-Metering Customer shall be billed for the net kWhs supplied by the Electric Utility in accordance with the rates and charges under the customer's standard rate schedule.

E. If the kWhs generated by the Net-Metering Facility and fed back to the Electric Utility exceed the kWhs supplied by the Electric Utility to the Net-Metering Customer during the applicable Billing Period, the utility shall credit the Net-Metering Customer with any accumulated Net Excess Generation in the next applicable Billing Period.

Rule 2.07 Net Excess Generation Credits

A. Net Excess Generation Credits remaining in a Net-Metering Customer's account at the close of a Billing Period shall not expire and shall be carried forward to subsequent Billing Periods indefinitely.

B. For Net Excess Generation Credits older than 24 months, a Net-Metering Customer may elect to have the Electric Utility purchase the Net Excess Generation Credits in the Net-Metering Customer's account at the Electric Utility's estimated annual average Avoided Cost rate for wholesale energy if the sum to be paid to the Net-Metering Customer is at least $100.

C. An Electric Utility shall purchase, at the Electric Utility's estimated annual average Avoided Cost rate for wholesale energy, any Net Excess Generation Credits remaining in a Net-Metering Customer's account when the Net-Metering Customer:

i. ceases to be a customer of the Electric Utility;

ii. ceases to operate the Net-Metering Facility; or

iii. transfers the Net-Metering Facility to another person.

D. When purchasing Net Excess Generation Credits from a Net-Metering Customer, the Electric Utility shall calculate the payment based on its annual average avoided energy costs in the applicable Regional Transmission Organization for the current calendar year.

Rule 2.08 Renewable Energy Credit

Any Renewable Energy Credit created as a result of electricity supplied by a Net-Metering Customer is the property of the Net-Metering Customer that generated the Renewable Energy Credit.

Rule 2.09 Additional Meters

A. Upon request from a Net-Metering Customer, an Electric Utility must apply Net Excess Generation Credits to the Net-Metering Customer's Additional Meters provided that:

1. The Net-Metering Customer must give at least 30 days' notice to the Electric Utility of its request to apply Net Excess Generation Creidts to the Additional Meter(s).

2. The Additional Meter(s) must be identified at the time of the request.

3. In the event that more than one of the Net-Metering Customer's Additional Meters is identified, the Net-Metering Customer must designate the rank order for the Additional Meters to which Net Excess Generation Credits is to be applied. The Net-Metering Customer cannot designate the rank order more than once during the Annual Billing Cycle.

B. Net Excess Generation Credits shall be credited to one or more of the Net-Metering Customer's Additional Meters in the rank order provided by the customer at the rate established by the applicable tariffs attached to these Rules.

Rule 2.10 Application to Exceed Generating Capacity Limit

C. A Net-Metering Customer shall file an application with the Commission seeking approval to install a Net-Metering Facility with a generating capacity of more than 300 kW for non-residential use under Ark. Code Ann. §§ 23-18-604(b) (5) or (7) as appropriate.

D. The application shall be filed in conformance with Section 3 of the Commission's Rules of Practice and Procedure and shall, at a minimum, include:

1. Evidence that the Net-Metering Facility in excess of 300 kW satisfies the requirements of Ark. Code Ann. §§ 23-18-604(b)(5) or (7):

2. A description of the proposed Net-Metering Facility including:

   a. Project proposal;

   b. Project location (street address, town, utility service area);

   c. Generator type (wind, solar, hydro, etc.);

   d. Generator rating in kW (DC or AC);

e. Capacity factor;

f. Point of interconnection with the Electric Utility;

g. Single Phase or Three Phase interconnection;

h. Planned method of interconnection consistent with Rule 3.01.B.;

i. Expected facility performance calculated using an industry recognized simulation model (PVWatts, etc.);

3. Evidence that the electrical energy produced by the Net-Metering Facility is not intended to-exceed the amount necessary to offset part or all of the Net-Metering Customer requirements for electricity in the form of:

   a. The monthly electric bills for the 12 months prior to the application for the Generation Meter and Additional Meter(s), if any, to be credited with Channel 2 Excess Generation and Net Excess Generation Credits or
   b. In the absence of historical data reasonable estimates for the class and character of service may be made; and

4. A copy of the Preliminary Interconnection Review Request submitted to the Electric Utility and the results of the utility's interconnection site review conducted pursuant to Rule 3.03.

SECTION 3. INTERCONNECTION OF NET- METERING FACILITIES TO EXISTING ELECTRIC POWER SYSTEMS

Rule 3.01 Requirements for Initial Interconnection of a Net-Metering Facility

A. A Net-Metering customer shall execute a Standard Interconnection Agreement for Net-Metering Facilities (Appendix A) prior to interconnection with the utility's facilities.

B. A Net-Metering Facility shall be capable of operating in parallel and safely commencing the delivery of power into the utility system at a single point of interconnection. To prevent a Net-Metering Customer from back-feeding a de-energized line, a Net-Metering Facility shall have a visibly open, lockable, manual disconnect switch which is accessible by the Electric Utility and clearly labeled. This requirement for a manual disconnect switch shall be waived if the following three conditions are met: 1) The inverter equipment must be designed to shut down or disconnect and cannot be manually overridden by the customer upon loss of utility service; 2) The inverter must be warranted by the manufacturer to shut down or disconnect upon loss of utility service; and 3) The inverter must be properly installed and operated, and inspected and/or tested by utility personnel.

C. The customer shall submit a Standard Interconnection Agreement to the Electric Utility at least thirty (30) days prior to the date the customer intends to interconnect the Net-Metering Facilities to the utility's facilities. Part I, Standard Information, Sections 1 through 4 of the Standard Interconnection Agreement must be completed for the notification to be valid. The customer shall have all equipment necessary to complete the interconnection prior to such notification. If mailed, the date of notification shall be the third day following the mailing of the Standard Interconnection Agreement. The Electric Utility shall provide a copy of the Standard Interconnection Agreement to the customer upon request.

D. Following notification by the customer as specified in Rule 3.01.C., the utility shall review the plans of the facility and provide the results of its review to the customer, in writing, within 30 calendar days. Any items that would prevent Parallel Operation due to violation of safety standards and/or power generation limits shall be explained along with a description of the modifications necessary to remedy the violations.

E. The Net-Metering Facility, at the Net-Metering Customer's expense, shall meet safety and performance standards established by local and national electrical codes including the National Electrical Code (NEC), the Institute of Electrical and Electronics Engineers (IEEE), the National Electrical Safety Code (NESC), and Underwriters Laboratories (UL).

F. The Net-Metering Facility, at the Net-Metering Customer's expense, shall meet all safety and performance standards adopted by the Electric Utility and filed with and approved by the Commission pursuant to these Rules that are necessary to assure safe and reliable operation of the Net-Metering Facility to the Electric Utility's system.

G. If the Electric Utility's existing facilities are not adequate to interconnect with the Net-Metering Facility, the Net-Metering Customer shall pay the cost of additional or reconfigured facilities prior to the installation or reconfiguration of the facilities.

