APSC FILED Time: 6/1/2020 2:51:27 PM: Recvd 6/1/2020 2:50:19 PM: Docket 16-027-R-Doc. 423

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF NET METERING	)	
AND THE IMPLEMENTATION OF	)	DOCKET NO. 16-027-R
ACT 827 OF 2015	)	ORDER NO. 28

ORDER

By this Order in Phase 3 of this Docket, the Arkansas Public Service Commission (Commission) implements the provisions of Act 464 of 2019 (Ark. Code Ann. §§ 23-18-601 *et seq.*) and, through promulgation of revised Net-Metering Rules (NMRs), establishes rates, terms, and conditions for Net-Metering (NM) in Arkansas.

SUMMARY

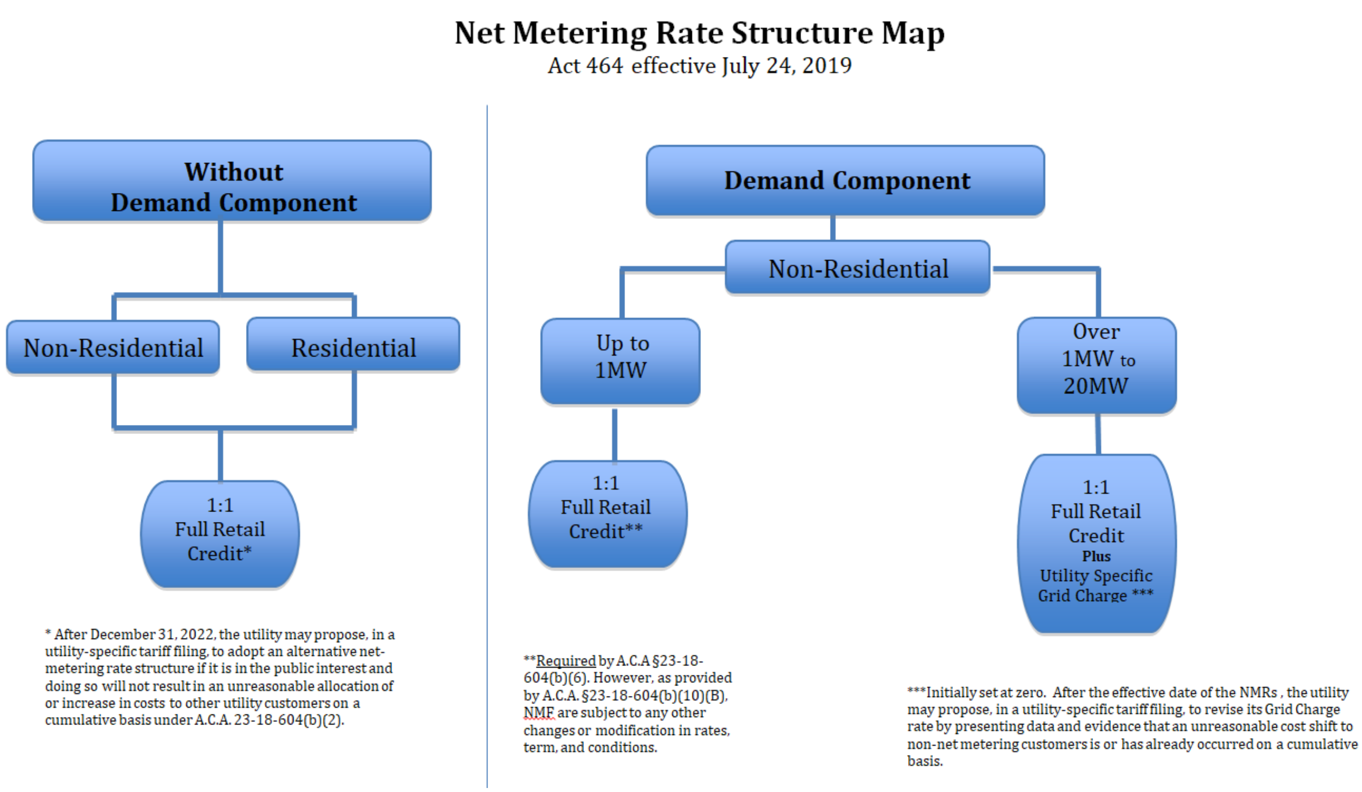
In summary, the Commission approves revised NMRs to implement the provisions of Act 464 of 2019. First, the Commission adopts and defines the rate structure for Net-Metering Customers. For Residential and Non-residential Customers without a demand component, the Commission finds that the current 1:1 full retail credit for net excess generation should be retained for now as the default Net-Metering rate structure. However, after December 31, 2022, a utility may request approval of an alternative Net-Metering rate structure that is in the public interest and will not result in an unreasonable allocation of, or increase in, costs to other utility customers.

For Non-residential Customers up to 1 MW with a demand component, the Commission finds that continuation of 1:1 full retail credit for net excess generation is required.

For demand-component customers installing Net-Metering Facilities with generation capacity from over 1 MW to 20 MW, the Commission finds that there is some evidence of potential cost-shifting which justifies a change in the Net-Metering rate structure to 1:1 full retail credit for net excess generation plus the adoption of a grid charge. The grid charge will initially be set at zero. Once the Net-Metering Rules become effective, a utility may request approval of a revised grid charge rate based upon evidence that an unreasonable cost shift to non-Net-Metering Customers is occurring or has already occurred on a cumulative basis, rather than on the basis of an individual Net-Metering Customer's proposed facility(ies).

All Net-Metering Facilities remain subject to any other changes or modification in rates, terms, and conditions.

The revised Net-Metering rate structure may be illustrated as follows:



Second, the Commission affirms that the eligibility for grandfathering is based on the date the customer submits a signed Standard Interconnection Agreement to the utility.

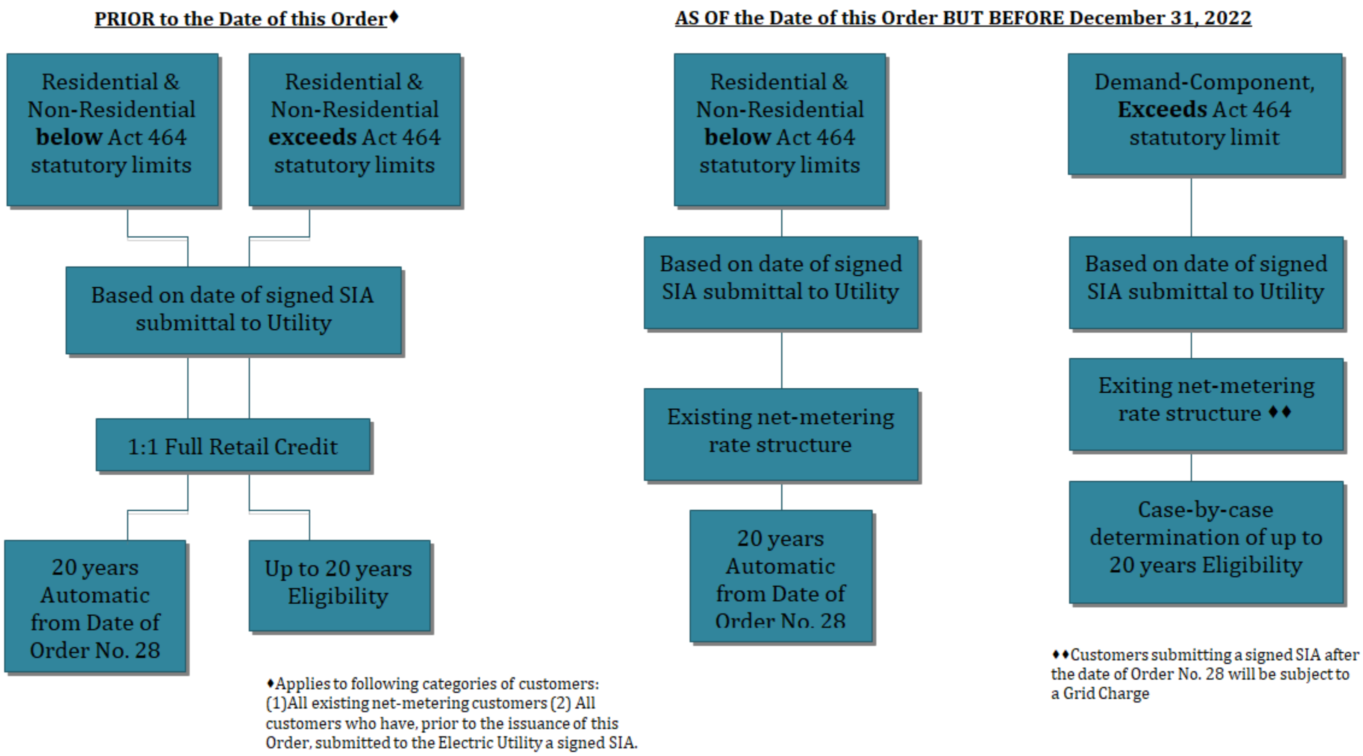
For residential and non-residential Net-Metering Facilities below the statutory size limits, the Commission finds that the grandfathering period shall be twenty years from the date of this Order for the following categories of facilities: (1) all existing Net-Metering Facilities with generating capacity below the pre-Act 464 or Act 464 (as applicable) statutory limits approved or installed prior to the effective date of this Order; and (2) all Net-Metering Facilities with generating capacity below the Act 464 statutory limits where the Net-Metering Customer has submitted to the Electric Utility a signed Standard Interconnection Agreement between the date of this Order and December 31, 2022.

For Net-Metering Customers seeking approval on a case-by-case basis to exceed the statutory limits and to be grandfathered under the Net-Metering rate structure as of the date of the customer's submission to the Electric Utility of a signed Standard Interconnection Agreement, the Commission reaffirms its authority and discretion to approve grandfathering periods up to twenty years for these large-customer facilities, if the Net-Metering Facilities are determined to be in the public interest, including a finding that they will not result in an unreasonable allocation of costs to other customers. This eligibility shall apply where the Net-Metering Customer has submitted to the Electric Utility a signed Standard Interconnection Agreement before December 31, 2022. Where the Standard Interconnection Agreement is submitted before the date of this Order, the Net-Metering Facility is eligible to be grandfathered under the 1:1 Net-Metering retail rate credit. Where the Standard Interconnection Agreement is submitted on or after the date of this Order but before December 31, 2022, the Net-Metering Facility is eligible to be grandfathered under the 1:1 Net-Metering retail rate credit plus a grid charge.

The grandfathering rules may be illustrated as follows:

Grandfathering Net Metering Rate Structure

Act 464 effective July 24, 2019



The Commission finds that it is in the public interest to waive the application of this rule in one instance. The Commission finds that under certain conditions, it is reasonable to allow a customer who has submitted a Preliminary Interconnection Site Review Request to the utility before the date of this Order, but has not yet submitted a signed Standard Interconnection Agreement, to be eligible to be grandfathered on the existing 1:1 retail rate credit when that customer petitions the Commission for approval to exceed the statutory limit.

Third, the Commission provides procedures to address customer protection issues and gaming and the need for codes of conduct for unregulated third-party distributed energy providers and utilities.

Fourth, the Commission implements provisions of Act 464 that expand the facility size thresholds for customers to engage in Net-Metering and authorize the leasing of Net-Metering Facilities.

Fifth, the Commission sets in motion procedures in other dockets to address interconnection issues and community solar programs.

Given the length and complexity of this Order and the number of issues to be decided under the Arkansas Renewable Energy Development Act (AREDA)[1] as amended by Act 464, the Commission provides herein a complete procedural history of the three phases of this Docket and summaries of the comments and testimony filed by the Parties in Phases 2 and 3.

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[1] §23-18-601 *et seq*.

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I. PROCEDURAL HISTORY

Order No. 1 established a docket to gather information to be used to determine appropriate rates, terms, and conditions under Act 827 of 2015 (Act 827) for net-metering contracts, including any changes necessary to the Commission's NMRs. Act 827 provides, *inter alia*, that the Commission, after notice and an opportunity for public comment:

> (1) Shall 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 electricity 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 . . .

Act 827 at § 3, codified at Ark. Code Ann. § 23-18-604(b)(1)(Repl. 2015). Act 827 amended AREDA, in which the General Assembly found that net-metering "encourages the use of renewable energy resources and renewable energy technologies" and that:

> [i]ncreasing 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 agricultural sectors, reduces environmental stresses from energy production, and provides greater consumer choices.

Ark. Code Ann. § 23-18-602(a). Act 827 therefore requires the Commission to examine the balance of the costs and benefits of net-metering, within the framework of a statutory subchapter aimed at promoting customer-owned, distributed renewable energy production.

In Order No. 1, the Commission noted that Act 827's provisions regarding the costs and benefits of net-metering and approval of net-metering facilities larger than 300 kW raise a series of questions that should be considered in the development of net-metering policy and any resulting changes to the NMRs (Ark. Code Ann. §§ 23-18-604(b)(5) and (7)). As part of consideration of any such changes, the Commission established a procedural schedule under which Staff would file Initial Comments and a "strawman" proposal for amendments to the NMRs, followed by responsive comments or expert testimony by the Parties, including answers to a series of questions posed by the Commission. The questions were divided into two groups:

> Section A questions relate to guiding principles for the establishment of 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 (hereinafter, "Rate Issues").
>
> Section B questions relate to guidelines for approval of non-residential net-metering facilities exceeding 300 kW.

The following parties have been participants in the various Phases of this Docket: all jurisdictional electric public utilities (Entergy Arkansas, LLC (EAL) (f/k/a Entergy Arkansas, Inc.), Southwestern Electric Power Company (SWEPCO), Oklahoma Gas and

Electric Company (OG&E), Empire District Electric Company (Empire), Arkansas Electric Cooperative Corporation (AECC), 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, Farmers Electric Cooperative Corporation, First Electric Cooperative Corporation, Mississippi County Electric Cooperative, Inc., North Arkansas Electric Cooperative, Inc., 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, and Woodruff Electric Cooperative Corporation); the Attorney General (AG); the General Staff (Staff) of the Commission; and the following intervenors: Pulaski County, Arkansas; Mr. William Ball; Mr. Francis M. Kelly; Ms. Pat Costner; Mr. Louis Contreras; Wal-Mart Stores Arkansas, LLC and Sam's West, Inc. (Walmart); Scenic Hill Solar, LLC (Scenic Hill Solar); Solar Energy Arkansas, Inc. (SEA); The Alliance for Solar Choice (TASC); Arkansas Electric Energy Consumers, Inc. (AEEC); the Arkansas Advanced Energy Association, Inc. (AAEA); the National Audubon Society (Audubon); the Sierra Club (Sierra), and collectively referred to as the Parties.[2]

[2] The Commission notes that several Parties filed jointly at times in Phases 2 and 3 (*e.g.*, AAEA, Audubon, and Sierra filed jointly in Phase 3 and have been designated by the Commission as the Distributed Solar Advocates in Phase 3; some groups of electric cooperatives also filed joint comments in Phase 3), and some Parties later withdrew from the Docket (SEA and TASC). Several Parties filed *pro se* in one or more phases and not in others (e.g., Mssrs. Kelly and Contreras and Ms. Costner).

A. PHASE 1 PROCEEDINGS – ADOPTION OF AMENDED NMRS AND FACILITIES EXCEEDING 300 KW

On July 22, 2016, Staff filed Initial Comments, proposed amendments to the NMRs, and provided responses to questions posed by the Commission in Order No. 1. On August 18, 2016, by Order No. 4 in this docket, the Commission approved a unanimous proposal by the Parties to bifurcate the issues in this docket, such that Phase 1 of the docket would address the adoption of amended NMRs, including guidelines for approval of non-residential net-metering facilities exceeding 300 kW under Act 827 of 2015, and Phase 2 would address rate issues after investigation by a Net-Metering Working Group (NMWG) established pursuant to that Order.

Pursuant to Order No. 4, the Parties addressed the remaining issues in accordance with the Phase 1 procedural schedule: (1) Staff's proposed revisions to the NMRs and Appendices; (2) the effect of Act 827's passage on the currently-effective *Standard Interconnection Agreements for Net-Metering Facilities* (Appendix A to the current NMRs), including from the effective date of Act 827 until the Commission approves a new rate structure for net-metering customers, including the issue of whether current customers should be grandfathered under the current rate structure; and (3) policies and issues related to the questions included under Section B, concerning approval of non-residential net-metering facilities exceeding 300 kW. On August 19 and September 9, 2016, respectively, the Parties filed Reply and Surreply Comments and Testimony, including the filing by Staff of mark-up and clean versions of Staff's proposed strawman NMRs, with the mark-up highlighted to reflect the changes recommended in its Surreply Comments and Attachments 1 and 2 (as amended by Errata filed on September 29, 2016).

On October 4, 2016, the Commission conducted a public hearing on the Phase 1 issues. On March 8, 2017, the Commission issued Order No. 10 (as amended by Errata Order No. 14 on August 16, 2017, correcting scrivener errors of references and punctuation), approving amended Net-Metering Rules as reasonable, appropriate, and in the public interest. On September 25, 2017, General Counsel for Staff notified the Secretary of the Commission by letter, certifying that the referenced rules were reviewed and approved under § 10-3-309 by the Administrative Rules and Regulations Subcommittee of the Arkansas Legislative Council on September 12, 2017, and by the full Arkansas Legislative Council on September 15, 2017, and were therefore effective as of September 15, 2017. On September 19, 2017, by Order No. 15, the Commission directed all electric utilities to make compliance filings to update their net-metering tariffs as necessary to comply with the new NMRs. On November 17, 2017, by Order No. 17, the Commission rejected the initial tariff filings made by each utility and approved the proposed tariff revisions as recommended by Staff, finding the revisions reasonable and in the public interest. By this notification, the Commission's Phase 1 proceedings in this Docket were concluded.

B. PHASE 2 PROCEEDINGS – RATE ISSUES

In its August 18, 2016 Order No. 4 bifurcating the net-metering issues, the Commission approved the request of the parties to establish the NMWG, to be led by Staff to address the rate structure and tariff issues referred to Phase 2 of this Docket, including the development of consistent rates, terms, and conditions for net-metering contracts for all electric utilities pursuant to the provisions of Ark. Code Ann. § 23-18-604(b), as amended by Act 827 of 2015, guided by the questions related to this statutory provision that were posed by the Commission in Order No. 1 (Questions Part A, 1 through 8). The Commission directed the NMWG to report on its progress toward reaching consensus. Order No. 4 at 3-5.

On June 15, 2017, the NMWG filed its *Joint Progress Report and Proposed Procedural Schedule* (Progress Report), stating that the NMWG had held five in-person meetings with phone participation to discuss the Rate Issues and related matters and that the Parties had an opportunity to present their positions before the group and engage in meaningful discussions. The Progress Report states that two broad schools of thought existed within the NMWG and as a result, two sub-groups were formed to develop detailed recommendations for the NMWG to consider. Sub-Group 1[3] advocated 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. Sub-Group 2[4] advocated an embedded cost-of-service 2-Channel Billing approach and certain rate design options that include changes to prospective net-metering customers' rates following Commission approval in this proceeding. Progress Report ¶ 2.

According to the Progress Report, the Commission established the NMWG in Order No. 4 "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 of the NMWG to

[3] Sub-Group 1 includes the following parties: AAEA; Audubon; Francis M. Kelly; Luis Contreras; Pat Costner; Scenic Hil); SEA; TASC; Sierra Club; and William R. Ball.
[4] Sub-Group 2 includes the following parties: AEEC; AG; AECC; Arkansas Valley Electric Cooperative Corporation; Ashley Chicot Electric Cooperative, Inc.; C&L Electric Cooperative; Carroll Electric Cooperative Corporation; Clay County Electric Cooperative Corporation; Craighead Electric Cooperative Corporation; EAL; Farmers Electric Cooperative Corporation; First Electric Cooperative Corporation; Staff; Mississippi County Electric Cooperative, Inc.; North Arkansas Electric Cooperative, Inc.; OG&E; Ouachita Electric Cooperative Corporation; Ozarks Electric Cooperative Corporation; Petit Jean Electric Cooperative Corporation; Rich Mountain Electric Cooperative, Inc.; South Central Electric Cooperative, Inc.; SWEPCO; Empir); and Woodruff Electric Cooperative Corporation.

the Commission for its consideration. The Progress Report states that, consistent with the parties' unanimous Joint Motion that was approved in Order No. 4, Staff led the NMWG and the NMWG generally followed procedures consistent with those approved by the Commission for the Parties Working Collaboratively (PWC) in the Commission's energy efficiency proceedings, which provide an opportunity for parties with divergent points of view to work cooperatively toward finding common ground. The Progress Report states that although the NMWG participants had not reached consensus on a comprehensive recommendation to the Commission, they planned to continue meeting and seeking areas of agreement to the greatest extent possible. Progress Report ¶ 3. The Progress Report summarized the positions of the two Sub-Groups as of June 2017 and expressed the commitment of the parties to continue their discussion of the issues and their hope to identify some areas where agreement by the entire NMWG might be achieved and to present their Report and recommendations to the Commission on September 15, 2017, in accordance with a procedural schedule they proposed, to include Reply and Sur-Reply Comments and a public hearing. Progress Report ¶¶ 4 – 7. On June 26, 2017, by Order No. 12, the Commission approved the proposed procedural schedule, setting an evidentiary hearing for November 30, 2017.

On September 15, 2017, the Joint Parties filed their *Joint Report and Recommendations of the Net-Metering Working Group* (Joint Report), containing Attachment A: Sub-Group 1 Recommendations and Responses to Questions Posed by the Commission in Order No. 1 and Attachment B: Sub-Group 2 Recommendations and Responses to Questions Posed by the Commission in Order No. 1. The Joint Report also includes Attachment C: Recommendations of Pulaski County and Attachment D:

Recommendations of William Ball. On October 20, 2017, Sub-Group 1, Sub-Group 2, and William Ball filed separate Reply Comments (with Errata to Sub-Group 1's Reply Comments filed on November 6, 2017). On October 24, 2017, Pulaski County filed Reply Comments (accepted as late-filed by Order No. 16 on October 30, 2017).

On November 9, 2017, Sub-Group 1 and Sub-Group 2 filed separate Surreply Comments. On November 22, 2017, by Order No. 18, the Commission excused Mr. Contreras and Walmart from the November 30, 2017 evidentiary hearing. On November 22 and 29, 2017, respectively, by Order Nos. 18 and 19, the Commission granted TASC and SEA's motions to withdraw as parties.

On November 30 and December 1, 2017, the Commission conducted a public evidentiary hearing at the Commission. In support of their positions, the parties presented the following witnesses for questioning by the Commission:

For Sub-Group 1:

Sierra Club -- Thomas Beach

Sierra Club – Karl Rabago

AAEA – Katie Niebaum

Scenic Hill Solar – Bill Halter

Pat Costner

For Sub-Group 2:

EAL – Andrew Owens

AECC – Robert Shields

AEEC – Brad Mullins

AG – Barbara Alexander

Staff – Matthew Klucher

William Ball, *pro se*

Pulaski County – Adam Fogleman

On February 7, 2018, the Commission granted the Joint Motion of the Joint Parties to permit the filing of simultaneous Initial and Reply Briefs on February 23 and March 16, 2018, respectively. On those dates, Sub-Group 1, Sub-Group 2, William Ball, and Pulaski County filed Initial and Reply Briefs (with Errata substitution of an attachment to Sub-Group 2's Reply brief filed on February 28, 2018).

C. <u>PHASE 3 PROCEEDING – RATE ISSUES AFTER ACT 464 OF 2019</u>

Act 464 of 2019 made fundamental changes to net-metering law in Arkansas. In response, the Commission determined that it is necessary and appropriate to open Phase 3 of this Docket to consider and implement changes to the Commission's NMRs, including the rate structure that will be adopted pursuant to the requirements of and authorization granted in Act 464. To begin Phase 3, the Commission issued Order No. 22 on May 30, 2019, which directed Staff to re-convene the Net-Metering Working Group (NMWG), and be assisted by a facilitator if feasible and desired. The Commission directed the NMWG to engage collaboratively to further address rate issues and other issues raised by the passage of Act 464 and explore whether the Parties could converge on an agreement for rate structure and other amendments to the NMRs. In particular, the Commission directed the NMWG to consider whether there should be market-based incentives to increase data sharing and transparency of the distribution system. The Commission also directed the NMWG to consider whether safeguards should be developed to protect against gaming of the new 1,000 kW threshold for net-metering facilities, below which net-metering customers are not required to seek Commission approval. For those rate issues and additional Act 464 issues for which the NMWG might come to an agreement, the Commission directed the NMWG to file proposed rules to address those issues. For those rate issues and additional Act 464 issues for which the NMWG could not come to an agreement, the Commission directed Staff to file a strawman proposal to begin the comment process. Order No. 22 at 1-6.

On September 17, 2019, Staff filed its Strawman proposal and rules. On October 15, 2019, Comments were filed by AEEC, Empire, the AG, OG&E, Walmart, AECC, Carroll Electric, EAL (with the Supplemental Testimony of David Palmer, Andrew Owens, and Michael Schnitzer), SWEPCO, Distribution Cooperatives (Ashley-Chicot, Clay County, Craighead, Farmers, and South Central), AAEA/Audubon/Sierra, Scenic Hill Solar, and Staff.

On November 5, 2019, Reply Comments were filed by AEEC, OG&E, AG, SWEPCO, Mr. Ball, EAL, AECC, AAEA/Audubon/Sierra, eight Distribution Coops, Scenic Hill Solar, and Staff (with the Direct Testimony of Kathleen Kelly).

On November 19, 2019, Surreply Comments were filed by: OG&E; Ball; AG; Carroll Electric; AECC; SWEPCO; Staff; EAL; AEEC; Scenic Hill Solar; and AAEA/Audubon/Sierra. On December 3, 2019, the coops withdrew 1 set of comments and on December 4, 2019, the coops withdrew another set of comments.

Hearing was held on December 5, 2019. On December 13, 2019, Order No. 27 scheduled an additional PC hearing which was held on February 19, 2020.

Almost 400 public comments were filed in this Docket between August 2016 and the date of this Order, and 44 public comments were made at the two hearings. The comments covered a wide variety of issues.

II. SUMMARY OF EVIDENCE

A. PHASE 2 SUMMARIES OF COMMENTS AND TESTIMONY

1. Joint Report And Recommendations Of The Net-Metering Working Group

On September 15, 2017, the Joint Parties comprising the NMWG filed the *Joint Report and Recommendations of the Net-Metering Working Group* (Joint Report), noting that the six meetings of the NMWG generally focused on identifying the quantifiable costs and benefits of net-metering, potential rate structure options, and pros and cons associated with various options. The Joint Report states that two broad schools continued to exist within the NMWG following the issuance of the Progress Report and that each sub-group developed detailed recommendations for the NMWG to consider, which are briefly set out in the Overviews below, followed by more detailed Summaries of each sub-group's positions. The Joint Report Recommendations of other, non-sub-group parties are summarized at the end of the detailed Summaries of Sub-Group 1 and Sub-Group 2 Recommendations. The Crossborder Study sponsored by the Sierra Club (a member of Sub-Group 1) and attached to the Joint Report is also summarized in detail below, following the Sub-Group 1 detail Summary.

2. Overview of Sub-Group 1 Recommendations

Sub-Group 1 recommends that the Commission continue to use the current net metering one-for-one full retail credit rate design until a full assessment of the costs and benefits of net metering has been conducted. Sub-Group 1 takes 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. To this end and in part due to the NMWG's decision not to undertake such a study, the Sierra Club (a member of Sub-Group 1) contracted with Crossborder Energy, Inc., a consulting firm with extensive expertise in distributed generation valuation, to conduct an analysis of the costs and benefits of distributed generation for EAL, and presents the study as part of this report. Joint Report at 3.

3. Overview of Sub-Group 2 Recommendations

Sub-Group 2 advocates an embedded cost-of-service (COS) approach to determine the costs and benefits associated with net-metering. Under this approach Sub-Group 2 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. Sub-Group 2 asserts that a different excess generation credit rate based on an embedded COS approach is required in order to comply with the provisions of Act 827 of 2015 (Act 827), codified as Ark. Code Ann. § 23-18-604(b). Sub-Group 2 explains that currently, net-metering customers are credited at the full retail rate for excess kWh that are exported to the grid. Sub-Group 2 contends that 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. According to Sub-Group 2, 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. Therefore, Sub-Group 2 argues, the current net-metering policy that credits excess generation at the full retail rate must be changed for new net-metering customers. Joint Report at 4.

Sub-Group 2 submits that quantifiable benefits can be determined primarily through consideration of an individual utility's embedded COS and that using an embedded COS 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 thus 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 it asserts is more appropriate than the full retail rate, ensuring that net-metering customers pay rates more accurately reflecting the utility cost of providing service. *Id*. at 4 - 5.

4. Sub-Group 1 Recommendations and Responses to Commission Questions Posed in Section A of Order No. 1

a. Sub-Group 1 Recommendations

i. Summary. Sub-Group 1 recommends that the Commission find that the existing net-metering tariffs comply with Arkansas Code § 23-18-604(b)(1) and that § 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. *Id*. at 14, footnote 5. In doing so, Sub-Group 1 asserts that the Commission should base its decision on a thorough analysis of the benefits and costs of net metering and informed by best practices from an extensive literature on distributed generation valuation, citing studies by the National Renewable Energy Laboratory, the Rocky Mountain Institute, and other sources. *Id*.

According to Sub-Group 1, the Crossborder Study shows that the value of distributed solar generation for EAL exceeds the residential retail rate under either of two scenarios: (1) a conservative scenario employing several of Entergy's own estimates from its latest (2015) Integrated Resource Plan (IRP) and energy efficiency (EE) 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 EE programs. The study by Crossborder shows that distributed solar helps EAL 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, Sub-Group 1 asserts, net metering does not shift costs to non-solar customers. If the Commission believes that further action must be taken to ensure compliance with AREDA, Sub-Group 1 recommends that the Commission first contract for an independent and comprehensive statewide study of the benefits and costs associated with distributed generation. Sub-Group 1 asserts that a comprehensive study should cover the average lifetime of solar systems and should not be limited to data in the utility's embedded cost-of-service study. Sub-Group 1 points out that, as the 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," citing Order No. 10 at 143. The Commission therefore has ample time to gather data and review comprehensive studies prior to taking action. Sub-Group 1 organizes its comments first to present relevant legal background; second to offer principles for the Commission to apply when interpreting and applying Act 827; and third, to summarize the findings of the Crossborder Study. Sub-Group 1 also offers some procedural recommendations for future working group processes and provides specific responses to the Commission's Questions posed in Section A of Order No. 1. Joint Report at 14-16 and Attachment A-3.

ii. Legal Background

Arkansas Renewable Energy Development Act (AREDA)

Sub-Group 1 states that the Legislature's intent was to establish a net metering policy that promotes distributed generation development. To conform to the General Assembly's intent, Sub-Group 1 argues that the Commission must establish rules for distributed generation that preserve the basic net metering construct that is based on a billing period (monthly for residential customers), reflect all the benefits and costs of distributed generation, and enable meter aggregation to expand distributed generation. Joint Report 16-17. Sub-Group 1 notes that 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 General Assembly clearly recognized net metering as the billing arrangement that would promote distributed generation, which would be in "Arkansas's long-term interest," citing Ark. Code Ann. § 23-18-602(a). Sub-Group 1 further notes that in the next section of AREDA, § 23-18-602(b), 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." In short, Sub-Group 1 asserts that the General

Assembly has made manifest its direction that net metering is intended to promote the use and development of renewable technologies. *Id*. at 17-18.

Sub-Group 1 states that previous Commission Orders have consistently interpreted AREDA as promoting customer-owned distributed renewable energy production through net metering policies in order to realize public benefits, both to the utility's system and to society at large, citing to Order No. 1 at 2, "[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*." Joint Report at 18 (emphasis added). Sub-Group 1 also cites Order No. 13, which quotes from what it calls a "steady stream" of previous orders in a variety of dockets in which the Commission had been guided by this legislative purpose. *Id*. at 18.

Act 827 Amendments to AREDA

In 2015 the General Assembly amended AREDA with Act 827. The statute requires the Commission to establish rates for net-metering customers that recover the entire cost of providing service to those customers. The new rate for recovering the "cost of providing service" must include any quantifiable "additional costs" associated with net metering, and be net of any quantifiable benefits associated with net metering. Act 827 also added provisions to allow meter aggregation. Thus, Sub-Group 1 argues, the statute evinces the General Assembly'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. Further, Sub-Group 1 notes that in requiring utilities to allow meter aggregation, 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 purpose of the Act.*" Order No. 4 in Docket No. 12-060-U at 38 (emphasis added). Additionally, Sub-Group 1 asserts that the Commission's acknowledgement that meter aggregation is essential to achieving the legislature's purpose in advancing net metering and the General Assembly's subsequent endorsement of meter aggregation, make it clear that any changes to the net metering rules, contracts, or rates approved by the Commission should not hamper the effectiveness of meter aggregation. *Id.* at 19-22.

Implementation of Act 827

Sub-Group 1 argues that the Commission should be guided first and foremost by the statutory purpose of promoting the development of distributed renewable energy resources. Sub-Group 1 discusses the economic impact the renewable energy industry has had on Arkansas to date. Sub-Group 1 also discusses the economic impact from recent utility-developed solar projects, such as EAL's 81 MW facility in Stuttgart and Ouachita Electric Cooperative's 1 MW facility in Camden. *Id.* at 22-24.

Sub-Group 1 calls for the Commission to look beyond the conventional embedded COS framework when implementing Act 827 and argues that traditional COS studies do not evaluate the defining characteristic of net-metering customers — their export of power to the utility's grid. Nor does a COS study capture the full benefits or costs of serving a net-metering customer, Sub-Group 1 states, especially when many of the benefits specified by the legislature involve avoiding future utility costs. According to Sub-Group 1, to fully capture these costs and benefits requires a study over the lifetime of the net-metered system, rather than taking a snapshot of their value. In other words, Sub-Group 1 contends, the distributed generation system should be treated as a system resource that provides value over many years. *Id.* at 26-27.

Sub-Group 1 says a conventional COS study could be helpful in one instance, explaining that load data can be collected from net metering and non-net-metering customers within the same rate class and compared to evaluate how embedded costs are being allocated. Sub-Group 1 warns that this analysis is not sufficient to meet AREDA's requirements because it ignores costs or benefits associated with the generation exported by net-metering customers. Sub-Group 1 notes that Oklahoma Gas and Electric Company (OG&E) in Oklahoma actually performed this type of analysis to determine if there were any intra-class subsidies of distributed generation customers by non-net-metering customers. According to Sub-Group 1, OG&E completed a COS study that, for analytical purposes only, treated residential distributed generation customers as a separate rate class. Sub-Group 1 states that OG&E's analysis revealed that residential distributed generation customers were actually less costly to serve than other residential customers due to their reduced peak load, and that these distributed generation customers paid a higher percentage of their cost of service than any other subset of the residential class. *Id.* at 27-28.

Sub-Group 1 argues that the fundamental issue the Commission must consider is whether net-metering customers pay their full, adjusted cost of service under the current net metering tariffs. Sub-Group 1 strongly disagrees 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 argues 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. Sub-Group 1 goes on to discuss other state commissions that have conducted extensive studies before making changes to existing net metering policies. *Id.* at 30-32.

iii. Crossborder Study

On May 17, 2017, Staff requested that each sub-group present a calculation of the avoided costs associated with distributed generation at the following NMWG meeting. In response, Sierra Club (a party to Sub-Group 1) contracted with Crossborder Energy, which has extensive expertise evaluating the costs and benefits of distributed generation, to undertake a comprehensive study for the Entergy Arkansas, Inc. system. Sub-Group 1 states that the study by Crossborder concluded that net metering is a net benefit to EAL and all its customers, and thus, maintaining net metering as it is currently implemented is consistent with AREDA and the Act 827 amendments thereto. *Id.* at 33-34.

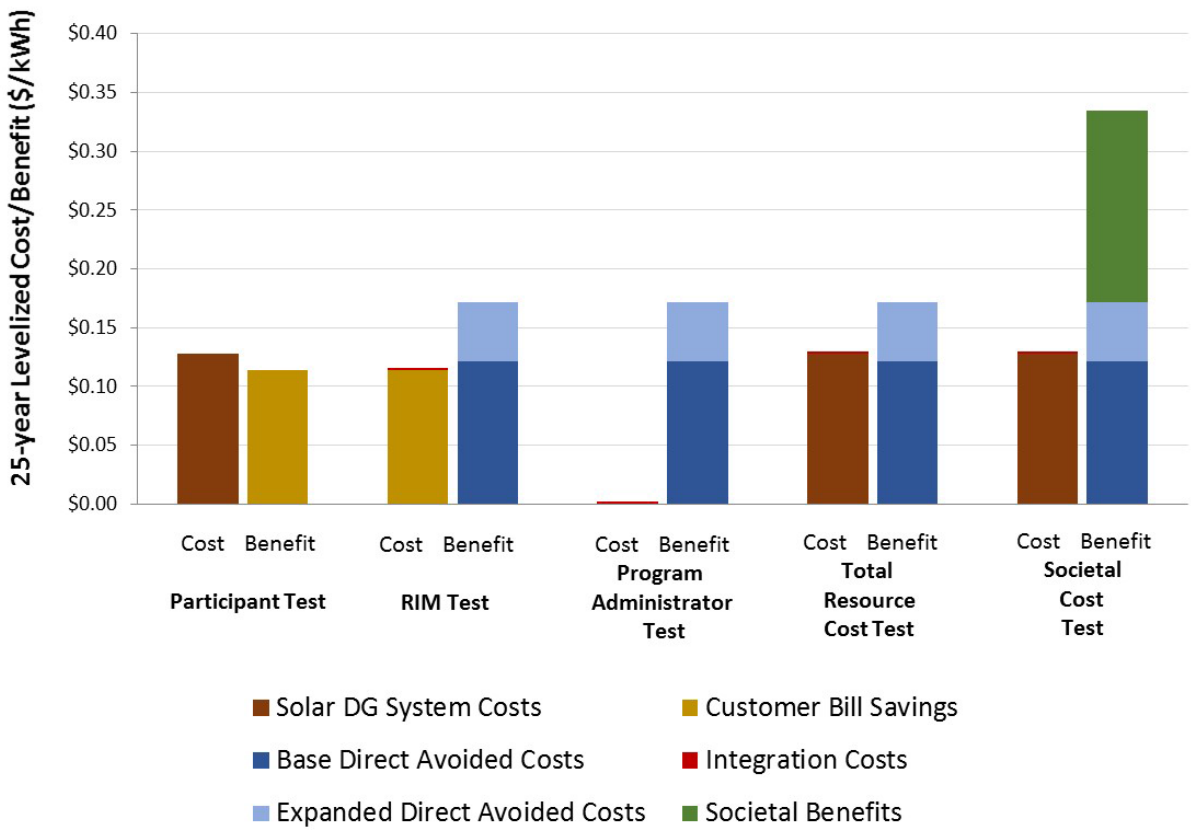
The Crossborder Study considers the benefits and costs of distributed generation over a 25-year period. Consistent with similar studies, Crossborder quantifies several benefits including direct benefits such as energy, generation capacity, transmission and distribution capacity and line losses, avoided market and fuel price risk, and carbon emission regulatory costs. Crossborder measures the costs and benefits, using the same cost-effectiveness tests commonly used to evaluate EE programs: Participant test, Ratepayer Impact Measure (RIM) test, Program Administrator test, Total Resource Cost (TRC) test, and Societal Cost test. Crossborder presents two scenarios for these direct benefits. The first scenario ("Base Case") uses many of the assumptions EAL uses in evaluating its EE programs, while the second scenario ("Expanded Case") expands upon those assumptions to include a larger set of benefits. Crossborder also quantifies indirect, societal benefits that the Arkansas General Assembly 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. Finally, Crossborder examines the reliability implications of distributed generation, which the Legislature specifically listed in Section 23-18-604(b)(1)(A). Sub-Group 1 states that 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 34-35.

Sub-Group 1 states that the Crossborder study shows that, for EAL, the direct benefits of distributed generation under the Base Case add up to 12.9 cents per kWh, and 19.2 cents per kWh under the Expanded Case (shown at Table 14 & Figure 9). Neither of these figures includes the quantifiable societal benefits associated with distributed generation, Sub-Group 1 observes, and yet both exceed EAL's residential energy rates.[5] *Id.* at 35.

According to Sub-Group 1, 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. The results of Crossborder's study are shown in Figure 1 below and included as Attachment A-1 to the study.

[5] Sub-Group 1 notes that under EAL's General Purpose Residential Service Tariff, customers are charged between 5.2 and 9.6 cents per kWh used, depending on the time of year and quantity of electricity used during the billing period, for an average of about 7.3 cents, citing 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 kWh basis.

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



Id. at 36.

Sub-Group 1 states that full retail net metering also passes the program administrator (utility) cost test and the RIM test, using both the Base and Expanded benefit cases, and notes that 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). Sub-Group 1 states that 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 negative, meaning that for most customers, the current net-metering compensation scheme does not adequately incentivize the development of distributed generation, consistent with data showing relatively slow rates of distributed solar adoption in the state. Thus, Sub-Group 1 states, 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. *Id.* at 36-37.

Sub-Group 1 recommends that if the Commission wishes to expand the Crossborder analysis to include other utilities, or to include additional data points to be provided by utilities for this specific purpose, the study process should: (1) be open to stakeholder participation, input, and evaluation; (2) allow time for utilities to gather necessary data (load research on net-metering customers, distribution system planning costs, etc.); and (3) be professionally facilitated by a neutral party. *Id.* at 37. Sub-Group 1 concludes its recommendation by noting that, as the Commission noted in Order No. 10 at 143-44, Act 827 did not predetermine that changes to net metering are required, 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. Sub-Group 1 states that that work remains, and that its members are committed to supporting the Commission's efforts to meet the requirements of the statute. *Id.* at 37-38.

Summary of Crossborder Report: *The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc.*

Background of Study

The Crossborder Report is a study prepared at the request of Sub-Group 1. It provides a comprehensive benefit-cost analysis of demand-side solar in EAL's territory. Key attributes of the study are that it:

- Analyzed benefits and costs of solar distributed generation (DG) from the perspective of DG customers, other ratepayers, the utility system, and society. These are the public interest stakeholders.
- Used the full set of cost-effectiveness tests for demand-side resources commonly used in the utility industry.
- Considered a comprehensive list of benefits and costs.
- Used a long-term, life-cycle approach of at least 25 years.

Id. at 42-43

<u>Benefits</u>

- Benefits were calculated starting with the same avoided costs that EAL uses in analyzing benefits of other demand-side (EE) programs.
- Those avoided costs were supplemented with data from EAL's Federal Energy Regulatory Commission (FERC) Form 1 and market data from the gas and electric markets in the region where EAL operates.
- The study considered an expanded set of avoided costs.
- The study draws upon relevant analysis from other states and also uses "public tools" for evaluating net metered DG developed in California and Nevada.

Costs

- The study included system costs, lost revenues, and integration costs as appropriate under each of the cost-effectiveness tests.
- The cost for participating customers were considered (those that have solar DG systems.)
    - The report contends that the cost of a solar DG resource for the utility system is the levelized cost of energy (LCOE) from the solar DG installations.
    - To calculate the LCOE for residential solar the study used $3/watt$_{DC}$ plus typical operating and financing assumptions.
- The costs for non-participating ratepayers are mainly the revenues the utility loses when DG customers reduce their loads and energy purchases.
    - Those costs are calculated using the 25-year levelized lost revenues from residential customers who install solar DG under net metering.
    - It is assumed EAL's rates escalate 2 percent per year in the long run.
- The study included a cost of integration of $2/MWh for the cost of additional ancillary services that might be needed to integrate solar DG into the grid.

Analysis Conclusions

The Crossborder analysis concluded that the benefits exceed the costs as shown below.

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

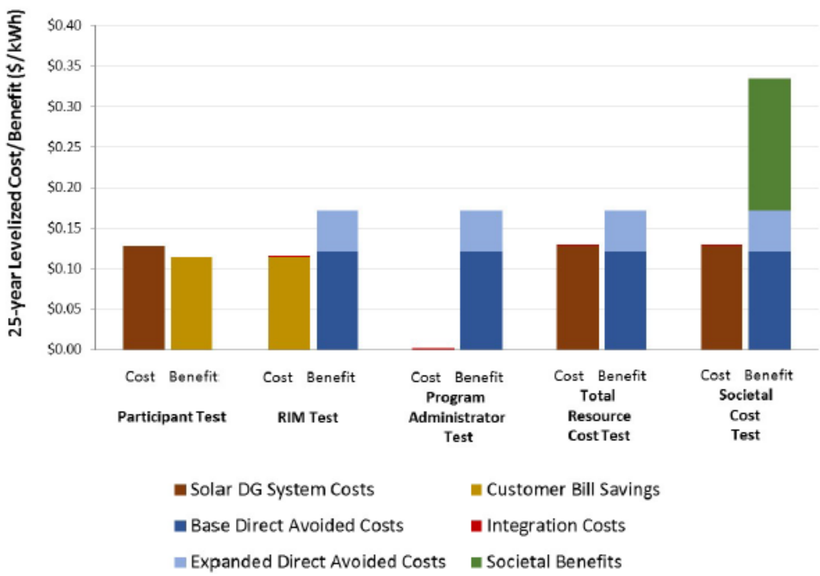


Table ES-1: *Benefits and Costs of Solar DG for EAI (25-yr levelized cents/kWh)*

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**	

Summary of Conclusions:

- Benefits equal or exceed costs in the Total Resource, Program Administrator, and Societal Tests. In the long-run, solar DG will decrease COS.
- Ratepayer Impact Measure shows no cost shift to non-participating ratepayers.