Rule 3.02 Requirements for Modifications or Changes to a Net-Metering Facility

A. Prior to being made, the Net-Metering Customer shall notify the Electric Utility of, and the Electric Utility shall evaluate, any modifications or changes to the Net-Metering Facility described in Part I, Standard Information, Section 2 of the Standard Interconnection Agreement for Net-Metering Facilities. The notice provided by the Net-Metering Customer shall provide detailed information describing the modifications or changes to the Electric Utility in writing, including a revised Standard Interconnection Agreement for Net-Metering Facilities that clearly identifies the changes to be made. The utility shall review the proposed changes to the facility and provide the results of its evaluation to the customer, in writing, within thirty (30) days of receipt of the customer's proposal. Any items that would prevent Parallel Operation due to violation of applicable safety standards and/or power generation limits shall be explained along with a description of the modifications necessary to remedy the violations.

B. If the Net-Metering Customer makes such modification without the Electric Utility's prior written authorization and the execution of a new Standard Interconnection Agreement, the Electric Utility shall have the right to suspend Net-Metering service pursuant to the procedures in Section 6 of the Commission's General Service Rules.

C. A Net-Metering Facility shall not be modified or changed to generate electrical energy in excess of the amount necessary to offset all of the Net-Metering Customer requirements for electricity.

Rule 3.03 Requirements for Preliminary Interconnection Site Review Request

A. For the purpose of requesting that the Electric Utility conduct a preliminary interconnection site review for a proposed Net-Metering Facility pursuant to Rule 2.05.B.4, or as otherwise requested by the customer, the customer shall notify the Electric Utility by submitting a completed Preliminary Interconnection Site Review Request. The customer shall submit a separate Preliminary Interconnection Site Review Request for each point of interconnection if information about multiple points of interconnection is requested. Part 1, Standard Information, Sections 1 through 4 of the Preliminary Interconnection Site Review Request must be completed for the notification to be valid. If mailed, the date of notification shall be the third day following the mailing of the Preliminary Interconnection Site Review Request. The Electric Utility shall provide a copy of the Preliminary Interconnection Site Review Request to the customer upon request.

B. Following notification by the customer as specified in Rule 3.03.A., the Electric Utility shall review the plans of the facility interconnection and provide the results of its review to the customer, in writing, within 30 calendar days. If the customer requests that multiple interconnection site reviews be conducted the Electric Utility shall make reasonable efforts to provide the customer with the results of the review within 30 calendar days. If the Electric Utility cannot meet the deadline it will provide the customer with an estimated date by which it will complete the review. Any items that would prevent Parallel Operation due to violation of safety standards and/or power generation limits shall be explained along with a description of the modifications necessary to remedy the violations.

C. The preliminary interconnection site review is non-binding and need only include existing data and does not require the Electric Utility to conduct a study or other analysis of the proposed interconnection site in the event that data is not readily available. The utility shall notify the customer if additional site screening may be required prior to interconnection of the facility. The customer shall be responsible for the actual costs of conducting the preliminary interconnection site review and any subsequent costs associated with site screening that may be required.

D. The preliminary interconnection site review does not relieve the customer of the requirement to execute a Standard Interconnection Agreement prior to interconnection of the facility.

SECTION 4. STANDARD INTERCONNECTION AGREEMENT, PRELIMINARY INTERCONNECTION SITE REVIEW REQUEST, AND STANDARD NET-METERING TARIFF FOR NET-METERING FACILITIES

Rule 4.01 Standard Interconnection Agreement, Preliminary Interconnection Site Review Request, and Standard Net-Metering Tariff

Each Electric Utility shall file, for approval by the Commission, a Standard Interconnection Agreement for Net-Metering Facilities (Appendix A), Standard Interconnection Agreement for Net-Metering Facilities – Disclaimer (Appendix B); Preliminary Interconnection Site Review Request (Appendix C), a Net-Metering Tariff – Grandfathered (Appendix D), and a Net-Metering Tariff in standard tariff format (Appendix E).

Rule 4.02 Filing and Reporting Requirements

Each Electric Utility shall file in Docket No. 06-105-U by March 15 of each year, a report individually listing each Net-Metering Facility, the type of resource (Solar, Wind, etc.), its use (Residential or Other), generator capacity rating, inverter capacity rating, and if the Net-Metering Facility is associated with Additional Meters (Yes or No), as of the end of the previous calendar year. The annual report shall be provided in spreadsheet format.

APPENDIX A

STANDARD INTERCONNECTION AGREEMENT FOR NET-METERING FACILITIES

I. STANDARD INFORMATION

Section 1. Customer Information

Name:_____
Mailing Address:_____
City:_____ State: _____ Zip Code: _____
Facility Location (if different from above):_____
Daytime Phone: _____ Evening Phone: _____
Utility Customer Account Number (from electric bill) to which the Net-Metering Facility is physically attached: _____

Section 2. Generation Facility Information

System Type: Solar Wind Hydro Geothermal Biomass Fuel Cell Micro turbine (circle one)
Generator Rating (kW): _____ AC or DC (circle one)
Describe Location of Accessible and Lockable Disconnect (If required): _____
_____
Inverter Manufacturer: _____ Inverter Model: _____
Inverter Location:_____ Inverter Power Rating: _____
Expected Capacity Factor: _____
Expected annual production of electrical energy (kWh) calculated using industry recognized simulation model (PVWatts, etc.): _____

Section 3. Installation Information

Attach a detailed electrical diagram of the Net-Metering Facility.
Installed by: _____
Qualifications/Credentials: _____
Mailing Address:_____
City:_____State: _____ Zip Code:_____
Daytime Phone:_____ Installation Date:_____

Section 4. Certification

The system has been installed in compliance with the local Building/Electrical Code of
_____(City/County)
Signed (Inspector):_____ Date:_____
(In lieu of signature of inspector, a copy of the final inspection certificate may be attached.)

The system has been installed to my satisfaction and I have been given system warranty information and an operation manual, and have been instructed in the operation of the

system.
Signed (Owner):_____ Date:_____

Section 5. E-mail Addresses for parties
Customer's e-mail address: _____
Utility's e-mail address: _____ (To be provided by utility.)

Section 6. Utility Verification and Approval
Facility Interconnection Approved: _____ Date: _____
Metering Facility Verification by: _____ Verification Date: _____

II. INTERCONNECTION AGREEMENT TERMS AND CONDITIONS

This Interconnection Agreement for Net-Metering Facilities ("Agreement") is made and entered into this _____day of _____, 20_____, by _____ ("Electric Utility") and _____ ("Customer"), a_____(specify whether corporation or other), each hereinafter sometimes referred to individually as "Party" or collectively as the "Parties". In consideration of the mutual covenants set forth herein, the Parties agree as follows:

Section 1. The Net-Metering Facility
The Net-Metering Facility meets the requirements of Ark. Code Ann. § 23-18-603(6) and the Arkansas Public Service Commission's *Net-Metering Rules*.

Section 2. Governing Provisions
The Parties shall be subject to the provisions of Ark. Code Ann. § 23-18-604 and the terms and conditions set forth in this Agreement, the Commission's *Net-Metering Rules*, the Commission's *General Service Rules*, and the Electric Utility's applicable tariffs.

Section 3. Interruption or Reduction of Deliveries
The Electric Utility shall not be obligated to accept and may require Customer to interrupt or reduce deliveries when necessary in order to construct, install, repair, replace, remove, investigate, or inspect any of its equipment or part of its system; or if it reasonably determines that curtailment, interruption, or reduction is necessary because of emergencies, forced outages, force majeure, or compliance with prudent electrical practices. Whenever possible, the Utility shall give the Customer reasonable notice of the possibility that interruption or reduction of deliveries may be required. Notwithstanding any other provision of this Agreement, if at any time the Utility reasonably determines that either the facility may endanger the Electric Utility's personnel or other persons or property, or the continued operation of the Customer's facility may endanger the integrity or safety of the Utility's electric system, the Electric Utility shall have the right to disconnect and lock out the Customer's facility from the Electric Utility's electric system. The Customer's facility shall remain disconnected until such time as the Electric Utility is reasonably satisfied that the conditions referenced in

this Section have been corrected.

Section 4. Interconnection

Customer shall deliver the as-available energy to the Electric Utility at the Electric Utility's meter.

Electric Utility shall furnish and install a standard kilowatt hour meter. Customer shall provide and install a meter socket for the Electric Utility's meter and any related interconnection equipment per the Electric Utility's technical requirements, including safety and performance standards.

The customer shall submit a Standard Interconnection Agreement to the Electric Utility at least thirty (30) days prior to the date the customer intends to interconnect the Net-Metering Facilities to the utility's facilities. Part I, Standard Information, Sections 1 through 4 of the Standard Interconnection Agreement must be completed be valid. The customer shall have all equipment necessary to complete the interconnection prior to such notification. If mailed, the date of notification shall be the third day following the mailing of the Standard Interconnection Agreement. The Electric Utility shall provide a copy of the Standard Interconnection Agreement to the customer upon request.

Following submission of the Standard Interconnection Agreement by the customer, the utility shall review the plans of the facility and provide the results of its review to the customer, in writing, within 30 calendar days. Any items that would prevent Parallel Operation due to violation of applicable safety standards and/or power generation limits shall be explained along with a description of the modifications necessary to remedy the violations.

If the Electric Utility's existing facilities are not adequate to interconnect with the Net-Metering Facility, the Customer shall pay the cost of additional or reconfigured facilities prior to the installation or reconfiguration of the facilities.

To prevent a Net-Metering Customer from back-feeding a de-energized line, the customer shall install a manual disconnect switch with lockout capability that is accessible to utility personnel at all hours. This requirement for a manual disconnect switch will be waived if the following three conditions are met: 1) The inverter equipment must be designed to shut down or disconnect and cannot be manually overridden by the customer upon loss of utility service; 2) The inverter must be warranted by the manufacturer to shut down or disconnect upon loss of utility service; and 3) The inverter must be properly installed and operated, and inspected and/or tested by utility personnel.

Customer, at his own expense, shall meet all safety and performance standards established by local and national electrical codes including the National Electrical Code (NEC), the Institute of Electrical and Electronics Engineers (IEEE), the National Electrical Safety Code (NESC), and Underwriters Laboratories (UL).

Customer, at his own expense, shall meet all safety and performance standards adopted

by the utility and filed with and approved by the Commission that are necessary to assure safe and reliable operation of the Net Metering Facility to the utility's system.

Customer shall not commence Parallel Operation of the Net-Metering Facility until the Net Metering Facility has been inspected and approved by the Electric Utility. Such approval shall not be unreasonably withheld or delayed. Notwithstanding the foregoing, the Electric Utility's approval to operate the Customer's Net-Metering Facility in parallel with the Utility's electrical system should not be construed as an endorsement, confirmation, warranty, guarantee, or representation concerning the safety, operating characteristics, durability, or reliability of the Customer's Net-Metering Facility.

Section 5. Modifications or Changes to the Net-Metering Facility Described in Part 1, Section 2

Prior to being made, the Customer shall notify the Electric Utility of, and the Electric Utility shall evaluate, any modifications or changes to the Net-Metering Facility described in Part 1, Standard Information, Section 2 of the Standard Interconnection Agreement for Net-Metering Facilities. The notice provided by the Customer shall provide detailed information describing the modifications or changes to the Utility in writing, including a revised Standard Interconnection Agreement for Net-Metering Facilities that clearly identifies the changes to be made. The Electric Utility shall review the proposed changes to the facility and provide the results of its evaluation to the Customer, in writing, within thirty (30) calendar days of receipt of the Customer's proposal. Any items that would prevent Parallel Operation due to violation of applicable safety standards and/or power generation limits shall be explained along with a description of the modifications necessary to remedy the violations.

If the Customer makes such modification without the Electric Utility's prior written authorization and the execution of a new Standard Interconnection Agreement, the Electric Utility shall have the right to suspend Net-Metering service pursuant to the procedures in Section 6 of the Commission's General Service Rules.

A Net-Metering Facility shall not be modified or changed to generate electrical energy in excess of the amount necessary to offset all of the Net-Metering Customer requirements for electricity.

Section 6. Maintenance and Permits

The customer shall obtain any governmental authorizations and permits required for the construction and operation of the Net-Metering Facility and interconnection facilities. The Customer shall maintain the Net-Metering Facility and interconnection facilities in a safe and reliable manner and in conformance with all applicable laws and regulations.

Section 7. Access to Premises

The Electric Utility may enter the Customer's premises to inspect the Customer's protective devices and read or test the meter. The Electric Utility may disconnect the interconnection facilities without notice if the Electric Utility reasonably believes a

hazardous condition exists and such immediate action is necessary to protect persons, or the Electric Utility's facilities, or property of others from damage or interference caused by the Customer's facilities, or lack of properly operating protective devices.

Section 8. Indemnity and Liability

The following is Applicable to Agreements between the Electric Utility and to all Customers except the State of Arkansas and any entities thereof, local governments and federal agencies:

Each Party shall indemnify the other Party, its directors, officers, agents, and employees against all loss, damages, expense and liability to third persons for injury to or death of persons or injury to property caused by the indemnifying party's engineering, design, construction, ownership, maintenance or operations of, or the making of replacements, additions or betterment to, or by failure of, any of such Party's works or facilities used in connection with this Agreement by reason of omission or negligence, whether active or passive. The indemnifying Party shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity. The indemnifying Party shall pay all costs that may be incurred by the other Party in enforcing this indemnity. It is the intent of the Parties hereto that, where negligence is determined to be contributory, principles of comparative negligence will be followed and each Party shall bear the proportionate cost of any loss, damage, expense and liability attributable to that Party's negligence. Nothing in this paragraph shall be applicable to the Parties in any agreement entered into with the State of Arkansas or any entities thereof, or with local governmental entities or federal agencies. Furthermore, nothing in this Agreement shall be construed to waive the sovereign immunity of the State of Arkansas or any entities thereof. The Arkansas State Claims Commission has exclusive jurisdiction over claims against the state.

Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to or any liability to any person not a Party to this Agreement. Neither the Electric Utility, its officers, agents or employees shall be liable for any claims, demands, costs, losses, causes of action, or any other liability of any nature or kind, arising out of the engineering, design, construction, ownership, maintenance or operation of, or the making of replacements, additions or betterment to, or by failure of, the Customer's facilities by the Customer or any other person or entity.

Section 9. Notices

The Net-Metering Customer shall notify the Electric Utility of any changes in the information provided herein.

All written notices shall be directed as follows:

Attention:
[Electric Utility Agent or Representative]
[Electric Utility Name and Address]

Attention:
[Customer]
Name:_____
Address: _____

City:_____

Customer notices to Electric Utility shall refer to the Customer's electric service account number set forth in Section 1 of this Agreement.