- No changes to net metering are needed to recover the utility's full COS over time.
- Economics of solar DG are marginal for EAL's residential customers since the Participant Test result is <1, but may improve as solar costs fall. Reducing the compensation to solar DG customers likely will slow growth of solar DG.
- Significant, quantifiable societal benefits exist from solar DG. These include local economic benefits and public health improvements from reduced air pollution.
- Other benefits that are harder to quantify include:
  - enhanced reliability and enhanced resiliency;
  - more customer freedom;
  - customers using their own private capital to install solar DG provide a new source of capital that expands the clean energy infrastructure; and
  - customer investments take advantage of federal tax incentives for DG.

Id. at 42-47.

Methodology

Arkansas law recognizes that both benefits and costs must be estimated. The issues and impacts raised by behind-the-meter DG are not new and have been addressed in EE and demand response (DR) programs. A set of standard cost-effectiveness tests for demand-side programs has been developed by the utility industry. The Crossborder Report evaluated the long-term benefits and costs of net-metered solar DG using these major cost-effectiveness tests (see Table ES on previous page).

Data Used In the Crossborder Study

The study started with data from the key assumptions (the "EE Assumptions") for the avoided costs that EAL uses in evaluating EE programs that was filed in May 2017 in Docket 07-085-TF. Additional data was added from EAL's 2015 IRP, data on loads and market prices on the Midcontinent Independent System Operator (MISO) system in Arkansas, EAL FERC Form 1 data, and information from analyses from other states. All of the data was public data and none was confidential. *Id.* at 52-53.

Benefits Consideration in the Crossborder Study

The choice of benefits to include was guided by the following three sources:

1. Ark. Code Ann. §23-18-604(b)(1)(A) that calls for the consideration of energy, generation capacity, transmission, distribution, and reliability benefits;
2. Societal benefits cited in A.C.A. §23-18-602; and
3. Crossborder's knowledge of benefits recognized and quantified in many other distributed generation studies.

The largest quantifiable direct benefits are avoided energy; avoided generation capacity; avoided transmission and distribution capacity; and avoided line losses. DG is similar to energy efficiency and demand response in that it has shorter lead times and smaller scalable incremental deployment than supply-side options. The Base Set of direct benefits used the avoided costs in the EE Assumptions from EAL. *Id.* at 53.

Sub-Group 1's Expanded set of avoided costs includes more direct benefits, including: fuel hedging benefits, price mitigation benefits, and long-term avoided Transmission and Distribution (T&D) costs. Quantifiable societal benefits are also provided. The study used recent quantifications from other studies of environmental benefits like reduced greenhouse gases and reduced use of water. The societal benefits of local economic activity generated by DG are quantified. The study discusses but does not quantify the benefits of enabling customers to enhance reliability or resiliency, or expanding customer choice or competition. *Id.* at 53-54.

Costs Considered

The costs vary across the benefit-cost tests. The DG customers' costs for capital, financing, and operating their systems, offset by federal tax credits, are included in the Total Resource Cost, Societal, and Participant Tests. The size, installation costs, financing terms, and output of the systems vary. For tests where utility costs are relevant, the study estimated solar integration costs that the utility will incur. These utility costs were based on studies performed by other utilities with larger amounts of DG on their systems. *Id.* at 54.

A cost for non-DG ratepayers has been added to the RIM test for lost revenues. The solar integration cost estimates were added to these lost revenues. *Id.* at 55.

The costs and benefits of solar DG for EAL were estimated over a 25-year period and have been levelized using the 6.1 percent discount rate that EAL uses in evaluating demand-side programs.

Discussion of Direct Benefits of Solar DG

The Crossborder Study discusses and computes a value for seven direct benefits, in a Base Case or Expanded Case with the results shown in the following table. A discussion of each of the benefits follows this table.

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**

Joint Report at 77.

Energy Benefit

The avoided generation resulting from solar DG in EAL's territory in the MISO South market area will be mainly gas-fired generation. The report 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 EIA's 2017 long-term forecast of natural gas prices. The analysis included a base case, and low and high scenario forecasts for natural gas prices. All of the prices were levelized over a 25 year period using EAL's 6.1 percent discount rate. An assumed decrease in solar output of 0.5 percent per year due to degradation over time was included. Crossborder calculated an energy benefit of $63.50 per MWh in both the Base Case and Expanded Case. *Id*. at 55–58.

Generation Capacity Benefit

The capacity value of solar DG is based on its ability to reduce peak demand for power on the grid. This reduction also lowers the reserve capacity requirements. The study took into account that the capacity value of solar resources is far less than the nameplate capacity because the solar unit does not produce at full capacity during the afternoon demand peaks. The MISO accreditation formula was used and the result was increased by 12 percent to reflect EAL's reserve margin. Crossborder calculated a generation capacity benefit of $32.10 per MWh in both the Base Case and Expanded Case. *Id.* at 59-60.

Line Losses Benefit (T&D Losses Benefit)

The study increased the avoided energy and capacity benefits to reflect the marginal line losses that are avoided by solar DG for both transmission and distribution. The study used EAL's EE Assumptions and increased them by 50 percent to reflect the higher marginal losses avoided by DG resources, based on a study by the Regulatory Assistance Project (RAP). An assumption was also made that the 2.0 percent transmission losses included in the EE Assumptions are already included in the MISO LMP used in the avoided energy costs. Crossborder calculated a T&D Losses benefit of $11.60 per MWh in both the Base Case and Expanded Case. *Id.* at 60-61.

T&D Capacity Benefits

Typically, 40 percent to 60 percent of a solar DG system's output is used on-site, thereby reducing loads on the utility's T&D system. For power exported to the grid, it most likely is used entirely on the distribution system by neighbors, which also unloads the distribution and transmission system. This is similar to other energy-efficiency and DR resources. Solar DG avoids T&D capacity costs to the extent that solar production occurs at peak demand on the T&D system. By reducing load and load growth, the need for load-related T&D investments is deferred or avoided. Solar DG may also defer the need for new transmission to access utility-scale renewables if the DG provides an alternative to the utility-scale investment. The benefits may increase as solar DG penetration increases and is considered in utility planning processes. In this study, the Base Case uses the EE Assumptions for avoided T&D capacity costs. The Expanded Case includes the long-term avoided costs in addition to those included in the Base Case. The study used EAL's EE Assumptions for 2016 and escalated at 2 percent per year over the 25-Year period and included a 0.5 percent per year degradation in solar output. A capacity contribution of solar photovoltaic (PV) to reducing peak transmission loads of 52.2 percent of the nameplate capacity was used based on a Peak Capacity Allocation Factor (PCAF) analysis over a five-year period. Actual solar insolation was used to capture the correlation between solar output and hot summer weather that drives periods of high demand. Crossborder calculated an Avoided T&D Marginal Capacity Cost benefit (T&D Capacity Benefit) of $10.20 per MWh in the Base Case. *Id*. at 64.

In the Expanded Case, the study used the National Economic Research Associates (NERA) regression method. To calculate the transmission portion, Crossborder used 18 years of EAL's reported historical load growth and transmission expenditures from EAL's FERC Form 1. A 2.6 percent adder for general plant and a carrying charge of 6.5 percent based on EAL's currently authorized capital structure and cost of capital was included. The same capacity contribution of 52.2 percent, based on the PCAF method and solar insolation that was used in the Base Case, was also applied. The result was an avoided transmission capacity cost of $13.20 per MWh. Estimating the impact on the distribution capacity costs is more complex than is the case with transmission. Crossborder used the same methods discussed for transmission, then used hourly profiles of EAL's residential loads to determine a PCAF allocation of residential demand. This PCAF allocation was applied to the typical meteorological year profile of hourly solar output in Little Rock to arrive at a capacity contribution factor. Crossborder calculated an avoided distribution benefit of $8.30 per MWh in the Expanded Case. The combined T&D Capacity Benefit calculated by Crossborder in the Expanded Case is 10.20 + 8.30 = $21.50 per MWh. *Id.* at 61-70.

Environment Benefit: CO_2

The Crossborder Report developed a base case using EAL's 2015 IRP Reference Case, a high case using EAL's 2015 IRP High Case, another high case using the U.S. EPA's social cost of carbon (SCC) to value the societal benefits from reduced carbon emissions, and a low case using EAL's EE Assumptions. The low case resulted in avoided environmental costs related to CO_2 of $3.50 per MWH. The Expanded Case used the $12.00 per MWh avoided environmental cost that resulted from using EAL's 2015 IRP reference case. *Id.* at 70-71.

Fuel Price Uncertainty Benefit

The report calculated a benefit related to the fuel hedging provided by renewable generation. The benefit was calculated following the Maine Distributed Solar Valuation Study, which recognizes that if one contracts now for future natural gas supplies, one eliminates the uncertainty of future gas costs. Crossborder used EIA's Annual Energy Outlook (AEO) 2017 gas cost forecast, U.S. Treasury rates, and a marginal heat rate to derive 25-year levelized benefits valued at $28.60 per MWh. *Id.* at 71-74.

Market Price Mitigation Benefit

Crossborder states that additional penetration of renewable generation will place downward pressure on market prices for energy in the region, for both electricity and natural gas. The magnitude of the benefit will depend on the overall amount of renewables on the grid. The largest reductions in market prices occur from the initial 5 percent of penetration of solar, which Arkansas is still within. Extensive studies have been conducted to calculate this market benefit. Crossborder used an average of the Demand Reduction Induced Price Effect (DRIPE) from two recent New England states studies, or a 4 percent reduction in avoided energy costs. Crossborder applied this 4 percent reduction to its avoided energy costs plus associated losses to arrive at a $2.80 per MWh benefit. *Id.* at 74-77.

Societal Benefits

Crossborder discusses a list of societal benefits and the methods of computing the values shown in the following table:

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

Id. at 78-91.

Participant Costs of Solar DG

The Report performed a cash flow analysis to estimate the levelized cost of solar for a residential customer of 12.8 cents per kWh. *Id*. at 91-92.

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

Crossborder states that lost revenues and solar integration costs are the two additional costs that utilities and non-participating ratepayers bear. The study modeled the bill impacts using a customer that uses 15,000 kWh per year that is reduced by 12,000 kWh per year initially (then degraded 0.5 percent per year afterwards) after installing solar

DG. The 25-year levelized bill savings impact -- lost revenues -- are 11.4 cents per kWh. Integration costs to the utility have been estimated in several studies. These costs range as follows:

Xcel Energy Colorado Study – $1.80 per MWh on a 20-year levelized basis.

Duke Energy 2014 Study - $1.43 to $9.82 per MWh, depending on penetration

Arizona PSC 2012 Study - $2.00 per MWh in 2020

Crossborder used the $2 per MWh as a reasonable assumption in Arkansas. Crossborder combined the costs for reduced customer bills and solar integration costs to equal 11.6 cents per kWh. *Id.* at 92-94.

The Crossborder Report reprises the results and key conclusions on pages 94-97. Those were presented at the beginning of this Crossborder Report Summary.

For convenience, the positions of Sub-Group 2 regarding some of the assumptions made by Sub-Group 1 and the Crossborder Report, are presented below:

Direct Benefits of Solar DG

Avoided Energy Cost

Sub Group 1

Avoided Energy Cost = $0.0635 per kWh (Base Case on a 25-year levelized value in 2018 dollars). Crossborder Report at 58. Sub-Group 1 used MISO's historic Arkansas day-ahead LMP prices and EIA's AEO 2017 natural gas forecast. *Id.* at 55-57.

Sub Group 2 Initial Recommendations

Avoided Incremental Fuel Cost = $0.02966 per kWh (Distribution Line Losses of 7.4 percent are included in this amount). Sub-Group 2 calculates avoided incremental fuel using the 2016 annual hourly real-time LMPs based on the previous calendar year from

MISO and Southwest Power Pool (SPP). Joint Report, Sub-Group 2 Recommendations, Attachment B at 169.

Sub-Group 2 – Reply

Sub-Group 2 says the amount of excess energy that is exported to the grid is a function of the customer's load and the inherent intermittency of solar, both of which are outside the control of the utility. For this reason, Sub-Group 2 say using a day-ahead price is not appropriate. Real-time LMPs should be used to value avoided energy cost. Sub Group 2 Reply, Attachment 1 at 32.

Avoided Generation Capacity Cost

Sub Group 1

Avoided Generation Capacity Cost = $0.0321 per kWh

(Base Case on a 25-year levelized value in 2018 dollars).

Below are the assumptions Sub-Group 1 used in its calculation of avoided capacity cost.

Table 5: *Avoided Generation Capacity Costs (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	EAL Avoided Reserves	12%	EAL reserve margin
6	**Solar Avoided Capacity Cost**	**$0.0321 / kWh**	[(2 x 3) / 4] x 1.12

Crossborder Study at 60.

Sub Group 2 Initial Recommendations

Avoided Generation Capacity Cost = $0.02153 per kWh

Sub-Group 2's calculation uses the generation capacity base rate of $0.04003 and multiplies it by the capacity benefit of 54 percent. Sub-Group 2 calculates the capacity benefit percentage using the 4CP method and inputs PVWatts hourly load profile and Net-Metering Customers' hourly peak demand for each month. Joint Report, Sub-Group 2 Recommendations, Attachment B at 175-176.

Sub Group 2 - Reply

Sub-Group 2 says Crossborder used old data from EAL's 2015 IRP report to calculate avoided capacity. Sub-Group 2 says Crossborder should have used the avoided capacity forecast from EAL's 2017-2019 EE Program Plan, which is based on MISO market value in the near term. Sub Group 2 Reply, Attachment 1 at 33. Sub-Group 2 points out that Crossborder used the peak hours from 2:00 pm to 4:00 pm. Sub-Group 2 says EAL's peak hours are actually from 3:00 pm to 5:00 pm, and using these peak hours would lower the solar capacity value by 42 percent in Crossborder's analysis. Sub-Group 2 Reply, Attachment 2 at 37.

Line Losses

Sub Group 1

Avoided Line Losses (Energy & Capacity) = $0.0116 per kWh

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

Crossborder Study at 61.

Sub-Group 1 used the average line losses amounts included in the EE Assumptions then increased the amounts by 50 percent to convert them to marginal losses. Crossborder Study at 60.

Sub Group 2 Initial Recommendations

Sub-Group 2 included Line Losses in its Avoided Energy Cost in #1 above. Sub-Group 2 says Distribution Line Loss benefits are $0.00205 per kWh or 7.4 percent of the historical hourly LMP. Sub-Group 2 states that transmission line loss and congestion cost savings is already reflected in the hourly LMP. Joint Report, Sub-Group 2 Recommendations Attachment B at 169.

Sub Group 2 - Reply

Sub-Group 2 says line losses relating to avoided *capacity* cost do not exist and as such should not have been included in Crossborder's analysis. Sub-Group 2 points out that Crossborder used marginal line losses from EAL's EE program and multiplied them by 150 percent. Sub-Group 2 says it is not necessary to gross up the value by 150 percent. Sub Group 2 Reply, Attachment 1 at 32-33.

Transmission and Distribution Capacity

Sub Group 1

Sub-Group 1 calculated avoided T&D capacity costs using $23.86 per kW-year in 2016 that are included in EAL's *EE Assumptions*. This amount was multiplied by 52.2 percent, the solar capacity contribution, then, divided by 1,530 kWh, the annual solar output. The result is $8.14 per MWh ($0.00814 per kWh) using 2016 data. Sub-Group 1 says the 25-levelized cost is $10.20 per MWh. Crossborder Study at 62-64.

Sub-Group 2 Initial Recommendations

Sub-Group 2 states that the embedded capacity benefit is a quantifiable percentage of each component of the functionalized base rate costs and is calculated in Table 5 below.

Table 5 – EAL's Functionalized Residential Embedded Capacity Credit

Function	Base Rate	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**

Attachment B Sub-Group 2 Recommendations at 173-176.

Sub Group 2 Reply

Sub-Group 2 says the $23.86 per kW-year value used by Crossborder is out of date and has been superseded by a new lower value. Sub Group 2 Reply, Attachment 1 at 34.

Avoided Carbon Compliance Costs

Sub Group 1

Sub-Group 1 calculated avoided carbon costs using the Environmental Protection Agency's (EPA) "AVoided Emissions and geneRation Tool" (AVERT) and assumed 3 MW of DG solar in the state. Sub-Group 1 says the 25-year levelized cost is $3.50 per MWh ($0.0035 per kWh) in avoided carbon costs. Crossborder Study at 70-71.

Sub Group 2 Initial Recommendations

Sub-Group 2 did not calculate an avoided carbon cost benefit.

Sub Group 2 Reply

Sub-Group 2 says Crossborder's estimate for carbon costs is significantly over-stated and does not reflect the recent emissions profile of EAL's portfolio. Sub Group 2 Reply, Attachment 1 at 34.

Total Direct Benefits

Sub Group 1

Sub-Group 1 summarizes their direct benefits in the table below:

Direct Benefit	Base Case – Avoided Costs using EE Assumptions ($ per MWh)
Energy	63.50
Generation Capacity	32.10
T&D Losses	11.60
T&D Capacity	10.20
Environment: CO2	3.50
Total Benefits	**120.90**
	12.1 cents per kWh

Crossborder Study at 77.

Societal Benefits of Solar DG

Sub Group 1

Sub-Group 1 has calculated societal benefits totaling 16.3 cents per kWh. The table below summarizes the benefits that Sub-Group 1 quantified.

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

Crossborder Study at 91.

Sub Group 2

Sub-Group 2 did not calculate Societal Benefits.

b. Sub-Group 1 Responses to Commission Questions

Question 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.

Question 1a: If so, which, if any additional costs are quantifiable?

Response: Additional direct costs that are quantifiable include administrative costs and integration costs to maintain the proper frequency and voltage of the distribution system given variable exports. These costs are likely to be *de minimis* given the very low number of net metering accounts in Arkansas. Joint Report at 110-111.

Question 1b: How should any such quantifiable, additional costs be valued, for the purpose of Act 827?

Response: Integration costs are quantifiable based on the interconnection studies conducted by the utility. Administrative costs can be quantified and captured in the utility's COS Study. Joint Report at 111.

Question 1c: Are there existing or emerging technologies or policies that could mitigate such costs?

Response: Did not provide an answer.

Question 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.

Question 2a: If so, which, if any of these benefits are quantifiable?

Response: Sub-Group 1 says its Crossborder study identifies quantifiable benefits associated with the interconnection and providing service to net-metering customers. Joint Report at 112.

Question 2b: How should any such quantifiable, additional benefits be valued, for the purpose of Act 827?

Response: Sub-Group 1 says its Crossborder study identifies methodologies for valuing those benefits. Joint Report at 112.

Question 2c: Are there existing or emerging technologies or policies that could enhance such benefits?

Response: Did not answer.

Question 3a: As a matter of ratemaking, 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-term evaluations of costs and benefits fail to accurately assess the full beneficial impact of distributed generation. The long-term costs and benefits of distributed generation can be amortized and factored into short-term analysis like a COS study. Joint Report at 112-113.

Question 3b: 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: Sub-Group 1 has seen no evidence to date. Joint Report at 13-14.

Question 3c: Should rates incorporate time-differentiated rates for net-metering customers (either residential or commercial)?

Response: Time-differentiated rates can more accurately reflect the value of solar generation, which tends to occur during system peak periods. Sub-Group supports time-differentiated rates for net metering and non-net-metering customers alike. Joint Report at 114-115.

Question 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 otherwise result in the need to acquire emission permits. Joint Report at 115-116.

Question 5. How should the Commission consider or take into account economic costs or benefits beyond the utility's entire cost of providing service, including:

5a: 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 should be considered by the Commission as part of determining fair, just and reasonable rates for net-metering customers. The Crossborder study quantifies local economic benefits of distributed generation as part of the Societal Cost test. Joint Report at 117.

5b: Any public interest, beyond the direct costs and risks associated with compliance with environmental regulation, associated with environmental impacts?

Response: The Commission should consider the benefit to public health that distributed generation would have by displacing fossil fuel generation. The Crossborder study estimates the benefits associated with avoided greenhouse gas emissions, avoided SO_2, PM2.5, and NOx emissions, and avoided water and land use as part of the Societal Cost test. Joint Report at 118.

Question 6: Should policies related to net metering in Arkansas take into account developments in smart-grid, demand response, storage, or other technologies?

Response: Yes. 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. This data could then be used by the Commission to understand how net-metering customers' load profiles differ from others in their class. Joint Report at 118-119.

Question 7: What can be learned from the recent consideration of these net metering valuation issues in other states?

Response: Except for a few states, primarily with much higher levels of solar penetration, comprehensive cost-benefit studies conclude that benefits of distributed solar exceed its costs. Sub-Group 1 says 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. Joint Report at 120-123.

Question 8: What other issues, if any, should be addressed in implementation of Act 827?

Response: Sub-Group 1 recommends that the Commission initiate a process that would encourage utilities to 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. Joint Report at 124-125.

5. Sub-Group 2 Recommendations and Responses to Commission Questions Posed in Section A of Order No. 1

a. Summary of Recommendations

i. Introductory Discussion Supporting Recommendations

Sub-Group 2 concludes that the current rate structure for net-metering customers does not meet the statutory requirements of Ark. Code Ann. § 203-18-604(b)(1)(A) as amended by Act 827. They assert that crediting net-metering customers' excess generation kWh at the full retail rate results in the utilities' failure to recover the actual cost of service, net of quantifiable benefits. Sub-Group 2 does not oppose customers using the unmetered generation used behind the meter to reduce their bill. However, Sub-Group 2 contends that crediting the excess generation of kWh at the full retail rate does not adhere to the requirements of Act 827. *Id.* at 148 – 149.

Currently, Sub-Group 2 states, retail rates are designed to collect the embedded cost for generation, transmission, and distribution based on a utility-specific COS Study that allocates the embedded costs. Most of these costs do not change if a net-metering customer uses more or less energy than it did prior to installing a net metering facility. Sub-Group 2 states that crediting net-metering customers at the full retail rate for excess generation credits the customer for embedded costs of providing utility service that are not avoided due to the customer's reduced consumption. This results in utilities not recovering the entire cost to serve net-metering customers, a shortfall that is ultimately recovered from non-net-metering customers through the normal ratemaking process. Costs not fully recovered from net-metering customers include:

- Generation, transmission, and distribution;
- Billing, metering, reliability programs, efficiency programs; and
- Approved investments and ongoing costs essential to maintaining the distribution and transmission systems.

Sub-Group 2 urges the Commission to change the current net metering policy for new net-metering customers because there is a fundamental flaw in the mechanism for crediting excess generation. *Id.* at 149.

Sub-Group 2 recommends adoption of 2-Channel Billing and states that it is a fair, balanced, and equitable approach to addressing the relevant provisions of Act 827. 2-Channel Billing collects the utility's cost to serve 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 that the net-metering customer provides through self-generated energy exported to the grid through Channel 2. *Id.* at 150.

ii. Net Metering Rate Structure Options

Sub-Group 2 identified, evaluated, and considered the strengths and weaknesses of five different options that potentially would address the quantifiable costs and benefits of a net-metering customer's continued use of the utility's generation, transmission, and distribution systems. Some of the meetings included all of the other working group participants. 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

Id. at 150.

Option 1: 2-Channel Billing

Under 2-Channel Billing the energy delivered by the utility and consumed by the customer is recorded on Channel 1 of the net-metering customer's bi-directional meter. The excess self-generated energy exported to the grid is recorded on Channel 2 of that same bi-directional meter. The customer is billed at retail rates, including fuel and riders, for the energy delivered by the utility and consumed by the customer (Channel 1). A credit is recorded for the customer for any excess self-generated energy exported to the grid (Channel 2) during a billing cycle, using a pre-determined excess generation credit rate. Sub-Group 2 does not recommend measuring or recording self-generated energy consumed directly by the net-metering customer behind the meter, which would require the installation of a separate meter to measure the output of the customer's generation facility. *Id.* at 150.

Other asserted benefits of 2-Channel Billing include:

- It utilizes the bi-directional digital meter that is used today.
- It does not require that the customer install a second meter to measure or record self-generated energy directly consumed behind the meter by the customer.
- The customer fully retains the benefit of its reduced energy consumption (the energy it self-produces and uses behind the meter). This is similar to the impact of energy efficiency programs or other customer actions to reduce their usage such as weatherization or conservation.

- It collects the utility's cost to serve for energy delivered by the utility through Channel 1.
- It 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 through self-generated energy exported to the grid.
- It represents a fair, balanced, and equitable approach to addressing the relevant provisions of Act 827.
- The rate charged for Channel 1 would be the Commission-approved tariff rate.
- The only change from the current net metering rate structure is that a different excess generation credit rate would be used for excess kWh exported to the grid.
- Both the rate paid for consumption and the credit rate for excess generation will be based on the utility's actual embedded cost of serving net-metering customers, net of benefits.

Id. at 154-156.

Option 2: 3-Part Rate

A 3-Part Rate schedule recovers a greater portion of the utility's costs under the fixed or demand rate charges and uses a combination of the following:

- A fixed monthly customer charge designed to recover some portion (or all) of the embedded customer costs, such as metering, billing, and customer service;
- A demand charge designed to recover a portion of embedded production, transmission, and distribution costs; and
- A volumetric energy charge(s), expressed in cents/kWh, designed to recover the remaining portion of the utility's costs.

A net-metering customer billed under a 3-Part Rate would receive a kWh credit equivalent to the full retail rate for energy exported to the grid.

Id. at 151-152.

Option 3: Grid Usage Charge

A Grid Usage Charge is an additional monthly fee that can take various forms. In one variation, the monthly fee is a fixed rate expressed in $/kW-month. This fixed rate is multiplied by the size of the net-metering customer's generator. The utility would need to derive a $/kW-month charge to be applied each month based on the utility's underlying COS study. The net-metering customer would receive a kWh credit equal to the full retail rate for excess energy exported to the grid. *Id.* at 152.

Option 4: Minimum Bill

Under a Minimum Bill option, a specific threshold dollar value is set 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. 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. However, the excess energy credit in a billing cycle can never result in a bill that would be less than the otherwise applicable minimum bill. *Id.* at 153.

Option 5: Time of Use (TOU) Rate

Under a TOU Rate, the volumetric charge(s) in a rate schedule vary to incorporate time of day and/or seasonality. A net-metering customer will receive a credit equivalent to the full retail rate that varies based on the time in which the excess energy delivered to the grid occurs. Few Arkansas utilities offer TOU residential rates. *Id.* at 153.

iii. Implementation of 2-Channel Billing

Only non-demand billed tariffs would be billed using 2-Channel Billing, though there may be limited exceptions. Excess self-generated credits during a billing period will be accumulated and carried forward and applied in the next applicable billing period, consistent with current treatment. For aggregated meters with a generation meter, the customer will still be responsible for providing the utility with a list of the customer's accounts and the priority order to which any net excess generation shall be credited. Under the 2-Channel Billing scenario illustration provided by Sub-Group 2, the net-metering customer still saves $53, only $8 less than under the current policy. *Id.* at 156-159.

iv. Framework for 2-Channel Billing Rate Structure

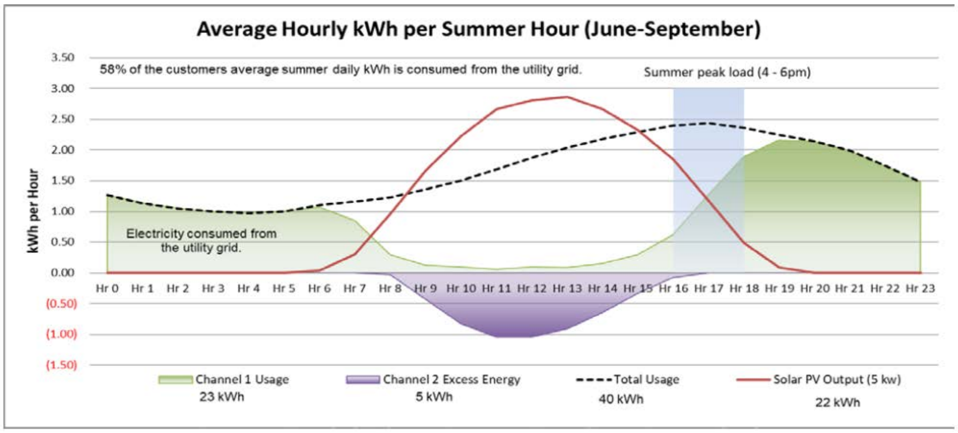
To the extent that net metering facilities provide benefits that may occur over time, those will be reflected in the COS Study and resulting rates as approved by the Commission. The excess generation credit should be developed using COS methodologies consistent with those used to allocate the utility's costs from its most recent COS Study used to set the current rates as well as the CP values used in the COS Study. *Id.* at 160-162.

Net-metering customers' requirements for electric service are not different from other customers. Sub-Group 2 provided an illustration shown below of hourly electricity flows for the Average Summer Day of June-September which shows:

- Excess energy exported to the grid generally falls outside of the utility's summer peak load hours, thus not lowering the utility's peak load.
- The output of a typical solar PV system offsets some of the utility's peak load, but not 100 percent.

- The utility has to have sufficient infrastructure in place to meet the net-metering customer's needs in the late afternoon when the solar PV system output is declining.

Illustrative Electricity Flows for the Average Summer Day



Id. at 163-166.

Sub-Group 2 does not recommend that net-metering customers be placed into a separate COS rate class. Their energy usage profile will vary from that of a non-net-metering customer, Sub-Group 2 states, but that alone does not justify a separate COS class, noting that differences between customers within a class are generally handled through rate design. *Id.* at 166.

Current Net Metering Policy and Utility Rate Design

Beginning with the discussion on page 167 and continuing through page 179 of the Joint Report, Sub-Group 2 utilizes EAL-specific values in its analysis, ending with Table 6, which shows a monthly bill comparison for an EAL typical customer.

A net-metering customer does not invest in transmission or distribution services, so without the grid they have no way to export their excess generation. The transmission and distribution costs of the grid are incurred by the utility and embedded in the utility's rates. 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 service, net of quantifiable benefit. Report at 167-168.

Excess Generation Credit Methodology

Sub-Group 2 identifies two potential benefit categories for developing the excess generation credit methodology:

1. Avoided incremental fuel benefit
2. Embedded capacity benefit

Excess generation credit = Dollar value of the avoided incremental fuel expressed in $/kWh + Embedded capacity credit expressed in $/kWh. *Id.* at 168-169.

Avoided Incremental Fuel Benefit

The avoided incremental fuel benefit would utilize historical annual real-time LMPs from the previous calendar year for MISO and SPP, or both, as applicable to each utility. The LMP would be adjusted by the utility's distribution line-loss factor to allow for the line losses that locally generated and used generation avoids. *Id.* at 169.

Embedded Capacity Benefit

The capacity benefit is 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 delivered to the grid. Sub-Group 2 quantified an appropriate embedded capacity percentage to credit by analyzing solar capacity for each hour for a year using a standard model and comparing those values to the peak hours of the utility. The solar capacity factor as well as the utility peak hour varies through the year. *Id.* at 170.

Sub-Group 2 recommends using the average monthly peak hour over the most recent 5 years for each utility and also recommends averaging the solar capacity factor for the peak hour and the hour before and the hour after the peak. Table 3 illustrates this using EAL's information. *Id.* at 171-172.

Development of the Embedded Capacity Credit

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, Sub-Group 2 recommends using the maximum hourly capacity factor of solar that coincides with the utility's peak hours. This gives credit to the maximum production capacity of the generator, not just the excess generation exported to the grid. *Id.* at 173.

The table below shows a comparison of the capacity benefits calculated using EAL's Peak and Solar Capacity Average Hour Factor and the Solar Capacity Maximum Hour Factor

Function	Allocated Using	Using Solar Capacity Factor Average Hour	Using Solar Capacity Factor Maximum Hour
Generation	4CP	42%	54%
Transmission	12CP	26%	36%

Table 5 illustrates the computation of EAL'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

Distribution costs are allocated by number of customers and non-coincident peak (NCP). The number of customers does not change, and the NCP may not change as a result of net metering. *Id.* at 176.

Rate Impact

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. *Id.* at 177. Table 6 illustrates EAL's typical customer monthly bill under each possible four situations.

Table 6
EAI's Typical Customer Monthly Bill

							Typical Bill with Solar - 5 kW		
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	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**

Id. at 179.

Sub-Group 2 provides a summary of 2-Channel Billing Impact by Utility for each electric Arkansas jurisdictional Investor Owned Utility and Cooperative at page 217 of the Joint Report.

Changes to the Net Metering Rules to Implement 2-Channel Billing

Sub-Group 2 proposes a number of changes to the *Net Metering Rules*, attaching a copy of the existing Rules as well as a Red-Line version reflecting the proposed changes. The changes proposed into these categories:

- Definitions – added definitions for four new terms and removed 8 definitions that are not referenced in the Rules.
- Rule 2.04 - renamed to indicate that it would apply to those taking service under the Grandfathered Net-Metering Tariff. Several of the subsections were renumbered as separate Rules.
- Rules 2.05 through 2.09 – were added as a result of the new billing requirements related to the proposed changes or for the subsections removed from Rule 2.04 as separate Rules.
- Rule 4.01 – updated consistent with the proposed appendix additions.

Id. at 180-182.

Changes Required to Tariffs to Implement 2-Channel Billing

Sub-Group 2 proposes two tariffs that are both based on the approved Net-Metering Tariff included in Errata Order No. 14. They also propose 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 – this tariff would apply to all Net-metering customers who sign such a Standard Interconnection Agreement (SIA) prior to the Phase 2 Order Date. This tariff would revise the current Net Metering Tariff. This tariff is reflected in Appendix D of the Red-Line and Clean versions of the Net metering Rules.
- Net metering Tariff – this tariff would apply to all Net-metering customers who sign a SIA with the electric utility after the date of the Order in Phase 2 pursuant to Order No. 10 as amended by Errata Order No. 14 (Phase 2 Order Date). This tariff is reflected in Appendix E of the Red-Line and Clean versions of the Net metering Rules.

Id. at 183.

Red-line Version of the Net metering Rules – *Id.* at 218-263.

Clean Version of Net- Metering Rules – *Id.* at 264-306.

b. Sub-Group 2 Response to Commission Questions

Question 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. Additional costs imposed include costs such as billing, customer service, interconnections and operational impacts. Some of these costs would be expected to grow as the number of net-metering customers increases.

Question 1a: If so, which, if any additional costs are quantifiable?

Response: Interconnection costs are quantifiable based on the interconnection studies conducted by the utility. Other additional costs are quantified and captured in the utility's COS Study.

Question 1b: How should any such quantifiable, additional costs be valued, for the purpose of Act 827?

Response: Additional costs should be quantified using well-established COS methodologies based in each utility's specific COS data. These methodologies have been reviewed before the APSC for many years and follow the principle of cost causation.

Question 1c: Are there existing or emerging technologies or policies that could mitigate such costs?

Response: Yes. Existing technologies include sensors with communication capability, smart inverters, condition-monitoring sensors, and energy storage technologies. The impact of emerging technologies or future policies can be considered in future rate cases for each utility and recognized in the associated COS study. *Id.* at 186-189.

Question 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 purposes of establishing rates for net metering the benefits considered should be well defined, readily quantifiable, transparently accounted for, based on the actual embedded cost of providing service, and based on the individual utility's COS Study.

Question 2a: If so, which, if any of these benefits are quantifiable?

Response: Embedded generation and transmission capacity benefits occur if net-metering customers reduce their peak load requirements. Incremental energy adjusted for distribution line losses is avoided if net-metering customers export excess energy to the grid.

Question 2b: How should any such quantifiable, additional benefits be valued, for the purpose of Act 827?

Response: Benefits should be valued using traditional COS methodologies and rely on the most recent COS Study for the utility. Avoided incremental energy benefits can be quantified based on the annual hourly real-time LMPs for the previous historical year, plus distribution line losses. A weighted average annual avoided incremental energy cost per kWh should be determined.

Question 2c: Are there existing or emerging technologies or policies that could enhance such benefits?

Response: Yes. Many of the technologies discussed in response to 1c would be equally applicable to enhancing the benefits. Challenges exist in incorporating them. Also, they could bring additional regulatory challenges. *Id*. at 189-191.

Question 3a: As a matter of ratemaking, 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 these by relying on the utility's most recent COS Study. This will appropriately balance short- and long-term cost causation.

Question 3b: 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: Not at this time. Net-metering customers are unique due to the fact that at times they may export power back onto the utility system. However this difference from other customers in their class is best addressed through rate design.

Question 3c: Should rates incorporate time-differentiated rates for net-metering customers (either residential or commercial)?

Response: Time-differentiated rates could be explored within the context of future utility general rate cases. Mandatory time-differentiated rates are not necessary at this time in Arkansas due to the small number of net-metering customers. If available, a choice of rates should be available to all customers. *Id*. at 192-193.

Question 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 US Supreme Court. It is not possible to know the future of environmental regulations. Any reduction in utility's investments and expenses related to environmental compliance costs will be reflected in the utility's future COS Study or the fuel and purchased energy recovery mechanisms. *Id*. at 193-194.

Question 5. How should the Commission consider or take into account economic costs or benefits beyond the utility's entire cost of providing service, including:

5a: Any public interest associated with economic development or job creation in the distributed energy sector, including the potential impact of federal tax benefits?

Response: Such benefits are not comprehended in the utility costs or recoverable by the utility and should not be considered by the Commission to determine just and reasonable rates for net-metering customers. They are also difficult to quantify and speculative in nature.

5b: 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. *Id.* at 194.

Question 6: Should policies related to net metering in Arkansas take into account developments in smart-grid, demand response, storage, or other technologies?

Response: Yes. Such developments that affect the utility's actual cost of providing service to all customers should be taken into account, but only at a time when they have emerged to a point where they have a quantifiable impact. *Id.* at 195-196.

Question 7: What can be learned from the recent consideration of these net metering valuation issues in other states?

Response: Many other jurisdictions have reached the conclusion that net metering rates which provide a kWh credit equal to the full retail rate for excess generation from net metering facilities fail to recover the full cost of serving those net-metering customers and shift costs to other customers. Many jurisdictions have had proposed, or have adopted, a 2-Channel Billing framework the same, or similar to, that proposed by Sub-Group 2. Those that have implemented 2-Channel Billing type framework vary in their valuation of the excess energy. See also Attachment B-3 to Sub-Group 2's recommendations. *Id.* at 195-196.

Question 8: What other issues, if any, should be addressed in implementation of Act 827?

Response: None at this time. *Id.* at 196.

Lessons Learned From Other States and Jurisdictions

See Attachment B-3 to Sub-Group 2's recommendations. *Id.* at 197-216.

6. Other Party Comments/Recommendations

According to the Joint Report, some NMWG participants provided differing perspectives from those advocated by either Sub-Group 1 or Sub-group 2. These are summarized below:

a. Pulaski County, Arkansas

Pulaski County believes that 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, Pulaski County asserts that there has been no factual basis presented to change the existing net-metering compensation structure 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, Pulaski County argues, 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 AREDA, which Pulaski County urges the Commission to avoid. Pulaski County asserts that 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. Pulaski County Comments at 306.

In its Recommendations in the Joint Report, Pulaski County states that while the relevant statute, Ark. Code Ann. § 23-18-604(b), does use the language "shall [e]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. Pulaski County submits that 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 created by Act 827 for the Commission to change the existing rate structure for net-metering customers. In fact, Pulaski County argues, 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 AREDA. *Id*. at 306-307.

Pulaski County states that the burden set forth in the statute 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. Pulaski County further states that, because Act 827 does not necessitate a specific time period for the Commission to establish appropriate rates, term, 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. According to Pulaski County, the Commission should take a conservative approach, ordering a long-term, independent study that analyzes usage patterns, actual occurrences, practices, and results. *Id*. at 306.

Pulaski County further asserts that any proposal regarding costs and benefits of 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. Based upon evidence presented at the hearing in Phase 1 of this docket, Pulaski County stipulates that there are 500 net-metering customers in Arkansas, which it asserts 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, Pulaski County argues, the impact in cost and benefits of 500 net-metering customers may not be consistent with the costs and benefits of 5,000 or 50,000 net-metering customers. Thus, the study Pulaski County recommends would enable the Commission to 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. *Id*. at 308.

Finally, Pulaski County notes in the Joint Report that AREDA contemplates economic development and job creation as a motivation for adoption, thus necessitating that the Commission consider the impact of the net-metering rules and rate structures on those matters. Pulaski County states that through its Order No. 5 regarding grandfathering of net-metering customers, the Commission has recognized that uncertainty, complexity, and shifting winds deter 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, Pulaski County submits, "grandfathering" of existing users for a sufficient term, to reasonably calculate future expectations, directly addresses 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 to avoid driving away investment, especially for residential and small commercial customers that traditionally struggle to receive capital investment. Pulaski County states that direct investment in distributed generation and net-metering results in a capital improvement to real property and results in the collection of sales taxes on the sale of capital goods. This produces additional tax revenue 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. Pulaski County extols net metering for its simplicity and argues that any proposal that changes the existing net-metering compensation model is likely overly complicated and will hinder the intent of AREDA. *Id*. at 309.

b. The Alliance for Solar Choice

The Alliance for Solar Choice (TASC) did not actively participate in Phase 2 of this Docket and abstained from formally joining any part's recommendation in the Joint

Report. On November 21, 2017, TASC requested to withdraw as a party. The Commission granted the request by Order No. 18 on November 22, 2017.

c. Solar Energy Arkansas, Inc.

On November 28, 2017, Solar Energy Arkansas, Inc. filed a Motion to Withdraw, which was granted by Order No. 19 on November 29, 2017.

d. William Ball

In his short Recommendations included in the Joint Report, Mr. Ball states that Act 827, a statutory sub-chapter of 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. Mr. Ball observes that there has been little progress in reaching a consensus among the Parties. He notes that there is 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, he says, then one would recognize the importance of robust development of our renewable energy resources. He acknowledges that it is very difficult to assign a monetary figure to the universal value of net metering. He agrees with comments from some Parties that establishing a rate schedule or protocol that is "a guess or a wish on the part of Parties on either side of the arguments" is putting the cart before the horse. *Id*. at 309-310.

Mr. Ball states that both obvious and intangible benefits must first be fully and fairly evaluated and points to remedies being adopted by other states as indicating that some have valued benefits more highly than others. Some jurisdictions have determined that, far from shifting costs, net-metering customers create net value to the grid and all grid users, while other states have focused more on costs to a utility and somehow "keeping them whole." He asserts that a program whereby utilities could purchase all energy, or just net excess energy, produced by a net-metering customer could be considered if one is attempting to keep the utilities whole and if purchase prices include the value of benefits derived from sustainable energy generation. He adds that utilities could recover their purchases through existing mechanisms and, in purchasing, gain ownership of the Renewable Energy Credits (RECs) associated with renewable energy.

Mr. Ball disavows a belief that utilities care only about protecting profits and monopolies that have never faced competition, asserting 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. He states that some of those technologies will provide greater universal benefit in the form of grid services that communicate with and aid the grid. He suggests that providing policies that nourish robust net metering growth and encourage further development and experiences with grid services technologies should be our goal. Among those are time-of-use pricing, peak shaving after the sun goes down, self-consumption, grid zero, grid support (Rule 21 in California), and 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. Mr. Ball notes that Arkansas has very low penetration of solar power and suggests that policy that recognizes public policy benefits of bringing the future to Arkansans could well be an under-recognized benefit of net metering. *Id*. at 310-311.

Mr. Ball submits that the consideration of 2-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, he states, 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, he urges, at the very least the Commission should (1) wait until a full study of benefits is completed and (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. *Id*. at 311-12.

Mr. Ball notes that he has argued that there are minimal "additional costs" to a utility from a net-metering customer that are not incurred by the utility serving non-net-metering customers within a given customer class. If lost revenues are not part of the consideration, he states, 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-programmed by the technician before coming to the site.
3. Administrative costs associated with billing of a net-metering customer's consumption and net excess generation, which must be mitigated by the fact that

non-net-metering customers' billing routinely presents similar administrative costs associated with tracking time of use or levelized billing.

Id. at 312.

Mr. Ball states that 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, he asserts. He concludes his comments in the Joint Report by stating that 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." He observes that AREDA did not require an amendment directing the Commission to evaluate the prudence of assessing a net-metering customer a greater fee, noting that that authority has been there all along. Perhaps, he concludes, the rate structures for all customer classes do not accurately reflect the actual cost-of-service to those customers. *Id*. at 313.

7. Sub-Group 1 Reply Comments

Sub-Group 1 asserts that Sub-Group 2 does not provide sufficient evidence that net metering fails to recover the COS. The Crossborder Energy study submitted by Sub-Group 1, as well as Sub-Group 2's own COS principles, disproves Sub-Group 2's assertion that net-metering customers are not paying their full COS. Sub-Group 1 argues that Sub-Group

2's approach is conceptually flawed in incorrectly assuming that net metering must change. However, Sub-Group 1 notes, the Commission in Order No. 10 stated that parties should not assume that changes are necessary. Instead, Sub-Group 1 argues, the issue is whether compelling evidence has been demonstrated to justify a change in net metering, and Sub-Group 2 did not provide such evidence. Sub-Group 1 Reply at 1-3.