Section 10. Term of Agreement

The term of this Agreement shall be the same as the term of the otherwise applicable standard rate schedule. This Agreement shall remain in effect until modified or terminated in accordance with its terms or applicable regulations or laws.

Section 11. Assignment

This Agreement and all provisions hereof shall inure to and be binding upon the respective Parties hereto, their personal representatives, heirs, successors, and assigns. The Customer shall not assign this Agreement or any part hereof without the prior written consent of the Electric Utility, and such unauthorized assignment may result in termination of this Agreement.

Section 12. Net-Metering Customer Certification

I hereby certify that all of the information provided in this Agreement is true and correct, to the best of my knowledge, and that I have read and understand the Terms and Conditions of this Agreement.

Signature: _____ Date: _____

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized representatives.

Dated this _____ day of _____, 20__.

Customer:	Electric Utility:
_____	_____
By: _____	By:_____
Title: _____	Title:_____
Mailing Address:	Mailing Address:
_____	_____
_____	_____
E-mail Address:	E-mail Address:
_____	_____

APPENDIX B

STANDARD INTERCONNECTION AGREEMENT FOR NET-METERING FACILITIES

Disclaimer

POSSIBLE FUTURE RULES OR RATE CHANGES, OR BOTH AFFECTING YOUR NET-METERING FACILITY

The following is a supplement to the Interconnection Agreement you signed with _____[Electric Utility].

1. Electricity rates, basic charges, and service fees, set by [Electric Utility] and approved by the Arkansas Public Service Commission (Commission), are subject to change.
2. I understand that I will be responsible for paying any future increases to my electricity rates, basic charges, or service fees from [Electric Utility].
3. My Net-Metering System is subject to the current rates of [Electric Utility], and the rules and regulations of the Commission. The [Electric Utility] may change its rates in the future with approval of the Commission or the Commission may alter its rules and regulations, or both may happen. If either or both occurs, my system will be subject to those changes.

By signing below, you acknowledge that you have read and understand the above disclaimer.

_____
Name (printed)

_____
Signature

_____
Date

APPENDIX C

PRELIMINARY INTERCONNECTION SITE REVIEW REQUEST

I. STANDARD INFORMATION

Section 1. Customer Information

Name:_____
Contact Person:_____
Mailing Address:_____
City:_____ State: _____ Zip Code: _____
Facility Location (if different from above):_____
Daytime Phone: _____ Evening Phone: _____
E-Mail Address:_____Fax:_____
If the requested point of interconnection is the same as an existing electric service, provide the electric service account number:_____
Additional Customer Accounts (from electric bill) to be credited with Net Excess Generation:_____
Annual Energy Requirements (kWh) in the previous twelve (12) months for the account physically attached to the Net-Metering Facility and for any additional accounts listed (in the absence of historical data reasonable estimates for the class and character of service may be made):_____

Section 2. Generation Facility Information

System Type: Solar Wind Hydro Geothermal Biomass Fuel Cell Micro Turbine (circle one)
Generator Rating (kW): _____ AC or DC (circle one)
Expected Capacity Factor: _____
Expected annual production of electrical energy (kWh) of the facility calculated using industry recognized simulation model (PVWatts, etc):_____

Section 3. Interconnection Information

Attach a detailed electrical diagram showing the configuration of all generating facility equipment, including protection and control schemes.
Requested Point of Interconnection:_____
Customer-Site Load (kW) at Net-Metering Facility location (if none, so state): _____
Interconnection Request: Single Phase:_____Three Phase:_____

Section 4. Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Preliminary Interconnection Site Review is true and correct.

Signature: _____ Date: _____

II. TERMS AND CONDITIONS

Section 1. Requirements for Request

For the purpose of requesting that the Electric Utility conduct a preliminary interconnection site review for a proposed Net-Metering Facility pursuant to the requirement of Rule 2.06.B.4, or as otherwise requested by the customer, the customer shall notify the Electric Utility by submitting a completed Preliminary Interconnection Site Review Request. The customer shall submit a separate Preliminary Interconnection Site Review Request for each point of interconnection if information about multiple points of interconnection is requested. Part 1, Standard Information, Sections 1 through 4 of the Preliminary Interconnection Site Review Request must be completed for the notification to be valid. If mailed, the date of notification shall be the third day following the mailing of the Preliminary Interconnection Site Review Request. The Electric Utility shall provide a copy of the Preliminary Interconnection Site Review Request to the customer upon request.

Section 2. Utility Review

Following submission of the Preliminary Interconnection Site Review Request by the customer the Electric Utility shall review the plans of the facility interconnection and provide the results of its review to the customer, in writing, within 30 calendar days. If the customer requests that multiple interconnection site reviews be conducted the Electric Utility shall make reasonable efforts to provide the customer with the results of the review within 30 calendar days. If the Electric Utility cannot meet the deadline it will provide the customer with an estimated date by which it will complete the review. Any items that would prevent Parallel Operation due to violation of safety standards and/or power generation limits shall be explained along with a description of the modifications necessary to remedy the violations.

The preliminary interconnection site review is non-binding and need only include existing data and does not require the Electric Utility to conduct a study or other analysis of the proposed interconnection site in the event that data is not readily available. The Electric Utility shall notify the customer if additional site screening may be required prior to interconnection of the facility. The customer shall be responsible for the actual costs for conducting the preliminary interconnection site review and any subsequent costs associated with site screening that may be required.

Section 3. Application to Exceed 300 kW Net-Metering Facility Size Limit

This Preliminary Interconnection Site Review Request and the results of the Electric Utility's review of the facility interconnection shall be filed with the Commission with the customer's application to exceed the 300 kW facility size limit pursuant to Net Metering Rule 2.05.B.4.

Section 4. Standard Interconnection Agreement

The preliminary interconnection site review does not relieve the customer of the requirement to execute a Standard Interconnection Agreement prior to interconnection of the facility.

APPENDIX D

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.	
Replacing:	Sheet No.	
Name of Company		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. X		
Title: NET-METERING TARIFF -GRANDFATHERED		PSC File Mark Only

X. GRANDFATHERED NET-METERING AVAILABLE TO NET METERING FACILITIES WITH A SIGNED, STANDARD INTERCONNECTION AGREEMENT SUBMITTED BEFORE AAAA XX, 20XX

X.1. AVAILABILITY

X.1.1. To any residential or any other customer who takes service under standard rate schedule(s) _____ (list schedules) who is an owner of a Net-Metering Facility and has submitted a completed and signed Standard Interconnection Agreement for Net-Metering Facilities with the customer's Electric Utility prior to [date of Order in Phase 2]. This schedule will expire on [date of Order in Phase 2 + 20 years]. The generating capacity of Net-Metering Facilities may not exceed the greater of: 1) twenty-five kilowatts (25 kW) or 2) one hundred percent (100%) of the Net-Metering Customer's highest monthly usage in the previous twelve (12) months for Residential Use. The generating capacity of Net-Metering Facilities may not exceed three hundred kilowatts (300 kW) for non-residential use unless otherwise allowed by the Commission. Net-Metering is intended primarily to offset part or all of the customer's energy use.

If a customer sells premises with a Net-Metering Facility, the Standard Interconnection Agreement may be transferred to the new owner and this tariff shall continue in effect for the remainder of the term.

Thirty (30) days' prior to the expiration date of this schedule, the Electric Utility shall provide notice to the customer that this tariff will expire and that the customer's service will be subject to an applicable tariff.

The provisions of the customer's standard rate schedule are modified as specified herein.

APPENDIX D

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.	
Replacing:	Sheet No.	
Name of Company		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. X		
Title: NET-METERING TARIFF -GRANDFATHERED		PSC File Mark Only

X.1.2. Net-Metering Customers taking service under the provisions of this tariff may not simultaneously take service under the provisions of any other alternative source generation or co-generation tariff except as provided in the Net-Metering Rules.

X.2. MONTHLY BILLING

X.2.1. The Electric Utility shall separately meter, bill, and credit each Net-Metering Facility even if one (1) or more Net-Metering Facilities are under common ownership.

X.2.2. On a monthly basis, the Net-Metering Customer shall be billed the charges applicable under the currently effective standard rate schedule and any appropriate rider schedules. Under Net-Metering, only the kilowatt hour (kWh) units of a customer's bill are netted.

X.2.3. If the kWhs supplied by the Electric Utility exceed the kWhs generated by the Net-Metering Facility and fed back to the Electric Utility during the Billing Period, the Net-Metering Customer shall be billed for the net kWhs supplied by the Electric Utility in accordance with the rates and charges under the customer's standard rate schedule and any appropriate rider schedules.

X.2.4. If the kWhs generated by the Net-Metering Facility and fed back to the Electric Utility exceed the kWhs supplied by the Electric Utility to the Net-Metering Customer during the applicable Billing Period, the utility shall credit the Net-Metering Customer with any accumulated Net Excess Generation in the next applicable Billing Period.

X.2.5. Net Excess Generation shall first be credited to the Net-Metering Customer's Generation Meter.

X.2.6. After application of X.2.5 and upon request of the Net-Metering Customer pursuant to X.2.8, any remaining Net Excess Generation Credits shall be credited to one or more of

APPENDIX D

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.	
Replacing:	Sheet No.	
Name of Company		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. X		
Title: NET-METERING TARIFF -GRANDFATHERED		PSC File Mark Only

the Net-Metering Customer's Additional Meters in the rank order provided by the customer.

X.2.7 The billing amount in a given Billing Period will never be less than the otherwise applicable minimum bill or customer charge.

X.2.8. Net Excess Generation Credits shall be credited as described in X.2.5, X.2.6, and X.2.7 during subsequent Billing Periods. Net Excess Generation Credits remaining in a Net-Metering Customer's account at the close of a Billing Period shall not expire and shall be carried forward to subsequent Billing Periods indefinitely.

X.2.9. For Net Excess Generation Credits older than 24 months, a Net-Metering Customer may elect to have the Electric Utility purchase the Net Excess Generation Credits in the Net-Metering Customer's account at the Electric Utility's estimated annual average Avoided Cost-rate for wholesale energy if the sum to be paid to the Net-Metering Customer is at least $100.

X.2.10. An Electric Utility shall purchase at the Electric Utility's estimated annual average Avoided Cost rate for wholesale energy any Net Excess Generation Credits remaining in a Net-Metering Customer's account when the Net-Metering Customer: 1) ceases to be a customer of the Electric Utility; 2) ceases to operate the Net-Metering Facility; or 3) transfers the Net-Metering Facility to another person.

X.2.11. When purchasing Net Excess Generation Credits from a Net-Metering Customer, the Electric Utility shall calculate the payment based on its annual average avoided energy costs in the applicable Regional Transmission Organization for the current calendar year.

X.2.12. Upon request from a Net-Metering Customer, an Electric Utility must apply Net Excess Generation Credits to the Net-Metering Customer's Additional Meters provided that:

APPENDIX D

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.	
Replacing:	Sheet No.	
Name of Company		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. X		
Title: NET-METERING TARIFF -GRANDFATHERED		PSC File Mark Only

(e) Additional Meter(s) shall be under common ownership within a single Electric Utility's service area; shall be used to measure the Net-Metering Customer's requirements for electricity; may be in a different class of service than the Generation Meter; shall be assigned to one and only one Generation Meter; shall not be a Generation Meter; and shall not be associated with unmetered service.

(f) The Net-Metering Customer must have given at least 30 days' notice to the Electric Utility of its request to apply Net Excess Generation Credits to the Additional Meter(s).

(g) The Additional Meter(s) must have been identified at the time of the request.

(h) In the event that more than one of the Net-Metering Customer's Additional Meters is identified, the Net-Metering Customer must designate the rank order for the Additional Meters to which Net Excess Generation Credits are to be applied. The Net-Metering Customer cannot designate the rank order more than once during the Annual Billing Cycle.

APPENDIX E

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.	
Replacing:	Sheet No.	
Name of Company		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. X		
Title: NET-METERING TARIFF		PSC File Mark Only

X. NET-METERING

X.1. AVAILABILITY

X.1.1. To any residential or any other customer who takes service under standard rate schedule(s) _____ (list schedules) who is an owner of a Net-Metering Facility and has submitted a completed and signed ~~a~~ Standard Interconnection Agreement for Net-Metering Facilities with the customer's Electric Utility after [date of Order in Phase 2]. The generating capacity of Net-Metering Facilities may not exceed the greater of: 1) twenty-five kilowatts (25 kW) or 2) one hundred percent (100%) of the Net-Metering Customer's highest monthly usage in the previous twelve (12) months for Residential Use. The generating capacity of Net-Metering Facilities may not exceed three hundred kilowatts (300kW) for non-residential use unless otherwise allowed by the Commission. Net-Metering is intended primarily to offset some or all of the customer's energy use.

The provisions of the customer's standard rate schedule are modified as specified herein.

X.1.2. Net-Metering Customers taking service under the provisions of this tariff may not simultaneously take service under the provisions of any other alternative source generation or co-generation tariff except as provided in the Net-Metering Rules.

X.2. MONTHLY 2-CHANNEL BILLING

X.2.1. The provisions of X.2 are applicable to the following non-demand based rate schedules: [list utility specific schedules].

APPENDIX E

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.	
Replacing:	Sheet No.	
Name of Company		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. X		
Title: NET-METERING TARIFF		PSC File Mark Only

X.2.2. The Electric Utility shall separately meter, bill, and credit each Net-Metering Facility, even if one (1) or more Net-Metering Facilities are under common ownership.

X.2.3. On a monthly basis, the Net-Metering Customer shall be billed the charges applicable under the currently effective standard rate schedule and any appropriate rider schedules for all kWhs supplied to the Net-Metering Customer by the Electric Utility measured through Channel 1.

X.2.4. If the kWhs supplied by the Electric Utility as measured on Channel 1 exceed the customer's Channel 2 Excess Generation, including any Net Excess Generation Credits, all Channel 2 Excess Generation, including any Net Excess Generation Credits, shall be credited at the rate established by the Excess Generation Credit Rider.

X.2.5 If the customer's Channel 2 Excess Generation, including any Net Excess Generation Credits, exceeds the kWhs supplied by the Electric Utility as measured on Channel 1, then the Channel 2 Excess Generation, including any Net Excess Generation Credits, not to exceed the kWhs measured on Channel 1 during the Billing Period, shall be credited at the rate established by the Excess Generation Credit Rider.