According to Sub-Group 1, Sub-Group 2 does not explain what the COS for net-metering customers, as defined by AREDA, actually is. Thus, Sub-Group 2's assertion that net-metering customers don't pay their full cost of service is wrong for these reasons:

- It assumes, without proof, that the value of the distributed generation exported to the grid is less than the utility's cost to deliver a kWh to the same location; and
- It does not grapple with the COS that AREDA prescribes, which requires an assessment of *additional* quantifiable costs, net of quantifiable benefits.

Id. at 3.

Sub-Group 1 contends that Sub-Group 2 has not quantified the alleged shortfall in revenue recovery. Therefore it cannot demonstrate that its proposed Billing and exported generation credit methodology recovers the appropriate amount from net-metering customers. In addition, Sub Group 2 does not provide any evidence that the proposed reduced compensation to customer-generators is matched to revenue deficiencies caused by any additional costs of net metering. Sub-Group 2's approach thus appears intended to discriminate against self-generation and stifle innovation and investment in distributed generation – contrary to the express purposes of AREDA. *Id*. at 4.

Sub-Group 1 argues that Sub-Group 2's 2-Channel billing proposal treats self-generated kWh used behind the meter differently from self-generated kWh exported to the grid, by compensating them at different rates. Sub-Group 2's proposal thus picks distributed generation winners and losers based on individual load distribution rather than utility costs. *Id*. at 5.

Sub-Group 1 posits that Sub-Group 2's method for calculating the net excess generation credit is based on a narrow view of the costs and benefits that AREDA requires to be evaluated. Sub-Group 1 notes that Sub-Group 2's COS for production and transmission is based on embedded costs and fails to consider future costs avoided. Sub-Group 1 acknowledges that Sub-Group 2's analysis correctly uses the marginal cost for energy. *Id*. at 5.

Sub-Group 1 asserts that a longer-term view of avoided marginal costs associated with distributed generation must be considered in order to capture the full range of costs and benefits. Sub-Group 1 Reply at 6. Sub-Group 1 states that embedded COS analyses were never contemplated for measuring the benefits of customer-sited generation, and are wholly inadequate to do so. The COS approach fails to value real and quantifiable benefits provided by the investment of net-metering customers. Additionally, Sub-Group 1 notes, many of the COS studies of utilities in the state are dated and may not reflect recent costs or the drivers of those costs. *Id*. at 7.

Sub-Group 1 states that Sub-Group 2's assertion that "Channel 1" load is no different than that for any other residential customer is an untested assumption and a fundamental error and that Sub-Group 2's own data shows otherwise. Sub-Group 1 states that because at least half of a net-metering customer's generation is consumed on-site, that customer's grid-supplied load is less than that of a typical customer at the times that determine cost responsibility -- during peak load hours. To that extent, Sub-Group 1 argues that the net-metering customer's load is less costly to serve. *Id.* at 7-8.

Sub-Group 1 provides as Attachment A to its Reply Comments Crossborder Energy's critique of Sub-Group 2's approach (White Paper). Sub-Group 1 states that utility data shows that net metering provides net benefits to Entergy's system and other customers. *Id.* at 8-9.

Sub-Group 1 asserts that another problem with Sub-Group 2's COS approach is that it treats system peak load reductions different in cases where the net-metering customer's generation reduces her own Channel 1 usage through behind-the-meter consumption, rather than offsetting the usage of a neighbor. However, Sub-Group 1 argues that the system benefits are the same in either case – there is no cost causation justification for treating customer generation differently based on whether it is consumed behind the meter or not. In sum, Sub-Group 1 argues, not only does Sub-Group 2's proposal fail to adequately consider future benefits of net-metering generation, but it also fails to properly apply its own COS methodology to study what are the actual costs to serve a net-metering customer. As a result, the Sub-Group 2 foundation does not appropriately meet the COS-driven approach it asserts to have taken. *Id.* at 9.

Sub-Group 1 asserts that Sub-Group 2's exported generation calculation leaves out important avoided costs and is improperly based on generic assumptions about distributed solar systems. According to Sub-Group 1, Sub-Group 2 proposes to compensate all generation not used instantaneously on-site at a significantly lower rate based on a handful of utility system costs which that generation is said to avoid, noting that Sub-Group 2 presents its methodology for this "net excess generation" credit in the Joint Report at pages 169 to 176. Sub-Group 1 states that the term as employed by Sub-Group 2 is "confusing and incorrect," noting that AREDA defines "net excess generation" to mean "the amount of electricity that a net-metering customer has fed back to the electric utility that *exceeds the amount of electricity used* by that customer during the applicable period." Ark. Code Ann. § 23-18-603(3). This "applicable" period refers to the monthly billing cycle. Sub-Group 1 notes that AREDA allows for compensation of that "net excess generation under certain conditions at the electric utility's estimated annual average avoided cost rate for wholesale energy. . . ." Ark. Code Ann. § 23-18-604(b)(6)(A)(ii). *Id.* at 9-10

By contrast, Sub-Group 1 argues, Sub-Group 2 misuses the term to apply to any electricity exported to the grid at any point during the billing period, rather than to apply to any electricity that a customer has fed back to the grid, net of their usage, during that billing period. Sub-Group 1 states that if there were any doubt that Sub-Group 2's "net excess generation" is not what AREDA means by that term, it is settled by the fact that Sub-Group 2 proposes a methodology for the value of its "net excess generation" that is inconsistent with the value required under Section 604(b)(6)(A)(ii). To avoid confusion, Sub-Group 1 instead proposes and utilizes the term "exported" generation to refer to the quantity of a distributed generation system's production that is not used instantaneously behind the meter. *Id.* at 10.

Sub-Group 1 states that AREDA calls for the analysis of benefits of distributed generation, "including without limitation benefits to the electric utility's capacity, reliability, distribution system, or transmission system." Ark. Code Ann. § 23-18-604(A)(ii)(b). Sub-Group 1 notes that Sub-Group 2's proposal purports to capture benefits as required by AREDA by quantifying the avoided production and transmission capacity costs and avoided energy costs associated with exported generation. Joint Report at 157. Sub-Group 1 notes that "strikingly," Sub-Group 2 assumes zero distribution system benefits of the exported generation, which AREDA specifically calls for the Commission to evaluate as one of the benefits of net metering. According to Sub-Group 1, Sub-Group 2's explanation for ascribing zero avoided distribution cost credit to the exported generation rate is that "the [non-coincident peak] may not change," citing Joint Report at 176 (emphasis added). Sub-Group 1 states that it is unclear whether Sub-Group 2 lacks the data to assess whether net metering exports will affect the residential class's non-coincident peak, or has simply chosen not to undertake such an analysis. In either case, Sub-Group 1 argues, it is unrealistic and indefensible to simply assume, without evidence, that no reduction in distribution costs will occur. Sub-Group 1 states that this is true whether looking only at a customer's responsibility for embedded distribution system costs based on contributions to non-coincident peak, or on a forward-looking basis as Sub-Group 1 advocates. Sub-Group 1 asserts that dozens of studies, including the Crossborder Study of Entergy Arkansas, have found an appreciable, non-zero reduction (about 15%) in the non-coincident peak. Joint Report at 10-11 and 69.

Moreover, Sub-Group 1 argues, Sub-Group 2's narrow focus on embedded costs fails to consider other widely accepted avoided costs that are regularly attributed to distributed renewable generation, such as natural gas price volatility and avoided regulatory costs related to environmental compliance. Sub-Group 1 notes that EAL recognized the natural gas volatility benefit in asking for cost recovery of its Stuttgart solar project.[6] Sub-Group 1

[6] *See* Direct Testimony of Kurtis W. Castleberry in Docket No. 15.014-U at 15.

states that Sub-Group 2's backward-looking analysis likewise ignores avoided regulatory costs related to environmental compliance that are likely to accrue over the lifetime of solar systems installed today, and which are reflected in utility IRPs and in the cost-effectiveness evaluations of other types of demand-side resources. *Id.* at 11-12.

Sub-Group 1 states that Sub-Group 2's reading of AREDA is in conflict with itself because Sub-Group 2 asserts that the cost-only assessment included in a utility COS study is sufficient to meet the standard of the law, even while the plain words of AREDA require an assessment of the benefits that the Sub-Group 2 approach ignores. Sub-Group 1 argues that the statute must be read in a way that gives meaning to all its words. *Id.* at 12.

Sub-Group 1 argues that Sub-Group 2's calculation of the exported generation credit fails to consider and accurately value the multitude of differing solar array characteristics, noting that it is based on the incremental fuel and avoided embedded capacity benefit associated with a single, very specifically defined distributed solar system – specifically a fixed-axis, south facing, solar system located in Little Rock with the other defaulting system attributes included in PVWatts. Other array characteristics include tracking systems, improved inverter efficiency, and difference in tilt and orientation, for which Sub-Group 2's one-size-fits-all approach is not appropriately tailored. Sub-Group 1 notes that as single and dual-axis tracking systems become more common and system efficiencies improve, Sub-Group 2's approach, by undervaluing the avoided costs associated with such systems, would effectively punish innovation that could provide maximum benefits to the grid. At the very least, the Commission should require that the exported generation rates be developed based on the particular solar installation types with higher capacity factors. *Id.* at 12-13.

Sub-Group 1 argues that Sub-Group 2's proposal is inconsistent with AREDA's definition of net metering. 2-Channel billing as proposed by Sub-Group 2 does not "net" or measure the difference between consumption and production of electricity (in kilowatt-hours), but rather the monetized difference between the two. According to Sub-Group 1, it is more aptly described as net billing. 2-Channel Billing creates a complicated structure in which customer-generated energy is classified as either offsetting consumption on an instantaneous – not monthly – basis, or as excess to the customer's instant energy needs. For offsetting energy production, the customer (effectively) earns retail credit. For exported energy, the utility would pay a much lower export rate based on certain avoided costs as captured in the utility's COS study. Sub-Group 1 notes that this rate design creates the perverse result that customers who conserve or use very little energy during periods of peak solar production get significantly lower compensation for their distributed generation than those who increase their loads during hot sunny days. *Id*. at 13-14.

In contrast to Sub-Group 2's approach, Sub-Group 1 observes that the statutory definition of net metering speaks only in terms of netting based on kilowatt hours. Sub-Group 1 argues that any changes the Commission may make through this proceeding must, to be consistent with the net metering statute, preserve netting on a kilowatt-hour basis, not a monetized value, across the entire monthly billing period. Netting on a kilowatt-hour basis is consistent with the Commission's earlier interpretations of AREDA in Docket No. 02-046-R. In that docket, the Commission expressly rejected a similar scheme proposed by the investor-owned utilities to credit all output from net-metering customers at the avoided cost rate, and instead found that "by definition, the utility should credit net metering output at the full bundled rate in order to promote the use of renewables consistent with the purposes of the Act." Docket 02-046-R, Order No. 3 at 4-5. Sub-Group 1 notes that Sub-Group 2's use of the term "net excess generation" or "excess generation" is inconsistent with AREDA's definition of that term and encourages Sub-Group 2 to avoid the conflation of this term to avoid confusion. *Id.*at 14.

Sub-Group 1 argues that Sub-Group 2 has improperly construed the ratesetting authority provided in Ark. Code Ann. § 23-18-604(b)(1)(A)(i), which states that the Commission shall establish "[a] requirement that *rates charged* to each net-metering customer recover the electric utility's entire cost of providing service" (emphasis added). Under 2-Channel Billing, Sub-Group 1 notes, the utility would pay for exported energy, which is not a rate charged to the customer. The rate charged to a customer under Sub-Group 2's proposal is the retail rate for energy provided by the utility. For the authority to pay a net metered customer less than the retail rate for exported energy, the Commission would need to look at § 23-18-604(b)(2), which states that the Commission "[m]ay 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." According to Sub-Group 1, that section explicitly provides that environmental and public policy benefits must be included when assessing any fee or charge and, while a valuation of these benefits for the entire state of Arkansas has not been attempted, the Crossborder study quantified some of these benefits for EAL. (Joint Report, Attachment A-1). Additionally, Sub-Group 1 states, other studies have found these benefits to be worth several cents per kWh, which would further bolster its assertion that net metering is a net benefit to utility ratepayers generally. Sub-Group 1 Reply at 14-15.

Sub-Group 1 asserts that a key benchmark for the Commission in reviewing the proposed 2-Channel Billing structure is whether it would promote distributed generation, noting that AREDA (Ark. Code Ann. §23-18-602(a)) requires utilities to offer net metering in order to "encourage[] the use of renewable energy resources and renewable energy technologies," as detailed in Sub-Group 1's initial recommendations. Sub-Group 1 states that 2-Channel Billing likely would result in the exact opposite – stunting the growth of distributed generation for numerous reasons. *Id.* at 15-19.

In contrast to 2-Channel Billing, which is complicated and confusing, Sub-Group 1 points out that net metering is a simple, easily understood billing framework in which customers receive one-to-one credits for their generation. Sub-Group 1 points to Bonbright's principles of rate design published in 1961 as well as those of Garfield and Lovejoy, published in 1964, as citing desired characteristics of rates to include simplicity, understandability, public acceptability, and feasibility of application and interpretation. Sub-Group 1 states that these principles are widely applied and there is no reason such principles should not extend to the rates applicable to distributed generation customers just as they do to customers at large. Sub-Group 1 notes that the complicated nature of 2-Channel Billing will impede a customer's ability to respond properly to the rate, and more significantly, to understand the economic advantages of installing distributed generation. *Id.* at 16.

Sub-Group 1 states that 2-Channel Billing can result in peculiar billing results that are likely to confuse and distress customers and provides an example of a scenario in which a customer's Channel 1 consumption was 800 kWh and her Channel 2 exports were 850 kWh. This scenario could arise where a customer consumes most of her electricity at off-peak hours, or is out of town for part of the month. Under net metering, that customer would pay only the customer charge or minimum bill for the month, and the extra 50 kWh would roll over to the next month. *Id.*

Under Sub-Group 2's 2-Channel Billing proposal, however, only 800 kWh of the Channel 2 generation would be multiplied by the Channel 2 rate and applied to the current bill, and the other 50 kWh would also be multiplied by the exported generation rate. However, the resulting credit would be rolled over to the next bill. That customer would have a bill equal to 800 kWh times the retail rate, minus 800 kWh times the exported generation rate (plus customer charges and riders), and simultaneously have a credit on the next month's bill of 50 kWh times the excess generation rate. Sub-Group 1 contends that the notion that a customer could have a bill today for energy usage, and also a kWh credit they cannot apply to that bill, is counter-intuitive and confusing. *Id.* at 16-17.

Sub-Group 1 states that to critique 2-Channel Billing as complicated is not to say that customers are incapable of understanding it, but rather to say that its complicated nature will impede a customer's ability to respond properly to the rate, and more significantly, to understand the economic advantages of installing distributed generation. A customer may be able to understand the basic concept of 2-Channel Billing after some explanation, but Sub-Group 1 contends that to understand how 2-Channel Billing will affect one's own electricity bill after installing distributed generation is an entirely different matter. *Id.* at 17.

Sub-Group 2 argues that the uncertainty inherent in 2-Channel Billing will dramatically diminish the growth of distributed generation, noting that the value proposition for distributed generation, from the customer's perspective, relates to how quickly the system can pay for itself by reducing the customer's electricity bill. Before a customer decides to invest in a distributed generation system, he or she must be able to estimate monthly bill savings. Net metering makes this relatively simple, Sub-Group 1 notes, since the customer can look at past bills, compare to the system's output, and calculate the monthly bill savings. Because the compensation paid for exported generation is tied to the retail rate, the customer can rest assured that his or her return on investment will keep pace with utility bill expenses, regardless of future rate changes. *Id.* at 17.

By contrast, Sub-Group 1 asserts, there is significant uncertainty inherent in 2-Channel Billing that makes it very difficult to determine the payback of a contemplated solar system: To determine monthly payback on a distributed generation system under 2-Channel Billing, a customer needs to know the exact coincidence between the projected generation from their solar system and their on-site usage. The share of power exported under 2-Channel Billing is based on the instantaneous relationship between DG production and the amount of power used on-site.[7] Sub-Group 1 notes that this will vary significantly from customer to customer (based on different load profiles) and from solar system to solar system (based on differences in system size, siting, and orientation). According to Sub-Group 1, this introduces significant uncertainty for solar installations that customers and installers do not have adequate data to remedy, noting that most

[7] Sub-Group 1 states that the most severe impacts would be to customers who seek to apply generation from one site against their usage at a separate site via the Commission's meter aggregation rules, who would see the most dramatic reduction in savings (as Sub-Group 1 discusses below).

customers have no way of knowing how much of their planned system's output they will use behind the meter, and how much they will export. *Id.*

Sub-Group 1 states that a second significant source of uncertainty arises from the fact that the exported generation rate will presumably change with every COS study update, since a potential solar customer would need to forecast how their exported generation credit would change over the years, based on a complex relationship between modeled solar generation data and a utility's ever-changing coincident peaks, not to mention possible future changes in COS methodologies. Sub-Group 1 asserts that customers are in no position to do this, nor to be able to confirm bill reduction projections offered to them by a solar installer. There is a high possibility that the exported generation credit will shrink as a percentage of the overall retail rate, especially if rates increase due to distribution system costs, which Sub-Group 2 has excluded from its calculation of the rate. Sub-Group 1 states that significant swings in the exported generation credit could occur based on test year weather affecting the exact timing of system peak loads and notes that it is impossible for a customer or a solar installer to predict the changes in the exported generation credit over the 25- or 30-year lifetime of the solar system, adding yet another layer of uncertainty to whether and when the solar system will provide a return on investment. *Id.* at 18-19.

Sub-Group 1 states that such a complex, essentially unpredictable rate design will frustrate the emerging self-generation market, which is overwhelmingly characterized by ordinary residential customers seeking to offset their consumption charges and achieve more manageable electric bills. According to Sub-Group 1, the 2-Channel approach is the kind of tariff arrangement that should be reserved for large, sophisticated independent power producers with operations management staff, if for any customer. Sub-Group 1 notes that ironically exactly those customer types most able to grapple with the complexities of a 2-Channel approach have been excluded from Sub-Group 2's proposal. *Id.* at 19.

Sub-Group 1 further argues that the proposed export generation credit represents a significant reduction in the return on investment for a solar system. In addition to the significant uncertainty of 2-Channel Billing, the basic fact that the exported generation credit is substantially lower than the retail rate inherently diminishes the investment value of a solar system and will deter installations. Sub-Group 1 cites Sub-Group 2's Exhibit B-4, which summarizes the 2-Channel Billing impacts by utility, which average to $10 per month bill increases for investor-owned utilities and $12 increases for rural electric cooperative customers. Assuming a customer has exactly the usage profile that formed the basis of Sub-Group 2's bill impact analysis (which Sub-Group 1 considers a significant assumption), that customer can expect reduced bill savings of nearly $150 annually, which could all but eliminate the economic feasibility for many customers to install distributed solar systems. *Id.* at 19-20.

Sub-Group 1 urges the Commission to carefully review Sub-Group 2's summary table Exhibit B-4 when drawing conclusions about the fairness and bill impacts of Sub-Group 2's proposal, noting that Sub-Group 2's recommendations present information only about EAL's exported generation credit rate and bill impact. As can be seen in this table, Sub-Group 1 states, EAL's exported generation credit rate represents the highest "effective Percentage of Retail Rates" of any of the utilities in the state (84% versus the cooperatives' average of 79%). Sub-Group 1 asserts that even this "effective percentage" figure can be misleading, since the full credit granted for behind-the-meter consumption tends to mute the more dramatic reduction from the retail that the exported generation credit represents. Likewise, Sub-Group 1 contends, the modeled EAL net-metering customer will see the lowest impact on their bill savings ($9 less than under net metering), while some cooperative net-metering customers would see bill savings that are as much as $16 less than under net metering. *Id.* at 20.

Sub-Group 1 observes that all of these bill impacts are based on assumptions about behind-the-meter and exported consumption that are identical across utilities, but which will in fact vary greatly according to the solar customer's energy usage patterns. Sub-Group 1 emphasizes that customers who consume more electricity during peak period will see greater bill reductions, whereas customers who use less during that time (and whose on-site generation serves the load of their neighbors) will see less benefit on their bills. Sub-Group 1 further discusses below these "arbitrary and perverse effects of 2-Channel Billing." *Id.* at 20-21.

To further illuminate how variable the bill impacts of 2-Channel Billing are across net-metering customers, Sub-Group 1 presents as Attachment B to its Reply Comments an alternative bill impact analysis based on the actual rather than modeled load profiles of five current net-metering customers of a rural electric cooperative who voluntarily disclosed their usage data to Sub-Group 1. This analysis shows that bill impacts varied widely across customers based on their usage patterns, the nature of their system, and other factors. Sub-Group 1 states that this variability demonstrates the difficulty of forecasting bill savings for any individual customer and therefore, that the impediment that 2-Channel Billing poses to Arkansas' growing solar industry is in direct opposition to the purposes of AREDA. *Id.* at 21.

Sub-Group 1 asserts that Sub-Group 2's 2-Channel Billing proposal fundamentally undermines meter aggregation and is therefore inconsistent with AREDA's intention for meter aggregation to expand access to distributed renewable energy resources. While Sub-Group 2 briefly explains, with respect to aggregated meters, that "[a]ny 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" (Joint Report at 157), its explanation fails to acknowledge that a solar generation facility servicing multiple customer accounts whose load is not located at the site of the generator would have a significantly reduced ability to offset a load not physically attached to the generation site. Instead, Sub-Group 1 asserts, a significant portion of the output of the solar generation at a meter aggregation generating facility would be compensated at the lower export generation rate, even if, in fact, the account to which the generation is credited had used electricity at exactly the same time it was being generated. In other words, Sub-Group 1 states, because behind-the-meter usage is impossible for aggregated meter customers, the value of their investment is severely diminished. The effect of using the 2-Channel Billing approach is that net-metering customers participating in meter aggregation would face unfair discrimination even though they were participating in the very kind of project that sought to generate electricity at the most advantageous locations and often employing systems with a higher capacity factor and peak coincidence than the average rooftop system. Sub-Group 1 asserts that to discourage meter aggregation in this way represents a major step backwards for this Commission's and the General Assembly's efforts to expand access to distributed generation. *Id.* at 21-22.

According to Sub-Group 1, the 2-Channel proposal raises serious policy implications that Sub-Group 2 did not thoroughly evaluate: The 2-Channel arrangement eliminates the traditional "netting" in net metering and treats exported generation as essentially a sale to the utility. Sub-Group 1 asserts that generation that is operated to offset consumption under traditional net metering, as defined by federal law (16 U.S.C. § 2621) and Arkansas statute (Ark. Code Ann. § 23-18-603(6)(E)) is not considered a jurisdictional sale even when generation exceeds the instantaneous level of consumption. Under net metering, customers are entitled to export a reasonable amount of energy to the grid as a consequence of investing in and operating systems with the primary purpose of generation for use. Sub-Group 1 notes that FERC and IRS precedent recognize that a reasonable level of exports does not convert a customer-generator into a wholesale energy marketer because those exports are incidental to the generation for self-use. *Id.* at 22.

Sub-Group 1 asserts that because 2-Channel Billing artificially segregates generation into two categories – generation that is used, and generation that is exported – it could pose significant problems that would undermine net metering policy. For example, residential customers could be required to treat their exports as sales and document those sales as an involuntary business enterprise. Sub-Group 1 notes that federal law provides tax incentives for Qualifying Solar Energy Property, defined as facilities that generate primarily for use, and not for sale. Internal Revenue Code section 25D(e)(7) establishes that a residential customer can only take the residential tax credit to the extent that no more than 20% of the energy is being sold to the customer's utility under a form of a feed-in-tariff program. Sub-Group 1 asserts that the Sub-Group 2 proposal treats all distributed generation like a sale and could impair the ability of individual Arkansas citizens to take advantage of generous tax credits. At the very least, Sub-Group 1 argues, the proposal should be accompanied by a ruling from the IRS that it would not affect eligibility for this tax benefit. *Id.* at 23.

Sub-Group 1 further asserts that the law recognizes that sales incidental to generation for self-use are not subject to federal jurisdiction and remain within the state's purview as part of the retail relationship. According to Sub-Group 1, the distinction between generation for use and generation for sale implicit in the 2-Channel Billing, as well as the high proportion of system output that would be treated as net excess generation, create a substantial risk that the net excess generation would no longer be considered incidental to the customer's use. In addition to the tax consequences for the customer, Sub-Group 1 suggests that this risks abdication of state ratemaking authority over distributed generation, contending that under 2-Channel Billing, all exports would be FERC-jurisdictional sales over which the State has little or no authority to set rates. *Id.* at 23-24.

Expounding further on the asserted perverse incentive for distributed generation customers to increase on-peak usage of energy, Sub-Group 1 states that under the Sub-Group 2 proposal, the customer can optimize the return on their investment in the solar system by increasing their usage during periods of peak generation from their equipment. Moreover, this incentive to increase consumption during periods of peak generation means that other customers will not receive the benefits of highly coincident local generation. According to Sub-Group 1, ordinary net metering, by allowing netting within the billing period, avoids this problem. Sub-Group 1 points to the analysis provided in the Crossborder Study (Joint Report Appendix A-1) as demonstrating that today's net-metering customers are essentially trading high value on-peak or near-on-peak exported generation for credit applied against less costly off-peak energy needed when the net metered facility is not operating. Sub-Group 1 argues that the Sub-Group 2 proposal eliminates this common benefit of net metering to all ratepayers. *Id.* at 24.

Sub-Group 1 argues that net metering for demand-billed customers should not change, agreeing with Sub-Group 2 on this recommendation. Sub-Group 1 notes that the analysis performed by Sub-Group 2 focused on the residential class, which bundles all costs into a volumetric rate. According to Sub-Group 1, in the NMWG and in countless other working groups across the country, there has been a general acknowledgement that demand-metered customers have lower volumetric rates than residential customers, and net metering offsets the volumetric rate, so utilities are less concerned, or unconcerned, about net metering for demand-metered customers. Accordingly, Sub-Group 2's recommendation is consistent with this general recognition that net metering for demand-metered or demand-billed customers poses little concern. *Id.* at 24-25.

In conclusion, Sub-Group 1 states that AREDA establishes a state policy to promote the development of distributed generation through the mechanism of net metering, for the variety of utility and societal benefits that it provides. According to Sub-Group 1, Sub-Group 2 has not shown that there is any shortfall in COS recovery from net-metering customers in the terms AREDA requires, and the solution it offers to address the problem that it has not established is both conceptually flawed and inconsistent with AREDA's purpose to promote distributed renewable generation. Sub-Group 1 asks the Commission to conclude that net metering as it exists today recovers the cost of serving net-metering customers, and therefore no changes to the existing rates are needed. Failing that, Sub-Group 1 requests the Commission to order a more thorough investigation of the costs and benefits of net metering through a third-party study, and pending the results of that study, to leave the current net metering program in place.

a. Summary of Attachment A to Sub-Group 1 Reply Comments: Response to Net Metering Working Group Sub-Group 2 (White Paper)

The White Paper responds to the recommendations of Sub-Group 2, noting that the Arkansas General Assembly has charged the Commission with ensuring that the rates charged to net-metering customers, first, recover the utility's costs, and second, consider both the benefits and the costs of net metering to the electric utility and its ratepayers. Sub-Group 1 Reply at 29. Sub-Group 2 asserts that the fundamental problem with net metering is that distributed generation (DG) customers receive a credit at the full retail rate for the power that they export to the grid, alleging that this credit does not accurately reflect the costs which DG customers avoid by producing their own power:

> 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. . . .[8]

[8] Sub-Group 2 Recommendations, Attachment B to Joint Report, at 149.

The White Paper discusses six "overarching" conceptual problems with Sub-Group 2's COS approach and then presents a complete COS analysis for all DG output, including the portion that is used on-site and that produces a lower cost of service for Channel 1 loads which Sub-Group 2 fails to consider. *Id.* at 29-30.

1. Sub-Group 2's COS approach considers only the impact of excess, exported DG on the utility's COS. However, about half of the typical output of a DG facility remains on-site, never touches the grid, is not exported, and directly serves the distributed generation customer's on-site load. The output that is used onsite significantly reduces Channel 1 loads at times of system and class peaks, resulting in a lower cost to serve the Channel 1 retail load of the DG customer compared to the cost to serve a comparably-sized residential customer. Sub-Group 2 did not analyze the impact on the cost to serve a DG customer of the DG power used on-site. A full COS analysis of both Channel 1 load and Channel 2 exports produces a very different conclusion from what Sub-Group 2 presents. *Id.* at 30.
2. Sub-Group 1 states that avoided costs are not embedded costs. Avoided costs are, by definition, counterfactual – they are costs that the utility never incurs because it procures a service from another source. Sub-Group 1 states that it is questionable whether avoided costs can be measured accurately by the utility's embedded costs. Embedded costs are historical costs that the utility has incurred, citing the Public Utility Regulatory Policies Act of 1978 's (PURPA) definition: "avoided costs mean the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such

utility would generate itself or purchase from another source."[9] As a result, Sub-Group 1 questions whether avoided costs can be measured accurately by the utility's embedded costs, which are not counterfactual but are the historical costs which the utility actually has incurred. Sub-Group 1 asserts that the more accurate way to measure avoided costs is to calculate the utility's long-run <u>marginal</u> costs, which measure how the utility's costs vary with the change in demand or supply that results from the addition of a new long-term resource such as DG. This is the approach used in Crossborder's benefit/cost study on net metering on the EAL system. *Id.* at 31-32.

3. Sub-Group 2's analysis only uses marginal costs for the energy portion of the excess generation credit: for the EAL example, Sub-Group 2 uses MISO locational marginal prices as the "incremental" cost of energy. It does not calculate the marginal costs associated with generation, transmission, or distribution capacity, even though there are well-accepted techniques in the utility industry for doing so. Instead, Sub-Group 2 simply analyzes how already-incurred embedded costs are re-allocated among the utility's customer classes if a customer in the utility's customer classes installs DG. This does not necessarily measure the capacity costs that the utility avoids (*i.e.*, does not incur) as a result of DG. *Id.* at 33.

4. Sub-Group 1 states that a COS approach does not consider long-term avoided costs. DG can avoid future costs – for example, DG in combination with other demand-side resources, can avoid or defer a new generating unit or a transmission line planned to be built several years in the future. The costs of this avoided capacity

[9] PURPA, 18 C.F.R. Part 292.101(b)(6) (emphasis added).

may never become part of the utility's embedded costs, and thus an analysis based only on already-incurred embedded costs fails to capture the costs avoided over the entire life of a DG facility. *Id.*

5. Sub-Group 1 states that DG produces certain direct, quantifiable benefits (avoided costs) for ratepayers that are not included in the embedded cost rates. These include avoiding the risk of volatile natural gas prices, and avoiding future compliance costs associated with reducing carbon dioxide emissions. These are avoided costs that are reflected in utility IRPs and in the cost-effectiveness evaluations of other types of demand-side resources. *Id.*
6. An embedded COS study does not consider other important perspectives. These include key longer perspectives of whether DG is a reasonable long-term investment for the DG customer, the utility system, and for society as a whole. The combination of all these perspectives constitutes the public interest of net metering. *Id.* at 33-34.

Sub-Group 1's White Paper does not further discuss Issues 2 through 6, noting that they are addressed and quantified in the long-term benefit/cost study prepared for the NMWG. The remainder of the paper addresses and quantifies the first issue – the failure of Sub-Group 2 to perform a complete COS analysis that includes the impact of the DG power used on-site on the cost to serve a DG customer's Channel 1 load. *Id.* at 34.

In revising the costs to serve DG customers' on-site Channel 1 loads to determine how the addition of DG changes the costs to serve the on-site load of a residential customer, Sub-Group 1's White Paper authors used the same COS approach used by Sub-Group 2. The authors note that the addition of DG changes the size and profile of the DG customer's load on the utility system, as measured by the Channel 1 meter in the Sub-Group 2 proposal for 2-Channel Billing. They also used the same cost allocation methodologies to assess the impact of adding DG on the energy, production, transmission, and distribution costs allocated to the Channel 1 loads of residential customers. They extended the Sub-Group 2 COS analysis to the Channel 1 loads by cost component, assuming a 5kW DG system, as discussed in detail below: *Id.* at 34-35.

- **Energy** – Sub-Group 2 correctly used the solar-weighted LMP in the MISO energy market in Arkansas. This incremental or avoided energy cost is larger than the average embedded cost of energy that is the fuel charge component of rates. Thus, the portion of DG output which serves the customer's onsite load reduces the utility's costs by the solar-weighted LMP times the amount of DG output used onsite. The authors deducted the avoided energy cost from the DG customer's pre-solar fuel charges to determine the energy costs for the DG customer's Channel 1 usage. *Id.* at 35.
- **Production** – For EAL, embedded production capacity costs are allocated based on coincident peak loads in the four summer months (4 CP loads). For example, adding a 5 kW-DC DG system reduces the 4 CP loads of an average residential customer from 3.18 kW to 0.66 kW, *i.e.*, to 21 percent of the pre-solar level. This reduces the production capacity costs allocated to the average residential customer from $0.03836 per kWh to $0.01222 per kWh, as illustrated in Figure 1 on page 36 of Sub-Group 1's Reply Comments. This calculation accounts for the fact that, with a 5 kW-DC system, the post-DG kWh usage of the customer is 65 percent of the usage before adding DG. *Id.* at 35-36.

- **Transmission** – For EAL, transmission costs are allocated using coincident peak loads in all 12 months (12 CP). Based on Sub-Group 2's model, the DG system reduces the 12CP loads as well, from 2.82 kW to 1.22 kW, and transmission costs allocated to this customer decrease from $0.01038 to $0.00647 per kWh, which again accounts for the fact that the post-DG kWh usage of the customer is 65 percent of the usage before adding DG. *Id.* at 36.
- **Distribution** – The White Paper authors assumed that 50 percent of distribution costs are allocated based on the NCP and 50 percent based on the number of customers. The 50 percent allocated based on customer count is a fixed dollar amount per customer. When a customer reduces its usage by adding DG, this portion of distribution rate increases on a per unit basis. For example, if a customer with a 5 kW-DC system reduces its usage by 35 percent, the per unit rate for the fixed 50 percent of distribution costs allocated to this customer will increase by a factor of 1/0.65 = 1.54, *i.e.*, a 54 percent increase. The portion of the distribution rate allocated on the basis of NCP also will increase, on a per unit basis, after a customer adds DG, but by much less than the portion that is invariant to usage. Thus, the authors state, with respect to distribution costs, their analysis shows that the Channel 1 usage of a solar customer is <u>more costly</u> to serve, per kWh, than a non-solar customer. This is less favorable than Sub-Group 2's assumption of no impact on distribution costs allocated per unit allocation of distribution costs.

Table 1 shows the combined results of the Sub-Group 1 authors' analysis, which concludes that the costs to serve the Channel 1 loads of DG customers are 35 percent lower than the cost to serve the average residential customer.

Table 1: *Functional Base Rate Components: Pre-solar and Channel 1 ($/kWh)*

Base Rate Component	Allocators	Pre-solar COS	Post-solar: Channel 1 COS	Change
Production	4 CP	0.03836	0.01222	-68%
Transmission	12 CP	0.01038	0.00647	-38%
Distribution	50% NCP, 50% # of customers	0.01967	0.02571	+31%
Total		0.06841	0.04440	-35%

Id. at 34-38.

If net metering is to be analyzed using a COS frameworks, the authors state that the additions they made to Sub-Group 2's analysis are necessary to accurately reflect the COS for the Channel 1 loads of DG customers. They contend that under a fully cost-based application of 2-Channel Billing, customers who install DG should receive a significant rate reduction for their Channel 1 usage, alongside the lower export rate that Sub-Group 2 calculates. Combined, they note, this actually results in higher bill savings for DG customer than they would receive under net metering at the full retail rate. Table 2 shows that fully cost-based rates for both Channel 1 usage and Channel 2 exports – including retail rates for the Channel 1 usage of DG customers that are lower than standard retail rates – would result in greater bill savings for DG customers than now available under current net metering.

Table 2: *Monthly Bill Savings ($) for Residential DG Customers*

System Size *(kW-DC)*	Current Net Metering	Two-channel: Sub-Group 2 Proposal	Two-channel: Complete Channel 1 Cost-of-service
2 kW	24	24	30
4 kW	49	44	63
5 kW	61	53	80
8 kW	99	77	116
9.6 kW	110	84	122

The Sub-Group 1 authors also examined a conservative, worst-case sensitivity that assumed 100 percent of distribution costs are fixed and are the same for all residential customers. Even in this worst-case DG customers bill savings remain higher than under today's net metering. Table 3 shows the results of this worst-case analysis.

Table 3: *Sensitivity: Monthly Bill Savings ($) with Fixed Distribution Costs*

System Size *(kW-DC)*	Current Net Metering	Two-channel: Sub-Group 2 Proposal	Two-channel: Complete Channel 1 Cost-of-service - Fixed Distribution
2 kW	24	24	29
4 kW	49	44	60
5 kW	61	53	76
8 kW	99	77	109
9.6 kW	110	84	116

Sub-Group 1 Reply at 40-41.

Sub-Group 1's White Paper authors' conclusion is that the complete COS analysis shows that fully cost-based compensation for net metered residential DG customers actually would increase their compensation compared to current net metering at the full retail rate. Current net metering thus does not impose a burden or a cost shift on ratepayers who do not participate in the program. In fact, the authors state, the conclusion of this short-term COS analysis is the same as the long-term benefit/cost study prepared for Sub-Group 1: there is no cost shift from solar DG in EAL's service territory under today's net metering rules, and all ratepayers benefit from the installation of this new clean energy infrastructure. Sub-Group 1 Reply at 41.

b. Summary of Attachment B to Sub-Group 1 Reply Comments: Annual Net Energy Charge for Five Net-metering customers under Current Net Metering and under Sub-Group 2's Proposed 2-Channel Billing

Sub-Group 1 provided in Attachment B comparisons between Sub-Group 2's model systems and Sub-Group 1's computed results of electricity consumption and export for five actual PV customers using actual data for the utility for 2016. Sub-Group 1 provides a table and 4 graphs which present the data and results. Sub-Group 1 Reply at 42-47. Sub-Group 1 Attachment B provides Table 2. This table shows that all of the five customers analyzed would have paid higher Annual Net Energy Charges (ANEC) under Sub-Group 2's proposed 2-Channel Billing. Sub-Group 1 states that it is noteworthy that the customer who had the smallest ANEC increase under 2-Channel Billing also had the highest annual consumption of utility energy. *Id.* at 42.

Table 1: *Net-metering customers*

	PV System Capacity, kW	System Installation	Household	Heating/cooling
PV1	3.3	3 steel pedestals: 1 passive tracker; 2 with adjustable tilt angles.	1,600 ft^2 house, energy-efficient design and construction.	Air-source heat pump for 3 seasons; woodstove for winter.

PV2	9.8	Ground-mounted, fixed tilt angle.	1,200 ft^2 house; 540 ft^2 guest house; woodshop.	Air-source heat pumps for house & guest house; propane heat for woodshop.
PV3	8	Roof-mounted, fixed tilt angle.	4,000 ft^2 house; 1,000 ft^2 workshop.	Conventional central air conditioning; propane furnace.
PV4	6	Ground-mounted, fixed tilt angle.	1,800 ft^2 house.	Central propane/electric system; woodstove backup.
PV5	10.8	Roof-mounted, fixed tilt angle.	1,570 ft^2 energy-efficient design and construction	Geothermal

Id.

Grid Energy Consumption and PV Energy Export

Sub-Group 1 shows in Figures below profiles of utility energy consumption and PV energy exported by these five customers and the profiles of the model devised by Sub-Group 2 and proposed to the Commission. Sub-Group 2's model entails a hypothetical customer with PV systems of 2, 5, and 8 kW generating capacities. As expected, seasonal changes in grid energy use are readily apparent for Sub-Group 2's model systems and somewhat less discernible among the five customers. Likewise, seasonal patterns are obvious for Sub-Group 2's model and apparent but more muted among the customers. *Id.* at 43.

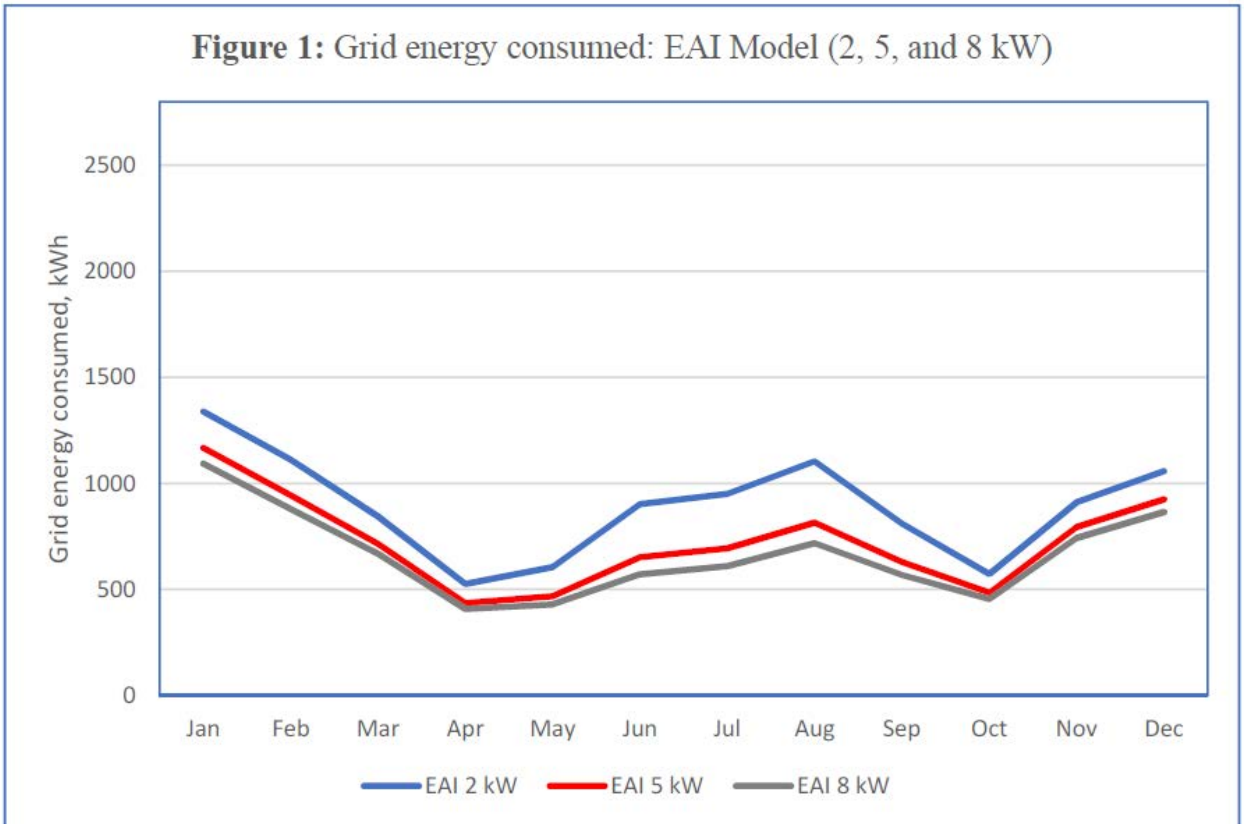


Figure 1: Grid energy consumed: EAI Model (2, 5, and 8 kW)
Grid energy consumed, kWh
2500
2000
1500
1000
500
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
EAI 2 kW
EAI 5 kW
EAI 8 kW

Id. at 44.

Figure 2: Grid energy consumed: Residential PV Systems

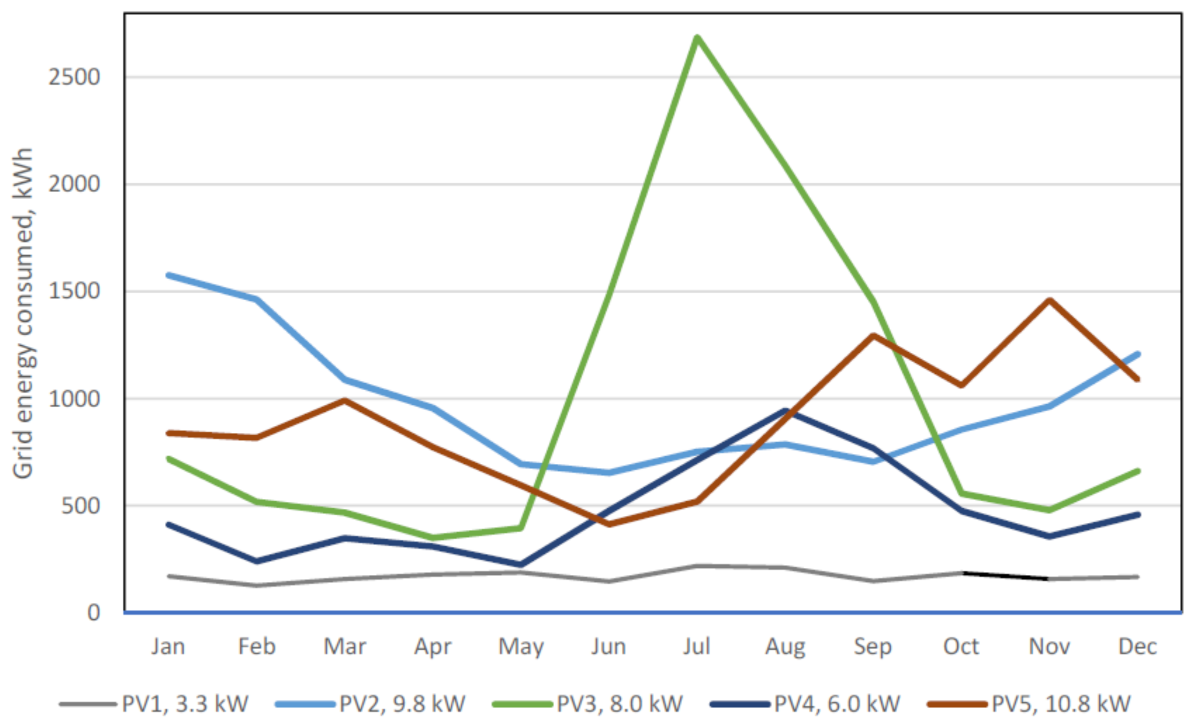
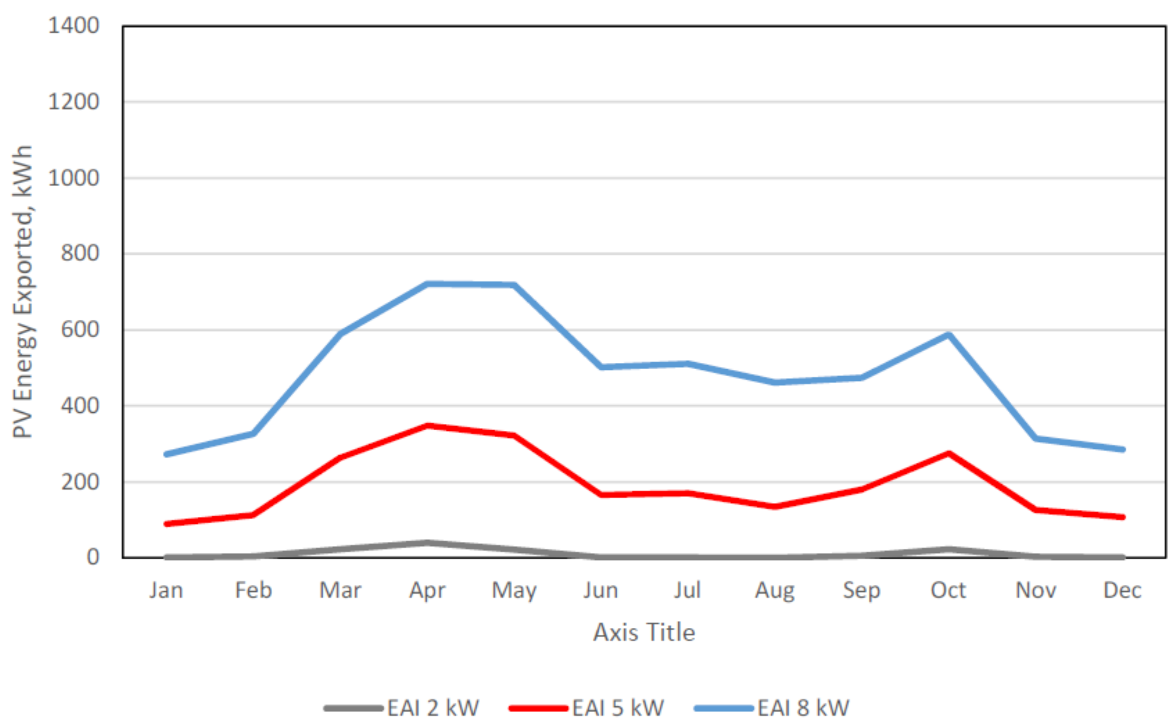
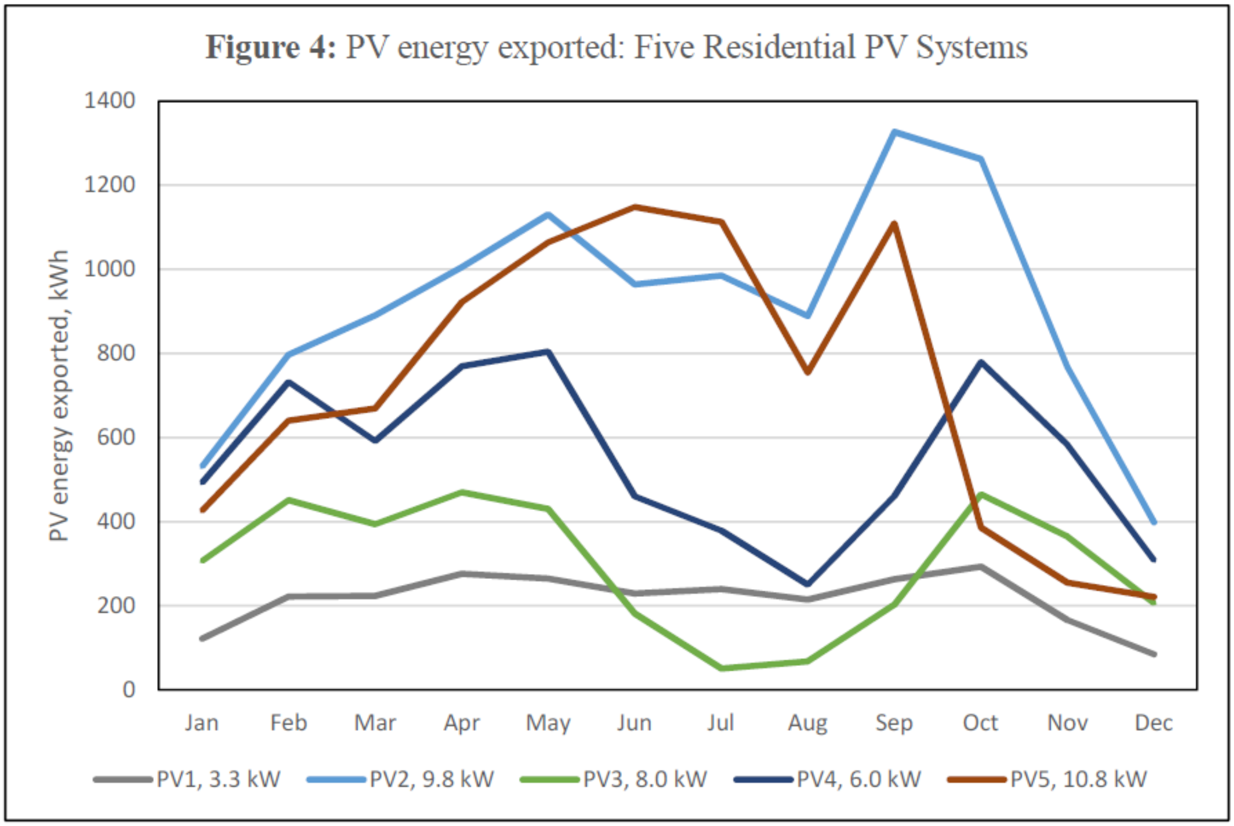


Figure 3: PV Energy Exported: EAI Model (2, 5, and 8 kW)



Id. at 46.



Id. at 47.

Annual Net Energy Charge

Sub-Group 1 describes the ANEC as the amount paid for grid energy by a net-metering customer in a year. For each of the five customers, the ANEC was calculated according to both the current net metering regime and Sub-Group 2's proposed 2-Channel Billing.[10] As shown in Sub-Group 1's Table 2 below, all the customers would have paid a higher ANEC under Sub-Group 2's proposed 2-Channel Billing and, for four of the five, their ANEC would have been markedly higher. Sub-Group 1 finds it noteworthy that the

[10] Calculations were made using Carroll Electric Cooperative Corporation's energy price of $0.080/kWh, the average flat rate presented in "Ch.2 Example Carroll" that was distributed to the NMWG, and a PV export energy price of $0.037/kWh as given in the Joint Report to the Commission, Attachment B, at 217.

customer who had the smallest ANEC increase under 2-Channel Billing, Customer PV3, had the highest annual consumption of utility energy. Two net-metering customers, PV1 and PV4, exported more electricity to their utility than they purchased from the utility. *Id*. at 48.

Table 2: *Annual Net Energy Charge for Five Current Net-metering customers under Net Metering and 2-Channel Billing*

	PV1, 3.3 kW	PV2, 9.8 kW	PV3, 8.0 kW	PV4, 6.0 kW	PV5, 10.8 kW
Net Metering	$0.00	*$147.68*	$661.20	$0.00	$111.27
2-Channel Billing	$48.54	*$528.93*	$815.70	$200.66	$511.29
% Change		*258%*	23%		359%

Id. at 48, as modified by Errata (shown in italics) to Reply Comments of Sub-Group 1 filed on November 6, 2017. Sub-Group 1 notes that the corrected values are shown in italicized, underlined text in the table above and that the changes in these values are not material and do not affect the conclusion Sub-Group 1 contends should be drawn from these data, which are that the bill impacts of 2-Channel Billing will vary widely across net-metering customers.

Table 2: *Annual Net Energy Charge for Five Current Net Metering Customers under Net Metering and Two-channel Billing*

	PV1, 3.3 kW	PV2, 9.8 kW	PV3, 8.0 kW	PV4, 6.0 kW	PV5, 10.8 kW
Net Metering	$0.00	$150.16	$661.20	$0.00	$111.27
Two-channel Billing	$48.54	$530.08	$815.70	$200.66	$511.29
% Change		253%	23%		359%

8. Sub-Group 2 Reply Comments

Sub-Group 2 continues to recommend the 2-Channel Billing approach and the methodology whereby each utility can determine its own appropriate excess generation credit rate (EGCR) for net metering. Sub-Group 2 argues that Sub-Group 1's proposal to leave net metering rates at the current full retail rate is not consistent with the requirements of AREDA nor is it in the public interest. Sub-Group 2 Reply at 1-2.

Sub-Group 2 argues that under the current policy only a portion of the cost-to-serve net-metering customers is being recovered from non-net-metering customers through the normal ratemaking process. As such, the current policy of providing a credit at the full retail rate for the net-metering customers' excess generation does not adhere to the requirements of AREDA and must change. *Id*. at 4-5.

Sub-Group 2 disagrees with Sub-Group 1's assertion that AREDA was established to develop a statewide renewable energy policy or a distributed generation policy. Sub-Group 2 argues that AREDA and this docket were only meant to address net metering, which is a specific type of billing mechanism used to credit customers for renewable energy they supply to the grid. In Order No. 1 of this docket, the Commission stated that the purpose of this proceeding is to determine appropriate rates, terms, and conditions for net metering contracts, including any changes necessary to the Commission's Net metering Rules. Sub-Group 2 interprets AREDA as being more narrowly focused on encouraging the use of renewable energy through net metering while requiring that the net-metering customers pay rates that reflect the cost of serving them, net of quantifiable benefits they provide. Therefore, Sub-Group 2 contends that Sub-Group 1 inaccurately portrays both the purpose of AREDA and the purpose of this proceeding. *Id*. at 5-7.

Sub-Group 2 argues that using a long-term avoided cost study as recommended by Sub-Group 1 does not align with the requirements of AREDA or the statutory framework that underlies ratemaking in Arkansas. Sub-Group 2 says the Commission's regulatory authority to establish rates is derived from existing ratemaking statutes that require rates based on incurred costs. These costs have been historically defined using the embedded COS approach that incorporates statutory ratemaking requirements, such as appropriate test years. Sub-Group 2 says AREDA, as amended by Act 827, did not replace this existing COS regulatory framework for establishing just and reasonable rates. Sub-Group 2 argues that Sub-Group 1's long-term avoided cost study is full of uncertain assumptions and predictions about future energy prices and policy changes and therefore should not be relied upon by the Commission. Sub-Group 2 points out that Sub-Group 1's Crossborder Report relies on cost-effectiveness tests commonly used to evaluate the merits of promotional practices, energy efficiency programs, and demand-side management resources. Sub-Group 2 argues that these tests can be useful in determining whether a particular energy efficiency program or investment will be cost effective over the long run, but such tests are not appropriate for establishing the cost-based rates that recover the actual costs incurred by a utility. *Id*. at 7-10.

Sub-Group 2 asserts that its recommended EGCR framework is based on each utility's COS Study and market data from their RTO. Taken together the data captures the full quantifiable costs and benefits of serving a net-metering customer. To the extent net-metering customers provide additional quantifiable benefits in the future, such benefits will be comprehended in future COS Studies and rates. *Id*.at 10-11.

Sub Group 2 asserts that its COS approach proves that net-metering customers are not paying their full COS under the current net metering policy. For example, EAL's average residential embedded COS is 7.1 cents per kWh (this figure does not include fuel or other riders). Based on Sub-Group 2's COS approach, the embedded avoided capacity cost benefit attributable to the net-metering customer's self-generation is 2.6 cents per kWh. When a net-metering customer receives a capacity credit at the full embedded COS amount; the customer thus receives a credit of 4.5 cents per kWh (7.1 cents minus 2.6 cents) in excess of the benefits the net-metering customer provides when it self-generates. A shortfall in revenue occurs because EAL does not avoid and continues to incur 4.5 cents per kWh in infrastructure and operating costs to provide service to the net-metering customers. This shortfall is ultimately recovered from other ratepayers through the ratemaking process. *Id*. at 12-13.

According to Sub-Group 2, Sub-Group 1 argues that the true costs and benefits of solar cannot be determined solely by using historical cost-of-service analysis and that the benefits specified by the General Assembly involve avoiding future utility costs. Sub-Group 2 further asserts that Sub-Group 1 recommends using a Value of Solar (VOS) based approach, which gives value to societal benefits and environmental advantages over fossil fuel generation, in addition to the traditional costs and benefits recognized by the COS methodology. Sub-Group 2 argues that the General Assembly did not provide any textual authority to warrant a rate justified by a VOS approach. In enacting Act 827, the General Assembly neither included the phrase VOS (or one similar to VOS), nor implied or intended any other approach that deviates from traditional COS-based ratemaking. Sub-

Group 2 says the Commission should not read a VOS-based approach into Act 827, as it was not included, implied, or intended by the General Assembly. *Id*.at 15-17.

Sub-Group 2 argues that Sub-Group 1 relies solely on the "Legislative Findings" section of AREDA, Ark. Code Ann. § 23-18-602 to justify using the VOS approach. That section, in part, says "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." According to Sub-Group 2, Sub-Group 1 interprets the word "encourages" to mean that any policy adopted by the Commission must and can only promote net metering in its present form without any other consideration including the potential impact on non-participating customers. Sub-Group 2 argues that this argument is fundamentally flawed, in that the "Legislative Findings" section simply explains, without any requirement or obligation, the reasons behind the General Assembly's enactment of AREDA. Instead, Sub-Group 2 says, the Commission must look to the "Commission Authority" section provided in Ark. Code Ann. § 23-18-604, which dictates the specific directives the Commission must follow in establishing the rates. When read together, Sub-Group 2 asserts, the "Legislative Findings" section and the "Commission Authority" section make clear that the setting of a rate applicable to net-metering customers based on the utility's cost of providing service is consistent with encouraging net-metering in Arkansas. *Id*. at 17-18.

According to Sub-Group 2, the General Assembly made clear that before any benefits may be netted against the utility's additional costs of providing service to a net-metering customer, the benefits must be (1) "quantifiable," and (2) "associated with" providing service to the net-metering customer. Furthermore, Sub-Group 2 says that those associated benefits must be *directly related* to the utility's cost of providing service to a net-metering customer. Under the COS principles, future costs are considered *quantifiable* if they are known and measurable and only if they occur during the pro-forma year. Sub-Group 2 argues that benefits should be quantified using the same known and measurable standard. Any other method would be too speculative. Benefits that are *associated with* providing service to a net-metering customer are benefits that are (1) measurable, (2) included in the COS study, and (3) directly related to the utility's cost of interconnection and providing service to the net-metering customer. Sub-Group 2 asserts that when read together, the benefits which are appropriate for netting under Act 827 are inseparably a function of the rates charged by the utility through the Commission-prescribed COS methodology. Said another way, Sub-Group 2 argues, the benefits that are authorized by Act 827 to be netted against the utility's costs must bear on and be included in (*i.e.*, "associated with") the utility's actual costs. Accordingly, if a benefit fails to offset the utility's cost, that benefit has no impact on the allocation of the utility's revenue requirement among customers. *Id*. at 19-21.

Sub-Group 2 disagrees with the Sub-Group 1's recommendation to hire a professional facilitator, arguing that a different outcome is unlikely. *Id*. at 21-27.

Sub-Group 2 provides as Attachment 1 to its Reply Comments a four-page table detailing its assessment and critique of the methodologies and calculations used in the Crossborder Study sponsored by Sub-Group 1. The assessment addresses Crossborder's costs or benefit calculation for avoided energy, avoided line losses, avoided capacity, avoided transmission and distribution capacity, avoided CO_2, reduced fuel price uncertainty, market price mitigation, societal benefits, and lost revenues. *Id*. at 32-35.

In Attachment 2, Sub-Group 2 offers observations of what it characterizes as Crossborder's "Value of Solar Study," arguing that this type of avoided cost study, which relies on future, estimated long-term "values" and the results of cost-effectiveness tests, is not the proper framework to establish the net-metering rate pursuant to AREDA and specifically Ark. Code Ann. § 23-19-604(b)(1)(A). According to Sub-Group 2, making just a few adjustments to the Crossborder Study using more appropriate EAL data has a significant impact on the outcome, thus demonstrating the study's sensitivity to inputs and the inherent uncertainty of relying on the results of this type of long-term study. Sub-Group 2 illustrates this point with tables showing how its adjustments to EAL's peak hours would affect avoided generation capacity costs, how changes to assumed solar capacity value affects avoided T&D capacity costs, and how changes in assumed retail rate escalation by 1 percent would affect the Crossborder Report's cost-effectiveness test results. In conclusion, Sub-Group 2 states, the Crossborder Report (like any such long-term VOS study) depends on many variables that are inherently uncertain based on forecasting over a 25-year time horizon. As such, Sub-Group 2 argues, the Crossborder Report is extremely sensitive to its inputs, and thus Crossborder's analysis is not an appropriate tool for the purpose of setting just and reasonable rates. *Id*. at 36-40.

9. Other Party Reply Comments

Reply Comments of William Ball

In Reply Comments, William Ball argues that the 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. He states that if lost revenues are no part of the consideration, there are only three areas of cost to a utility that are worthy of weighing against benefits:

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-programmed by the technician before coming to the site.
3. Possibly, administrative costs associated with billing of a net-metering customer's consumption and net excess generation. Administrative costs specifically charged to a net-metering customer should demonstrate that they are distinguished somehow above administrative services offered to non-net-metering customers. Almost all customer billing routinely presents similar administrative costs associated with metering time-of-use, levelized billing, or other tariffs and programs utilities currently offer consumers.

Mr. Ball states that providing policies that nourish robust net-metering growth and encourage further development and experience with "grid services" technologies should be the goal, citing time-of-use, peak shaving after the sun goes down, self-consumption, grid zero, and grid support. Ball Reply at 1-2.

Mr. Ball states that Act 827 was intended to strengthen net-metering policy 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. He notes that a path to recover cost weighed against benefits has been in AREDA all along and asserts that utilities could have pursued extra fees for net-metering customers at any time since the passage of AREDA. He concludes that this is no time to weaken Arkansas's net-metering policy. *Id*. at 2.

Reply Comments of Pulaski County

Noting how far apart the parties are in this matter, Pulaski County asserts that the plain language of Act 827 clearly does not create a presumption of a different rate structure for net-metering customers. Accordingly, Pulaski County believes that there is an affirmative burden, pursuant to Act 827, for the electric utilities to establish that there are additional quantifiable costs incurred due to net metering, before a change to the existing rate structure for net-metering customers is imposed. Pulaski County observes that the two Sub-Groups are inextricably divided in their views of net metering:

- Sub-Group 1 does not really acknowledge that there are any "quantifiable additional costs associated with the net-metering customer's use of the electric utility's capacity, distribution system, or transmission system and any effect on the electricity utility's reliability[,]" as contemplated by Ark. Code Ann. § 23-18-604(1)(A)(ii)(a). Nevertheless, it states, Sub-Group 1 is not alone in zealously advocating for the position that is best for its members.
- Sub-Group 2's recommendation does not appear to acknowledge that there are any "quantifiable benefits associated with the interconnection with and providing service to the net-metering customers, including without limitation benefits to the electric utility's capacity, reliability, distribution system, or transmission system [,]" as contemplated by § 23-18-604(1)(A)(ii)(b).

Pulaski County Reply at 1-2.

Pulaski County further states that while Sub-Group 2 does not appear to acknowledge that there are any quantifiable benefits associated with net metering, it believes that no tangible evidence has been produced by Sub-Group 2 demonstrating that there are any quantifiable additional costs associated with net metering. However, Pulaski County believes that pursuant to Act 827, Sub-Group 1 has no affirmative duty to demonstrate any quantifiable additional benefits of net-metering until Sub-Group 2 demonstrates that there are quantifiable additional costs associated with net metering. Accordingly, Pulaski County argues, since Sub-Group 2 has failed to fulfill its obligations pursuant to Act 827, Sub-Group 1 has no real obligation to address the quantifiable additional costs of net metering. Nevertheless, Pulaski County does not necessarily believe the Commission should accept as true all of Sub-Group 1's positions. Pulaski County observes that Sub-Group 1 is "burdened by a dearth of data," and despite what may appear in the Crossborder Study, Pulaski County believes that all of Sub-Group 1's recommendations are speculative as well. *Id*. at 2-3.

In conclusion, Pulaski County states that based on Act 827's lack of an explicit mandate to change net-metering rates, without the condition precedent of quantifiable evidence that costs associated with net-metering are net of benefits provided by net-metering, the Commission should do nothing. The Commission should let net metering develop and progress. Pulaski County adds that if the Commission feels obligated to do something, it could set a threshold of net-metering penetration that will provide the Sub-Groups and the Commission with enough data to accurately determine if the quantifiable costs of net-metering are in excess of the benefits. Once the threshold is met, Pulaski County states, this docket should be re-opened and a neutral facilitator retained to present a study on the matter and facilitate the docket activity. Only then can the Commission fulfill its obligations pursuant to Act 827. *Id*. at 2-3.

Walmart Surreply Comments

Walmart notes in Surreply that while it participated in the NMWG established in this docket and was named as one of the Joint Parties in the Joint Progress Report and Proposed Procedural Schedule, it takes no position on the disputed net-metering rate issue and requests that it be excused from the procedural hearing. The Commission granted its request by Order No. 18.

10. Sub-Group 1 Surreply Comments

Sub-Group 1 states that the purpose of AREDA is to promote Arkansas's long-term interest by adopting net metering, so as to encourage the use of renewable energy resources. Sub-Group 1 argues that Sub-Group 2 downplays AREDA's purpose and its ramifications for the Commission's decision in this matter, noting that the General Assembly recognized a wide spectrum of net-metering benefits: "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."[11] Sub-Group 1 Surreply at 3.

Sub-Group 1 acknowledges that AREDA does not require the Commission to promote renewable energy regardless of the cost to non-participating ratepayers.

[11] Ark. Code Ann. § 23-1-602(a).

However, Sub-Group 1 argues that its proposal to keep net metering rates as they are is not in conflict with AREDA's purpose, noting that its Crossborder Study demonstrates that net metering in fact does provide net benefits to other ratepayers by encouraging private investment in generation resources that reduce the utility's costs. Sub-Group 1 cites the Crossborder Study's findings that net metering of solar distributed generation receives a score greater than 1.0 on the Ratepayer Impact Measure (RIM) test. *Id.* at 4-5. Sub-Group 1 asserts that 2-Channel billing would not promote distributed generation in Arkansas, noting that it would make it very difficult for potential solar customers to understand the bill savings they might achieve after installing distributed generation, due to the uncertain percentage of their generation that would be consumed on-site versus exported, as well as the uncertain value of an excess generation credit rate that would fluctuate with each rate case. Sub-Group 1 argues that the 2-Channel construct would be especially detrimental to meter aggregation, as little to none of the distributed generation system's output would likely be "credited" at the higher retail rate -- arbitrarily narrowing the set of Arkansans who could conceivably deploy net metering facilities. *Id.* at 5.

Sub-Group 2 argues that AREDA requires the Commission to strictly adhere to embedded COS principles and ignore long-term benefits associated with distributed generation, when setting net metering rates. Sub-Group 1 responds that this argument is flawed. First, Sub-Group 1 says the statute defines the "cost of providing service to each net-metering customer," using language that modifies the traditional meaning of "COS," and thus creating an issue of first impression for the Commission as to the proper approach to set rates in this context. Secondly, Sub-Group 1 states that the Commission is not required to, nor does it, mechanically follow COS when allocating costs or designing rates, but instead considers other policy objectives within its purview. *Id.* at 6.

Sub-Group 1 argues that the language added to AREDA by Act 827 requires the Commission to consider the benefits associated with net metering, yet traditional COS studies do not evaluate such benefits (*i.e.*, negative costs) associated with net metering. Therefore, Sub-Group 1 says the Commission has a matter of first impression in Arkansas law before it – what does it mean to net out benefits of a customer-sited generation resource against that customer's COS? This gives the Commission discretion to depart from a strict COS structure if it finds that such a departure would not accurately and fully capture the benefits to the utility, as the General Assembly required. Sub-Group 1 points out that the statute requires that rates *charged to* net-metering customers recover the full COS, but says the statute is silent as to rates *paid* to net-metering customers. Thus, Sub-Group 1 believes the Commission may interpret AREDA's benefits provision to refer to long-term avoided utility system costs associated with distributed generation, and factor such benefits into the rates set for net-metering customers. *Id.* at 6-9.

Sub-Group 1 says Sub-Group 2's interpretation of AREDA reduces the Commission's role in rate-setting to a mechanical application of a COS study. Sub-Group 1 says nothing in AREDA prevents the Commission from using its authority to depart from COS principles when setting the net metering rates. Further, Sub-Group 1 argues that this type of application is not what the General Assembly intended. Sub-Group 1 also points to past Commission decisions that recognize policy interests rather than strict adherence to COS when setting rates. One such example is the Commission's acceptance of rate mitigation strategies to ensure that no class receives a rate decrease when other classes are receiving rate increases. *Id.* at 11-12.

Sub-Group 1 discusses Sub-Group 2's alleged revenue recovery shortfall from residential net-metering customers. Sub-Group 2 estimates there is a current under-recovery of $10 per customer per month or $120 per year. Sub-Group 1 says this comes out to $60,000 annually assuming there are 500 current net-metering customers. Spread across the roughly 1.2 million residential meters in Arkansas, the alleged cost shift to non-participants amounts to about 5 cents per year. Sub-Group 1 makes the point that even if net metering grew by a factor of 10, the cost shift would only go up to 50 cents per year. Sub-Group 1 says some level of quantifiable cross-subsidization is inherent in all rate design, particularly for large diverse classes, so an independent finding of a material cost shift should be required before regulators authorize substantial changes to rates or rate design. In summary, Sub-Group 1 argues that the Commission is not required to eliminate every *de minimis* shortfall in cost-of-service recovery, especially when doing so would cause Arkansas to forgo the long-term benefits to utility customers shown in the Crossborder study, not to mention the economic development benefits that would accompany this market growth. *Id.* at 13-15.

a. Crossborder Study

Sub-Group 1 says its Crossborder study is highly relevant because it is the only evidence in the record demonstrating that distributed generation helps utilities avoid direct system costs. Sub-Group 1 summarizes the findings of its study as follows:

1. Solar DG is a cost-effective resource for EAL, as the benefits equal or exceed the costs in the Total Resource Cost, Program Administrator, and Societal tests.

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.
4. The economics of solar DG are marginal for EAL's residential customers, as shown by the Participant test results below 0.9. This means that any reduction in the compensation provided to solar DG customers is likely to be detrimental to the growth of this resource.
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.

Sub-Group 1 Surreply at 16-17.

Sub-Group 1 says it is not advocating using the cost-effectiveness tests from the Crossborder study to set rates for net-metering customers. Instead, the tests should be used as tools to better understand and quantify the costs and benefits that net metering provides to the utility's system from a variety of perspectives relevant to this Commission's assessment of whether current rates unfairly shift costs to other ratepayers. Sub-Group 1 Surreply at 19.

b. Sub-Group 2's Proposal

Sub-Group 1 believes that Sub-Group 2's proposal is technically flawed and demonstrates selective application of COS principles and therefore will not promote distributed generation in Arkansas. Sub-Group 1 argues that Sub-Group 2 never says what the cost to serve a net-metering customer, as defined by AREDA, actually is. Sub-Group 1 contends that Sub-Group 2 has simply assumed incorrectly that the cost to serve net-metering customers is the same as any other customer in the class. Sub-Group 1 also argues that Sub-Group 2 has incorrectly assumed that any benefits associated with the net-metering customer's system are captured by its "excess generation credit rate." Sub-Group 2's assumptions for how it determined cost responsibility for net-metering customers ignores the benefits net-metering customers create by reducing their peak loads. Sub-Group 1 argues that the peak reduction savings should be added to Sub-Group 2's "excess generation credit rate," which would actually mean net-metering customers are providing higher bill savings than the current net metering rate. Sub-Group 1 says there is a second flaw in Sub-Group 2's "excess generation credit rate" calculation. Sub-Group 1 says the calculation is incorrectly based on the output from a 5 kW solar system. Sub-Group 1 argues that the average solar system size for net-metering customers is 8 kW, which if used instead of 5 kW, would have resulted in higher avoided costs for net-metering customers. Sub-Group 1 Surreply at 19-21.

11. Sub-Group 2 Surreply Comments

Citing revisions to Ark. Code Ann. § 23-18-604(b)(1), Sub-Group 2 repeats its position that Commission action was mandated by the General Assembly and is required to ensure that "the rates charged to each net-metering customer recover the electric utility's entire cost of providing service to each net-metering customer...." Sub-Group 2 states that the issue before the Commission in Phase 2 of this proceeding is how to further modify the NMRs beyond what occurred in Phase 1 in order to comply with this specific mandate. Sub-Group 2 Surreply at 1. Noting that Sub-Groups 1 and 2 have submitted separate recommendations based on fundamentally different views of ratemaking to assist the Commission with addressing the issue before it, Sub-Group 2 asserts that Sub-Group 1's approach will cause non-net-metering customers to absorb additional costs through the ratemaking process for uncertain future benefits that may never materialize. Sub-Group 2 recommends that the Commission adopt 2-Channel Billing for new net-metering customers taking service under non-demand billed tariffs, which represents a fair, balanced, and equitable approach to addressing the relevant provisions of Act 827 of 2015. *Id*. at 2.

Sub-Group 2 states that it provided a specific methodology to calculate the credit for excess generation that is grounded in long-standing COS ratemaking principles, is data-driven, evidence-based, and can be applied to every Commission-jurisdictional utility in the state of Arkansas.[12] *Id*.

Sub-Group 2 argues that there are two notable flaws in Sub-Group 1's recommendation and the supporting Crossborder Report.

- First, Sub-Group 1's long-term, avoided cost study incorporates numerous assumptions regarding future benefits that may or may not occur. This is inconsistent with Arkansas law and established COS principles that the Commission uses for ratemaking. In support of this position, Sub-Group 2 reiterates several key points from pages 8-10 of its Reply Comments filed on October 20, 2017. *Id*. at 3.
- Second, there are many flaws and incorrect assumptions in the Crossborder analysis.

Id. at 3-6.

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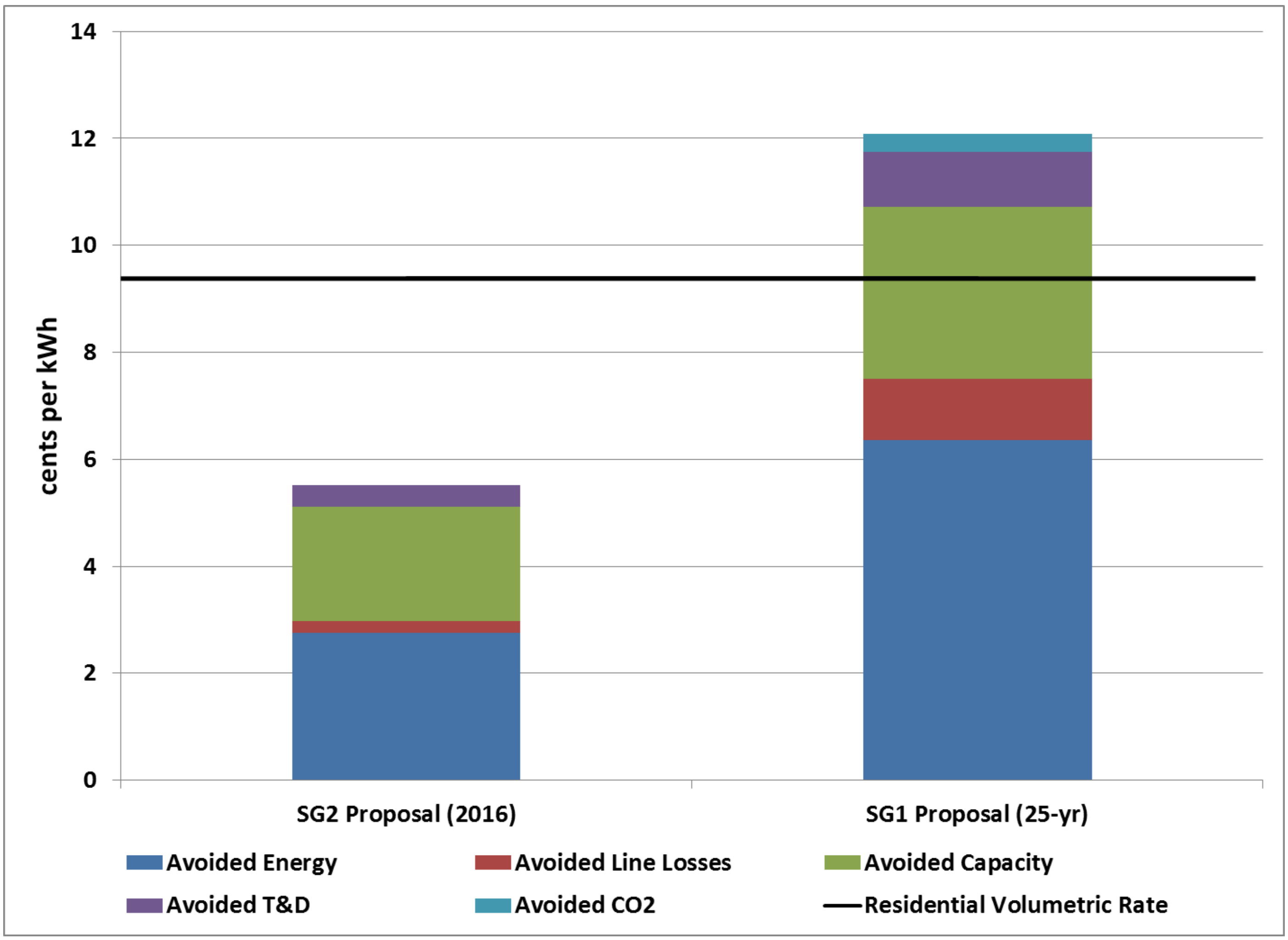
[12] Sub-Group 2 notes that its original proposal filed in this Docket on September 15, 2017, provided the results of calculations for every such utility, as well as supporting work papers.

Illustrating the differences in the two approaches to ratemaking, Sub-Group 2 provides Figure 1 to support its contention that adoption of 2-Channel Billing and setting a more appropriate cost-based credit rate for excess energy delivered to the grid is based on actual incurred and embedded costs from 2016, which, using EAL's numbers, results in a credit value of approximately 5.5 cents per kWh.

Figure 1: (values shown are all applicable to Entergy Arkansas, Inc.)



Sub-Group 2 Surreply at 4.

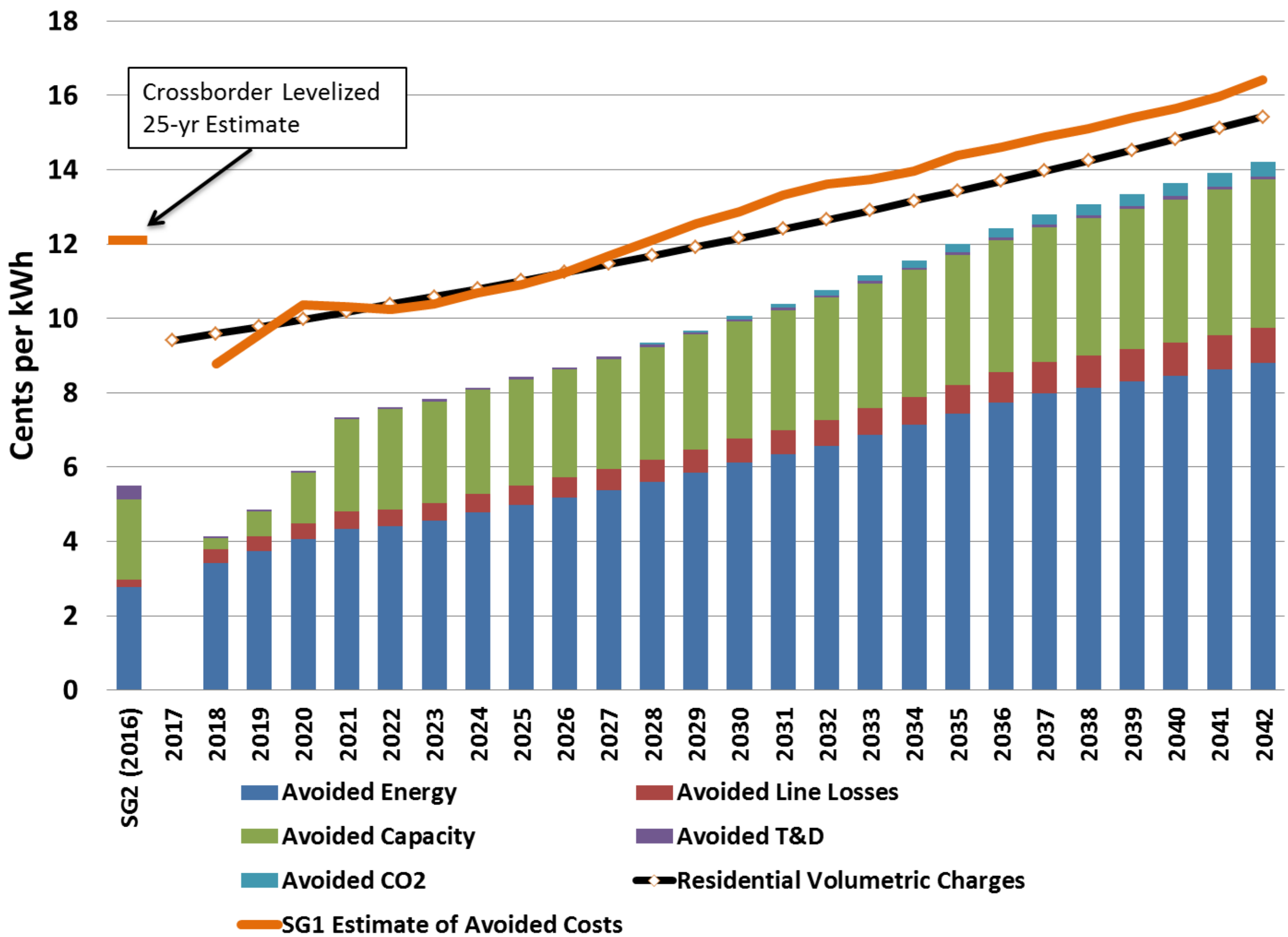
Sub-Group 1, on the other hand, relies upon Crossborder's calculations that use 25 years of "forward, speculative, unrealized, and currently unquantifiable benefits" which result in a levelized, nominal value of solar of approximately 12.1 cents per kWh. *Id.* at 4-5. Sub-Group 2 asserts that Crossborder's calculation of the levelized, nominal value of Avoided Energy alone "remarkably" exceeds the total current value of 2016 embedded costs in Sub-Group 2's recommendation, noting that as reflected in Figure 1, the actual value of energy in 2016 provided by a net-metering customer in the MISO market was approximately 2.76 cents per kWh. According to Sub-Group 2, Sub-Group 1 would argue that the "value" of the same solar energy produced today is actually much higher (6.35 cents per kWh) because producing that kWh with a solar PV system that is net metered "somehow, someway" helps "avoid" future energy costs that would otherwise be much higher. Based on that conclusion and incorporating future values for other categories of benefits, Sub-Group 1 argues that the Commission should retain the current NMRs and net-metering billing framework. *Id.* at 5.

Sub-Group 2 responds to this contention by noting that Arkansas's electric utilities represent more than electrons flowing through distribution and transmission wires, or the energy that net-metering customers and their neighbors are receiving, whether the utility generates that energy or purchases it. Sub-Group 2 states that not only does a utility have an obligation to serve and stand ready to serve 24 hours a day, seven days a week, but the utility provides, among many other things, administrative services, customer services, storm restoration services, optional programs, efficiency programs, and investments in and maintenance of substations, poles, and wires essential to electric service for all customers, including net-metering customers. All of these costs, along with infrastructure costs, debt service, etc., are embedded in the rates that utilities charge their customers and that the Commission has approved through regulatory proceedings. *Id.* at 5-6.

Sub-Group 2 states that its 2-Channel Billing proposal is flexible and provides a framework for calculating appropriate excess energy credit values that can be updated periodically to reflect current, actual costs. As a result, Sub-Group 2 argues, should the value of avoided energy increase over time, that higher value will no doubt be captured in future updates to the utility-specific excess energy credit rates being proposed by Sub-Group 2. *Id*. at 6.

Discussing the second flaw that it finds in Sub-Group 1's recommendation and the Crossborder Report, Sub-Group 2 cites to Attachments 1 and 2 to its Reply Comments, and provides Figure 2 that purportedly corrects certain errors and inputs included in Crossborder's "base case" scenario over each of the 25 years of the forecasted analysis (2018-2042).

Figure 2: (values shown are all applicable to Entergy Arkansas, Inc.)



Sub-Group 2 Surreply at 7.

Sub-Group 2's Figure 2 also shows a projection of EAL's total volumetric rate over 25 years assuming an increase of two percent annually, as well as Crossborder's underlying annual estimates used to develop its 25-year levelized values. Sub-Group 2 states that the items corrected and revised for 2018-2042 include real-time (instead of day-ahead) MISO energy price data within the avoided energy calculations; using current, more accurate estimates of capacity value and accounting for solar degradation in the avoided capacity calculations; using the metric currently approved for EAL's energy efficiency programs to calculate avoided T&D costs; and calculating avoided CO_2 costs by using both EAL's current internal forecast for CO_2 prices as well as EAL's 2016 actual resource portfolio CO_2 emission rate. Sub-Group 2 states that correcting the errors in Crossborder's methodology and inputs makes a very significant difference in the outcome of the analysis underlying Sub-Group 1's recommendation to maintain the status quo. Not only do the purported benefits fail to exceed costs in the first year, Sub-Group 2 states, but the benefits do not exceed costs as reflected by the line labeled Residential Volumetric Charges at any point within the 25-year study horizon. *Id*. at 7-8.

In a long section of its Surreply Comments, Sub-Group 2 responds in detail to 22 Arguments made by Sub-Group 1 and the other Parties (Pulaski County and William Ball). These arguments and responses are summarized below.

A. Burdens of Production and Persuasion. According to Sub-Group 2, Sub-Group 1 uses previous statements of the Commission to "infer" the issue before the Commission, but Sub-Group 2 asserts there is no inference required.[13] See, *e.g*., Order No. 10 at 143, wherein the Commission stated that the initial "issue confronting the Commission" is whether compelling evidence has been demonstrated to justify a change in

[13] *See, e.g*., Order No. 10 at 142-43, (the Order adopting new *Net-Metering Rules*) wherein the Commission stated the following in its Findings, *inter alia*:

- The need for grandfathering is premised on the assumption that the Commission will establish a new rate structure in Phase 2 of this Docket....However, the Commission will not pre-judge any positions on a new Net-Metering rate structure and makes no findings in this Order on whether a new Net-Metering rate structure should be adopted or, if it is, the details of that new rate structure.
- The Commission finds that adoption of a grandfathering period to provide such notice and to promote certainty in the market for Net-Metering Facilities need not conflict with Act 827's requirement that "each" Net-Metering Customer pay its entire cost of service. In Phase 2 of this proceeding, the Commission may or may not determine that a new rate structure is necessary. Agreement may be reached quickly by the parties, or it may require a longer period or be further adjusted in future years. Under any of these scenarios, a grandfathering period beginning with the date of any order, if any, adopting a new rate structure and ending with a "drop-dead date: 20 years later ensures that each Net-Metering Customer will transition to any new rate structure adopted by the Commission.
- The Commission finds that the most reasonable date to use for grandfathering is the date of the order, if any, in Phase 2 which adopts a new Net-Metering rate structure.

net metering. Sub-Group 2 cites to the first sentence in Order No. 1, in which the Commission stated that it established the docket to "gather information to be used to determine appropriate rates, terms, and conditions under Act 827 of 2015 (Act 827) for net metering contracts, including any changes necessary to the Commission's Net Metering Rules (NMRs)." Sub-Group 2 states that this determination is mandated by the General Assembly in Ark. Code Ann. § 23-18-604(b)(1). Thus, Sub-Group 2 contends, Sub-Group 1's and Pulaski County's separate assertions regarding prerequisites and burdens for ratemaking are "misplaced and inapplicable." *Id.* at 9.