X.2.6. The billing amount in a given Billing Period will never be less than the otherwise applicable minimum bill or customer charge, plus any non-by-passable charges as approved by the Commission.

X.2.7. Net Excess Generation Credits remaining in a Net-Metering Customer's account at the close of a Billing Period shall not expire, shall be carried forward to subsequent Billing Periods indefinitely, and shall be applied as described in X.2.4, X.2.5, and X.2.6 during subsequent Billing Periods.

APPENDIX E

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.	
Replacing:	Sheet No.	
Name of Company		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. X		
Title: NET-METERING TARIFF		PSC File Mark Only

X.2.8. For Net Excess Generation Credits older than 24 months, a Net-Metering Customer may elect to have the Electric Utility purchase the Net Excess Generation Credits in the Net-Metering Customer's account at the Electric Utility's estimated annual average Avoided Cost rate for wholesale energy if the sum to be paid to the Net-Metering Customer is at least $100.

X.2.9 An Electric Utility shall purchase at the Electric Utility's estimated annual average Avoided Cost rate for wholesale energy any Net Excess Generation Credits remaining in a Net-Metering Customer's account when the Net-Metering Customer: 1) ceases to be a customer of the Electric Utility; 2) ceases to operate the Net-Metering Facility; or 3) transfers the Net-Metering Facility to another person.

X.2.10 When purchasing Net Excess Generation Credits from a Net-Metering Customer, the Electric Utility shall calculate the payment based on its annual average avoided energy costs in the applicable Regional Transmission Organization for the current calendar year.

X.3. MONTHLY BILLING FOR DEMAND METERED TARIFFS

X.3.1. The provisions of X.3 are applicable to the following demand based rate schedules: [list utility specific schedules].

X.3.2. The Electric Utility shall separately meter, bill, and credit each Net-Metering Facility even if one (1) or more Net-Metering Facilities are under common ownership.

X.3.3. On a monthly basis, a Net-Metering Customer taking service under a Demand Metered Tariff pursuant to X. 3 of this rate schedule shall be billed the charges applicable under the currently effective standard rate schedule and any appropriate rider schedules. For Demand Metered Tariffs, only the kWh units of a customer's bill are netted.

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X.3.4. If the kWhs supplied by the Electric Utility exceed the kWhs generated by the Net-Metering Facility and fed back to the Electric Utility during the Billing Period, the Net-Metering Customer shall be billed for the net kWhs supplied by the Electric Utility in accordance with the rates and charges under the customer's standard rate schedule.

X.3.5. If the kWhs generated by the Net-Metering Facility and fed back to the Electric Utility exceed the kWhs supplied by the Electric Utility to the Net-Metering Customer during the applicable Billing Period, the utility shall credit the Net-Metering Customer with any accumulated Net Excess Generation Credits in the next applicable Billing Period.

X.3.6. The billing amount in a given Billing Period will never be less than the otherwise applicable minimum bill or customer charge, plus any non-by-passable charges as approved by the Commission.

X.3.7. Net Excess Generation Credits shall be credited as described in X.3.5 and X.3.6 during subsequent Billing Periods. Any Net Excess Generation Credits remaining in a Net-Metering Customer's account at the close of a Billing Period shall not expire and shall be carried forward to subsequent Billing Periods indefinitely.

X.3.8. For Net Excess Generation Credits older than 24 months, a Net-Metering Customer may elect to have the Electric Utility purchase the Net Excess Generation Credits in the Net-Metering Customer's account at the Electric Utility's estimated annual average Avoided Cost rate for wholesale energy if the sum to be paid to the Net-Metering Customer is at least $100. An Electric Utility shall purchase at the Electric Utility's estimated annual average Avoided Cost rate for wholesale energy any Net Excess Generation Credits remaining in a Net-Metering Customer's account when the Net-Metering Customer: 1) ceases to be a customer of the Electric Utility; 2) ceases to operate the Net-Metering Facility; or 3) transfers the Net-Metering Facility to another person.

APPENDIX E

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Original	Sheet No.	
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Title: NET-METERING TARIFF		PSC File Mark Only

When purchasing Net Excess Generation Credits from a Net-Metering Customer, the Electric Utility shall calculate the payment based on its annual average avoided energy costs in the applicable Regional Transmission Organization for the current calendar year.

X.4. MONTHLY BILLING FOR ADDITIONAL METERS

X.4.1. Upon request from a Net-Metering Customer, an Electric Utility shall apply Net Excess Generation Credits to the Net-Metering Customer's Additional Meter(s) provided that:

(e) Additional Meter(s) shall be under common ownership within a single Electric Utility's service area; shall be used to measure the Net-Metering Customer's requirements for electricity; may be in a different class of service than the Generation Meter; shall be assigned to one and only one Generation Meter; shall not be a Generation Meter; and shall not be associated with unmetered service.

(f) The Net-Metering Customer must give at least 30 days' notice to the Electric Utility of its request to apply Net Excess Generation Credits to the Additional Meter(s).

(g) The Additional Meter(s) must be identified at the time of the request.

(h) In the event that more than one of the Net-Metering Customer's Additional Meters is identified, the Net-Metering Customer must designate the rank order for the Additional Meters to which the Net Excess Generation Credits are to be applied. The Net-Metering Customer cannot designate the rank order more than once during the Annual Billing Cycle.

X.4.2. Net Excess Generation Credits shall be applied to one or more of the Net Metering Customer's Additional Meter(s) in the rank order provided by the Net Metering Customer. Net Excess Generation Credits applied to an Additional Meter during any

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Title: NET-METERING TARIFF		PSC File Mark Only

Billing Period shall not exceed the kWhs supplied by the Electric Utility to the Additional Meter.

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APPENDIX F

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.	
Replacing:	Sheet No.	
Name of Company		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. X		
Title: EXCESS GENERATION CREDIT RIDER		PSC File Mark Only

X. EXCESS GENERATION CREDIT RIDER

X.1. APPLICABILITY

This Excess Generation Credit Rider (EGC Rider) applies to all Net-Metering Customers taking service pursuant to Section X.2 - Monthly 2-Channel Billing of the Net-Metering Tariff.

X.2. PURPOSE

The purpose of this EGC Rider is to establish the credit rate that is to be applied to kWhs classified as Channel 2 Excess Generation and Net Excess Generation Credits.

X.3. EXCESS GENERATION CREDIT RATE

The Excess Generation Credit Rate (EGC Rate) shall be determined in the manner approved by the Arkansas Public Service Commission (Commission) pursuant to Order No. {xx} in Docket No. 16-027-R and shall become effective upon the date established by the Commission. The EGC Rate listed in Attachment A to this EGC Rider shall be redetermined annually through filings made in accordance with the provisions of § X.4 of this EGC Rider.

X.4. ANNUAL RE-DETERMINATION

On or before March 1 of each year beginning in 2019, a re-determined EGC Rate shall be filed by the Company with the Commission. The re-determined EGC Rate shall be determined by application of the Formula set out in Attachment A to this EGC Rider. Each such revised EGC Rate filing shall be filed in Docket xx-xxx-TF and be accompanied by a set of workpapers sufficient to fully document the calculations of the revised EGC Rate.