B. Cost of Service under AREDA. Sub-Group 2 challenges Sub-Group 1's assertion that the 2-Channel Billing proposal is unjustly discriminatory because the costs that Sub-Group 2 alleges are created are not matched to alleged revenue deficiencies caused by any "additional costs" of net metering.[14] Sub-Group 2 argues that Sub-Group 1 misstates the basis upon which Sub-Group 2 determined the appropriate credit rate for excess energy for net metering, and explains that Sub-Group 2's illustrative EGCR for EAL is based on the utility's entire embedded cost of providing service to the residential class as reflected in the utility's COS Study. Sub-Group 2 states that it did not identify or quantify any additional embedded costs associated with providing service to net-metering customers through the utility's base rates,[15] and consequently there is no *new* revenue deficiency calculated or purported "matching" required. *Id.* at 9.

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[14] Citing to Sub-Group 1 Reply Comments at 4.

[15] Sub-Group 2 notes that as the number of net-metering customers continue to increase in Arkansas, utilities may incur added administrative, operational, and related costs associated with providing service to net-metering customers that are not included in embedded costs today. Sub-Group 2 adds that should those additional costs materialize, they will be captured in updates to the EGCR in accordance with Sub-Group 2's proposed methodology.

Sub-Group 2 states that the underlying premise of its approach to determining the net-metering rate is that the current embedded COS (infrastructure and other services) to serve all customers, including net-metering customers, does not change and is the appropriate basis for determining the costs that should be recovered from net-metering customers. Sub-Group 2 states that differences between customers within a class are generally addressed through rate design, as is the case in Sub-Group 2's determination of the EGCR. *Id*. at 9-10.

Sub-Group 2 cites to its Reply Comments (at 166) as describing how its COS Study and the RTO Market data encompass the full, quantifiable costs and benefits of the utility's capacity, reliability, distribution system, and transmission system and form the basis for defining the EGCR. Sub-Group 2 argues that its proposed 2-Channel Billing approach is not discriminatory, as it is based on actual COS data and evidence underlying rates in Arkansas -- in contrast to Sub-Group 1's "maintain the status-quo" approach, which Sub-Group 2 contends is based on assumed and speculative information regarding the "hypothetical future value of solar generation." Furthermore, Sub-Group 2 argues, Sub-Group 1's proposed approach does not align with the requirements of AREDA or the statutory framework that underlies ratemaking in Arkansas. *Id*. at 10.

Sub-Group 2 rebuts Sub-Group 1's allegation that Sub-Group 2 did not explain the cost to serve net-metering customers, arguing that it has provided a clear explanation of these costs. Sub-Group 2 notes that currently, net-metering customers are credited at the full retail rate for excess kWh that are exported to the grid, and asserts that 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. According to Sub-

Group 2, this 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. Therefore, Sub-Group 2 argues, the current net-metering policy must be changed for new net-metering customers. *Id.* at 10-11.

Sub-Group 2 elaborates by explaining that, for EAL, when a net-metering customer receives a capacity credit at the full embedded COS amount, the customer receives a credit of 4.5 cents per kWh in excess of the benefits the net-metering customer provides when it self-generates. Further, Sub-Group 2 asserts, the utility does not avoid and continues to incur 4.5 cents per kWh in infrastructure and operating costs to provide service to the net-metering customer during hours of the day when the utility is responsible for serving the net-metering customer's load and to allow the net-metering customer to export self-generated excess energy to the grid.[16] *Id.* at 11.

C. Net-Metering Rate Change. Sub-Group 2 responds to Sub-Group 1's contention (Sub-Group 1 Reply at 3) that Sub-Group 2's proposal is based on the unfounded premise that the current rate structure does not fully recover the cost of serving net-metering customers, noting that Sub-Group 2's recommendation is fully supported by its COS analysis, is consistent with Ark. Code Ann. § 23-18-604(b)(1)(A)(i), and is therefore not unfounded. Sub-Group 2 explains that a kWh credit equivalent to the full retail rate for excess generation effectively credits the net-metering customer for costs of providing services and programs which the utility does not avoid due to the net-metering customer's excess generation exported to the grid. Therefore, Sub-Group 2 states, under the present net-metering policy, utilities do not recover the entire cost of their investments

[16] Sub-Group 2 notes that the 4.5 cents per kWh value for EAL noted above does not include non-fuel riders that the net-metering customer also avoids where the associated cost incurred by the utility does not simply disappear.

in generation, transmission, and distribution to serve net-metering customers, including costs for metering systems, billing systems, customer care systems, storm restoration costs, and energy efficiency program costs that apply to all customers. Sub-Group 2 notes that significant portions of a utility's embedded costs are typically recovered through the volumetric portion of a customer's bill and thus allowing net-metering customers to avoid that portion of the charges for maintaining and operating the grid upon which they rely 24-hours a day every day of the year means that the current net-metering billing mechanism does not "recover the electric utility's entire cost of providing service to each net-metering" customer." *Id*. at 12.

D. Sub-Group 2 Does Not Seek Repeal of Net Metering. Sub-Group 2 denies that it wishes to repeal net metering, arguing that the 2-Channel Billing approach is the appropriate rate methodology to ensure compliance with AREDA, "ensuring that net-metering customers' rates reflect the utility's entire cost of providing service." Sub-Group 2 reiterates that 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. The primary difference between 2-Channel Billing and current net-metering. Sub-Group 2 asserts, is that there are different rates associated with the excess energy exported to the grid measured by Channel 2 and energy received from the grid measured by Channel 1. *Id*. at 12-13.

E. Analysis Supporting Change. Sub-Group 2 finds without merit Sub-Group 1's claim that Sub-Group 2 did not conduct a study measuring the impact of net metering, citing to the Joint Report and Recommendations of Sub-Group 2 to adopt 2-Channel Billing and quantifying the COS impacts of net-metering generation for all Arkansas utilities, which Sub-Group 2 notes is based on actual incurred and embedded costs for 2016, which results in a credit value of 5.5 cents per kWh using EAL figures. Sub-Group 2 states that its analysis demonstrates that the COS impacts of net-metering excess generation are materially less than current volumetric rates, which, in the case of EAL, are approximately 9.4 cent per kWh. This relationship shows, according to Sub-Group 2, that under the status quo the utility is not recovering its entire cost of service for excess generation, and thus a change from the status quo is warranted. *Id.* at 14.

Sub-Group 2 acknowledges that Act 827 contains no requirement that a rate change be premised on the existence or determination of cross-subsidies, or quantifying the magnitude of such cross-subsidies, as the result of net metering. But, Sub-Group 2 asserts that AREDA does require that the Commission establish rates that recover the entire cost of serving net-metering customers, net of any quantifiable benefits those customers provide. Sub-Group 2 argues that under the current full retail approach, these entire "costs to serve" are not collected from the net-metering customers and must be paid by other customers through the ratemaking process. *Id.* at 14.

F. <u>Behind the Meter and Exported Generation.</u> Sub-Group 2 denies Sub-Group 1's allegation that 2-Channel Billing treats self-generated kWh used behind the meter differently from self-generated kWh which are exported, in that the former are effectively compensated at the retail rate, while the latter receive only the exported generation credit, creating "winners and losers" based on individual load distribution.[17] Instead, Sub-Group 2 responds, 2-Channel Billing provides cost-based justification based on COS and

[S] Sub-Group 1 Reply Comments at 5.

traditional ratemaking principles for the effective behind-the-meter retail rate and the EGCR. *Id.* at 14-15.

Sub-Group 2 explains that the reduction in purchased energy from the utility associated with behind-the-meter (BTM) generation is similar to conservation and energy efficiency activities such as turning off lights, adjusting the thermostat, adding insulation, sealing leaks, replacing windows, installing LED lights and/or purchasing more efficient appliances. Sub-Group 2 states that because its 2-Channel Billing approach does not change the underlying residential rate structure, for purposes of COS ratemaking Sub-Group 2 did not seek to treat the lost revenues associated with BTM energy conservation resulting from self-generation any differently from the way lost revenues are treated for any other type of customer-directed energy conservation effort. Therefore, under 2-Channel Billing, Sub-Group 2 states, net-metering customers continue to effectively receive the full retail rate for their conservation behind the meter and are treated like all other customers when they are taking service from the utility under Channel 1.[18] *Id.* at 15-16.

Sub-Group 2 further explains that net-metering customers are different, however, from all other customers when they are exporting excess generation to the grid. Consistent with traditional ratemaking methodology, Sub-Group 2 asserts, this difference among customers within a class is addressed through rate design – in this case the establishment of the EGCR for net-metering customers. Sub-Group 2 thus used a COS approach to determining the EGCR, which includes providing the net-metering customer with the

[18] Sub-Group 2 states that while it investigated alternative rate design scenarios including rates that recovered fixed charges through a demand rate or a grid charge to recover BTM lost revenues, and believes that these alternative rate designs may have merit in the absence of 2-Channel Billing, Sub-Group 2 proposed 2-Channel Billing at this time in order to avoid a significant change in the existing residential rate structure.

quantifiable benefits of avoided capacity costs associated with the net-metering customer's entire self-generation, both BTM generation and excess generation exported to the grid. *Id*. at 16.

According to Sub-Group 2, the EGCR also appropriately recognizes costs that are essential to provide utility service that are not avoided by net-metering customers and should not be credited to net-metering customers. Excess generation exported to the grid is simply electrons and does not include all of the attributes of utility service such as billing, metering, reliability, EE programs, and other approved investments and ongoing costs essential to maintaining utility infrastructure. Sub-Group 2 states that the net-metering customer does not offset these essential utility costs when it exports kWh to the grid and should not be credited for these services as is the case when the net-metering customer is credited at the full retail rate. Sub-Group 2 thus argues that the EGCR ensures that the utility recovers its entire cost of providing service, net of quantifiable benefits, from net-metering customers, adding that the difference between the effective rate for BTM conservation and the EGCR is fully consistent with COS principles and recognizes the ratemaking differences between conservation and excess generation exported to the grid. *Id*.

Sub-Group 2 also responds to Sub-Group 1's contention that Sub-Group 2's treatment of BTM usage creates "a perverse incentive for distributed generation customers to use more electricity while their systems are producing, which is detrimental in many respects,"[19] citing the definition of net metering in Ark. Code Ann. § 23-18-603(6)(E) as: "intended primarily to offset part or all of the net-metering customer requirements for

[19] Sub-Group 1 Reply Comments at 5.

electricity." Sub-Group 2 states that the most efficient way for a customer with self-generation to serve its own energy needs is to directly consume its self-generated energy behind the meter, and therefore, Sub-Group 2's treatment is consistent with AREDA and appropriate, not perverse or detrimental in some manner. *Id.* at 16-17.

G. Long-Term Avoided Costs. Sub-Group 2 considers incorrect Sub-Group 1's assertion that a longer-term view of avoided marginal costs such as that taken in resource planning is the more appropriate approach to developing net-metering rates.[20] According to Sub-Group 2, resource planning is a planning process that screens various utility supply-side and demand-side resources to ascertain the optimal, lowest cost way to serve future load. It is not, in Sub-Group 2's view, and should not be, the basis for establishing electric rates. Instead, Sub-Group 2 argues, the Commission's regulatory authority to establish rates is derived from existing ratemaking statutes that require rates based on costs. *Id.* at 17.

Historically, Sub-Group 2 observes, the Commission has developed rates using COS Studies, which provide the regulatory framework for establishing rates based on costs that include not only COS, but also benefits associated with the costs avoided by net-metering customers. Sub-Group 2 states that the General Assembly is presumed to know how the Commission defines and determines COS, and therefore its treatment of avoided costs is historically consistent both with the Commission's ratemaking process and AREDA. *Id.*

Sub-Group 2 reiterates its position that 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

[20] *Id.* at 5.

customers will be captured in future, updated utility COS Studies and approved revenue requirement and rates. The same is true for any utility investments to comply with environmental regulations associated with existing generation – the benefits of those embedded costs will be reflected in future COS Studies and future rates, Sub-Group 2 asserts. *Id.* at 18.

H. Channel 1 Cost of Service. Sub-Group 2 discusses and responds at some length to Sub-Group 1's argument that there are a number of "conceptual problems" with Sub-Group 2's COS approach,[21] noting that Sub-Group 1 presents what it characterizes as a complete COS analysis for all net-metering output, including the portion that is used on-site and that produces a lower COS for Channel 1 loads, which Sub-Group 2 allegedly fails to consider. Sub-Group 2 posits that Sub-Group 1 errs in that Sub-Group 2 focuses only on the net-metering customer's excess energy exported to the grid and that Sub-Group 2's recommendation is a 2-Channel Billing framework which recognizes the kWh measured on Channel 1 and Channel 2 as separate and unique billing determinants. *Id.* at 18-19.

For the kWh measured on Channel 1, Sub-Group 2 recommends using the base rate in each utility's tariff and using a COS approach for developing just and reasonable rates for the net-metering customer's excess generation that is exported to the grid and measured on Channel 2. The EGCR methodology considers all of the net-metering customer's generation capacity and only focuses on the energy exported to the grid to the extent that the net-metering customer delivers excess energy to the grid. *Id.* at 19.

Sub-Group 2 asserts that its recommended 2-Channel Billing approach also uses traditional COS and rate design methods in developing the EGCR and uses the known

[21] *Id.* at 30-31 and Attachment A thereto.

billing determinants – namely energy measured on Channel 1 and Channel 2, which represent the net-metering customer's usage of the grid and export to the grid, respectively, and provides clear and accurate price signals. Sub-Group 2 further describes the 2-Channel Billing framework and EGCR methodology as simple to understand and apply universally to all utilities in Arkansas. Sub-Group 2 states that Attachment B-4 of Sub-Group 2's Recommendations shows that estimated customer impact is consistent across all utilities. *Id*. at 19-20.

According to Sub-Group 2, any rate mechanism that deviates from the billing determinants that reflect the service provided to the customer will make it increasingly difficult to recover the entire cost of serving the net-metering customer and does not send customers the proper price signals that encourage efficient use of the system. Sub-Group 2 contends that a 2-Channel customer's bill is highly correlated with the customer's actual use of the electric grid, including both the consumption of energy measured on Channel 1 and exports of energy measured on Channel 2. Sub-Group 2 asserts that this is not the case with the current 1:1 full retail rate credit reflected in net-metering rates. *Id*. at 20.

Sub-Group 2 agrees with Sub-Group 1's assertion "that many of the cost savings associated with net-metering come from behind-the-meter usage," but emphasizes that under the recommended 2-Channel Billing framework, the same BTM savings that current net-metering customers receive today will still be available to new net-metering customers in the future. Sub-Group 2 states that its recommended approach will allow the net-metering customer to retain the significant benefit of lower overall consumption and a lower bill, compared to non-net-metering customers. *Id*.

In addition, Sub-Group 2 argues, the 2-Channel Billing framework provides the correct economic price signals that promote and encourage net-metering customers to maximize the savings associated with the BTM usage. Sub-Group 2 also notes that the current 1:1 full retail rate credit has the practical effect of valuing all net-metering generation as if it were consumed directly behind the meter, and consequently, all of the cost savings associated with net-metering under the current 1:1 full retail rate credit comes from the level of net-metering generation and not with BTM usage. *Id*. at 20-21.

Sub-Group 2 argues against Sub-Group 1's suggestion that properly evaluating the BTM usage with a COS approach requires adjusting the Channel 1 rate as well as the Channel 2 rate, and disagrees with the "flawed assumption" that the current base rates contained in a utility's tariff are not capable of recovering a fair and reasonable level of costs from each customer based on their use of the utility system. *Id*. at 21.

In support of its position, Sub-Group 2 asserts that net-metering customers' infrastructure requirements for electric service are not different from those of other customers, noting that net-metering customers will still take energy generated by the electric utility via transmission and distribution facilities. Some customers will require more electricity and some less, depending on their needs, Sub-Group 2 says. Further, net-metering customers, like non-net-metering customers, expect safe and reliable service, and both use the same metering and billing systems, customer care and customer service functions and programs, and other utility systems. In short, Sub-Group 2 argues, when receiving electric service from the utility, a net-metering customer does not differ from any other customer and the electric service it receives will be measured on Channel 1. *Id*.

Sub-Group 2 states that the rates for energy charges are designed for the residential class to include all functional costs (generation, transmission, and distribution). Sub-Group 2 adds that the energy charge for Channel 1 is based on the per kWh rate for electric service based on the class under which the customer takes service each month. Sub-Group 2 observes that the energy charge will vary between customers based on the usage needed and requested by each customer in the class; however, the approved rate per kWh (based on the cost to serve the class) will not change based on a net-metering customer's usage in the month. In other words, Sub-Group 2 states, the net-metering customer's bill may be less due to lower usage recorded on Channel 1, but the cost per kWh will not be less. *Id*. at 21-22.

Sub-Group 2 states that the current rate designs used by utilities in Arkansas for usage on Channel 1 appropriately recognize that customers have varying usage and demand profiles. According to Sub-Group 2, the only difference between a net-metering customer and a non-net-metering customer is that the net-metering customer owns generation, consumes a portion of its own generation behind the meter, and, at times, exports excess energy to the grid. Sub-Group 2 notes that the exported energy will be measured on Channel 2 and netted against the "imported" energy measured on Channel 1 "during the applicable billing period," as required by Ark. Code Ann. § 23-18-603(4).

Sub-Group 2 stresses that even when a net-metering customer's self-supplied energy is greater than energy received from the utility, the utility's obligation to serve the net-metering customer has not changed, and the investment incurred to fulfill the obligation to serve the customer likewise has not changed. Sub-Group 2 argues that Sub-Group 1's flawed COS approach would lead to a new base rate for the energy measured on

Channel 1. In fact and as demonstrated in its Attachment A, Sub-Group 2 states, Sub-Group 1's COS approach cannot be applied to all customers, given that it would require a customized Channel 1 rate for each individual customer. Sub-Group 2 recommends against an approach that changes the base rate structure that is applied to all other customers in the class as part of this rulemaking proceeding. Sub-Group 2 contends that such an approach would likely entail separate rate proceedings to determine the COS for net-metering customers for each jurisdictional electric utility and the potential for implementing a rate structure with fixed or demand charges, which, Sub-Group 2 argues is ironically a result that solar proponents in other states have strongly opposed.[22] *Id*. at 22-23.

I. <u>"Net Excess Generation".</u> Sub-Group 2 denies Sub-Group 1's allegation that Sub-Group 2 misuses the term "Net-Excess Generation," when referring to the excess generation credit rate applicable to excess kWh exported to the grid as measured by Channel 2; therefore, Sub-Group 2 argues, there is no misapplication of this term. *Id*. at 23.

J. <u>Distribution System Benefits.</u> Sub-Group 2 asserts that Sub-Group 1 misinterprets AREDA and misstates Sub-Group 2's analysis by asserting that it ignores distribution system benefits. Sub-Group 2 states that Ark. Code Ann. § 23-18-604(b)(1)(A)(ii)(a) provides that in determining the "entire cost of providing service" the Commission must include "any quantifiable *additional* costs associated with the net-metering customer's use of the electric utility's . . . distribution system. . ." (emphasis added). Furthermore, Sub-Group 2 states, Ark. Code Ann. § 23-18-604(b)(1)(A)(ii)(b)

[22] Sub-Group 1 Reply Comments at 10.

provides that in netting quantifiable benefits, the Commission must consider ". . . benefits associated with the interconnection with and providing service to the net-metering customer including. . . benefits to the electric utility's. . . distribution system." *Id*.

Contrary to Sub-Group 1's assertion, Sub-Group 2 states that its proposed EGCR includes the benefits of distribution system line losses associated with the cost of delivering energy. Sub-Group 2 adds that its recommendation that no capacity-related distribution system benefits be included in the calculation of the rate credited to excess generation kWh measured on Channel 2 is based upon the COS studies underlying current rates. Sub-Group 2 contends that currently, there are no quantifiable distribution benefits provided by the net-metering customers, whether customers are receiving kWh from the utility as measured on Channel 1 or exporting excess kWh to the grid as measured on Channel 2, since the net-metering customer is using the poles, wires, transformers, and other distribution facilities of the utility. Sub-Group 2 states that if in the future net-metering customers provide any distribution system benefits, those will be reflected in future COS Studies for each utility and reflected in the rates the net-metering and other customers pay. *Id*. at 23-24.

K. Export Generation Credit Rate. In response to Sub-Group 1's assertion that Sub-Group 2's approach to calculation of the exported generation credit fails to consider differences in types of solar systems,[23] Sub-Group 2 notes that Sub-Group 1 does not provide any specifics regarding such "differences" in solar systems. Sub-Group 2 adds that to the extent that a customer installs a more or less efficient solar system, that fact will be reflected in how much energy the system produces. Sub-Group 2 states that its approach

[23] *Id*.at 12.

to ratemaking is also a commonly accepted practice by the Commission, which designs rates to bill the average customer. According to Sub-Group 2, rates are not tailored to fit each possible difference that a group of customers may have. Therefore, Sub-Group 2 asserts that Sub-Group 1's recommendation that exported generation rates be developed particular to solar installation types with higher capacity factors is not consistent with traditional ratemaking. *Id*. at 24-25.

L. Netting kWh. Sub-Group 2 responds to Sub-Group 1's argument that the 2-Channel Billing rate structure is inconsistent with AREDA's definition of net metering because it "does not 'net'" or measure the difference between consumption and production electricity amounts (in kilowatt-hours), but rather the monetized difference between the two. Sub-Group 2 cites to Ark. Code Ann. § 23-18-603(4), which defines net metering as "measuring the difference between electricity supplied by an electric utility and the electricity generated by a net-metering customer and fed back to the electric utility over the applicable billing period."

Sub-Group 2 states that Sub-Group 1's argument is inaccurate because electricity consumed and produced is only measured in kWh. Noting that AREDA has mandated that the Commission establish a rate for net-metering,[24] Sub-Group 2 states that 2-Channel Billing complies with all aspects of AREDA, as the approach measures the "electricity supplied" on Channel 1 and the electricity "fed back" on Channel 2 in kWh during the applicable billing period and establishes a cost-based credit for the electricity supplied to the grid by the net-metering customer. *Id*. at 25.

[24] Ark. Code Ann. § 23-18-604(b)(1).

Sub-Group 2 observes that the statutory definition of net metering does not speak in terms of netting based on kWh; however, since electricity consumed and produced is only measured in kWh, Sub-Group 2 is simply establishing a monetized value (EGCR) for the measured amount of electricity (kWh) exported to the grid by the net-metering customer over the monthly billing period, which is consistent with the statutory definition of net metering in AREDA. *Id*.

M. Docket No. 02-046-R. In response to Sub-Group 1's allegation that a proposal similar to the 2–Channel Billing approach was rejected by the Commission in Docket No. 02-046-R,[25] Sub-Group 2 states that Sub-Group 1 not only confuses the approach currently recommended by Sub-Group 2, but also the current law. Sub-Group 2 notes that Docket no. 02-046-R was established to implement the provisions of Act 1781 of 2001, which established AREDA. In that docket, Sub-Group 2 states, several of the investor-owned utilities proposed to treat net-metering customers as Qualifying Facilities subject to the Commission's *Cogeneration Rules*, and, in turn, establish the rate for all generation at the avoided cost rate. According to Sub-Group 2, the Commission found that due to Act 1781, net-metering customers were eligible for net-metering benefits that were greater than the avoided cost payments for this size of generators. Nonetheless, Sub-Group 2 argues, that was 15 years ago and a different law, and the 2015 amendments to AREDA, show a significant change in the legislative mandate, as the passing of those provisions by the General Assembly represents that the State is now concerned with ensuring that electric utilities are able to recover their entire cost of serving net-metering customers. Sub-Group 2 further argues that given that the Commission's determination in

[25] Sub-Group 1 Reply Comments at 14.

this matter relates to the implementation of the statutory provisions included in AREDA via Act 827, its interpretation regarding a prior version of the law is misplaced.[26] *Id.* at 26.

N. Rate Setting Authority. Sub-Group 2 responds to Sub-Group 1's contention that Sub-Group 2 has improperly construed the Commission's rate setting authority provided in Ark. Code Ann. § 23-18-604(b)(1)(A)(i).[27] Sub-Group 2 notes that this section provides that "appropriate rates, terms, and conditions for net-metering contracts" must include "[a] requirement that the rates charged . . . recover the electric utility's entire cost of providing service...."[28] Sub-Group 2 describes as "blatantly fallacious" Sub-Group 1's allegation that under 2-Channel Billing, the utility would *pay* for exported energy. Sub-Group 2 states that under 2-Channel Billing, as with the current net-metering approach, net-metering customers are not *paid* for energy – they are credited with kWh. This, Sub-Group 2 asserts, is consistent with the statutory requirement that electric utilities must "credit a net-metering customer with any accumulated net excess generation in the next applicable billing period."[29] Sub-Group 2 states that this is also consistent with the requirements that the "net excess generation credit" remaining in a customer's account is carried forward indefinitely[30] and that a net-metering customer may elect to have the utility purchase net excess generation credits older than 24 months at the utility's annual average avoided cost rate for wholesale energy.[31] According to Sub-Group 2, because the 2-Channel Billing approach does not propose any cash payment by the utility for exported energy, Sub-Group 1's argument relating to fictional payment to a "greater fee or charge"

[26] Docket No. 16-027-R, Order No. 3 at 5.
[27] Sub-Group 1 Reply Comments at 14-15.
[28] Ark. Code Ann. § 23-18-604(b)(1)(A)(i).
[29] Ark. Code Ann. § 23-18-603(b)(3).
[30] Ark. Code Ann. § 23-18-604(b)(6)(A)(i).
[31] Sub-Group 1 Reply Comments at 14.

authorized in Ark. Code Ann. § 23-18-604(b)(2) is misplaced and need not be addressed. *Id*. at 27.

O. <u>Encouraging the use of Renewables through Net Metering.</u> Sub-Group 2 takes issue with Sub-Group 1's assertion that the 2-Channel Billing approach is inconsistent with the intent of the General Assembly to promote net-metering and will diminish the growth of distributed generation.[32] Sub-Group 2 reiterates its position that AREDA and this docket only address net metering, which is a specific type of billing mechanism used to credit customers for renewable energy they supply to the grid. Sub-Group 2 asserts that AREDA does not establish Arkansas's renewable energy policy, but only addresses the promotion of renewable energy resources through net metering. Sub-Group 2 contends that Sub-Group 1 thus inaccurately portrays the purpose of this proceeding. In addition, Sub-Group 2 argues that its approach to net metering is fully consistent with the intent of AREDA to encourage the use of renewables through net metering, while ensuring that net-metering customers pay their entire cost of service, net of benefits. *Id*. at 28.

Sub-Group 2 argues against Sub-Group 1's contention that 2-Channel Billing is confusing. Citing to Sub-Group 1's statement that "[t]he notion that a customer could have a bill today for energy usage, and also a kilowatt-hour credit that they cannot apply to the bill, is counter-intuitive and frankly, confusing,"[33] Sub-Group 2 notes that the billing scenario that Sub-Group 1 describes regarding unused excess kWh rolling over to the next month is the same way billing is done today, is something net-metering customers understand, and is not confusing. *Id*. at 28.

[32] *Id*. at 28.
[33] *Id*. at 17.

Sub-Group 2 responds to Sub-Group 1's allegation that unlike the current net-metering policy, in which a customer "can look at past bills, compare to the system's output and calculate the monthly bill savings,"[34] the 2-Channel approach contains "significant uncertainty" that makes it "very difficult" to determine the payback period of the net-metering facility."[35] According to Sub-Group 2, AREDA neither requires the Commission to ensure a particular payback period or return on investment for net-metering customers, nor that the non-net-metering customer absorb the utility's cost of serving net-metering customers. Instead, Sub-Group 2 argues, AREDA requires the Commission to establish rates for net-metering service that recover the utility's entire cost of serving net-metering customers from those customers. *Id*. at 29.

Furthermore, Sub-Group 2 asserts, there is uncertainty surrounding the calculation of any long-term "payback period." The calculation is, at best, an estimate that is full of assumptions that never results in a precise estimate, according to Sub-Group 2. Sub-Group 2 states that the standard rate for electricity pricing applied to Channel 1 is readily available, and the standard rate for calculating Channel 2 EGCR will be readily available as well, if 2-Channel Billing is approved. Using these two rates, Sub-Group 2 states, along with reasonable estimates of all of the other factors required to calculate a payback (including usage patterns), will result in a payback range. As shown in Sub-Group 2's Attachment B, Sub-Group 2 asserts that several other jurisdictions around the U.S. have adopted net-metering mechanisms that constitute a form of 2-Channel Billing. Sub-Group 2 adds that the prospective customers in these other jurisdictions that utilize 2-Channel Billing appear to be able to reasonably calculate a payback range and make a decision one

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[34] *Id*.
[35] *Id*. at 19.

way or another regarding investing in solar. Sub-Group 2 expresses confidence that Arkansas net-metering customers (with the assistance of their installers) would be able to do the same. Sub-Group 2 argues that any attempt to imply that a precise payback period can be calculated *only* with a full retail net-metering rate offset and/or with a precise customer-specific load profile is misleading, since there are so many other factors that can skew the numbers (including the weather, solar patterns, future rate changes, equipment performance, etc.). Sub-Group 2 views the expectation of a risk-free calculation as unrealistic, even with the best information. *Id*. at 29-30.

Sub-Group 2 re-stresses its assertion that under 2-Channel Billing the net-metering customers will continue to receive the full retail rate value for energy they self-generate and use behind the meter, which constitutes the majority of a customer's return on investment. Sub-Group 2 notes that the change in billing mechanisms only affects the energy exported to the grid and shows in Figure 3 below an example of an average EAL residential customer installing a 5 kW_{DC} solar net-metering system, who would still be able to save over $50 per month under 2-Channel Billing in comparison to that same customer without net-metering. In addition, Sub-Group 2 states, the difference between the current rules and 2-Channel Billing is estimated to have less than a $10 impact on a customer's total average monthly bill.

Figure 3: Comparison of Net-Metering Savings

	Average monthly bill	Difference compared to customer without net-metering
Customer without net-metering	$129	--
Customer with net-metering: Ch. 1 delivered rate (i.e. the impact of just the reduction in Ch. 1 usage; not including value of exported/excess energy)	$89	($41)
Customer with net-metering under 2-Channel Billing	$77	($53)
Customer with net metering under current APSC rules	$68	($61)

Id. at 30-31.

In response to Sub-Group 1's concern about the uncertainty that arises from the fact that the exported generation rate will presumably change with every COS update, the fact that the net-metering customer would thus need to forecast how their exported generation credit would change over the years, and that such a complex, essentially unpredictable rate design would frustrate the emerging self-generation market, Sub-Group 2 points out that all ratemaking contains, and will continue to contain, an element of uncertainty in forecasting long-term utility rates. Sub-Group 2 characterizes this as explicit in the nature of ratemaking and notes that all utility customers bear that uncertainty. No one, Sub-Group 2 states, including current, grandfathered, net-metering customers, is guaranteed that rates will remain unchanged, and it should be no different for net-metering customers subject to the Commission's decision in this docket. *Id*. at 31.

However, Sub-Group 2 states, to minimize changes, the EGCR is designed to be relatively stable and to mirror changes in underlying base rate costs. Fuel costs, which make up a significant portion of the EGCR, Sub-Group 2 notes, will vary with the cost of fuel, just as is the case today, and 2-Channel Billing does not add to the uncertainty of forecasting rates over 20-25 years. *Id*.

P. Meter Aggregation. Contrary to Sub-Group 1's assertion, Sub-Group 2 states that its recommended 2-Channel Billing approach does not undermine net-metering aggregation. Rather, Sub-Group 2 asserts, the 2-Channel Billing approach amends the credit rate applicable to the excess generation measured in kWh from the net-metering customer's generation meter, that are then applied to the net-metering customer's additional meters. Sub-Group 2 states that meter aggregation is a clear use of the electric utility's distribution system. Instead of discouraging meter aggregation, Sub-Group 2 states, 2-Channel Billing more properly aligns such a system to its realized costs and benefits to the utility, the electric system, and all customers. Sub-Group 2 states that net-metering customers who aggregate their loads should be subject to the same rates, terms, and conditions as customers who do not aggregate their loads. *Id*. at 31-32.

Q. FERC-Jurisdictional Sales. Sub-Group 2 disputes Sub-Group 1's assertion that 2-Channel Billing treats exported generation as "a sale to the utility." Sub-Group 1 states that "Generation that is operated to offset consumption under traditional net metering, as defined in federal law (16 U.S.C. § 2621) and Arkansas statute (Ark. Code Ann. § 23-18-603(6)(E)) is not considered a jurisdictional sale even when generation exceeds the instantaneous level of consumption.[36] Sub-Group 2 reiterates its position that its proposed 2-Channel Billing mechanism is designed to recover the electric utility's entire cost of providing service to the net-metering customer in accordance with the statute, and its recommendations do not alter net metering. Sub-Group 2 asserts that Sub-Group 1's

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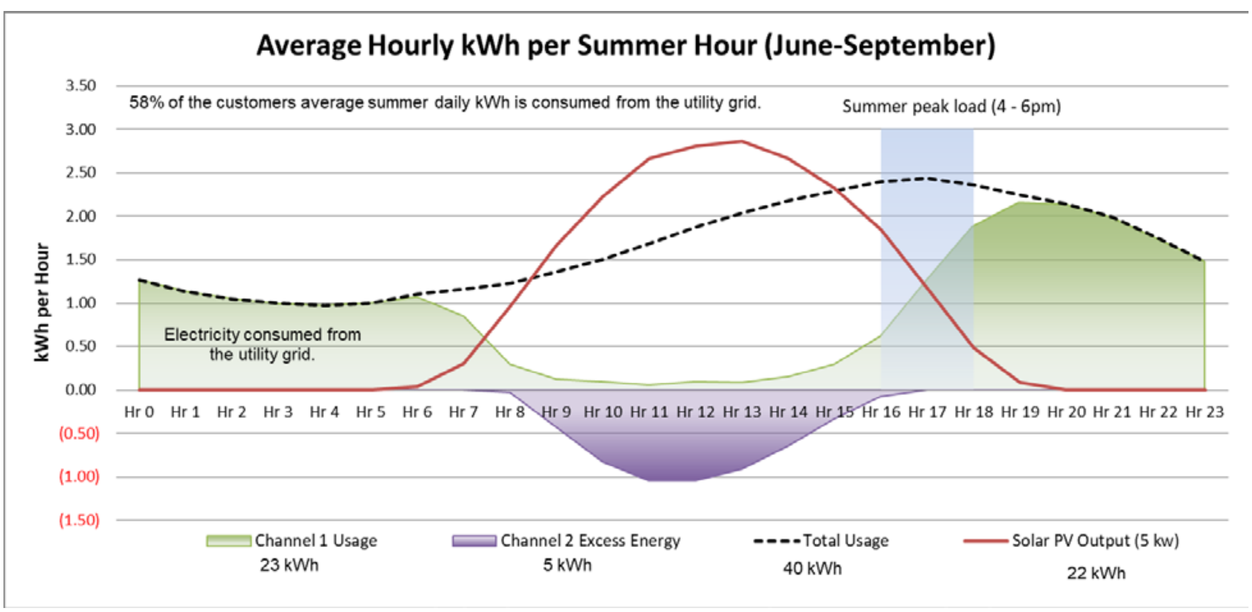
[36] *Id*. at 22.

labeling of the exported energy measured by Channel 2 as a "sale" is inconsistent with federal law, state law, and even its own comments. Since the energy measure on Channel 2 does not involve a sale in any manner, Sub-Group 2 states, the remainder of Sub-Group 1's concerns regarding treatment of the sale is moot. *Id*. at 32.

Sub-Group 2 states that this type of billing structure for net metering has been adopted in numerous states without sparking any jurisdictional issues at the state or federal level concerning net sales or Qualifying Facilities (QFs) under PURPA, Pub. L. 95-617, 92 Stat.3117, enacted November 9, 1978) or the Federal Power Act, 16 U.S.C. Chapter 12. Sub-Group 2 states that FERC has ruled previously that sales of energy from net metering would only constitute a jurisdictional sale if it is a net sale, meaning that the exported generation is greater than the consumer generation over the course of the applicable monthly billing period. With net metering, Sub-Group 2 states, there is no sale; instead, there is a netting of kWh through the use of monthly billing credits. Sub-Group 2 explains that the net-metering customer is credited for excess kWh exported to the grid, and the credits serve to offset future kWh consumed by the net-metering customer. In conclusion, Sub-Group 2 cites MidAmerican Energy Co., 94 FERC ¶ 61,340 at 61,345 (2001) for the proposition that "[n]o sale occurs when an individual homeowner or business installs generation and accounts for its dealings with the utility through the practice of netting." *Id*. at 33.

R. <u>Optimizing ROI.</u> Sub-Group 2 calls Sub-Group 1's allegation that the 2-Channel Bill approach creates a "perverse incentive" for distributed generation customers "without merit." Sub-Group 2 argues that net-metering customers should seek to optimize their return on investment by offsetting part or all of their requirements for electricity, consistent with the intent of the statutory definition of net-metering facility. Sub-Group 2 asserts that the purpose of net metering is not to export kWh to the utility – it is a rational plan for the net-metering customer to use its system and reduce his or her requirements for electricity. Sub-Group 2 illustrates this argument by providing its Attachment B, which Sub-Group 2 asserts shows that on average net-metering customers provide little to no excess generation to the utility during the utility's summer peak load hours of 4 p.m. to 7 p.m. Therefore, Sub-Group 2 contends, the net-metering customer is not denying the benefits of excess generation to other customers during the utility's peak as alleged by Sub-Group 1. Sub-Group 2 presents Figure 4 (below) showing this phenomenon, which indicates that the majority of the excess energy is provided to the grid between 9 a.m. and 3 p.m. Sub-Group 2 argues that it is a rational plan for the net-metering customer to use its system and reduce his or her requirements for electricity by shifting part of his or her energy needs between 4 p.m. and 7 p.m. (the utility's peak hours) to the hours of 9 a.m. to 3 p.m. (solar peak hours), when the customer's self-generation is available. *Id*. at 33-34.



Id. at 33-34.

S. Bill Impacts. Sub-Group 2 responds to Sub-Group 1's allegation that the 2-Channel Billing approach has an "arbitrary and perverse" impact on net-metering customers' bills due to the variability of the solar customer's energy usage patterns.[37] In support of this allegation, Sub-Group 1 presented Attachment B to its Reply Comments, which compares the usage profile of five "actual" customers to the "hypothetical" customer Sub-Group 2 used in the development of the EGCR. According to Sub-Group 2, Sub-Group 1 hoped to show the wide variety of bill impacts to net-metering customers based on their usage patterns and other factors resulting in difficulty in forecasting billing savings, which Sub-Group 1 contends undermines AREDA. However, Sub-Group 2 states, once the data for the five customers provided by Sub-Group 1 was adjusted to place it on an apples-to-apples basis with Sub-Group 2's analysis, the data provided support that Sub-Group 2's customer is representative of the average net-metering customer. *Id*. at 35.

Sub-Group 2 takes issue with Sub-Group 1's conclusions regarding four figures Sub-Group 1 provides comparing the energy consumed and energy exported by Sub-Group 1's five customers and Sub-Group 2's three modeled kW systems. Sub-Group 1 stated that "As expected, seasonal changes in grid energy use are readily apparent for Sub-Group 2's model systems and somewhat less discernible among the five customers. Likewise, seasonal patterns are obvious for Sub-Group 2's model and apparent, but more muted among the customers."[38] The four figures are shown below. *Id*. at 35.

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[37] *Id*. at 20-21.
[38] *Id*., Attachment B at 43.

Fig. 1. 3-kW Systems Model – Consumption

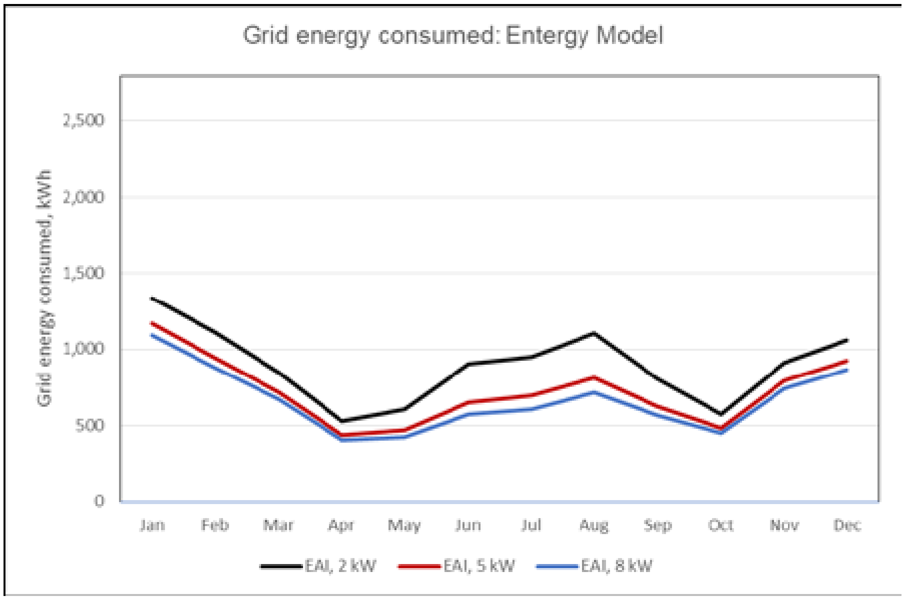


Fig. 2. 5-Customer Model – Consumption

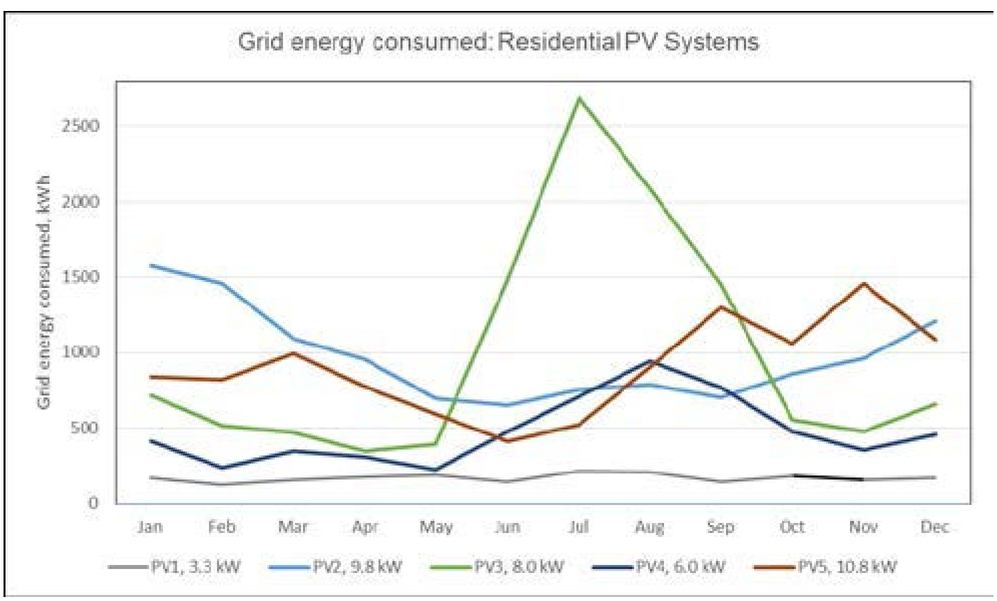


Fig. 3. 3-kW Systems Model - Consumption

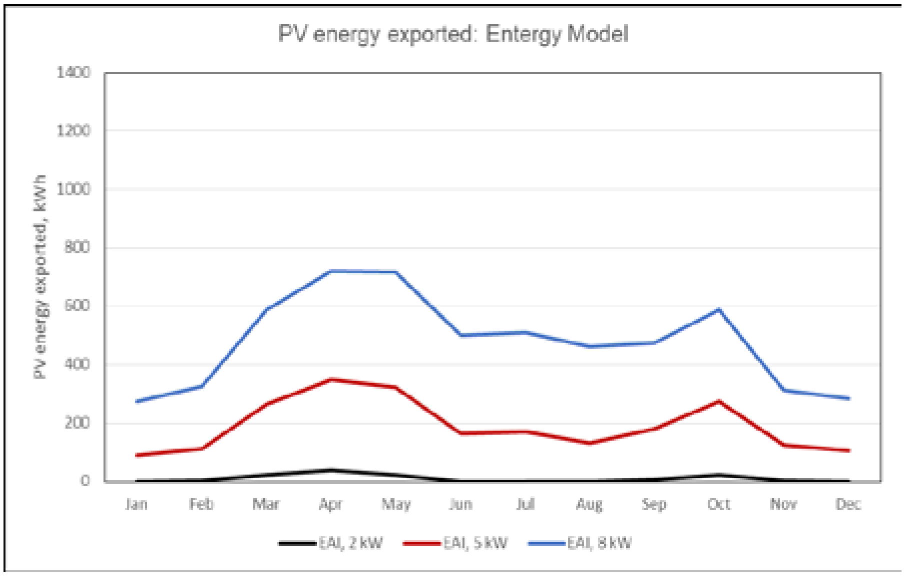
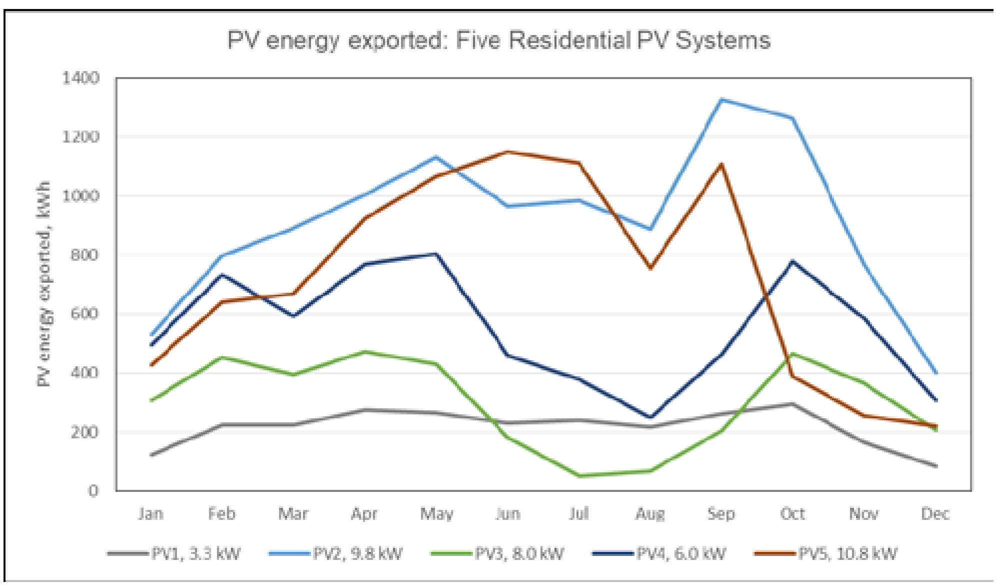


Fig. 4. 5-Customer Model - Consumption



According to Sub-Group 2, Sub-Group 1 does not attempt to make any clear conclusions about the information provided in the figures above, other than the previous comment that Sub-Group 2's model has clear seasonal changes, while the individual customers do not have clear seasonal changes. Sub-Group 2 surmises that Sub-Group 1 is perhaps trying to imply that Sub-Group 2's model cannot be relied on, as it does not represent these five customers. Sub-Group 2 responds that this is simply not the case.

According to Sub-Group 2, usage patterns will vary widely among individual consumers within a rate class, which is why traditional ratemaking methodologies base rates on the average customer. Sub-Group 2 reiterates that its model is intended to represent the average customer, not each individual customer. Thus, argues, Sub-Group 2, it is inappropriate to draw conclusions based on the usage of individual customers as suggested by Sub-Group 1. However, Sub-Group 2 notes, if the five customers provided by Sub-Group 1 were averaged to place the data on an apples-to-apples basis with Sub-Group 2's data and then compared with Sub-Group 2's average customer under the 2-Channel Billing approach, one would see that the average of Sub-Group 1's customers look more like Sub-Group 2's average customers, as shown in Sub-Group 1's Figures 5 and 6 below. *Id*. at 36-37.

Fig. 5. Sub-Group 1 and Sub-Group 2 consumption models

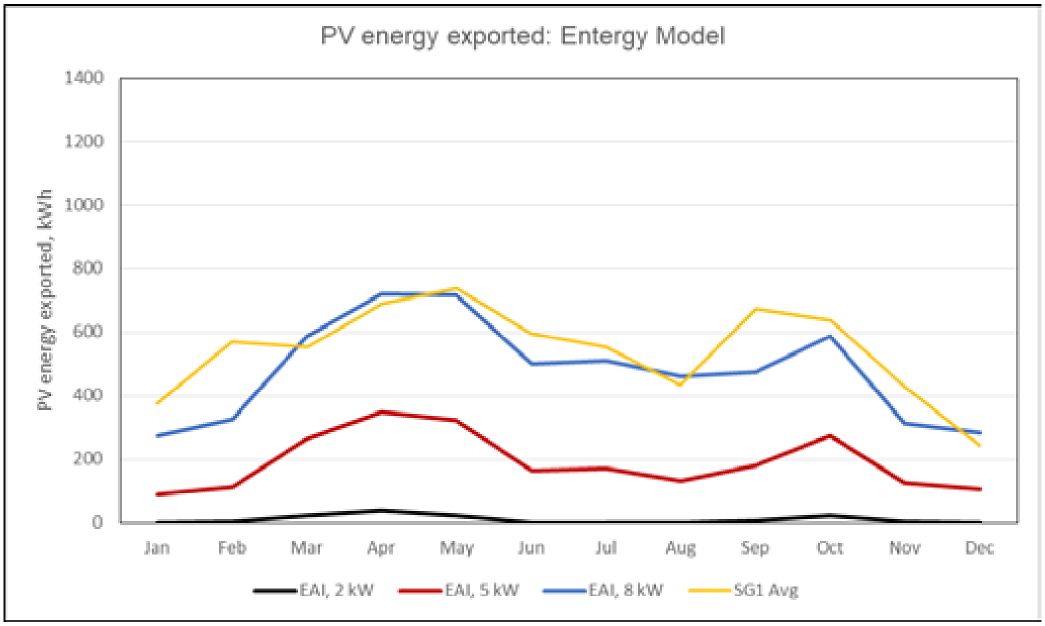
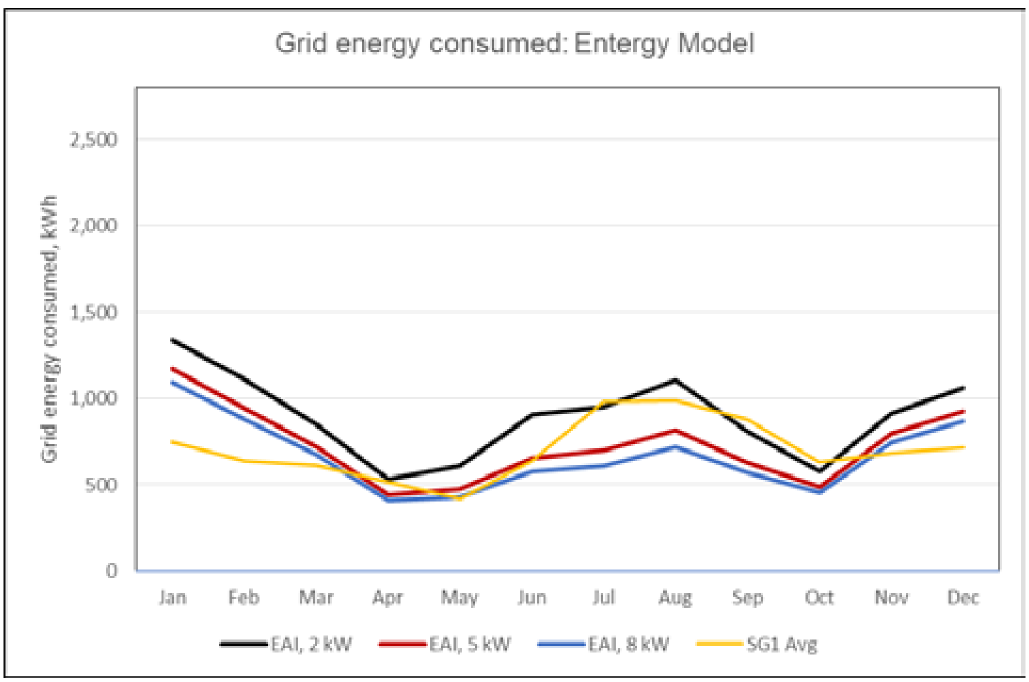


Fig 6. Sub-Group 1 and Sub-Group 2 export models



Sub-Group 2 states that these figures demonstrate that despite the small sample size, the average energy consumed and energy exported by Sub-Group 1's five customers is comparable to the "average" customers modeled by Sub-Group 2. Thus, Sub-Group 2 argues, rather than refuting Sub-Group 2's methodology, the individual customer data provides support that Sub-Group 2's customer is representative of the average net-metering customer. *Id*. at 37.

T. Further Study of Net Metering. With respect to Sub-Group 1's request that the Commission order a more thorough investigation of the costs and benefits of net metering through a third party and, pending the results of that study, leave the current net-metering mechanism in place, Sub-Group 2 responds that further third-party study is not necessary since a data-driven, evidence-based review of the existing COS studies reveals that the current practice of crediting excess generation kWh exported from the net-metering customers to the grid fails to comply with the requirements of AREDA and must change. Sub-Group 2 asserts that it has presented analyses, data, and evidence which demonstrate that its recommended 2-Channel Billing approach complies with the goals and requirements of AREDA. Sub-Group 2 asserts that its recommendation establishes rates for net-metering that recover the costs of serving the net-metering customers with both the costs and benefits measured through COS studies. Sub-Group 2 states that this approach is consistent with AREDA and with established ratemaking procedures and policies. Sub-Group 2 concludes with the assertion that Sub-Group 1's proposed Value of Solar approach is not consistent with either AREDA or established ratemaking procedures and policies and should not be used for any purpose in this proceeding. *Id*. at 38.

U. Pulaski County Recommendations. Sub-Group 2 responds to Pulaski County's recommendation that the Commission "should do nothing,"[39] but if the

[39] Pulaski County, Arkansas's Reply Comments at 3.

Commission felt compelled to do something it should follow Pulaski County's recommendation to set a threshold of net-metering penetration to gather enough data at which point the docket could be reopened and a neutral facilitator retained to study the matter. Sub-Group 2 argues that Pulaski County's suggestion ignores the statutory mandate to the Commission, which requires that the Commission establish rates for net metering that recover the costs of serving net-metering customers net of any quantifiable benefits. Sub-Group 2 asserts that the current practice fails to meet that requirement and must change to reflect the current statute and argues that AREDA does not include any provision for the Commission to establish some sort of threshold and delay action until that threshold is met. *Id*. at 38-39.

V. William Ball's Recommendations. Mr. Ball argues that the "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"[40] and thus only three areas of cost to a utility are worth weighing against benefits: a one-time cost to process a Net-Metering application; a one-time cost to verify the operation of the Net-Metering facility; and "possibly" administrative costs associated with billing. Sub-Group 2 repeats its opening comments in Sur-Surreply that this docket was established to "gather information to be used to determine appropriate rates, terms, and conditions under Act 827 of 2015 ("Act 827") for net-metering contracts, including any changes necessary to the Commission's NMRs. Sub-Group 2 asserts that Mr. Ball's proposal fails to encompass the electric utility's costs to serve the net-metering [customer], but notes that additional costs, such as those

[40] William Ball, pro se, at 1 (unnumbered).

described by Mr. Ball, are contemplated by the statute and may become relevant in the future in some other docket, but they are not relevant in this docket. *Id*. at 39.

Sub-Group 2 appends Attachments A, B, and C to its Sur-Surreply Comments as rebuttal to Sub-Group 1's Attachment A to its Reply Comments. Attachment A reproduces and responds in detail to Sub-Group 1's tables showing monthly bill savings for residential net-metering customers. Sub-Group 2 argues that Sub-Group 1's "flawed" COS approach cannot be applied to all customers, given that it would require a customized Channel 1 rate for each individual customer. Given that adjustments to Channel 1 rates cannot be individualized for every possible net-metering system, and setting aside the question of whether this would result in discriminatory rates, Sub-Group 2 argues that it is impractical from a ratemaking perspective to engage in such an analysis, since rates are designed for classes of customers, not individual customers. Sub-Group 2 further asserts that its 2-Channel Billing approach is simple to understand and can be applied universally to all utilities in Arkansas with bill impacts consistent from utility to utility. By contrast, Sub-Group 2 states, Sub-Group 1's analysis is significantly more complicated, makes assumptions that are not in accordance with longstanding COS principles, and has bill impacts that do not remain consistent from utility to utility. *Id*. at 43-45.

Sub-Group 2's Attachment B purports to show examples from more than a dozen states that have approved net-metering crediting mechanisms where either 100 percent of the energy generated by a net-metering system is credited at a different value than the full retail rate (*i.e.*, buy-all/sell-all arrangements) or only excess energy that is exported to the grid net of behind-the-meter usage is credited at a different value than the full retail rate (*i.e.*, 2-Channel Billing, or net billing). *Id*. at 46-49.

Sub-Group 2's Attachment C responds to Sub-Group 1's development of tables showing an ANEC amount that is paid by each of the five actual customers provided by Sub-Group 1 using both the current 1:1 full retail rate credit and Sub-Group 2's proposed 2-Channel Billing.[41] Sub-Group 2 notes that Sub-Group 1's analysis analyzes the annual percent increase in bills in support of its argument, while Sub-Group 2's analysis looks at the average monthly dollar increase in bills compared to the current net-metering rates.

12. Oral Testimony at Public Hearing

During the first day of the public evidentiary hearing, on November 30, 2017, all of the parties waived cross-examination of the witnesses presented by William Ball, Pulaski County, and the Sub-Group 1 parties. Accordingly, the only questioning of these witnesses was conducted by the Commission. The following is a summary of the oral testimony of these witnesses.

a. William Ball, pro se

The Commission cited Mr. Ball's comments (Joint Report at 311) recommending that the Commission look at remedies being adopted by other states, and that if the Commission does approve any additional cost, it should wait until there has been a full study and perhaps phase-in any new rates relative to the growth of net metering. Transcript Vol. 1[42] (T.) 610-11. When asked whether he had in mind any particular state that he thinks "gets it right in striking the right balance" and that the Commission should emulate, Mr. Ball responds that when one looks at the other states and what they have done, one sees that both sides are winning. Some states and local governments, like the city of Austin, Texas, actually did an evaluation and found that energy produced from solar

[41] Sub-Group 1 Reply Comments at 47.
[42] Transcript of portion of hearing held November 30, 2017.

net metering was worth more than the retail rate. Other states, like Nevada, found contrary to that, Mr. Ball states, and did something that was "quite onerous" from the perspective of pro-renewable energy development, and they had to come back and change that. He notes that they eventually grandfathered 32,000 installations that they had not done so on the front end. T. 611-12.

Mr. Ball testifies that Arizona took four years to come up with a satisfactory result, which he states somewhat emulates what he has tried to get passed through the Arkansas General Assembly since 2009, which was a law that would essentially monetize or give the ability to monetize production from solar and let utilities buy that power. By doing that, he asserts, the utilities would own the renewable energy credits and would be able to be reimbursed for it as a fuel adjustment charge because they are actually buying that energy. Mr. Ball cites as an example a poultry farmer that, under net metering, decides to produce his 5,000 kWh per month with solar, causing the utility to lose that sale and simply charge the customer a customer service charge. Whereas, if a process similar to that in Arizona were employed, the farmer would produce 5,000 kWh/month on a separate meter, which the utility would buy at a fair market value. The farmer would still buy his 5,000 kWh on his consumption meter and be repaid for his investment. The utility would retain the renewable energy credit (REC) and be able to recoup its purchase cost. Mr. Ball states that Arizona found that net-metering generation is worth about 12 cents per kWh. T. 612-14.

When pressed whether he believes there is enough data or penetration of solar to do a study in Arkansas, Mr. Ball states that he does not, citing as a contrasting example Louisiana, which has 25,000 solar systems and noting that Louisiana took Arkansas's net-metering statute and substituted Louisiana for Arkansas, but also embraced renewables by adopting a 50 percent income tax credit. T. 614.

In response to a Commission question regarding the Little Rock Port Authority and a project Mr. Ball is participating in, Mr. Ball acknowledges that the commercial and industrial (C&I) customers in that project pay a demand charge and states that he had suggested in the NMWG meetings that there be consideration of changing from a volumetric approach to a demand approach for residential customers. He states that he thought he got some consensus from the utilities that the way net metering was originally set up it did not envision what the impacts would be. Whereas, he notes, for C&I customers, they are paying their fair share of the grid through their demand charge. Mr. Ball testifies that he believes that Walmart agrees with him, thinking that commercial customers would not necessarily be negatively affected because they already pay a demand charge and are thereby already paying their fair share of supporting the grid. T. 615-17.

Responding to a Commission question regarding whether there is or should be a silo around solar through net metering, whereas it is not the only distributed energy technology, Mr. Ball states that the Distributed Energy Resources (DER) proceeding in Docket No. 16-028-U is going to be a "tough docket." He asserts that there is less experience with wind, biofuel, and other potential DERs than there is with solar and thus may require more direction from the legislature on how to proceed with distributed generation. Mr. Ball cites examples of utility-scale wind or solar projects that, under state law, allow utilities to make the investment through a power purchase agreement (PPA) and to get a "special dispensation" to increase what they charge from that investment, but points out the unfairness of customers in all classes investing their capital in solar not having the same liberty to enter into PPAs and get a more fair market price for the energy they produce. The only recourse for most of those customers, he states, is net metering. T. 618-19.

Mr. Ball responds to a question about how storage will work under the existing net metering law, stating that if there is a decision that would seriously negatively impact net-metering customers, there will be a lot more storage, since the customer will be incentivized to keep all of his/her consumption behind the meter and not export anything. Customers will store energy in their batteries and when the sun goes down draw from them and use their own power and self-consume. He cites Hawaii as an example of a state that reached 20 percent of solar penetration and could not distribute or dispatch the amounts of solar energy being produced during the middle of the day. He states that Hawaii thus did away with net metering and went to battery-based self-consumption. Mr. Ball states that he has been approached by utilities to evaluate storage so that during the day when solar is making energy, there is nothing put on the grid until after 5 o'clock p.m. when solar can be used to keep the peak demand down. Mr. Ball opines that storage and other technologies are in their infancy regarding services they will be able to supply and urges continued support for net metering to be able to capture these additional benefits. T. 620-21.

Mr. Ball responded to Commission questioning regarding how distributed energy resource alternatives can be consider in the integrated resource planning (IRP) process, so that one can figure out which is the best value for customers going forward, stating his concern that utilities have not considered the possible exponential growth of electric vehicles (EVs) in their IRPs. He advances the possibility that EVs may produce so much growth in demand on the electrical infrastructure that "we're going to be begging for more solar." Mr. Ball agreed that since one can't predict the future, there is a need for a policy that can accommodate a fairly wide range of technologies without having to go back and do "do-overs" like was done in Nevada. He concludes with the recommendation that the best move is to go slowly and make adjustments as conditions change. T. 623-24.

b. Adam Fogleman, Pulaski County

Mr. Fogleman, attorney for Pulaski County, responded to Commission questions, acknowledging that if the Commission were to agree with Pulaski County that a wait-and-see approach should be taken until there has been enough solar penetration in the state to justify a study, that approach would provide certainty for net-metering customers up to that level of penetration, but would carry with it a degree of uncertainty. Mr. Fogleman adds that the Commission needs to make rules that are durable and ask whether adopting a rule that may last for five years would be sufficiently durable, considering the rate of solar implementation and saturation. He questions whether there has been adequate evidence presented to demonstrate a net cost shifting to the utility, given the current level of penetration. He suggests that if the Commission does nothing now and at some future point a sufficient saturation level is reached, it would be appropriate to grandfather people from the reopening of a docket until a new rule is adopted. That approach, he opines, would permit net-metering customers to be able to take advantage of a stable policy structure that allows them to project into the future in order to make sound investments. T. 626-30.

Mr. Fogleman expresses a concern that a non-residential customer currently operating under a tariff with a demand charge should not be excluded from the possibility of shifting its usage to a rate class with a lower demand charge and a higher volumetric rate and thereby being able to reduce their cost by agreeing to net metering under a higher volumetric rate. With respect to demand response, storage, and other DER, and how to make the net-metering rules consistent with what the Commission may do in Docket No. 16-028-U, he states that it would depend on what rules the Commission adopts in that docket or what the legislature may do in the future. T. 631-33.

At the conclusion of Mr. Fogleman's testimony, Mr. Ball voiced the opinion that for purposes of determining saturation levels of solar, it does not matter whether the resource is utility-scale or residential, adding that in Arkansas, about 2,500 MW of nameplate solar capacity will equate to around 20 percent saturation. T. 633-34.

c. Thomas Beach, Crossborder Entergy, for Sub-Group 1

Mr. Beach is the author of *The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc.* (the Crossborder Study), Attachment A1 to the Joint Report of the NMWG; the supplemental COS analysis, Attachment A to Sub-Group 1's Reply Comments; and a response to the critiques leveled by Sub-Group 2 to his cost-benefit analysis, Attachment A to Sub-Group 1's Surreply Comments. He responds to Commission questions regarding these analyses, which were submitted on behalf of the Sierra Club and Sub-Group 1. T. 635-36.

Mr. Beach testifies that the NMWG did not reach agreement among the group as a whole to do a comprehensive study, but that the Crossborder Study of EAL was done for Sub-Group 1. He states that the study that was done was good, given the data that was available, although it is probably not as accurate as it could have been with better data. Mr. Beach states that when assessing penetration levels, one can look at either the number of net-metering customers or the amount of megawatts of solar. He cites Hawaii as an example of a state that has high penetrations of solar, approaching 20 percent of customers, making it very clear that they needed to move away from net metering because they were starting to have problems on their distribution circuits with too much solar in the middle of the day. T. 638-41.

In response to Commission questioning, Mr. Beach explains how California undertook to evaluate the economics of net metering and its effects on participating and non-participating ratepayers in a 50,000 MW system that has just less than 5,000 MW of solar – approximately 10 percent penetration based on nameplate capacity of distributed generation as a percentage of peak demand. He states that California, using a consultant, developed and made public a tool that employs all of the tests that Crossborder did for its Arkansas study. He notes that the parties to the proceeding, called Net Metering 1.0, submitted comments and results regarding whether there was or wasn't a cost shift, using that template of the public tool. He states that, in the end, California made some small changes to its net metering rates, which have an export rate that is slightly lower than the regular retail rate. California is now in Net Metering 2.0 and will continue on that path for several years and may look at it again in 2019. T. 642-44.

Mr. Beach provides Arizona as an example of another state with a large system and about 5 percent penetration of solar and opines that the importance of the penetration level is a matter of both the importance of having a good amount of data to use and of considering whether there is more than a *de minimis* impact on non-participating ratepayers. He states that when the penetration level gets to the 5 percent customer level, where solar starts to have an effect on the system, one starts to see lower prices in the middle of the day and "duck curve" issues, with sharper ramping needs in the evening when the sun goes down. T. 644-45.

Mr. Beach was questioned by the Commission regarding Sub-Group 1's assertion in Attachment A to its Reply Comments (p. 31-41 of the White Paper) that there is a lesser cost to serve net-metering costs, as contradicted by Sub-Group 2's response in its Surreply that net-metering customers' infrastructure requirements for electric service are not different from those of other customers and that the utility has the same obligation to serve them. He was also asked to respond to Sub-Group 2's assertion that Sub-Group 1's approach would lead to a new base rate for EAL on Channel 1 and would, in fact, perhaps require a customized Channel 1 rate for each net-metering customers. Mr. Beach responds that Sub-Group 1 is not advocating for a different rate on Channel 1, noting that Sub-Group 1 does not agree with Sub-Group 2's COS analysis, which he notes was directed only at revising the export rate. He testifies that Sub-Group 2 did not apply their own COS analysis to the Channel 1 usage. He explains that when a customer installs solar, it changes the profile of the service they take from the utility, and the Channel 1 usage of a solar customer is quite different than the usage of a regular customer. Mr. Beach further explains that while Sub-Group 1 is not advocating for a separate rate class for solar customers or a lower rate on Channel 1, it is pointing out that Sub-Group 2 forgot to take into account that analysis of Channel 1 usage shows that solar customers are actually less expensive to serve than regular customers. If a net-metering customer is going to continue to pay the same rate under Channel 1, Mr. Beach states, there is actually a subsidy going the other direction, with solar customers subsidizing regular customers. T. 646-48.

Asked by the Commission why a separate rate for net-metering customers would be bad, Mr. Beach responds that the great virtue of net-metering is its simplicity and that customers understand that it means running your meter backwards and feel that it is fair to solar customers. T. 648-49.

Mr. Beach acknowledges that one could look at 2-Channel Billing as consisting of three buckets: Channel 1, in which electric service from the utility is paid for at the regular retail rate; a "neutral" one-for-one bucket of energy produced from the customer's solar panel for instantaneous use on-site and which effectively offsets the retail rate; and a third exported power bucket compensated at the retail rate, which Sub-Group 2 contends is getting too much credit and undercutting costs in the first bucket. Mr. Beach responds, however, that Sub-Group 1 contends that when one puts solar panels on a house, part of the power stays on-site and is used to offset load. The net effect of that, he argues, is that you reduce the amount of power that you have to take from the utility, which Sub-Group 1's analysis shows turns that solar customer into one that is less expensive to serve. He reiterates that Sub-Group 2 did not take that into account. T.t 649-51.

In response to Commission questioning regarding the differences between a net-metering customer and a customer that reduces its load and energy consumption through implementation of energy efficiency, Mr. Beach explains that a customer with solar can produce up to 100 percent of his usage using solar and thereby provide benefits to the utility, which is more than one can do with an energy efficient appliance or measure. He asserts that Sub-Group 2 wants to cut the export rate in half, which is unfair to the solar customer that is providing benefits to the utility. In short, he argues, the net-metering customer would be taking a big cut on Channel 2, but the benefits the customer is providing on Channel 1 are not being taken into account. T. 651-52.

On the subject of the benefits side of the equation, the Commission asked which of the largest direct, quantifiable benefits of avoided energy, avoided generation, capacity, avoided transmission, avoided distribution, and avoided line losses does Sub-Group 1 assert are not being fairly credited by Sub-Group 2. Mr. Beach responds that the biggest difference would probably be avoided transmission and distribution costs. He also notes that Sub-Group 1 did a long-term analysis that goes over the life of a distributed generation system rather than just a single-year analysis. That approach, he states, results in energy benefits being somewhat higher because Sub-Group 1 considers the fact that energy prices are going to escalate over time. T. 653-54.

Mr. Beach discusses Sub-Group 1's expanded set of benefits, some of which are quantifiable and others which are not. He cites reduction of fuel price volatility as quantifiable and acknowledges the difficulty of quantifying reliability and resiliency and the fact that solar cannot provide backup power. On the other hand, he cites solar as a foundational element for a microgrid, which with batteries becoming more economic, could provide a backup system to enhance reliability and resiliency. T. 654-56.

Mr. Beach testifies that "cost of service" is a "trick term," and describes Sub-Group 1's analysis as a COS analysis that looks at the COS over 25 years, not just over a single test year. Sub-Group 1 looks at how the utility's costs going forward will be reduced by distributed generation, he states, noting that those are costs that would otherwise land in the COS. T. 656.

Mr. Beach expresses unfamiliarity with the Entergy Mississippi "adder" for unquantifiable benefits and the state's taking a pause to do a study, but he acknowledges that some states have adopted a similar adder in the energy efficiency context when societal and non-energy benefits are difficult to quantify. T. 657.

Mr. Beach explains the meaning of "intermonth netting" as netting imports and exports of energy on a time scale between instantaneous and monthly, depending on meter capabilities. T. 657-60. He also discusses Sub-Group 1's suggestion that the Commission initiate a process that encourages utilities to study their distribution system 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. He cites New York and California as states that are starting to make a serious effort to guide the deployment of DERs to parts of the grid where they produce the most benefits. T. 660-663.

Mr. Beach elaborates on Sub-Group 1's failure to advocate changing the Channel 1 rate to recognize the benefits provided by the net-metering customer, stating a preference to keep things simple for the customer and thus to keep the export rate and the import rate the same. In short, he said, Channel 1 balances out Channel 2. He also expresses support for implementing pilot programs to get more data on net metering, citing the example of Xcel Energy in Colorado, which is implementing Advance Meter Infrastructure (AMI) infrastructure and piloting time-of-use rates of various kinds in order to increase the accuracy of the rate design and send better price signals to customers. He states that these kinds of initiatives would be important steps before making changes to net metering. T. 664-65.

In response to Commission questions concerning the Crossborder Study, Mr. Beach testifies that there is no projection in the Study of how many net-metering customers there will be in the future. Instead, he states, the Study looks at the costs and benefits for a customer who installs the distributed generation study today, because that system will be around for 25 years. For example, he explains, it is known that the system will avoid the utility having to produce energy in one of its power plants, so the Study did a 25-year projection of what that avoided energy cost would be for the solar panel that's being installed today. He states that the Study looks at marginal costs – the kilowatt-hour produced from a solar panel that's installed today will turn down a power plant and save the marginal kWh for the next 25 years. The Study forecasts what the cost of that is by looking at what the gas price forecast is over time. T. 665-66.

For avoided generation and transmission capacity, Mr. Beach states that the Study looks at a levelized cost of capacity. For example, he explains, you assume that if you're providing a kilowatt of capacity from a solar panel, that will avoid having to put in a kilowatt of a combustion turbine, and you calculate what the levelized cost of that combustion turbine is over the 25 years. The same is done for transmission and distribution, he states: what does installing a kilowatt of solar do to reduce the future investment of T & D that results from that savings of a kilowatt? T. 667-68.

Mr. Beach disagrees with Sub-Group 2's claim that these benefits will materialize over time, arguing that these are costs that the utility will never have to incur – they are avoided costs. He adds that the costs that will show up over time are actually lower, whereas if you just continue to do a set of COS studies the way Sub-Group 2 recommends, you will be significantly undervaluing the solar resource. In response to questions regarding whether the Sub-Group 1 study should have conducted a projected future or an after-the-fact re-dispatch to calculate the marginal value of a missing generation unit, Mr. Beach cites California's 5 gigawatts of solar and expresses concern that trying to reconstruct what a system would have been without those resources is going to be pretty speculative. He suggests that it is better to do it the way Sub-Group 1 did, where one is looking at what is the value of just what you're installing this year. He states that this is exactly the same analysis that one does with energy efficiency programs. He testifies that the benefits are not sunk costs, but are future costs that you are not going to have to spend. Mr. Beach acknowledges that trying to project the benefits and costs over a long period of time with any long-lived resource requires a forecast of fuel prices and other things and presents challenges. He states that one needs to look at sensitivities and key input assumptions, but notes that is the way one does planning. T. 669-73.

Mr. Beach responds to Commission questioning regarding the challenges of getting to a glide path from a 2-Channel Bill approach to a market system, where a demand charge becomes the basis of a capacity cost and the energy is the energy cost, and that's how it gets compensated. He recommends that the Commission work on metering infrastructure and rate design such as TOU rates, even demand charges (though he is not a fan), while letting the solar market in Arkansas grow beyond its fairly small stage today. He also recommends watching what other states with higher solar penetrations do with their net-metering programs and rate experiments and acting on information you will get when you reach 5 percent of customers. T. 673-75.

With respect to demand charges that assertedly give one a price to beat to determine whether to deploy storage, Mr. Beach expresses concerns that such charges are often inaccurate. For example, he states, a demand charge covering transmission costs driven by demand between the hours of 3:00 p.m. and 7:00 p.m., actually applies charges to a customer's highest demand 24 hours a day – which might occur at noon and thus not be a driver of transmission costs. This, he says, causes the customer to pay a very large bill that month – a nonsensical result. With a demand charge like that, he notes, storage ends up discharging in the morning or at noon, when it's not really beneficial to the system. T. 676-77.

Mr. Beach testifies that one of the issues Sub-Group 1 has with the Sub-Group 2 proposal is that they have designed an export rate based on solar alone, while there are a lot of DER technologies such as batteries, EVs, smart thermostats, etc. that would be better accommodated by a whole proliferation of different rate schedules for different kinds of technologies. He asserts that it is better to work on overall rate design and get price signals right across all the hours of the day. T. 677-78.

With respect to duck curve issues, Mr. Beach testifies that the most important driver is whether you have so much solar on your grid that it's changing the fundamental economics of the system. In California, he notes, there are now very low prices in the middle of the day and fundamental changes in load profiles. When that occurs, he states, that is the time to take another look at the economics of net metering, but it takes quite a bit of solar for that to happen. T. 679-681.

<u>d. Katie Niebaum, AAEA</u>

Ms. Niebaum testifies in support of continuing the current net-metering policy, stating that Arkansas is an example of a state that is "getting it right" and allowing the growth of the solar industry, with associated job growth. She states that both the reduced export rate and a departure from the simplicity of the full retail rate would chill this growth. She states that the Sub-Group 2 approach is overly complex and would require a solar provider to electrically meter-log a client's residence for a full year to get an accurate picture of what a customer's usage is before proposing and installing an array. These complexities would dampen and stifle deployment and growth, she notes. She acknowledges, however, that moving toward a market-based world so as to integrate all of these technologies is going to take some complexity, and expressed the opinion that it is a goal AAEA shares. T. 682-86.

e. Bill Halter, Scenic Hill Solar

Mr. Halter responds to Commission questions regarding whether an additional study should be conducted and whether there is a subsidy being provided by non-net-metering customers, including low-income customers. He states that Sub-Group 1 from the beginning of the NMWG felt that a study was the best way to get to a more precise answer. Second, he states, there is not enough data to do everything that is asked in the law, because the law asks that this be done utility by utility. The constraint there, he notes, is that some utilities have only a handful of net-metering customers, with little data. Mr. Halter cites the experience gained in other states and asserts that, directionally, the Arkansas-specific answers are unlikely to differ dramatically. Accordingly, he states, one can get some useful information from comprehensive studies that have been done in other states. He expresses the belief that there are less than a thousand net-metering residential customers in Arkansas. With this assumption, and assuming that the average utility bill is $70 per month or $840 per year, there would be $840,000 of total billings to those customers. He suggests that the cross-subsidization of that $840,000 would amount to "a hill of beans." Acknowledging a Surreply estimate in the record of a $60,000 cross-subsidy, Mr. Halter urges the use of common sense and asserts that ratepayers are already paying for more than that in legal fees to deal with the NMWG (perhaps racking up that much in one meeting of the Group). He asserts that Arkansas is not far enough along to be doing a lot of radical surgery on net metering. T. 688-94.

Mr. Halter asserts that a residential customer that is considering solar is faced with at least a $10,000 expense and the need for the solar provider to project what that is going to save in electricity bills over 25-30 years, plus consideration of the federal tax credit, and the need for financing. He states that this is already a tough decision that is information-constrained since the customer doesn't know what's going to happen with energy prices down the road and other unknown variables that could change. He acknowledges that the Commission's job is to make sure that the regulatory environment gives as much certainty as possible. With 2-Channel Billing, he states, all of a sudden the confusion and risk for the customer is suddenly ramped up because the payment to the customer varies over time. T. 695-67.

With respect to the asserted cross-subsidy by non-net-metering customers, Mr. Halter contends that the Sub-Group 1 study shows that the subsidy is going the other way. He suggests that with 2-Channel Billing, it borders on impossible for the customer to predict how much energy is going to fall into the excess channel, or what the specificity of its timing is. On top of that complexity, he notes, Sub-Group 2's proposal will change the prices for the customer year-by-year, which leaves the customer no way to accurately predict what he's going to save over time. Finally, he notes, if the customer can't predict it, the bank is not going to finance it, and thus he contends that 2-Channel Billing will deal a mortal death blow to residential solar. T. 698-701.

Mr. Halter testifies that a residential solar system producing excess energy is likely producing more excess energy when the value of that electricity is higher, namely at peak. He cites as an example the large commercial facility his company is installing for Clarksville Light & Water, which provides power during daylight hours on peak. Thus, Clarksville's system is providing not just energy savings, but demand charge savings for that municipality, as well as reductions in transmission charges that they face. He asserts that what Scenic Hill is doing for a municipal utility on a commercial basis a lot of residential solar systems collectively would be doing for the utility in their service territory – providing a benefit. T. 701-03.

With respect to utility assets that are "on the books" and must still be paid for, Mr. Halter notes that there are generating assets in the system that are going to be shut down. A better thing to do, he states, is to allow the private sector to provide incentives to deploy solar to replace the generation capacity from those assets that are going to be taken off the system. Using private sector capital to do it, he notes, means that the developers don't get a guaranteed return on their investment. He states that market incentive works pretty well for such developers – if they don't do it right, they're out of business. T. 703.

In response to a Commission question regarding how to get to a future in which private solar projects that are not dispatchable can be taken account of in a system where utilities have an obligation to stand ready to serve everyone 24/7, Mr. Halter states that utilities size their generation assets to address peak load, which is when private solar plants are helping shave that peak load. He adds that, while Arkansas does not have a duck curve problem, by the time that phenomenon might occur, there will be storage technology that eliminates the duck curve. Wind energy will be imported at night, stored in batteries, and dispatched as electricity during the day, he states. He states that he does not foresee doing without regulated utilities, but notes that other places have used private sector generating assets to help solve some of these problems. T. 703-05.

Mr. Halter extols the power of competition, the power of the free market to allocate resources appropriately, and the long-term desire of citizens for as much consumer choice as possible. He urges the Commission to address these three things in a way that helps, not harms, the system. T. 705-06. While noting that tracking systems address the declining value of the last hour of solar generation, he acknowledges the dilemma pointed out by the Commission: that while solar is highly correlated with peak and the time of day, the Arkansas statute says we can't differentiate that power or the value of those hours because we have got to trade kWh for kWh instead of value kWh for kWh, which makes it complicated to capture that value. T. 706-08.

In a discussion regarding fuel price volatility, Mr. Halter asserts that unpredictable shifts in the price of natural gas make the case for installing as much solar power as possible, noting that he can tell you to one one-thousandth of a penny what you're going to pay for solar power 30 years from now if you put in a plant today. He states that you have completely hedged fuel price volatility the more solar you deploy. On the other hand, he notes, if gas prices go down, gas customers will be celebrating, natural gas companies are happier, and solar providers are still happy. In short, he says, everybody is happier than in the alternative state of the universe where we didn't have enough fuel price hedges in place. He asserts this is an additional value of solar that needs to be put in the model. T. 708-14.

Mr. Halter agrees with the assertion that it is preferable to gradually move to a market run by individuals with different views about prices rather than a regulatory decision on what prices are going to be and urges the Commission to let that market work. With respect to that market, Mr. Halter asserts that there are two major sources of market inefficiency when it comes to renewable assets: (1) an uncertain information set, which is made worse by a 2-Channel Billing; and (2) a financing problem, which 2-Channel Billing also makes worse. He urges solving for market issues. T. 714.

Mr. Halter cites the positive health and economic development externalities of installing wind and solar, including his company's employment of 112 people and expenditure of $10 million into Clarksville, a town of 12,000 people. He asserts that deploying 800 MW of solar in Arkansas to replace one of the coal plants that will be going offline would be an investment of at least one billion dollars and thousands of people working, spreading a local tax base all over the state, and notes that these benefits are all referenced in AREDA. He notes the NMWG focus on 6 to 12 words that were inserted into the latest amendment of AREDA, and the lack of focus on the whole law and the legislative preamble, which has not changed and from which he quotes, citing benefits of net metering and pointing out that 2-Channel Billing hurts every one of the benefits and purposes set forth in the statute. T. 715-18.

Mr. Halter advocates letting the market work to establish value for the replacement of a coal plant in 2028, noting that if people like him who are developing solar misinterpret the value, they go broke and smarter people figure it out. He asserts that the killer combination is on the horizon – solar and storage and wind and storage. He posits that these technologies are going to result in Arkansas not needing to face some of the issues that early adopters of solar faced with the duck curve. He agrees with the value of phasing in to a market structure, but expresses concerns that dealing with the issues of getting these technologies deployed is about a lot more than just having the perfect theoretical rate structure. In the real world, he states, customers making these decisions have to have market breakdowns fixed. The information and financing breakdowns, he notes, are exacerbated by the 2-Channel Billing approach, which kills the market he agrees needs to prosper. T. 718-724.

Mr. Halter testifies that if the mechanism that his company was billing Clarksville was 2-Channel Billing, it would never have been financed. The financing was possible, he states, because of the certainty that Clarksville pays a pre-determined rate for the power. He states that bankers can put that in their spreadsheet, figure it out, account for weather risk, and adjust for technology risk, although it is still a hard financial decision. He applauds the Commission for having adopted grandfathering for 20 years in Phase 1 of this docket, noting that it provides certainty that can be financed. He asserts that no banker will finance a project where the price the customer is getting for solar power they generate varies every year. T. 724-25.

Mr. Halter acknowledges that solar providers are not getting long-term guaranteed contracts in California and Hawaii, but responds that they are getting the ability to offset what they were paying the utility for electricity. He notes that if you know that your solar power plant is going to be able to do that in a 7-, 8-, or 9-year period and your asset has a 30-year life and you can use third-party financing and third-party ownership (something *verboten* in Arkansas), you can make it go. Mr. Halter concludes his testimony with a brief discussion of his company's possible eventual filing of a proposal to address the prohibition against leasing and third-party financing. T. 726-28.

f. Pat Costner, pro se

Ms. Costner responds to Commission concerning her experience as a 3.3 kW solar-plus-storage customer of Carroll Electric Cooperative Corporation since 2005. She provides Attachment B to Sub-Group 1's Reply Comments, which contain data and analysis that illustrate the different impacts that 2-Channel Billing would have on her residential net-metering account. She states that her bill is almost always $12.61 per month, comprising just over $10 for the monthly customer charge and $2 in taxes. She states that Attachment B shows what she is paying every year for electrons alone -- $0 for electricity under one-to-one retail net metering. According to her calculations, she says, under 2-Channel Billing she would pay $48.54 per year. She states that she has invested $35,000 in her system, for which, when she started it in 2005, the cost was $10 per watt; she believes the cost is now down to $3.85 per watt on a national basis. She notes that Carroll Electric Cooperative Corporation has been very cooperative over the years, although they have had difficulty getting the billing right from an accounting perspective, and observes that 2-Channel Billing would be more of a challenge for them. T. 730-736.

Ms. Costner provides in her Attachment B an analysis of the bills under both billing approaches for four of her neighbors' systems, each of which have larger systems than hers and none of which have storage. The results are as follows: Customer PB2, with a 9.8 kW system, had an annual energy bill of $147, which would go up to $528.93 under 2-Channel Billing, an increase of 258 percent. Customer PB3, with an 8 kW system, would go from

$661.20 to $815, and increase of 23 percent. Customer PB4, a 6 kW system, essentially offsetting all their usage, has a zero bill for energy under current net metering and a $200 bill under 2-Channel Billing. And Customer PB5, a 10.8 kW system, pays $11 under net metering and $511 under 2-Channel Billing, a 359 percent increase. T. 736.

Ms. Costner concludes from her analysis that the larger the solar system, the longer the payback period. She does not agree that this is just because those larger systems tend to export more to the grid, but thinks the 2-Channel Billing system disincentivizes people to discourage them from building a system that is going to be closer to getting them their maximum offset. However, when questioned further she does agree that it makes sense that the larger systems, having a larger quantity of export, and that the export is reduced more under 2-Channel than the current one-for-one approach, and thus the more export you have, the more impact. T. 736-40.

Ms. Costner testifies that records show there are 632 net-metering customers at the end of 2016, as compared to about 495 at the end of 2015. The 2016 numbers thus amount to 0.045 percent of the ratepayers, which, she says, under a trend line would lead to about 1200 customers in ten years. She cites to the public comment testimony of one of her neighbors as saying that if he had been looking at installing a system under 2-Channel Billing, he would not have gone forward with it. She states her belief that this will be the case for most people – 2-Channel Billing discourages people from investing in solar. T. 740-41.

Ms. Costner addresses the subject of pilot studies and opines that focusing on more systems in a smaller area, such as Carroll Electric, might make for easier access and data retrieval than with a larger system in a larger area, like Entergy's. Ms. Costner describes her battery system, which enables her to flip a switch when the grid goes down. She notes that none of her neighbors have battery storage. T. 742-44.

g. Karl Rabago, Sub-Group 1

The Commission questioned Mr. Rabago regarding Sub-Group 2's assertion that the 2-Channel Billing approach is desirable because it tries to treat people who adopt energy efficiency the same way as net-metering customers, in that if you're offsetting your own usage instantaneously, then you're charged the same rate on Channel 1 as every other residential customer. Thus, the only thing the 2-Channel approach does is change the credit given for exported power. Asked whether the 2-Channel proposal seeks to treat everybody the same on the cost side, but maybe not on the benefits side when it comes to energy efficiency, Mr. Rabago states that at a very simplistic level, the fact that a customer reduces electricity use, however they do it, results in a reduction in what they otherwise would have paid. He explains that they could either do it by turning off the lights or by having their solar system run or discharging their battery if the grid is down. T. 744-46.

Mr. Rabago testifies that tariffs are contracts that are binding merely by acceptance by a qualified offerer and, because utilities have immense market power, we only pay for what we use, and don't pay for what we don't use. He says that is embedded in net metering and is reflected in the fact that if you don't use some electricity because of energy efficiency, or self-generation, it nets out. Thus, he agrees that it is different as to the exports, but it's not different just as to the rate. Mr. Rabago states his understanding that Arkansas has a differential rate for excess generation, but notes that what is different is the netting period. He observes that Arkansas's statutory definition of net metering is the same as the PURPA statutory definition, which is netting within the billing period. This, he explains, goes to some log-time that looks like instantaneous or very close to it, as opposed to allowing you to net on the monthly basis against your total gross consumption against your gross production. That, he says, is even more important than the export rate. T. 746-47.

As to the compensation rate for exports, Mr. Rabago says there is a difference between EE and net metering because you don't export from EE – you free up electricity but you don't make some. If you make an extra kWh with a solar system, he states, it goes immediately to the closest possible load on the grid, which is a neighbor, and then it goes through their meter and gets billed as if the utility made it. T. 747-48.