APPENDIX F

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.	
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Name of Company		
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Part III. Rate Schedule No. X		
Title: EXCESS GENERATION CREDIT RIDER		PSC File Mark Only

The Commission General Staff (Staff) shall review the EGC Rate to verify that the Formula in Attachment A has been correctly applied and shall notify the Company of any necessary corrections. After the Staff completes its review of the EGC Rate calculation, the Company shall make appropriate changes to correct undisputed errors identified by the Staff in its review. Any disputed issues arising out of the Staff review are to be resolved by the Commission after notice and hearing.

The EGC Rate so re-determined shall be effective for bills rendered on and after the first billing cycle of April of the filing year.

X.5. TERM

This EGC Rider shall remain in effect until modified or terminated in accordance with applicable regulations or laws.

APPENDIX F

Appendix A to
Rate Schedule No. XX
Attachment Page X of X
Schedule Sheet X of X
Including Attachments

[Company Name]
Excess Generation Rider Credit Formula
(Residential Rate Class)

Embedded Capacity

Column	1	2	3
Function	Functionalized Embedded Capacity $/kWh	Capacity Benefit %	Embedded Capacity Credit $/kWh
Production	$ 0.04003	54%	$ 0.02153
Transmission	$ 0.01083	36%	$ 0.00392

Embedded Capacity Credit $/kWh **$ 0.2545**

Avoided Incremental Fuel

Column	4	5	6
	Average Hourly LMP $/kWh	Embedded Distribution Line Losses %	Avoided Incremental Energy $/kWh
Avoided RTO Energy $/kWh	$ 0.02761	7.4 %	**$ 0.02966**

Residential Excess Generation Rider Credit $ 0.05511

APPENDIX F

Appendix A to
Rate Schedule No. XX
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Including Attachments

[Company Name]
Excess Generation Rider Credit Formula
(Non-Residential Rate Class)

Embedded Capacity

Column	1	2	3
Function	Functionalized Embedded Capacity $/kWh	Capacity Benefit %	Embedded Capacity Credit $/kWh
Production			
Transmission			

Embedded Capacity Credit $/kWh **$ 0.0xxxx**

Avoided Incremental Fuel

Column	4	5	6
	Average Hourly LMP $/kWh	Embedded Distribution Line Losses %	Avoided Incremental Energy $/kWh
Avoided RTO Energy $/kWh			

Non-Residential Excess Generation Rider Credit $ 0.0xxxx

APPENDIX F

Appendix A to
Rate Schedule No. XX
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Embedded Capacity

The allocation of the embedded functionalized base-rate cost by applying the capacity benefit of the net-metering facility

Avoided Incremental Fuel

The calculation of the cost of the avoided incremental fuel

Column 1 – Functionalized Embedded Capacity $/kWh

The embedded functionalized base-rate cost of providing production and transmission service for the Residential or non-Residential Class of customers expressed as a $/kWh based on the utility's last approved Cost of Service Study, as adjusted for a Formula Rate Plan, U-2811, Act 821, or other Commission approved adjustments to base rates.

Column 2 – Capacity Benefit %

The benefit of a customer's self-generation provided to production and transmission service for the Residential or non-Residential Class of customers derived from the solar capacity factor determined by using a three hour average capacity factor produced by the PVWatts ® Model for a window either side of the utility's peak hour over the most recent five years averaged for either a 1 CP, 4 CP, or 12 CP, consistent with the utility's the cost allocation methodology underlying rates approved by the Commission in the utility's last general rate case.

Column 3 – Embedded Capacity Credit $/kWh

The multiplication of Column 1 and Column 2.

Column 4 – Avoided Incremental Fuel $/kWh

The average weighted avoided increment fuel is represented by the historical annual hourly real-time locational marginal price (LMP), based on the previous calendar year from MISO, SPP, or both, as applicable for the utility determined by summing the product of each hours solar AC output in kWh times the hourly LMP for the calendar year divided by the annual AC kWh generation of the solar facility as determined by the PVWatts ® Model.

Column 5 – Embedded Distribution Line Losses %

The average distribution line losses consistent with the cost allocation methodology underlying rates approved by the Commission in the utility's last general rate case.

Column 6 – Avoided Incremental Energy $/kWh

The Avoided Incremental Fuel in $/kWh increased for Embedded Distribution Losses by multiplying Avoided Incremental Fuel by one (1) plus Embedded Distribution Line Losses. (Column 4 x (1+ Column 5)).

Excess Generation Rider Credit

The sum of the Embedded Capacity Credit $/kWh and the Avoided Incremental Energy $/kWh.

PULASKI COUNTY RECOMMENDATIONS

A. The Arkansas Public Service Commission ("the Commission") is under no obligation to promulgate rates for net-metering customers, as the burdens set forth in Act 827 of 2015 ("Act 827") have not been met.

There is no legal presumption, pursuant to Act 827, requiring the Commission to impose a different rate structure than already exists for net-metering customers. Further, there has been no factual basis presented to change the existing net-metering compensation structure that currently exists.

While the relevant statute, Ark. Code Ann. § 23-18-604(b), does use the language "shall stablish appropriate rates, terms, and conditions for net-metering contracts[,]" the statute creates a contingent precedent for rates being imposed: evidence presented that there are quantifiable additional costs to the electric utilities "associated with the net-metering customer's use of the electric utility's capacity, distribution system, or transmission system and any effect on the electric utility's reliability[,]" and only if those costs are net of the benefits provided to the electric utilities by net-metering customers.

There is an affirmative burden, pursuant to Act 827, to establish that there are additional quantifiable net costs incurred due to net metering, before a change to the existing rate structure for net-metering customers is imposed. There is no inherent obligation for the Commission, created by Act 827, to change the existing rate structure for net-metering customers. In fact, creating an additional rate structure or modifying the existing rate structure at this time, absent proof of a quantifiable net cost to the electric utilities, is clearly contradictory to the codified public purpose favoring net

energy metering set forth in the Arkansas Renewable Energy Development Act of 2001 ("AREDA").

Simply put, the burden set forth in Ark. Code Ann. § 23-18-604(b) requires proof of net costs to utilities before proceeding to the ratemaking phase. For the Commission to create a new rate structure for net-metering customers, including that costs be imposed upon net-metering customers, would be clearly contrary to Act 827, as there has been insufficient evidence presented that there are quantifiable additional costs created by net-metering customers, that outweigh the benefits of net-metering. As Act 827 does not necessitate a specific time period for the Commission to establish appropriate rates, terms, and conditions for net-metering contracts, the Commission should not rush into promulgating rates, terms, or conditions, as the record lacks relevant information reflecting the actual quantifiable benefits and costs associated with net-metering. The Commission should take a conservative approach, ordering a long-term, independent study that analyzes usage patterns, actual occurrences, practices, and results.

B. <u>Any proposed rates, terms, or conditions promulgated pursuant to Act 827 would be unduly speculative.</u>

Pulaski County asserts any proposal regarding costs and benefits regarding net metering is improperly speculative until an Arkansas-specific study and report is produced by a qualified, independent third party, with thorough data analysis, as has been done in other jurisdictions.

At the October 4, 2016 hearing, one (1) of the points of disagreement was over how many net-metering customers exist in Arkansas. While there was a range of figures, no one stated that there were more than five-hundred net-metering customers.

Therefore, for the sake of simplicity, Pulaski County will stipulate that there are five-hundred (500) net-metering customers in Arkansas, as that is consistent with the approximation recited at the hearing.