With regard to valuing the excess energy credit on an embedded COS method, Mr. Rabago cites Mr. Beach's report as saying that using the embedded COS study is like trying to drive 100 miles an hour with your eyes firmly fixed on the rearview mirror: All you know is what it cost to serve during that historical test year, which is based on antique data with known and measurable adjustments for one year's worth of service, a snapshot of amortization, the current state of capital acquisitions, the capital plan included in that rate, and the operating expenses as of that year. He states that when he was a regulator it was not how he evaluated energy efficiency or any other resource. T. 748-49.

Mr. Rabago states that this is a fundamental difference in the two approaches and asks whether the utilities are proposing to treat this as a resource or are they treating it as a deviation from the expected level of revenues for an average customer in that class, which is what the embedded COS study does. He states that all the embedded COS study turned into a rate does is take those numbers, applies the forecast, and says that if I then charge this resulting rate, the resulting revenues will equal my revenue requirement. He adds that the embedded COS approach used by the utilities and Staff says that if you reduce your consumption below the level that we expected, we now have a cost: It creates costs out of failure to consume the average consumed level for your class. He acknowledges that this gets into the three buckets way of looking at it, discussed by the Commission earlier in the hearing. If Bucket 1 is net consumption, Bucket 2 is consumption that is offset, and Bucket 3 is net product, he says it is a fair question to ask whether you should still be charged the same rate per unit of consumption for when your usage pattern changes. Going back to how rate cases are done, he states, they deploy a number of sample meters, come up with a sample profile of use by customers within that class, and then classify and allocate costs according to that pattern for all those customers. Since solar customers shift their peak off the average, in general, he says, they tend to contribute less to the system peak, although they don't eliminate it. T. 749-52.

Asked if some energy efficiency programs also reduce the system peak, Mr. Rabago says yes, they do, and when asked why do we not then charge them a lesser rate, he responds that actually we do charge them a lesser rate by providing incentives to cure the market failure that fails to compensate them for bringing that value to the system. You do that with a clean conscience, he observes, because as conservative and market-oriented as you may be, you know that you can pay those incentives, not cross the cost-effectiveness barrier, and still end up doing well by all customers. Thus, he states, you're already correcting for the under-compensation for those customers, but you do it with incentives. T. 752-53.

Questioned by the Commission about using an embedded COS approach to quantify benefits, Mr. Rabago – a lawyer – testifies that he cannot imagine why Sub-Group 2 went through the contortions they did to try to put blinders on the Commission's decision-making. He opines that the approach is not supported by the plain language of the statute. He states that it strains credibility to say that you will get your reward in heaven – or whenever we do our next COS study. Mr. Rabago states that there are a bunch of benefits and that there are IRP-types of analyses for looking at the long-run life of resources. He says that utilities regularly use production cost models and look at resources that last 20 and 30 years and have ways of bringing those all back to a LCOE comparison so that one can start identifying which resources to use. He states that the embedded COS study is so far from that, that it's convenient to think of the way that Sub-Group 1 put forward Mr. Beach's report as being in the middle. He says it uses as much real data as it possibly can, but of course, so does an IRP, and it asks: If we add another kWh of electricity from this solar when it's likely to appear, what other costs will it avoid? He adds that even PURPA lists a much broader range of benefits than was used by Sub-Group 2. T. 753-55.

Mr. Rabago testifies that excess energy credit is a rate or a billing determinant, but the full rate is the net-metering rate. Clearly, he states, Sub-Group 2 proposed a 2-Channel alternative as a bundle of rate components that they propose as a rate. He notes that all commissions set rates considering a wide range of factors and are encouraged by the full language of the act to keep those issues in mind as a matter of policy. He states that commissions deviate all the time from one person's opinion about what is the right way to calculate a rate because there's a lot of subjectivity in ratemaking. He also states that he does not "get" the idea that – because somewhere rates for consumption are described in a statute that was written for the notion that the only thing customers would do is consume – that somehow in spite of very different language in a new statute, you must give no meaning or intent to the new statute and hold yourself to the unchanged language of the old statute. In short, he says he has never seen an approach that, absent an explicit mandate, says that when you set the net metering rate you should ignore the benefits that you find. T. 755-78.

On the subject of value-of-solar studies, Mr. Rabago points to Minnesota as the gold standard and Maine as another one of the best, most recent comprehensive ones, various ones of which are cited in Sub-Group 1's Appendix A to its initial comments in the Joint Report. He notes that Minnesota completed its study in six months with a third-party facilitator and hundreds of comments, plus three rounds of Commission review, plus another round of review when the utilities adopted it. He also cites to a recent working group process in Rhode Island that created a table of all the bulk and small-scale net-metering values, which was adopted by the commission. He notes that in conducting a study it would help to have thousands of customers, so you could get some real statistical meaning to how their load curves change. T. 758-61.

Mr. Rabago cautions that there are other issues to deal with in doing such studies, because to the extent that the COS studies rely on non-coincident peaks (NCP), you'll run into a situation of erasing any of the peak-shifting benefits of solar. Just looking at the Channel 1 costs of a subgroup of solar customers, pretending as if they were on an island served by one grid themselves, which is what NCP approaches do, then you'll miss the fact that they're integrated into the grid in general and they actually help improve asset utilization and improve load factor for the entire grid by shifting their peak off-peak. He states that NCP systems don't catch that, and that you need more of a focus on coincident peak. T. 761-62.

With respect to the market, Mr. Rabago shares the idea that what we're trying to do is figure out, if these customers with solar are exporting, how do we create a system in which they only export the good stuff – the stuff that's worth more, the stuff we really want -- to displace what the utility made. In his view, Mr. Rabago states, the reduction of a cost does not create a cost. What that does, he says, is demonstrate that the utility thought they were going to sell a hundred, but now they're only selling 90 and they are going to reallocate the 10 they thought they could get. He notes that some have been calling for solar for 20 years; and now that it's appearing, the utilities are saying – wait, I built this distribution system as if there'd be no solar. And so, he states, there's a question of what price signal do you want to send in the marketplace to the utility to do a good job of forecasting, and do you want to insulate them from the consequences of bad forecasting? T. 762-63.

On the point of the law requiring that utilities recover their prudently incurred costs and the question on making an exception so that the responsibility falls on the utility, not the customers, Mr. Rabago responds that it is important to take the longer view. He testifies that if you limit yourself only to those embedded costs and treat all fixed costs as sunk costs, which he says is a kind of category error, then you will ignore the fact that there is a demonstrated reduction in future fixed costs. He agrees that in the long run, all costs are variable. But, he states, you know that you will experience a reduction and have to take into account the fact that, yes, there's a 10 kWh shift now, we'll allow them to recover it, but we're balancing that using LCOE against the fact that we believe there are more avoided costs in the future. That's what we do, he says, when we look at it as a resource. T. 763-64.

Asked how can the utility plan, with distributed generation that can pop up anywhere in either ideal or not-ideal places, Mr. Rabago responds that at a very simplistic level, you need data – short-, mid-, and long-run marginal distribution capacity cost at the sub-nodal, maybe feeder level through your grid. You need the utilities to know it, he says, and to know what does the next increment of capacity or energy cost at the sub-nodal level. He urges the gathering of that data so that you can do things like New York is trying to do – come up with the locational system resource value (LSRV), saying that if this solar system ends up over here, it's worth an extra penny per kWh., but if it comes up over there, it's going to be adding to a pre-existing congestion problem and it's not worth that extra penny, it may be even worth one penny less. But, he continues, until you have that data, you won't be able to send that market signal. T. 764-65.

Mr. Rabago states that the utility has to act like a bit of a billboard for prices, which is why some in other states are talking about a platform model. He adds that the utilities have to resist the temptation to live by a mantra that they and only they should be able to generate electricity, and instead treat generation that comes from customers as a resource that could have value in the right location and at the right time. T. 765-66.

Asked how the traditional distinction between energy and capacity plays in the absence of a demand charge – *i.e.*, how can you retain that when you have two different price signals – one for capacity and one for energy, Mr. Rabago responds that he has real problems with demand charges. He notes that most utilities propose demand charges as NCP-type charges or ratchets, acting as if everybody's NCP was cumulated into the system's coincident peak. He states that the utilities need to disaggregate from that and take a first great step toward that with time-variable rates – peak-time rates or critical peak pricing – which allow you to send a market signal to lots of people. With solar customers, Mr. Rabago states his belief that the policy goal should be to maximize the benefit of the kilowatt-hour that the customer has the ability to control whether and when to export. Policy should encourage them to do the thing that allows it to be exported if it's worth more, if it's a good kWh, he says. Ask yourself, he states, how 2-Channel Billing works, how net metering works, and then how your future ideal works. Today, he observes, net metering is about retail, he states, but given that most people don't exercise control over their solar production and, given the relative coincidence between solar production and system peaks, the odds are (and Mr. Beach has confirmed it) that an extra kWh in your system at your current penetration rates is going to be worth more. That's the import of Mr. Beach's Crossborder study, he says. Therefore, Mr. Rabago urges the Commission, at least out to several more percents of penetration, to rest assured that you have met the requirements of the statute to ensure that there is a rate in place for distributed solar that does not create an improper cost shift and that, in fact, has benefits that exceed costs if you just stick with net metering. He contends that that is what Sub-Group 1 has offered with empirical analysis to support it. T. 767-68.

Mr. Rabago poses a question of what happens on the 2-Channel Billing when a solar system is putting out a lot of kWh during a sunny time and there's high coincidence with peak. What does the rate encourage the customer to do: turn on a resistance heater because they maximize their return from that kWh by using it to offset load? Perhaps it will be a meaningful load, he says, but perhaps it will be, "Hey kids, hang out in front of the open refrigerator because we're making electricity and getting 10 cents per kWh when we do it. " T. 768-69.

Mr. Rabago observes that most customers don't have the time and tools to participate fully in a meaningful way, since they don't have rate signals coming from their utilities saying they are about to hit their peak or the utility's peak; they don't have devices saying when the cloud has passed and their solar system is starting to kick in; they don't have any practical experience measuring their consumption and tracking on any basis other than the monthly basis that the statute defines for net metering. He states that there is much more work to do to build a cohort of customers who are ready to engage and only release those extra kWh by backing off a load selectively or by discharging a battery, or vice versa. He agrees that an alternative would be to set up a system that has incentives to develop an automated tool that will do that for them; he calls that "third parties." He adds that it is necessary to figure out how to unwind and make available the data from AMI, distribution automation and distribution management systems, to set in motion a massive customer education effort, to mine the potential of time-varying rates of various kinds that would work complementarily to regulatory goals – not like 2-Channel Billing, which is contrary to your goals – and to turn non-dispatchable resources like solar into dispatchable resources through their electric vehicle or their stationary battery. T. 770-772.

Asked if the electric system overbuilds capacity, how does one determine ratepayer responsibility for that and what is the market signal that says we don't need more capacity, Mr. Rabago responds that he agrees with Mr. Ball – the best load growth potential is an aggressive pursuit of transportation electrification. He suggests that this would do a lot of good for poor communities, including communities of color, by getting diesel buses and other sources of pollution out of their neighborhoods by replacing them with EVs and solar. He recommends emulation of what other state commissions have done by starting with articulation of a vision, citing Hawaii, California, New York, Maryland, Missouri, and Iowa, and suggests that the DER docket might be the best vehicle for giving a description of where the Commission thinks this ought to go and then gauging the incremental steps toward it so as to maximize the benefits. He asserts that it is egregious to suggest that you have to have blinders on in addressing this, when everyone is watching to see whether there will be a really good demand response market, or energy storage, or EV market, or all sorts of opportunities in Arkansas, notwithstanding the narrow blinders that Sub-Group 2 is trying impose. T. 773-74.

Mr. Rabago acknowledges that in the IRP process, when projections show that a gas plant is the winner, the rates are not based on the projection, but on the actual fuel costs. Mr. Rabago was asked how you do that with distributed generation resource costs. He states that there is no way to guarantee that you can get a perfectly right projection, but you do your best when you realize the benefits that the IRP reveals. He states that the first tool you have to improve the accuracy of your IRP is to open it up, to get much more involvement, many more voices, so that you can overcome any intentional or unintentional bias that the utility might bring to it. Utilities are just normal, human, and have business plans they would like to see carried out. He recommends an iterative process and cites his involvement in Virginia with the Southern Environmental Law Center, where the Commission has taken a deliberate step-by-step basis to develop initial rough estimates of high-level solar integration costs, where the utility (Dominion) is participating in a DOE-funded project, and where the parties are watching how the numbers change and estimates change and their impact on the 20-year forecast. He notes that it doesn't really change a lot in the five-year short-term action plan. T. 774-75.

Mr. Rabago notes that because of the volatile – in many good ways –technological and economic environment, many states are looking at future test years and more frequent rate cases. He mentions that there are tools available to address "slow" rate cases and dealing with reductions in utility revenues, such as targeted earnings adjustment mechanisms (EAMs), which create an opportunity for an increased rate of return for doing stuff you want, such as low-income EE services, achieving faster interconnection of distribution generation, achieving higher penetration of EVs. This, he says, rewards utilities for being customer-facing – acting a bit more aggressively in the regulator's role as the substitute for the forces of competition. He notes that many people have said that the market is pushing this way and that the existential choice for commissions is: Are you going to be sort of handmaiden to resisting the change or work to find ways to usher utilities into the new environment? He acknowledges that we will make some mistakes, but will be able to diversify that risk if there is increased market participation by third parties, expanded opportunity for stakeholders to give input, and if more incremental decisions can be reviewed more often, as opposed to having to wait longer. T. 776-779.

<u>Witnesses for Sub-Group 2</u>

Sub-Group 1 parties and other non-Sub-Group 2 parties did not waive cross-examination of Sub-Group 2 witnesses.

h. Brad Mullins, consultant, Arkansas Electric Energy Consumers

As a representative of the organization of Arkansas's large industrial customers, AEEC, Mr. Mullins testifies that, although Sub-Group 2's proposal focuses on residential customers, it could turn into a problem that affects his members. He lauds how Arkansas has done well in making planning decisions that have resulted in low rates when compared to the rest of the country. He states that if the Commission acts proactively, it can avoid some of the negative consequences that have happened in other states. In response to Commission questioning regarding whether getting pricing right on demand and energy in the face of increased natural gas costs would provide options not only to net-metering customers but to industrials, Mr. Mullins answers "potentially." But he notes that ratepayers pay embedded costs, not marginal costs, and states that most industrial customers see the costs on the margin to be very low, perhaps below $30/MWh, in contrast to the $117 MWh of avoided costs calculated in the Crossborder study. T. 781-83.

i. Andrew Owens, EAL

Mr. Ball posed a question to Mr. Owens regarding how a customer could take advantage of meter aggregation to own a solar array offsite that would have no load and no consumption at the generator site. He asked how meter aggregation would be affected under the 2-Channel Billing approach and, in particular, whether the entire production from that customer's solar system would be on Channel 2 and thus get only half the value of that energy. Mr. Owens responds that the recommendation made by Sub-Group 2 affects accounts that have energy consumption at the load. He does not completely agree or accept it as a given that, under meter aggregation, the meter that the generator is connected to the meter does not have load. He cites his experience as a witness in an earlier matter where one of Entergy's customers was using meter aggregation and the load that was connected to consume most of the energy, but they were availing themselves of meter aggregation relative to their other accounts. He notes that most of those accounts were demand-metered and would be unaffected by the Sub-Group 2 proposal, although he says that they may have had some very small accounts that otherwise could have been affected. Mr. Owens goes on to observe that a location that doesn't have any load sounds like an independent power producer, which has a clear market in either MISO or SPP. He further notes that the MISO market is likely to be in the 2½ to 3½ cent per kWh range, which is quite a bit less than the 5½ cents per kWh value that would be ascribed by Entergy Arkansas, Inc. Transcript Vol. 2[43] (T2.) 5-8.

Sub-Group 1 attorney Casey Roberts questioned Mr. Owens regarding a statement by Sub-Group 2 in Attachment B to the Joint Report, at page 156, wherein Sub-Group 2 recognizes that there may be limited exceptions to the recommendation that demand-billed tariffs will continue to be billed the same way they are today – based on utility-specific rate schedules that are not specifically recognized as demand- or non-demand-based rate schedules. She inquired how a rate schedule can be neither demand- nor non-demand based. Mr. Owens responds that there are instances in which on the very small end of the commercial class of customers, often called Small General Service (SGS), there is a delineation between a customer that is very small and one that is a little bigger. He gives the example of a fast-food restaurant with an 80 kW load and a nail salon with a 6 kW load. Oftentimes, he says, a rate schedule will bill the very small customer sub-segment -- that looks as though it is a residential customer – on a volumetric (kWh) rather

[43] Transcript of portion of hearing held December 1, 2017.

than demand (kW) basis. He acknowledges that those SGS customers with such a small load will be subject to 2-Channel Billing under Sub-Group 2's proposal. Mr. Owens further explains that it does occur that some such SGS customers want to switch around – get bigger, get smaller, or become more efficient. It is conceivable, he says, if the customer's load is actually being reduced, that the customer with that shrinking load might fall below the load threshold and be switched from net metering to 2-Channel Billing. T2. 9-18.

On re-direct examination by EAL counsel, Mr. Owens clarifies that although both existing one-for-one net-metering customers and the proposed 2-Channel Billing customers are all net-metering customers, the existing SGS customers would be grandfathered, and new customers would be metered under the new rules. *Id.* at 18-19.

Mr. Owens responds to Commission questions and begins by clarifying what is meant by the language on page 157 of the Joint Report about "applicable minimum bills" and that refers to "non-bypassable riders" that would not be offset under the 2-Channel approach. Citing to a chart on page 159 of the Joint Report, Mr. Owens responds that the non-bypassable portion is the customer charge – in EAL's case $8.40 per month – that cannot be avoided. It is the major portion of a minimum bill, although there are also franchise fees and taxes often tagged on top of that, he adds, noting that those fees and taxes are non-bypassable even if a utility does not have any non-bypassable riders. He explains that there are some riders, such as fuel or energy efficiency riders, that are bypassable (avoidable). He cites a securitized storm rider as an example of a non-bypassable rider – a charge that cannot be avoided. He further explains that an applicable minimum bill is a catch-all piece of language that says if a customer has no consumption –

perhaps a vacation home with everything turned off – there's still going to be a minimum bill comprising a fixed customer charge and taxes. T2. 20-27.

Mr. Owens further discusses bypassable charges, such as franchise fees, and explains how the 2-Channel Billing method works to produce a bill crediting the customer for exported energy. He notes that although much discussion suggests that 2-Channel is too complex, somehow Ms. Costner found a way to create a quick spreadsheet for herself and several neighbors. He considers the approach pretty straightforward. T2. 27-30.

Mr. Owens states that he considers the notion that more study is needed is somewhat of a red herring: that given more time and more data and more analysis, the answer will magically appear. He states that Sub-Group 2 did have an enormous amount of study and analytical backup to its recommendation. He acknowledges that Sub-Group 1 understands ratemaking and had great witnesses, but states that they did not address the philosophical divide, which he describes as the notion of planning, modeling, analysis, forecasting, assumptions – things that utilities do – versus what they do to recover costs they incur in running their business and making investments. T2. 31-33.

Mr. Owens responds to Commission questioning about the need to hew to the requirements of the net metering statute, as amended [Act 827], regarding ensuring that net-metering customers are paying the entire cost of service and whether Sub-Group 2 has told the Commission by how much net-metering customers are not paying the entire cost. In short, the Commission asks, how do I guarantee a rate that ensures customers pay the entire cost if I don't know by how much they are not paying it now? Mr. Owens responds at some length, describing the process by which Sub-Group 2 arrived at a consensus through compromise and debate among a diverse group of IOUs, cooperatives large industrial customers, the AG's office, and Staff. One of the beginning principles that took shape, he notes, was the notion that Sub-Group 2 was not going to unpack for a net-metering customer the need for a higher fixed charge, a demand charge, or the need to look like a partial-requirements qualifying facility customer that just buys stand-by service. T2. 33-35.

When asked whether there needs to be some quantification of whether the net-metering customer is paying the entire cost, Mr. Owens points to a discussion of how Nevada fundamentally changed its net-metering rate design to establish a $40 per month fixed charge and a reduction in the volumetric rate to about three cents. He agrees that a backlash occurred, the legislature became involved, which led to the update of several studies and a quantification of the amount by which net metering was affecting other customers. T2. 35-36.

In response to the question whether any amount of the entire cost that net-metering customers are not paying would be *de minimis*, perhaps $60,000, Mr. Owens testifies that he agrees there is not a sizable effect on other customers, given the fairly small installations. In response to the question whether the Commission has the flexibility under the statute to consider a *de minimis* effect or must it act to make the entire cost is being recovered, even if it is $1, Mr. Owens states that it is more than $1 and acknowledges that he is not an attorney, but notes that the statutory provision that says "thou shall do something" doesn't have qualifiers – it doesn't say, only if it's a big problem or, if it's small, I'll look the other way. He urges the Commission to look around the country at states large and small, with high and low penetrations of solar, and make a measured, gradual decision. T2. 37-40.

Mr. Owens testifies that if there are carbon regulations or some real, new cost that a utility doesn't incur because a customer puts solar panels on their roof, then by all means that should be reflected in the value that's being provided. He notes that both Sub-Groups have made almost an unwritten agreement not to address what's happening behind the meter. He states that Sub-Group 2 thought about other alternatives to 2-Channel Billing, some of which would be more complicated to implement and some of which would have a much more dramatic effect mathematically than what Sub-Group 2 came up with. T2. 40-41.

Addressing the 3-Bucket approach posited by the Commission, Mr. Owens agrees that for the power that is actually delivered and consumed by the net-metering customer, the current residential rate in Bucket No. 1 recovers the cost for that amount, although he asserts that it is less a literal statement than a compromise among the Sub-Group 2 parties. He explains that Sub-Group 2 tries with its 2-Channel Billing approach to convey that although there are lots of different types of residential customers, they are billed on the same cost-based rate schedule. In short, he notes that he has a normal Residential rate schedule he uses typically, but he also has a sailboat dock that uses 15 kWh per month. Although the latter is not a normal-looking residential customer account, it is a residential customer subject to the same rate schedule. He states that to the extent a customer puts solar on their roof, they are reducing usage on the grid during daytime hours, but such systems are not tracking systems and don't follow the sun; by late afternoon they are not producing a lot of power relative to noon, whereas the utility peaks late in the day, when it would really need to power. He asserts that if the Sub-Group 2 parties had wanted to look at solar customers differently and consider creating a separate rate class and do all of the analysis, that would have led down a path that this rate design needs to be changed. He states that if Sub-Group 1 had done that, Sub-Group 2 believes they would have come up with a lower-priced tariff that's not accurate at all. T2. 43-44.

Asked if the Commission is seeking to determine costs and benefits, should it look at all three buckets as a whole or just focus on Bucket 3, Mr. Owens responds that the most modest, clearest, simplest path forward is to say, yes, these sort of look like the same residential customers just putting energy efficiency measures on: Channel 1 is reducing what they otherwise used and there's some use behind the meter, so we're going to bill them on the same rate schedule; what's used behind the meter is used behind the meter – we can't measure and are not going to touch it; customer, offset what you purchase from us. He then focuses on Bucket 3 and asks, what do you export to the grid? If the customer were a qualifying facility (QF) under PURPA, he notes, the customer would have a published avoided cost rate of three or four cents per kWh. For very large QFs or independent power producers, he says, they can sell their power to the market within MISO, which market says it is worth around three cents. So, according to Mr. Owens, starting from the premise of that avoided cost being the value of that energy, asks whether there is a different way to think about the world such that there is some benefit that such exported energy is worth. That, he states, is how Sub-Group 2 came up with five-and-a-half cents per kWh, which is far in excess of what the actual value of the energy is. T2. 44-45.

In response to a question concerning the discussion by Sub-Group 2 between pages 149 and 161 of the Joint Report, Mr. Owens acknowledges the statement that the current retail rate structure was developed using a COS study that allocates the embedded costs for generation, transmission, and distribution. He also acknowledges a sentence that says 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. When asked which costs do change, Mr. Owens responds "pure variable costs," with fuel and purchase power being the simplest example, since when someone uses fewer kWh, somewhere on the grid a generator did not produce that kWh, regardless of who owns the generator. He adds that for most utilities the truly variable costs are about 30 percent, with 70 percent fixed costs; some are 80/20, some are 60/40. T2. 46-47.

When asked about Sub-Group 1's assertion that it costs less to serve net-metering customers, while stating that they don't really seek to have a different rate on Channel 1, Mr. Owens responds that that is because they actually don't want that analysis to happen. He further responds that although the vast majority of the utility's costs are fixed and do not go down with lower usage, there is also a non-fuel portion that goes down when a customer installs rooftop solar panels, or a smart thermostat, or LED lighting. He asserts that if one were going to create a truly separate customer class for net-metering customers, one would need load research meters and to start from scratch and build it up to determine what fixed costs to serve are and what are the variable costs and how the costs should be allocated under Commission-approved methodologies. Mr. Owens states that this would lead to a probable outcome that certain members of Sub-Group 1 [sic] would say, time out – that's not what we talked about – because it opens the door to maybe higher fixed charges for every customer. He stresses again that to move things forward Sub-Group 2 sought to treat net-metering customers the same as people who have a smart thermostat or adopt EE measures. T2. 48-49.

On the subject of cross-subsidies, as discussed by Sub-Group 2 at page 14 of its Surreply Comments, Mr. Owens acknowledges that Act 827 contains no requirement that a rate change be premised on the existence or determination of cross-subsidies. He agrees with the Commission's conceptualization of the question of cross-subsidies being six-of-one or half-a-dozen of the other in terms of determining what the entire cost is or whether that entire cost is being paid. He further agrees that to the extent that net- metering customers are not paying the entire cost, other ratepayers will pick that up. He thus generally agrees that whether one calls it a cross-subsidy or the entire cost, it is the same thing. He also generally agrees that Act 827 is not prescriptive, and points to a statement made by state Representative Meeks during public comments that he thought that the Act meant a higher fixed cost of $5 per month. He states that Sub-Group 2 came up with a proposal that says $8 per month, which he suggests may be "close enough" to split the difference with some utilities that might have come up with $10 to $15 per month in higher fixed charges. T2. 49-50.

Mr. Owens was again asked by the Commission whether there is any quantification in the record of what that amount is, or by which amount that is not being paid or not being recovered from net-metering customers; in short, he was asked, whether there is anything else in the record beyond the $60,000 Sub-Group 1 posits. In response, Mr. Owens says, no. He states that Sub-Group 2 very consciously chose not to approach the problem from that perspective, and he acknowledges that qualitatively he doesn't think it is a big number relative to the two billion dollars that utilities bill customers. However, he doesn't agree that it is $60,000. He also notes that these are all grandfathered customers and questions the point of doing a calculation of how much the lost revenues are and the fact that these fixed costs don't go away. T2. 50-51.

Asked about the Mississippi Commission's adoption in 2015 of a two-and-a-half cent per kWh adder to the avoided cost rate, Mr. Owens notes that the adder is temporary (three years) and discusses how the Commission decided to take a flexible approach to dealing with benefits of net metering, when no one seems to be able to quantify them. He states that with the adder the net-metering rate for excess energy is four cents avoided cost plus two-and-a-half cents, or six-and-a-half cents per kWh and will change every year as avoided costs go up or down. He notes that the Mississippi Commission will do a study or report, followed by a rulemaking with a request for comments on whether the adder is the right number. T2. 52-54

In response to a question about "additional costs" mentioned in Act 827 and Sub-Group 2's statement at page 9 of it Sur-Surreply Comments that Sub-Group 2 did not identify or quantify any additional embedded costs associated with providing service to net-metering customers through the utility's base rates, Mr. Owens delineates two types of costs: administrative, operational, paperwork costs that are typically one-time and up-front and, for net-metering customers, would include replacing the meter or addressing safety concerns depending on the interconnection. He states that in Arkansas, EAL does not charge that customer anything, whereas some other utilities do. He states that what is contemplated as "additional costs" is something broader, for example the cost of billing meter aggregation customers manually, given the limited number of such customers. If, for example, the cost to serve such customers grew to, say $200,000, he says, which it might cost to modify the billing system, that cost would have to flow through the cost of service and be reflected in portions of the credit rate. He notes that such costs will affect every other customer and, consequently, because EAL has neither spent that money to bill 50 customers in an automated way nor included in what it's recommending net-metering customers pay EAL a fee, it will not appear as an additional fee in EAL's formula rate plan. He states that it will show up as a negative number in the EGCR because the utility incurs a new cost and some portion of it will flow as part of the cost of service to what the credit rate is. T2. 57-58.

Mr. Owens testifies that Sub-Group 2's proposal uses an embedded COS approach to develop the rider rate, except for the energy portion, for which it uses marginal costs, which he describes as a very significant benefit. He states that Sub-Group 1 agrees with this, as it is a pure variable cost. T2. 59-60.

Asked to address the argument that the embedded COS approach does not take into account future benefits, Mr. Owens refers back to his discussion of the philosophical divide. He cites as an example, EAL's utility-scale solar plants approved by the Commission, stating that EAL did a planning analysis through the RFP to select the resource that will provide benefits to customers. The analysis looks at the very same things, he says: What's the value of energy over time? What's the value of capacity? How much of that will you avoid? EAL posits that the net present value of this PPA makes sense, the benefits will happen over a long period of time, he notes, but points out that EAL is not billing customers today for the fact that in 20 years the value of the energy the resources produce might be worth six or seven cents per kWh. Instead, he notes, EAL only seeks to recover its prudently-incurred cost. He disputes a Sub-Group 1 contention that there were some benefits discussed with the Stuttgart Solar Project that are not being quantified in the Sub-Group 2 proposal, asserting that EAL did not ask customers to pay for something that might or might not happen in ten years. He states that he does not know how such a benefit is quantifiable, but the fact is, EAL did not ask the Commission to charge customers for it, which is what Sub-Group 1 is suggesting you should do. T2. 60-62.

Asked to distinguish between the "soft benefits" included in EAL's recently concluded AMI docket and those projected long in the future in this Docket, Mr. Owens states that there may be benefits, whether in AMI or rooftop solar – things that the utility may think is a good idea for customers -- but he notes that is separate and apart from the cost the utility recovers. He cites energy efficiency and the comparative cost-effectiveness tests used to pick between EE measures, noting that EAL has a set amount of dollars to spend on measures and programs. He states that when EAL comes to the Commission and says it spent X dollars, the utility does not go back to those tests and say we want all the benefit that those things provided. Instead, the way the process works is that the utility recovers the actual program cost – what was really incurred. He states that the utility cannot fantasize things that will happen down the road and then bring it back today and say, pay me for it. T2. 62-63.

Mr. Owens disagrees with Sub-Group 1's assertion that 2-Channel Billing privatizes the cost and socializes the benefits of net metering, explaining that he believes that the credit rate will eventually reflect the actual cost EAL incurs. He cites the possible regulation of carbon as an example, which at some point may have a discernable cost that the utility incurs with its carbon emissions. To the extent that the customer doesn't cause that cost to be incurred under a one-to-one approach, it would show up in the same way that the locational marginal price one-to-one shows up. He defers to Staff witness Matt Klucher to describe how the Sub-Group 2 formula and calculation were developed and how it will change over time. T2. 64-65.

On the subject of solar customers having no guarantee of a return on their investment, since they are subject to the vagaries of gas prices, Mr. Owens responds that he has numerous instances in which solar installers produce a payback analysis using a projection that utility rates will go up by a "magic number" into the future. He asks, what if they don't? T2. 65-66.

Referred to page 161 of the Joint Report, where Sub-Group 2 says that any benefits related to the embedded costs that may occur as a result of providing service to net-metering customers will be captured in future updated utility COS studies and approved revenue requirement and rates, Mr. Owens explains how that will occur. Citing additional generation as an example, he states that if EAL asked to build a new combined cycle project, and following its IRP, forecasting, and iterative process, it selected a resource, that would not mean that EAL would recover the cost of what that selection incurs. After construction, he states, the plant enters in service and its costs will flow through COS, as a portion of the $11 that relates to production (generation) cost. He states that production cost is the largest embedded non-fuel portion, adding that it is more than half of EAL's embedded production cost that the utility is saying a rooftop solar customer legitimately avoids. To the extent that that cost becomes incurred and is reflected in EAL's rates, he states, that will raise that portion of its costs of service attributable to that plant, and the rooftop solar customer will then avoid the incremental share of that new plant through the higher credit rate. T2. 67.

Asked to comment on the fact that electric cooperatives don't often update their COS studies if they don't have a rate case, Mr. Owens defers to AECC witness Robert Shields, acknowledging that because EAL is in the early days of a formula rate plan there is less regulatory lag than under traditional rate cases. He suggests that perhaps many of these costs are reflected in what the cooperatives purchase from the market. T2. 67-68.

Mr. Owens defers to Staff witness Klucher with respect to the valuation of distribution benefits associated with non-coincident peaks, although he states that EAL doesn't discern that a customer with rooftop solar that is still using the distribution system that peaks at 6:00 p.m. or later when the solar system isn't producing is actually avoiding any production costs. T2. 68-69.

Asked how Sub-Group 2 ended up selecting the 2-Channel Billing approach rather than a blend of the other options considered, Mr. Owens states that the Sub-Group 2 parties came together and stepped back from changing the rate design itself. He suggests that taking a blended approach would have produced something with more than the $8 per month effect of the 2-Channel Billing method and the parties might not have hung together as Sub-Group 2. T2. 70-71.

Asked whether, given Arkansas's low solar penetration, Sub-Group 2 ever considered a transition period before moving to 2-Channel Billing, Mr. Owens says he sees this approach as a gradual step and cites Arizona, which he says went the same route as Sub-Group 2 after seeing significant growth and lots of acrimony and fighting. T2. 71-72.

Mr. Owens describes the difficulties of developing avoided capacity costs for utilities in MISO (where current prices for capacity are very low) and SPP (which does not have a capacity market), and testifies that the back and forth debate among the parties led to consideration of the embedded basis as the fairest way to reflect a portion of avoided capacity or generation costs. T2. 73-77. He states that Entergy's distribution engineering planners are seeing costs and stress on the distribution system from the higher penetration of solar on feeders in New Orleans, where some feeders have five, ten, even 12 or 13 percent of customers with rooftop solar. However, instead of Entergy's asset planners looking at this as enabling something to avoid, they are saying, we need AMI, we need to understand harmonics issues, voltage flickering issues, fluctuations, tripping of relays, and the possibilities in a minimum daytime load where solar may backfeed and perhaps necessitate the installation of capacitor banks. He states that Entergy's system isn't designed for that and that distribution planners "are not thinking of it in any respect...that's beneficial." Their mission as asset planners is to provide 100 percent reliability at the lowest reasonable costs and their request is to get a budget to do what they can to get there. T2. 77.

With respect to Sub-Group 2's study of avoidable transmission and distribution investments, Mr. Owens points to the energy efficiency avoided transmission and distribution costs as the "whole underpinnings" of the work done by Sub-Group 2 to come up with a figure of $23 or $24 per kW year, as reflected in the EE evaluation report for 2016. He states that the ascribed potential distribution benefit they came up with is a very small number. He does not agree that an EE program will by definition reduce the peak because it is reducing energy usage, stating that peak will be reduced only if it is a demand response (DR) program, which EAL implements with Comverge using direct load control devices and smart thermostats, which provide capacity benefits. He notes that EAL has EE programs that provide very little if any capacity benefits. T2. 78-79.

On the subject of time-of-use rates, Mr. Owens testifies that EAL is on the planning cycle of thinking about how to roll out on a more widespread basis a TOU rate that will dovetail with the web portal planned for AMI implementation, along with customer education, to begin in 2019. He opines that it will dovetail with the 2-Channel approach to the extent that a customer chooses a TOU rate. He states that when EAL comes up with a different TOU rate it will be voluntary, consistent with the desire not to force a fundamental rate design change. He states that the Sub-Group 2 parties, including the other IOUs and the cooperatives would likely have not been on board if EAL had said the right answer was mandatory TOU rates. T2. 80-81.

While acknowledging that operational issues can arise with higher solar penetration levels, citing Hawaii as an example, Mr. Owens points to a different issue – the effect on other customers. He states that states like California that waited – that did not change the policy to begin to move in a different direction – ended up with studies such as E3 did for the state; that said, there are billions of dollars of costs that are getting shifted to non-net-metering customers. After a lot of debate, he notes, California went to Net Metering 2.0 and adopted a different approach that charges net-metering customers the same way we do today, but imposes on them more non-bypassable charges on Channel 1, which effectively reduces the overall credit rate. He states that California thus has an overall credit rate that is five or ten percent less because they "got there in a different way." T2. 81-82.

With respect to meter aggregation and Sub-Group 1's choice to treat other [non-generation] meters as export, Mr. Owens does not agree that it was a technology limitation or a policy choice that customers should pay because they are using the grid. He does not agree that the 2-Channel approach will kill meter aggregation, but acknowledges that every aggregation project will be individualized. He opines that there is not an easy way technologically to treat aggregated meters as one location. He notes that commercial net metering with aggregation of numerous accounts would not be affected by the 2-Channel approach, but Sub-Group 2 was not able to come up with a mathematically workable load shape or algorithm for aggregated residential accounts. T2. 83-84. He explains that with multiple aggregated accounts, the utility applies the kWh in the order the customer directs and does so manually because it is too costly and complicated to bill this, especially if the utility has to do it for every hour across every account. He surmises that an interval meter at each account and AMI could possibly get to something that would work and notes that in today's non-AMI world the utility has just a simple, bi-directional net meter. He expresses a willingness to brainstorm and think creatively about this problem, should the Commission wish that to happen. T2. 85-86. He acknowledges that some small commercial net-metering customers might consider installing a battery to avoid being moved to a demand-charge SGS rider.

Mr. Owens recounts Mr. Ball's statement that 2-Channel Billing may drive battery adoption and opines that that doesn't sound like a bad thing, since if the customer may think her solar energy is worth more than the five-and-a-half cents that Entergy would give her on Channel 2, she would install a battery and store the energy and at the end of the day use it to turn lights on, make dinner and wash dishes. T2. 87-88.

Mr. Owens testifies that the monthly billing increment is a technological accumulation of all the individual customer interactions that produced exports during the month, but that with a bi-directional meter, the utility doesn't know when the customer generation occurred. In the AMI world, the utility will be able to tell when a customer is exporting and importing. He acknowledges that in the AMI world one could make those hours price differentiated to a real-time price. He states that this opens the doors to provide a lot of flexibility, perhaps with a pilot option with a Locational Marginal Price-based credit rate. While it may require complex billing, Mr. Owens states that it may allow customers to provide the utility with value through time-of-use rates, real-time pricing, and critical peak pricing that may be coming. T2. 89-90.

In response to earlier questioning regarding SGS net-metering customers that are on a demand-charge tariff, counsel for EAL stated that the utility's rate administration group clarified that all such customers will still receive full one-to-one offset under 2-Channel Billing. T2. 92-93.

j. Robert Shields, AECC

Mr. Shields testifies in response to Sub-Group 1 questioning that in the case of electric cooperatives, there should not be any ambiguity about customers that have a demand-type rate, such as a pumping tariff based on horsepower. Even though they don't have a demand charge per se, he states, there is still an implicit charge based on demand and the customers would still receive the one-to-one swap under 2-Channel Billing. He agrees that this is likely to apply mostly to agricultural customers. T2. 95-96.

In response to Commission questioning about applicable minimum bills and non-bypassable charges, Mr. Shields testifies that distribution cooperatives generally have only one – the service availability charge – that can vary between co-ops from as low as $6 up to $20. He states that this charge will include transformation and metering, but that it does not include all of the fixed-cost components that supply distribution service, some of which end up in the volumetric energy charge. He asserts that this creates a market distortion, which can be changed by setting the proper price signal. He urges determining this signal today instead of when saturation is reached. T2. 96-97.

Mr. Shields states that the cooperatives do not favor doing a study, which would be expensive for their members, when some cooperatives have very few or even no net-metering customers. On the subject of *de minimis* costs, he acknowledges that there may be very little cross-subsidy for a cooperative with just one net-metering customer, but states that even one penny is being taken from the non-net-metering customers. T2. 98-99.

On the subject of the lack of a Sub-Group 2 explanation or quantification of the amount by which net-metering customers are not paying their "entire cost of service," Mr. Shields responds that it is empirical that they are not. He states that Sub-Group 2 went through an exercise of calculating Channel 2 at five cents as compared with the full retail rate of ten cents and asserts that this proves that there is overcompensation for rates that are totally volumetric, roughly in the amount of four-and-one-half cents. He states that as a rate analyst, he believes it speaks for itself that these volumetric rates on a one-to-one swap are being overcompensated because there are fixed-cost components in that rate. He agrees that the crux of that assertion is that there are embedded costs which they cannot avoid, but for which they are nonetheless being credited at the full retail rate. He contends that the work Sub-Group 2 did through the COS study quantifies that and that it is a good proposal that is justifiable and reasonable to address the requirements of Act 827. He states that a more appropriate rate design might be a demand rate, asserting that it is naïve to believe that in the future net-metering customers will not have demand rates. He asserts that the 2-Channel approach is a glide path toward demand rates – a "softer" treatment of net-metering customers than going to a three-part rate[44] with a demand charge. T2. 101-103.

Asked if a penetration level is reached that's the equivalent of a gas plant and that plant never gets built, how that benefit would be factored in, Mr. Shields responds that if the plant was never built, the cost was never incurred. He states that customers are receiving that benefit under 2-Channel Billing, since there is no new cost. He acknowledges that, to some degree, those benefits are shared equally – socialized – among all customers, when the cost incurred to avoid the gas plant were disproportionately incurred by net-metering customers. He states that the cost is also shared equally, including the cost of the net-metering credit, which ratepayers have to share in. T2. 104-105.

Mr. Shields states that the generation export credits for some cooperatives are lower than Entergy's, perhaps driven by the fact that the cooperatives tend to peak later in the day than Entergy does. But, he agrees that they are roughly similar. T2. 105.

k. Barbara Alexander, AG

Questioned by Mr. Ball, Ms. Alexander testifies that she does not question that there are adverse health impacts due to air pollution generally, but notes that to the extent that the utility has incurred costs to respond to directives to reduce air pollution, those appear in rates and would be reflected in Sub-Group 2's methodology. She observes that to date the Commission has not made changes in rates based on a calculation of social impacts and that Sub-Group 2 did not think it appropriate to propose that for initial adoption in

[44] Customer charge, demand charge, and volumetric charge.

this proceeding. She agrees that there are significant benefits to the net-metering customer and to all ratepayers in the form of avoided generation when a net-metering customer invests its own capital to produce clean energy. Where the two Sub-Groups differ, she states, is with respect to the distribution and transmission costs that are embedded in the rate structure, which essential services and costs are not avoided by the net-metering customer and which, if net-metering customers do not contribute, must be borne by other customers. T2. 107-108.

Ms. Alexander professes unfamiliarity with Mr. Ball's aggregated solar center, for which he paid $7,000 for a transformer which the utility now owns as infrastructure, but responds that she is reacting to the vast majority of residential customers who install solar panels and do not provide any additional investment to the utility to deliver or export their energy into the system. T2. 109.

In response to Commission questioning, Ms. Alexander testifies that another study would produce nothing other than what exists already, which is the Crossborder Study of estimated and predicted benefits that are not guaranteed to be delivered by anybody anywhere. These projected benefits and calculations, she states, would not answer the question of what actually is being provided as a benefit right now by a net-metering customer in Arkansas. The projected numbers do not tell you what rate should be paid for exported energy from a net-metering customer, she states, since they are not indicative of the ratemaking question now facing the Commission. T2. 110-111.

Regarding the entire cost of service net of quantifiable benefits, Ms. Alexander states that Sub-Group 2's approach is to use the plain language of the statute to calculate what it is that net-metering customers do with their solar systems on the roof – namely, generate electrons (kW and kWh). As a result of that, she says, net-metering customers use far less than other customers, and the 2-Channel approach grants them all of that benefit. She states that the reduction in usage that results in a commensurate reduction in the net-metering customer's bill is allowed to be retained under Sub-Group 2's approach and is a very significant benefit. The reduced usage means a lesser contribution to the utility system's revenue requirement and eventually that will all flow back to other customers, she states. T2. 111-112.

Asked whether it costs less to serve net-metering customers on Channel 1, Ms. Alexander responds that Sub-Group 2's opinion and recommendation was to focus only on the exported and excess energy for the purposes of the ratemaking process. She opines that delving into whether or not there should be a change in how they are allowed to keep the full value of their reduced usage would require a significant rate design proceeding that would need to look not only at net-metering customer's reduced usage, but everyone else's who takes action to reduce usage in their home, thereby contributing less to the established revenue requirement of the utility. T2. 112-113

When confronted with the fact that Sub-Group 1 did not advocate such a rate design change, but simply delineated or described the lesser cost to serve net-metering customers by way of showing the benefits of net metering, Ms. Alexander responds that Sub-Group 1's idea of lesser costs include distribution and transmission service with which Sub-Group 2 does not agree and for which there is no evidence to support. Asked why those cannot be quantified for the purposes of the statute, she says because there was a unanimous view of every utility that there was absolutely no lower distribution or transmission cost from the 1,000 or fewer solar customers in Arkansas. She agrees that, as solar grows there will be benefits, but only when they can show that benefits have actually been provided. She asserts that the beauty of the 2-Channel Billing approach is that the methodology for calculating actual generation supply benefit from these customers can be altered in the future based on actual fact-based evidence that solar customers have provided a benefit that would allow an expansion of the dollar amount that Sub-Group 2 recommended. T2. 113-114.