Five-hundred (500) net-metering customers does not provide enough relevant data to quantifiably demonstrate that there are either costs to the electric utilities associated with net-metering or tangible benefits to the grid. Consequently, the impact, in cost and benefits, of five-hundred (500) net-metering customers may not be consistent with the costs and benefits of five-thousand (5,000) or fifty-thousand (50,000) net-metering customers.

Thus, a long-term, ongoing independent study of Arkansas specific data should be conducted, so that the Commission can promulgate rates, terms or conditions that accurately reflect the actual quantifiable benefits and costs associated with net-metering for each rate class, for each utility. Approaching this matter conservatively, by commissioning a long-term study, will ensure that ratepayers and the electric utilities are protected, and that the demands of Act 827 are met.

C. <u>Distributed Generation and Net-Metering are good for local communities and school districts.</u>

AREDA contemplates economic development and job creation as a motivation for adoption, thus, Pulaski County believes this necessitates the Commission to consider the impact of the net-metering rules and rate structures on those matters. Pulaski County believes it can provide some additional perspective for the Commission.

The Commission, through its Order regarding grandfathering of net-metering customers, has recognized that uncertainty, complexity, and shifting winds deters investment. Additionally, Pulaski County believes it is a generally accepted principle

that simplicity and certainty are good for investment, whether in energy production or any other industry. As such, "grandfathering" of existing users for a sufficient term, to reasonably calculate future expectations, directly addressed this potential for disincentives. However, if a rate modification or additional fee is warranted by demonstrable, quantifiable net costs to electric utilities, Pulaski County urges the Commission to keep it simple. Complexity, especially unnecessary complexity, will drive away investment, especially for those that struggle to traditionally receive capital investment, such as residential and small commercial consumers.

Pulaski County's participation in this docket is motivated by a desire to establish clear boundaries for participation in net metering, and accomplish AREDA's intent, which will help all consumers, including local governments. Direct investment into distributed generation and net-metering results in a capital improvement to real property. Distributed generation and net metering also result in the collection of sales taxes on the sale of capital goods. This is vitally important to consider, as this investment results in additional tax revenues to cities, counties and school districts, which does not occur through traditional power production, where there are generally a few large facilities, directly impacting the tax districts where the improvement resides.

The great thing about net metering is its simplicity. Any proposal that changes the existing net-metering compensation model is likely overly complicated and will hinder the intent of AREDA, which the Commission should avoid. A simple and straightforward net-metering rate structure can accomplish AREDA's intent, which in turn can help local governments and schools.

RECOMMENDATIONS
William Ball
for inclusion in Joint NMWG Report.

Act 827, a statutory sub-chapter of the Arkansas Renewable Energy Development Act of 2001 (AREDA), requires the Commission to examine the balance of costs and benefits of net metering within the context of a statute aimed at promoting customer-owned distributed renewable energy production.

In Order No. 1 of Docket 16-027-R, the Commission directs the Parties to provide comments that include answers to questions to be considered in the examination of costs and benefits of net metering, and that such costs and benefits be defined and given a value. Subsequently, came the formation of the Net Metering Working Group (NMWG) and a series of meetings by the NMWG to attempt to come to some consensus or failing to do so, provide recommendations to the Commission. It is fair to state that there has been little progress in reaching a consensus among the Parties. There is certainly debate on the value of the benefits that Arkansas enjoys as a result of net metering. If one believes that sustainability, economic benefit, distribution system benefits, public policy benefits and environmental benefits are important, then one would recognize the importance of robust development of our renewable energy resources. Okay, so these benefits are important, but it is very difficult to assign a monetary figure to the universal value of net metering.

I agree with comments from some Parties observing that we are putting the cart before the horse. Both obvious and intangible benefits must first be fully and fairly evaluated before there could possibly be a a rate schedule or protocol establishing

numbers that are a guess or a wish on the part of Parties on either side of the arguments. We need only to look at remedies being adopted by other states to see that some have valued benefits more highly than others. Some jurisdictions have determined that, far from shifting costs, NEM customers create net value to the grid and all grid users. Yet other jurisdictions have focused more on costs to a utility and somehow "keeping them whole". A program whereby utilities could purchase all energy, or just net excess, produced by a net metering customer could be considered if we are attempting to keep them whole and if purchase prices include the value of benefits derived from sustainable energy generation. Utilities could recover their purchases through existing mechanisms and, in purchasing, gain ownership of the RECs associated with the renewable energy.

I do not believe that utilities care only about protecting profits and monopolies that have never faced competition. The truth is that calculating things like cost, return and rates in an era of anemic demand growth, aging infrastructure and shifting policy goals is difficult, even absent disruptive technologies knocking on the door. Some of those technologies will provide greater and greater universal benefit in the form of grid services that communicate with and aid the "grid". Perhaps providing policies that nourish robust net metering growth and encourage further development and experience with "grid services" technologies should be our goal. Time of use, peak shaving <u>after</u> the sun goes down, self-consumption, grid zero, grid support (see Rule 21 California) requiring inverters to have "ride through" capabilities that support a grid that may be experiencing voltage variations as opposed to simply shutting down as has been the norm for autonomous inverters. Arkansas has a very low penetration of solar power.

Policy that recognizes public policy benefits of bringing the future to Arkansans could well be an under recognized benefit of net metering.

The consideration of two channel billing to effect fees to net metering customers is an approach that basically negates net metering as a policy driven by statute. Regardless of fees that may or may not be charged to net metering customers, net metering is an exchange of a kWh for a kWh, no matter the cost of that kWh. If the Commission approves any additional costs to net metering customers, at the very least the Commission should (1)wait until a full study of benefits is completed (2)adopt rates that are phased in relative to the growth of net metering and flexible in order to account for future costs and benefits brought on by changes in technology.

I have argued that costs to a utility from a net metering customer not incurred by the utility serving non-net metering customers within a given customer class are minimal. If lost revenues are no part of the consideration, I believe there are only three areas of cost to a utility that are worthy of discussion.

1. A one-time cost to process a net metering application, which must be mitigated by the fact that applications to start, stop or move a customer account to a new location from non-net metering customers are received by utilities daily.

2. A one-time cost for a utility technician to verify operation of a net metering facility and either reprogram the existing customer meter on site or swap it for one that has been pre-programed by the technician before coming to the site.

3. Administrative costs associated with billing of net metering customer's consumption and net excess generation, which must be mitigated by the fact that not-net metering customer's billing routinely presents similar administrative costs associated with tracking time of use or levelized billing.

Act 827 was intended to enhance net metering by stipulating that net excess generation credits never expire and by raising then current limits on the size of a residential or commercial net metering facility. The requirement that the Commission

resolve whether net metering customers are "paying their fair share" was intended to prevent unintended consequences in light of enhanced benefits directed by the Act.

AREDA, when passed in 2001, provided that the Commission *"May authorize an electric utility to assess a net-metering customer a greater fee or charge, of any type, if the electric utility's direct costs of interconnection and administration of net-metering outweigh the distribution system, environmental and public policy benefits of allocating the costs among the electric utility's entire customer base;"* It did not require an Amendment directing the Commission to evaluate the prudence of assessing a net metering customer a greater fee, that authority has been there all along. Perhaps the rate structures for all customer classes do not accurately reflect the actual cost of service to those customers.

Respectfully submitted.

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