Asked how the benefits of net metering would flow through the generation credit and whether it would only flow through to the extent net-metering customers are offsetting more power than they are getting from the utility, Ms. Alexander responds that electric bills in Arkansas are not unbundled and the variable energy (kWh) rate includes many aspects of utility service, which does not allow the clear delineation of the distribution, transmission, or generation part of that service. She states that while that is not really known, it is known that when a solar customer generates some electrons on their roof, they are not avoiding the call center, the billing system, the metering system, the poles and wires that they rely on to deliver and obtain their electrons, storm restoration costs, AMI, etc. She states that those will not be avoided in any near-term sense. T2. 115-116.

Ms. Alexander acknowledges that there are states that are not unbundled and yet have come up with mechanisms to value exported power that is not based as strictly on the methodology that Sub-Group 2 is proposing and that have more generous payments for excess energy than the one proposed by Sub-Group 2. When asked whether there is conceptual difficulty in focusing only on the exported power rate when the statute may require quantification of whatever amount of the entire cost is <u>not</u> currently being paid , Ms. Alexander responds that Sub-Group 2 is asking the Commission to assume that net-metering customers are contributing to the cost of the system as any other residential customer is contributing, with the actual usage that they end up with after they have netted what they obtain from the rooftop system. She agrees with Mr. Owens that Sub-Group 2's comments state that all costs are being recovered on Channel 1 for the power that is actually supplied by the utility and consumed, noting that these costs are recovered in the same way they are recovered from all other residential customers. Therefore, she states, Sub-Group 2 stopped its analysis. T2. 116-117.

Asked whether the Commission is required to act if the impact of net metering in Arkansas now is *de minimis*, Ms. Alexander responds, yes, since the statute directed a new look and a potential change. She asserts that the difference between five-and-a-half cents and nine-and-a-half cents is not *de minimis*, adding that with every rooftop or solar customer that is added with the grandfathering provision already adopted, you have signed a 20-year contract to pay those customers nine cents or more per kWh for something they are delivering. She states that it is not worth that, when no solar in the market is getting nine cents, when you can get it for five or less. She predicts that the Commission will have to rent a convention hall to have its next hearing if it wants to make this change later and not now. T2. 117-118.

Ms. Alexander testifies that the Commission is not required to capture the value of exported power on some predicted 25-year analysis of estimates over which it and the solar customer and the solar industry have no control or risk to deliver. She emphasizes that it is not included in the quantifiable benefits since it is not subject to regulatory control to make sure it is delivered. She distinguishes between a solar project and a supply-side power plant justified with a long-term analysis which results in an approved contract and construction that the utility could not deliver at the price it proposed. With the power plant, she states, the Commission has the authority to do something because the utility is subject to oversight, audits, and regulation to ensure that the promises made are delivered. With solar, she asserts, the Commission has no tools available to ensure that the predicted benefits are actually delivered. T2. 118-119.

Ms. Alexander recommends against a sliding scale or glide path approach as solar penetration increases, stating that the Commission has an obligation under the statute to look at the facts and evidence about what is going on right now with regard to rates, ratemaking, and the cost shift that occurs with net-metering investments by customers. She notes that the vast majority of Arkansas customers cannot participate in solar power, citing Census data on income, health insurance, housing, and mortgage costs. T2. 119.

Ms. Alexander states that, to the extent they are avoided by net metering, distribution and transmission costs will result in lower costs for those systems for everyone, and they will show up in the cost of service. She asserts that the Commission should not be in charge of giving certainty to a small group of customers at the expense of the remaining customers who bear the risk every year that their investments in home energy efficiency will be whittled away with higher rates. T2. 122-23.

Asked how she knows that subsidy exists now and what the evidence for that is, Ms. Alexander states that she can assure the Commission that net-metering customers are not delivering a generation supply product worth nine cents per kWh. She states that Sub-Group 2 built up its proposed credit amount based on the potential generation benefits appropriate to be paid for the energy produced, but asserts that they are not avoiding the distribution and transmission costs that are worth about four-and-a-half cents.

Consequently, she states, by valuing the exported power, that by definition identifies the subsidy. When asked if it is not actually quantified on the cost side, but by negative implication from the exported value side, Ms. Alexander responds that it is quantified based on COS studies to determine what the value of generation is. She states that one is then left with the other aspects of COS studies that tell what part of T and D are not being provided.

When asked about flowing back benefits to solar customers if it could be established that the reason a lower distribution investment was necessary was because solar facilities were added, Ms. Alexander responds that the benefits should be spread to everybody because that is how rates are set for the residential class. Until the Commission does something differently, ratemaking ought to be looked at as a class-based exercise, she states. In the absence of a contract, she professes not to know how one could calculate so as to compensate or split the benefits with a customer who makes an investment in solar that produces distribution benefits. She cites experiments and pilots looking at locational-based distribution upgrades. She concludes with the assertion that if you need to pay more because you're getting more than five-and-a-half cents in benefits, you should pay more, but you should actually get it.

l. Matt Klucher, Staff

In response to Mr. Ball, Mr. Klucher disagrees with the characterization that universal benefits such as avoided carbon emissions or the deferral of new power plants are not being compensated by Sub-Group 2, asserting that Sub-Group 2 believes it is recognizing benefits provided by solar generation through the whole 2-Channel bill methodology. He asserts that the approach is a billing framework as a whole that represents the cost of serving a net-metering customer, including the net benefits they provide to the system. He denies that Sub-Group 2 is not quantifying any benefit and disagrees that Sub-Group 1's Crossborder Report is a COS report. He testifies that it compares lost-revenues – the subsidy or cross-subsidization – and identifies numerous hypothetical benefits that will occur over a long period of time and, then, show they outweigh the subsidy. Therefore, he states, since the benefits outweigh the subsidy, you do nothing. He disagrees with this approach. T2. 130-131.

What Sub-Group 2 has done, Mr. Klucher testifies, is not to run a COS Study to develop benefits, but to use methodologies similar to what is done in COS to quantify the benefits and "to a certain extent the less-costly-to-serve customers that net metering does have" and how to determine what that cost to serve is. He states that one cannot do that by looking at whether some hypothetical future benefit outweighs a cross-subsidy. T2. 131-134.

Mr. Klucher explains traditional COS mechanisms and discusses regulatory lag and cost-causation rate design principles. He compares a net-metering customer, which he states looks different from other customers, to an energy efficiency customer who doesn't export energy. He states his belief that a customer that has done energy efficiency projects is less costly to serve, but notes that he is still on the same rate structure as his neighbor who has not. He asserts that the EE customer benefits because rates are designed to recognize the fact that within a class, one customer may be more costly to serve than the other. Mr. Klucher states that there is both a benefit and a cost associated with export of energy, in that without the grid, it cannot happen. T2. 134-139.

Asked how he has specifically addressed economic development benefits that a net-metering policy will bring to Arkansas under Act 827, Mr. Klucher responds that he cannot identify any particular way to value in a rate the benefits of externalities that exist over a long period of time. On redirect examination regarding Table 1 of Sub-Group 2's Reply Comments, Mr. Klucher testifies regarding the provision in Act 827 that says that quantifiable benefits associated with the interconnection and providing service to net-metering customers must be netted against the quantifiable benefits. He states that he does not think this encompasses economic benefits. T2. 143-144.

In response to Commission questions regarding the three buckets and whether there might be lesser costs to serve net-metering customers, Mr. Klucher discusses Sub-Group 2's excess generation credit rate methodology, described beginning on page 168 of the Joint Report. He states that, for Entergy, the Channel 1 rate is the base rate, excluding fuel, for all residential customers, and includes distribution equipment such as wires, poles, transformers, customer service, the utility's return on investment, and the recovery of the cost of generation and transmission equipment. He notes that the utility needs approximately six cents per kWh to get that cost back. He describes how Sub-Group 2 used allocation methodologies to get to the six-cent base rate. He states that Channel 2 offsets Channel 1. He acknowledges that Channel 2 values two components – fuel and capacity. He explains that Sub-Group 2 allocated solar generation based on solar's capacity factor during the four coincident peak months (June –September), in a fashion similar to that done by Sub-Group 1. He states that this approach both values a capacity benefit and also gives credence to the lesser cost to serve a net-metering customer. Mr. Klucher states that if you were to do a class COS separate for a net-metering customer, you would most likely see lower generation costs. He acknowledges that Oklahoma Gas and Electric did a study that showed on a per-customer basis their cost to serve is lower. He asserts that the lesser cost to serve a net-metering customer is woven into the capacity because capacity is based on the average capacity they can produce during the peak hour. He states Sub-Group 2 takes the 4 CP months average of 41 percent and recognizes that the lower cost to serve and benefits are generally going to exceed the average, then Sub-Group 2 looks at the maximum solar generation of 52 percent to make sure that the benefits are captured. T2. 145-154.

Asked to explain why Sub-Group 2 uses only COS to value current benefits, Mr. Klucher explains that the current benefit of solar is avoided fuel, and there is no capacity benefit to the utility at this point. With increased penetration of solar, he states, there is hopefully some reduced cost in the future. What Sub-Group 2 does, however, he states, is offset Channel 1 at nine cents with additional offsets above and beyond fuel that represent capacity at five-and-one-half cents. Because anything consumed behind the meter is paid the full nine-cent value, he states, the more energy the consumer can use behind the meter, the more value they have. T2. 155-157.

Asked how the benefit of a power plant that is never built flows through either to all customers or specifically to the net-metering customer, Mr. Klucher cites the Crossborder Study as projecting that a customer will experience cost over a 25-year period at a full retail rate of 12 cents and since the projected benefit the customer is going to experience in the future will exceed that, the customers who are not net metering are not paying more than they should. What Sub-Group 2 says, according to Mr. Klucher, is that 2-Channel Billing uses essentially the same concept except it does not guess at when or if it is ever going to happen, although they hope it does. He states that because the net-metering customer still gets a one-to-one setoff for self-consumption behind the meter, that compensates them for these long-term benefits. He adds that there are two places where that happens – both in Channel 2 and behind the meter. He states that Sub-Group 2 doesn't know how to calculate what that is on a real meter, but can quantify it through modeling, as shown on Exhibit B-4 at page 217 of the Joint Report. T2. 158-161.

Mr. Klucher explains that the exhibit shows that under the existing one-to-one rate, the net-metering customer is effectively credited at 10.8 cents per Kwh, whereas under 2-Channel Billing, the same customer would effectively be credited 9.1 cents per kWh, or about 84 percent of what the utility is paying them today. He explains that that amount includes the lesser cost that it takes to serve net-metering customers and the concept of the power plant that never has to get built in 10 or 20 years. He states that under COS the way Sub-Group 2 attempted to do it, "kind of includes all of that, we quantify these benefits to the extent a customer has exports if you just look at their generation." Mr. Klucher states that he can say with this record what the amount of the entire cost is that net-metering customers are not paying now. He points to the $8 difference between $77 and $68 that Mr. Owens referred to as representing their cost to serve. T2. 161-165.

With respect to "additional costs," Mr. Klucher states his understanding that there would not be any additional costs that roll into this rider directly, although he says they would roll in indirectly by ending up in base rates. He distinguishes additional costs from the types of interconnection costs described by Mr. Ball, which are paid by a customer and do not end up in base rates. He notes that such additional costs will increase base rates, but will also have the impact of benefiting the net-metering customer to the extent it is set off one-to-one behind the meter. If that goes up, Mr. Klucher notes, all things being equal, the Channel 2 excess generation credit rate also goes up. T2. 165-66.

Mr. Klucher testifies in response to Sub-Group 1's assertion that non-coincident peaks may not change, stating that Sub-Group 2 quantified that through modeling, as shown in Surreply Comments. He states that it is included in Sub-Group 2's valuation of benefits to the extent the customer consumes it behind the meter. He adds that as utilities become more AMI compatible and better data can be collected, different allocations could be chosen. The cost correlation chosen from the available data uses 54 percent for generation, 36 percent for transmission, and zero for distribution. He states that one can always get better data and identify better factors. T2. 166-68.

Mr. Klucher testifies that if 2-Channel Billing is approved, Staff and the utilities would verify the functionalized cost of every utility. He recommends that this vetting be done to set the rates the first time rather than in the next rate case. He suggests that to identify different types of cost causation, Sub-Group 2 recommends something similar to unbundling to identify what goes where. T2. 168-170.

With respect to meter aggregation, Mr. Klucher opines that it is a physical limitation not a policy one, adding that a customer who aggregates is very different in that every single time they need that kWh, they need access to the grid to do so. He points to a trade-off of cost and benefit and states that Sub-Group 2 could not figure out a way to quantify it; it is likewise with distribution, he states. T2. 170.

On the subject of future benefits that cannot be quantified, Mr. Klucher agrees that the customer is overpaying 10 cents in Channel 1 and that over time, Sub-Group 2 will do "rough justice" because you'll be paying 9 cents. He states that Sub-Group 2 aimed to find the best cost causation drivers for net metering, just as would be done when developing rates for any other class. T2. 174.

Mr. Klucher testifies that the 2-Channel method can be used to phase in a new billing method, perhaps by putting a valuation to another piece of the cost – a higher generation value for example, until you hit a certain penetration level. He states his understanding that return on investment is important and, consequently his belief that 2-Channel helps push storage. He states that under full one-to-one net metering, if a customer's choice is to do it based on return on investment, the customer would have no incentive whatsoever to ever install a battery. As an example, he states that if a customer generates enough electricity to serve all his needs today, his bill is $12, but if he installs just $1,000 worth of batteries, his bill is still $12, which means there is no return on investment. He opines that we need a mechanism that encourages all distributed generation, not just one and that 2-Channel Billing is a step in that direction to make more distributed generation resources viable to customers. T2. 174-77.

Mr. Klucher states that if the Commission wanted to have a 2-Channel Billing mechanism that encourages solar to some level of penetration and would be willing in the short term to go above and beyond what Sub-Group 2 believes is the cost to serve, he would start with generation, perhaps by moving above the 54 percent number. One could also go to the distribution rate, which is two to three cents for Entergy. In short, he says there are different ways to go about it, including what Mississippi did with its adder for a certain period of time. He cautions about the need to deal with grandfathered customers if one of these other alternatives is pursued, asking whether a grandfathered customer who gets 100 percent would stay at that level or fall to whatever the valuation is as penetration rises; if so, a customer who comes in Year 6 will have a system that is going to be worth a lot less than a customer who comes in today. He recommends determining how you want to send that incentive by addressing that up front to let customers know that either they keep it forever or it goes away at some point. T2. 178-180.

B. SUMMARY OF PHASE 3 COMMENTS

1. Initial Comments

a. Staff

i. Strawman Proposal

Staff re-convened the NMWG as directed by Order No. 22 and, in furtherance of the Commission's directive, began the collaborative process by providing to the NMWG a mark-up of the current Net-Metering Rules (NMRs) to reflect the non-controversial language of Act 464. Staff and the NMWG held two rounds of collaborative discussions, but despite the Commission's guidance concerning its view of certain non-controversial issues, the NMWG was not able to achieve unanimous agreement concerning any of the NMRs. Therefore, on September 17, 2019, Staff submitted its Strawman Proposal to begin the comment process. *Staff's Submission of a Strawman Proposal as Directed by Order No. 22* (Staff's September 17 Strawman Proposal), at 2-3 and Exhibit A, *Strawman Rules*.

ii. Initial Comments

Introduction

On October 15, 2019, Staff filed *Initial Comments of the General Staff on Contested Issues* (Staff Initial Comments). Staff states that Act 464 built upon and expanded net metering in Arkansas – adding provisions that authorize third-party leasing of net-metering facilities; changing the threshold size of net-metering facilities that are exempted from compliance filings with the Commission from 300 kilowatts (kW) to 1,000 kW; allowing the Commission to approve certain nonresidential net-metering facilities up to 20,000 kW under certain circumstances; and including as a net-metering facility an energy storage device that is configured to receive electric energy solely from a net-metering facility. Staff notes that the Act removed certain legal constraints and uncertainties that were present under previous net-metering law and created new rate structure options. Staff Initial Comments at 1-2.

Staff states that it invited Parties to the Docket to provide comment on draft NMRs and reconvened the NMWG to address the Commission's directives set forth in Order No. 22. Staff states that it also provided a subsequent draft NMR attempting to address comments from the participating Parties, but notes that ultimately the NMWG was unable to reach a consensus on the revised NMRS. Consequently, Staff submitted its September 17th Strawman Proposal and Strawman Rules incorporating the provisions of Act 464 for the Parties to begin the comment process. Staff states that its proposed revisions to the NMRs incorporate language of Act 464 regarding rates, terms, and conditions for net metering implementation and leave the Parties flexibility to comment on any issues they believe Act 464 created in the manner they see fit. In essence, Staff concludes, because the NMWG could not reach an agreement on any provision, the entirety of Act 464 is contested. *Id*. at 2-3.

Rate Structure

Staff points out that Act 464 does not require a change in the current net-metering rate structure. Instead, Staff states, Act 464 provides "new rate structure options" for the Commission to consider – in particular with regard to non-demand metered (residential) customers. For those customers, Staff states that the Act allows the Commission to adopt alternative rate design options if doing so "will not result in an unreasonable allocation or increase in costs to other utility customers."[45] For customers with a demand component, Staff states that the Act continued the 1:1 rate structure,[46] which the Parties recommended for demand-metered customers during Phase 2 of this Docket.[47] For those customers without a demand component, Staff states that the Act allows the Commission the discretion for a variety of options, including 1:1 net metering.[48] *Id.* at 3.

According to Staff, absent a showing of unreasonable cost shift or increase in costs, changes to the current net metering rate structure in Arkansas should not be rushed or not well thought out. Staff states that doing so would set policies and implement rate design mechanisms that would have unintended consequences such as potentially discouraging customers from investing in net metering, which is particularly of concern in a low adoption state. Staff observes that some utilities have expended considerable effort to conduct the granular analyses required for such studies. *Id.* at 3-4.

Cost Shifting

Staff submits Attachment A, which shows the number of net metering installations as a percent of utility customers is 0.11% across all Arkansas utilities, with the highest penetration at 0.38% for Carroll Electric Cooperative Corporation. Staff believes that at the current low net-metering penetration levels there is minimal to no measurable cost-shifting occurring between customers within and between customer classes. Staff also explains that it is inevitable that a certain level of cost-shifting will occur as part of the

[45] Ark. Code Ann. § 23-18-604(b)(2)(B).
[46] Ark. Code Ann. § 23-18-604(b)(6).
[47] Joint Report filed in this Docket on September 15, 2017, at 155-56.
[48] Ark. Code Ann. § 23-18-604(b)(2)(A).

ratemaking process, but that does not necessarily mean the resulting rates are unjust and unreasonable. *Id*. at 4-5.

Staff states that it important to consider that foundationally a certain level of cost shifting is part and parcel of ratemaking based on grouped classes of customers. Staff notes that it is common in ratemaking to set revenue targets for grouped customer classes at their estimated COS based on output from a COS study, even though consumption profiles and related costs to serve may differ significantly among customers within the class. Further, Staff states, COS study results are often mitigated, shifting costs between classes to avoid adverse impacts and uphold the concept of gradualism. This, Staff states, inevitably involves some amount of cost shifting, but that does not necessarily mean the resulting rates are unjust and unreasonable. Staff states that it is not practical to set individual rates for each customer. Staff asserts that understanding from the outset that the COS results from a utility's last general rate case proceeding inherently reflect elements of cost shifting helps put in perspective the effort to capture such "changes." *Id*. at 5.

Staff argues that the length of time since a utility's last comprehensive COS study was performed is also a consideration, as changes will inevitably have occurred, as is recognizing that even within classes, customers use electricity in different ways and at different times. Staff notes that the level of detail in which costs were analyzed is likewise a key consideration. Staff adds that the need for further refinements to COS approaches is indicated, in light of anticipated technological advances and customer demands. Thus, Staff asserts, reliance on "averages" in setting utility rates and attempts to create as homogeneous groups (rate classes) remain imprecise in relation to the issues at hand regarding the potential for net-metering cost shifting. *Id*.

Staff states that estimating cost shifting is neither a cursory nor trivial exercise and provides the following issues that should be considered:

- Cost shifting estimates will depend on the analytical time frame, complicated by the fact that net-metering resources are long-term investments, whereas traditional regulatory rates are set on the basis of a single test year or *pro forma* year.
- Long-term analysis may show cost shifting to non-net-metering customers in the short-term, but show benefits for future ratepayers over the longer term.
- Consideration must be given to whether and how much net-metering resources should be compensated differently than if they were market participants in wholesale markets.
- The extent of cost-shifting may be different between customers within a class, between classes, and between net-metering customers utilizing different net-metering technologies.
- Analysis of costs and benefits based on future avoided costs alone cannot determine whether any rate structure results in cost-shifting for embedded delivery costs. That requires a separate COS study.
- Benefit-cost analysis may illuminate the issue of cost shifting, but a projection of net benefits does not definitively mean there is no cost shifting occurring, at least in the short-term.

Id. at 5-6.

Staff recommends that the Commission consider whether any current and near-term levels of cost shifting are significant enough to address at this time or rather, given the current very low levels of net-metering resource penetration, whether an approach based on the net-metering compensation mechanism currently in place should be sustained for the nearer term until net-metering resource penetration levels increase to a threshold that might result in more substantial cost shifting. Staff states that some reforms could be applied at this time depending on the proper balance of market development policy objectives for the state and the level of comprehensiveness of the analysis in support of quantification. *Id.* at 6-7.

Staff recommends that the Commission require robust and transparent analysis of the underlying costs and benefits before any changes are made to the rate structure. Staff notes that because each utility may face differing penetration levels currently and prospectively and have varying rate structures, a one-size-fits-all may not be the best approach to address the issues at hand. Staff states that the foundational basis for the analysis should be established, as well as the need for transparency. Staff recommends that a company-specific demonstration of all relevant factors, including unreasonable cost shifting and quantifiable benefits, should be considered in the Commission's determination. *Id.* at 7.

Grandfathering

Staff states that Act 464 solidified the Commission's authority to allow, at its discretion, what is commonly referred to as "grandfathering,"[49] noting that prior to Act 464 the Commission approved grandfathering on a case-by-case basis. Staff believes that Act 464 continues to give the Commission such discretionary authority. Staff states that because customer investment in net-metering systems requires a benefit period to pay the investment off and, with leasing in particular, typical benefit periods require a twenty-year

[49] Ark. Code Ann. § 23-18-604(b)(10)(A)

agreement. Changes to the underlying rate structure undergirding the initial investment in net-metering systems can significantly change the economics of a system, Staff notes, adding that regulators throughout the country have grandfathered systems for an extended period of time to ensure that decisions made under one tariff or rate structure are not rendered uneconomic. *Id.* at 7-8.

Staff states that the grandfathered systems are guaranteed the rate in existence at the time of a consumer decision to interconnect a solar system, such as the full retail rate for all generation produced for the duration of the grandfathered period. Such a policy can serve as a technology support tool, according to Staff, in particular where adoption rates are very low, and avoid the uncertainty that would chill the renewable energy market that AREDA is intended to promote. Staff states that Order No. 10 in this Docket issued March 8, 2017, approved the terms under which grandfathering would be allowed, adding that any question at that time as to whether legislation allows for grandfathering was squarely answered by Act 464. Staff concludes that the grandfathering option rests with the Commission and should continue in the current environment. *Id.* at 7-8.

Distributed Energy Resources

Staff points out that some large Net-Metering facilities that are not directly connected to their load appear to be small power producers, since these facilities will not physically serve a customer's load. Under the current definitions in the NMRs, all energy produced by these facilities will be excess generation, Staff states, and notes that it is only through a virtual billing mechanism that this excess energy provided to the distribution or transmission grid of a utility is credited to a specific customer's account. Staff acknowledges that the current NMRs allow for virtual billing of aggregated meters. But the underlying question Staff says the Commission must answer is whether this type of facility is more appropriately treated as a net-metering or a DER facility. Staff notes that the Commission is currently investigating how to incorporate DERs. Therefore, Staff recommends that the Commission defer any decision on rate treatment and the distinction of a DER as opposed to a net-metering facility until resolution of Docket No. 16-028-U. *Id.* at 8-9.

Interconnection Rules

Staff states that with the passage of Act 464 that now allows parties to lease net-metering facilities, the interconnection rules need to be amended. Staff recommends reviewing interconnection best practices, looking beyond net metering to include interconnection of DER facilities. Staff provides in Attachment B, the Interstate Renewable Energy Council's *Model Interconnection Procedures for 2019*, and recommends using these procedures as a guide for updating interconnection in Arkansas. *Id.* at 9.

Code of Conduct

Staff supports the creation of a code of conduct to protect both the solar provider and the public utility, to ensure that a fair and robust market is created so that customers can have an array of competitive options. Staff is currently researching existing resources on this subject. *Id.* at 9-10.

Consumer Guide

Based upon general inquiries Staff has received and reviewed of similar guides in other states and from other sources, Staff supports the development of a Consumer Guide as a tool to assist customers in evaluating net metering options. Staff states that it has identified ample existing resources to draw upon and is willing to lead or participate collaboratively with the Parties in an effort to develop this tool, should the Commission so direct. Staff provides a preliminary list of topics that could be included in such a guide. *Id.* at 10.

b. Attorney General

Introduction

The AG begins by asserting the Staff took it upon itself to file its own proposed net-metering Rule in its Strawman Proposal. She argues that the NMWG did develop an extensive list of contested issues, which Staff failed to file and that this will mean the Commission and parties will not be working from a single contested issues list. The AG also alleges that Staff and EAL have attempted to isolate and peel off certain issues into either a separate docket or on a separate expedited schedule within this Docket. Regarding this allegation, the AG footnotes references to Staff's application filed September 13, 2019, in Docket No. 19-055-U (Document 1) and to EAL's Motion in this docket for an interim net-metering rate schedule and accelerated procedural schedule. The AG argues that both actions serve to undermine the rulemaking the Commission has undertaken in this Docket and urges the Commission to keep all issues regarding Act 464 and net-metering in general in this Docket alone. AG Initial Comments at 3-4.

Rate Structure

The AG asserts that the rate structure issue is the most important contested issue in this Docket, noting that Order No. 22 has given the Parties an opportunity to re-evaluate previous positions in light of the new statutory landscape. The AG states that in the time between the recommendations of Sub-Group 2, which has since disbanded, and the present, the AG has been able to fine-tune its priorities specific to net-metering. The AG continues to advocate for a fair allocation of cost between net-metering and non-net-metering customers. The AG advocates for a "Do-No-Harm" approach that considers the benefits of changes from the status quo, but places a strong emphasis on potential negative impacts of making changes too quickly without due consideration of these potential negative impacts. *Id*. at 5-6.

The AG states that Act 464 now provides clearer guidance on which rate structures are allowable, specifically for customers who receive service under a rate that does not include a demand component. The AG acknowledges that Act 464 gives the Commission broad discretion on the net-metering rate as described in Order No. 22:

With regard to the rate structure issues, the Commission notes that the General Assembly left entirely to the Commission the decision to choose one of the various options set forth in the Act, or a hybrid thereof – for example, whether to:

- retain the current one-for-one net excess generation credit approach favored by Sub-Group 1 in Phase 2;
- adopt the 2-Channel net excess generation credit approach proposed by Sub-Group 2;
- develop an avoided cost approach for net excess generation credits, with an "additional sum" up to 40 percent of avoided cost; and/or
- recognize in net excess generation credits the monetary value provided to a utility by the use of net metering as specified by market mechanisms, if any, of the regional transmission organization of

> which the electric utility is a member and market mechanisms, if any, that measure utility distribution system benefits.[50]

Id. at 7.

In light of Act 464's clarifications of allowable rate structure options, specifically the option of a hybrid approach, the AG continues to support as a reasonable compromise the overall premise of 2-Channel Billing and the original position of Sub-Group 2. The AG asserts that this is a pragmatic solution to addressing cost allocation and recovery issues, while allowing customers the continued choice to install net-metering facilities to lower their energy bills. *Id*.

However, while continuing to support 2-Channel Billing and its protection for non-net-metering customers, the AG states that it is important to evaluate whether or not an immediate change to 2-Channel Billing would promote appropriate public policies, noting that abrupt changes in net-metering rate structures could have immediate, harmful effects that are not outweighed by their immediate benefits and thus violate the AG's "Do-No-Harm" principle. *Id*. at 8.

Accordingly, the AG recommends a gradual move towards full 2-Channel Billing while mitigating negative effects. The AG cautions against an abrupt move to 2-Channel Billing and cites the negative results of Nevada's sudden change to phase out the full retail credit. The AG favors a tiered or phased-in approach (such as the one in Nevada that resulted from legislative changes) that would move toward a credit based on avoided costs utilizing tiers that would be developed in this proceeding. The AG states that a tiered approach finds a balance between Sub-Group 1's and Sub-Group 2's original positions.

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[50] Docket No. 16-027-R, Order No. 22 at 2.

Thus, while the AG strongly advocates an end-point adopting full 2-Channel Billing, the AG recognizes the benefits of phasing in that rate structure. The AG discusses the 2-Channel Billing plus an "adder" approach adopted from the beginning by Mississippi and distinguishes Arkansas's circumstances from those in that state, noting that Arkansas should consider concerns such as job losses from a change in the rate structure. *Id.* at 9-10.

The AG cites Indiana as an example of how a phased-in approach could be beneficial for Arkansas, noting that Indiana moved away from a 1:1 credit mechanism, but took a more tempered approach by phasing this out over time. The AG observes that the main impact of the phase-out will impact net-metering customers in years much further out, thus demonstrating the benefits of a gradual change. *Id.* at 10.

The AG proposes a phased-in approach that would move toward a credit based on avoided costs, utilizing tiers to be developed in this proceeding. For example, the AG suggests that the first tier could begin with the credit equaling the retail rate with a phasing over time to a credit fully based on the avoided cost. Under this approach, the amount paid to the customers could be based on the separate reading of the amount being delivered back to the grid, but it would not initially be paid at an avoided cost rate. Instead it would be paid at the retail rate and over time it would be adjusted to an avoided cost rate by adjusting the weighting of each component. *Id.* at 11.

The AG argues that the tiered approach applies the concept of gradualism, similar to what frequently occurs in general rate cases: as cost-of-service studies show the proper allocation of revenue requirements across different rate classes, interclass subsidies are sometimes identified, and an effort to eliminate the subsidies may be undertaken. The AG notes that if subsidies are large and a change to eliminate all subsidies would cause rate shock for a given class of customers, the subsidies are usually not fully eliminated in that rate case. Instead, the AG states, the subsidies can be reduced in future rate cases over time to mitigate rate shock to any one particular rate class. The AG asserts that this same principle of reasonably mitigating negative effects should apply to net metering. *Id.*

The AG notes that while grandfathering would help eliminate rate shock to existing participating net-metering customers, the rooftop solar industry could experience a negative economic impact as was seen in Nevada. The AG states that it is sensitive to this impact, as rooftop solar businesses across the state have made business investments, like company vehicles and equipment and the hiring and training of personnel. The AG expresses concern that these companies may be unduly harmed if an immediate change of rate structure is implemented. *Id.* at 11-12.

The AG asserts that the phased-in approach would allow businesses to adjust over time as net metering grows in the state, and it would also allow solar equipment and installation costs to decrease, offsetting some of the lost opportunities from a lower payback on the investment for net-metering customers. The AG also believes the adoption of 2-Channel Billing could also act as a market stimulant to other energy management technologies: home energy management systems and batteries will be more appealing as net-metering customers will have an incentive to shift their energy loads to times of the day when the net-metering facility is generating electricity, or to store self-generated electricity for use during other time of the day to avoid the need for utility-supplied electricity. The AG notes that costs of battery technology will also likely decrease over time, giving customers an option to use more of their self-generated energy on-site. *Id.* at 12.

Grandfathering

The AG states that Act 464 sets out three levels of grandfathering:

- Level 1 – customers net metering prior to July 24, 2019, are automatically grandfathered at the full 1:1 retail rate. However the length of the grandfathering is not specified. The AG believes that Level 1 grandfathering should be limited to 20 years.
- Level 2 – net-metering customers that submit an interconnection request between the effective date of the Act and December 31, 2022. The AG contends that Level 2 requires the net-metering customer to individually seek review and approval from the Commission on a case-by-case basis to be grandfathered at the rate structure in place at the time of the signing of the standard interconnection agreement, for a period not exceeding 20 years.
- Level 3 – interconnection agreements submitted after December 31, 2022. The AG asserts that the statute does not contemplate grandfathering for those net-metering customers.

Id. at 12-13.

The AG states that Level 1 grandfathering acknowledges that net-metering customers prior to Act 464 made a significant financial investment decision based on the best information they had at the time. Although the proceeding in this Docket began in April 2016, the AG notes that there was no Commission decision made related to the rate structure. The AG states its belief that the treatment of net-metering customers prior to Act 464 is not being challenged by any party to the proceeding. According to the AG, Level

2 grandfathering provides the possibility of grandfathering with notice, opportunity for public comment, and approval by the Commission. *Id.* at 14.

Consumer Protection Rules

The AG expresses concern that in an effort to maximize profit during this period of uncertainty without clear NMRs, third-party developers may mislead utility customers and insert contract terms into agreements that could be harmful to customers. The AG notes that one element used to mislead potential net-metering customers is the short- and long-term benefits of the installation of net-metering facilities or, as Act 464 now allows, the short- and long-term benefits of a lease of net-metering facilities. The AG states that the Commission must consider the fact that unregulated entities are not currently restricted by Commission rules or standards in the marketing and development of facilities allowed under Act 464. For example, the AG states, there is a very real danger that onerous contract terms could be inserted into agreements, placing undue and unwarranted risk on ratepayers regarding changes to rates, escalating construction costs, and failure of contract terms to contemplate costs associated with replacement, repair, malfunction, or shutdown. The AG argues that contract terms must be clearly disclosed, displayed, and easy for lay persons to understand, adding that any assumptions used in payback calculations should also be clearly displayed. According to the AG, these should include, but not be limited to: full cost of equipment and installation; projected future maintenance costs; avoided rate; avoided rate escalation factor; projected on-site usage of self-generated electricity; and projected excess generation. *Id.* at 14-15.

To reduce these concerns the AG recommends that an ongoing working group be established by the Commission to develop a Code of Conduct and a process to certify providers and be responsible for setting terms and conditions for participating in net-metering in Arkansas. The AG suggests this could be similar to the Parties Working Collaboratively for energy efficiency programs. *Id.* at 15.

Leasing and Service Agreements

Regarding leasing providers (as well as other third-party developers), the AG expresses concern that a legislative solution may be needed to grant statutory authority to the Commission to regulate these providers. The AG submits that rules developed in Phase 3 should address Commission oversight of solar installers and net-metering facility owners that offer leasing options. The AG recommends that the leasing option be provided under the Code of Conduct, with terms that should be clear and conspicuous, and that leasing providers should be subject to the same program/expulsion rules developed by the customer protections workgroup. *Id.* at 15-17.

Draft Net Metering Rules

The AG recommends that a completely new set of NMRs be developed using Act 464 as the starting framework. The AG provides a draft of its recommended NMRs (Appendix A) that were provided to Parties during the one meeting of the NMWG. The AG also provides an analysis of the current NMRs and if/how they would need to change to comply with Act 464 (Appendix B). *Id.* at 17-19.

c. Entergy Arkansas

i. Initial Comments

Introduction

Along with its Initial Comments, EAL filed the supporting testimonies of Michael Schnitzer, who addresses the issue of cost shifting; Andrew Owens, who supports the

Company's position on an appropriate rate structure for net-metering; and David Palmer, who addresses issues that EAL has encountered in the Preliminary Site Review and interconnection process. EAL also attaches a draft mark-up of the Commission's NMRs and of EAL's proposed tariff to demonstrate how certain of the issues that EAL addresses in its Comments could be addressed in the NMRs and/or tariff. EAL Initial Comments at 1.

EAL states that in light of Staff's Strawman Filing and its decision not to file a list of contested issues, nearly every issue implicated by Act 464 is contested, requiring the Commission to consider, clarify, and render decisions regarding a number of matters in Phase 3. *Id*. at 1-2.

With respect to the contested issues, EAL urges the Commission to establish an overall framework and rate structure for net-metering that serves the public interest, ensures fairness and equity for all utility customers, and comports with the objectives of the Commission and the General Assembly – *i.e.*, to promote economic development of solar resources in Arkansas and to establish a market-driven approach to solar that does not rely on subsidies. Under the current rate structure, EAL asserts, customers that install net-metered facilities avoid paying their share of the costs incurred to provide and maintain the grid on which they continue to depend. Consequently, those costs are absorbed by EAL's other customers, whose rates necessarily will increase to account for the lost contribution from net-metered customers. *Id*. at 2-3.

Issues Outstanding

EAL argues that there are numerous outstanding issues that the Commission must address to assure that net-metering in Arkansas operates in the market-driven manner intended by the General Assembly and the Commission. EAL has identified the following issues:

- Rate structure issues;
- Eligibility for net metering including customer size and configuration;
- Additional requirements for Commission approval of net-metering requests in excess of 1 MW of capacity;
- Requirements for lease or power purchase agreements ("PPAs," referred to as "service agreements" in Act 464) to qualify for net-metering treatment;
- Eligibility of so-called "community solar gardens" including, if permitted, interconnection requirements and consumer protection measures;[51]
- Appropriate changes to the existing interconnection process; and
- Appropriate consumer protections and disclosures the Commission should require as a condition of approval, consistent with the public interest.

Id. at 3.

EAL asserts that the Commission's decisions on these pivotal issues will have a significant effect on energy costs for all Arkansans currently and well into the future. EAL notes that solar developers are actively marketing to larger commercial, governmental, and industrial customers across the state and exhorting them to make long-term investment decisions in purported net-metering facilities and touting projections of future customer cost savings based on assumptions of no change in current NMRs. According to EAL, the current rules encourage construction of facilities that are higher cost than grid-

[51] EAL notes that in Order No. 10, the Commission indicated that "community solar" –type arrangements would be handled in Docket No. 16-028-U and specifically stated that the Commission was not making any findings in that Order with respect to "community solar" or "virtual net metering."

scale solar project available to the utility. EAL asserts that the net-metered facilities provide benefits to participating customers at the expense of other customers. Conversely, EAL asserts, the utility grid-scale solar investments provide economic and other benefits to all of the utility's customers. *Id*. at 4.

EAL argues that the cost shift that it and other utilities assert exist through this and other dockets is not a fiction, as alleged by Scenic Hill Solar and other private solar advocates in this proceeding. EAL states that it has submitted substantial evidence to show that the cost shift is real, imminent, and adverse to the public interest.[52] EAL points to the Direct Testimonies of Kurtis W. Castleberry and Myra L. Tarkington, both filed in Docket 19-042-TF on August 15, 2019, as addressing the cost shift, noting that it incorporates those testimonies by reference pursuant to RPP Rule 3.05. EAL states that Mr. Castleberry described the essence of the cost shift and resulting unfairness that arises as a result of the customers electing to net meter under the 1:1 crediting mechanism further exacerbated by Act 464. According to Mr. Castleberry's testimony in that Docket, if a tax-exempt entity eligible under Act 464 chooses to purchase energy directly from an unregulated third-party solar developer through a long-term PPA and to participate in net metering as it currently is structured under a 1:1 full retail credit billing framework and under EAL's existing rate schedules, those customers will no longer pay the majority of the fixed costs incurred by EAL to provide them with electric service, with the result being that non-participating customers now will pay more through higher rates to cover those fixed costs no longer being paid for by the participating customers.[53] *Id*. at 4-5.

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[52] *See, e.g.*, EAL's Motion for Interim Net-Metering Rate Structure and to Establish Accelerated Procedural Schedule to Address Same, and Incorporated Memorandum in Support.
[53] Docket No. 19-042-TF, Castleberry Direct at 7-8.

EAL states that its witness Myra Talkington quantified in Docket No. 19-042-TF the annualized cost shifting that will occur and concluded that one could assume the total costs that would be avoided and recovered from non-participating customers if 100 percent of the estimated annual energy sales were lost would be approximately $75 million per year, which is a conservative estimate considering that there are substantial additional energy sales being made to tax-exempt customers under other rate schedules such as Large General Service (LGS). If all potentially eligible customers were to sign a long-term PPA for solar, including those on various LGS rate schedules, Ms. Talkington estimated that the annual energy sales lost would be approximately $126 million per year.[54] EAL asserts that absent action from the Commission, these circumstances will result in significant revenue erosion and cost shifting to other customers, which will be reflected in the form of higher electric rates for non-participating EAL customers in the near future. *Id*. at 5.

EAL contends that it has presented ample evidence that the utility's fixed costs are not materially lowered because of net metering. Instead, EAL argues, customers who install net-metered facilities simply avoid paying their share of the costs incurred to provide and maintain the grid on which those customers continue to depend, and those costs are absorbed by the utility's other customers, whose rates necessarily will increase to account for the lost contribution from net-metered customers. EAL asserts that this point is incontrovertible and lies at the center of the many net-metering issues facing the Commission – namely, what rate structure should be put in place for net-metering that ensures just and reasonable rates for all utility customers in Arkansas. *Id*. at 5-6.

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[54] Docket No. 19-042-TF, Talkington Direct at 16-17.

EAL argues that in their attempts to refute such incontrovertible evidence of cost shifting, parties like Scenic Hill Solar point to studies performed in Phase 2 that relied upon numerous "erroneous assumptions and methodological flaws" that were well-documented by EAL and other parties during that phase of the proceeding. EAL asserts that these parties can no longer hide behind the argument that the number of customers participating in net metering is so small in Arkansas that there is no need to address these concerns at this time, noting that since March 2019, EAL has received over 200 Preliminary Site Review totaling over 40 MW. *Id*. at 6.

EAL posits that ultimately, these private solar advocates will likely assert that the solar energy produced by their facilities "benefits" all customers rather than shifts costs, just as they sought to do with the Crossborder Report analysis submitted in Phase 2. That study, or a similar study with the same premise – *i.e.*, that avoided costs somehow actually exceed retail rates in Arkansas – EAL argues, cannot overcome the ample evidence provided by EAL showing that net-metered facilities are more costly to construct than grid-scale solar resources, and that cost-shifting is an unavoidable outcome if the positions of those parties are adopted by the Commission and the existing 1:1 full retail credit framework goes unaltered as a result of this process. *Id*. at 6-7.

According to EAL, the arguments about the benefits of net-metered solar in the Crossborder Report and similar reports from other proceedings around the country largely have been challenged by the emergence of low-cost, grid-scale solar facilities, which deliver the same environmental benefits at a fraction of the cost arising from crediting net-metered solar at the full retail rate for the energy that such systems produce. In addition, EAL argues, the Crossborder Report is of limited value in this proceeding, given a fundamental assumption in that report that the net-metered facility is located "on [the customer's] premises" and "behind the meter [reducing the customer's use of power from the utility." This assumption is simply false with respect to the majority of the large projects for which customers in Arkansas currently are pursuing, EAL argues. In those circumstances, EAL asserts, as its witness Michael Schnitzer discusses in his testimony supporting these Initial Comments, there is no "own use" of solar; instead, the customer is simply injecting solar power into the grid at one location and consuming grid power at a different location or locations.[55] *Id*. at 7-8.

EAL asserts that where a significant amount of load for a net-metering customer is located at a different location from the injection point of the customer's solar generation, and certainly in instances where the customer's solar generation is at a location with no customer load, that arrangement likely constitutes retail wheeling in violation of FERC rules and applicable federal law governing transmission service. EAL states that this is true regardless of whether the injection point is at distribution voltage. Should the Commission permit these types of arrangements, EAL argues that the facts and circumstances surrounding each such scenario would need to be analyzed to determine whether, through the net-metering arrangement, the customer effectively is utilizing the transmission system to serve its load. EAL argues that the Commission should instead require that net-metering facilities actually be behind-the-meter, to help avoid any potential violation of FERC rules or federal law. *Id*. at 8.

EAL asserts that another issue the Commission must consider in developing rules and standards for net metering, particularly any rules addressing standardized contracts

[55] Schnitzer Direct Testimony at 14.

or a code of conduct for unregulated private solar developers, involves RECs associated with energy from net-metered facilities. In particular, EAL states, the Commission should adopt rules – consistent with AREDA – requiring that, to qualify for net metering, the RECs associated with the energy from a net-metering facility must, at a minimum, be assigned to the customer whose energy usage the facility purportedly will offset (and not to the private solar developer). EAL argues that such a requirement may be established both generally and as a specific condition for obtaining Commission approval of a new net-metering facility for which such approval is required. Absent such a requirement, EAL asserts, there is reasonable cause to question whether the energy from the facility qualifies as solar energy at all and whether the facility qualifies for net metering under the Commission's existing NMRs and Arkansas law. *Id*. at 8-9.

EAL states that a utility obtains RECs with respect to energy generated by or purchased from its owned, grid-scale solar generating facilities, whereas that is not the case with respect to net-metered energy. EAL notes that AREDA provides that the customer retains ownership of the RECs its net-metering facility produces and that the REC entitles its holder to claim that it has caused renewable, or green, energy to be produced. EAL states that the ability to make that claim – the REC – has value. Accordingly, EAL argues, in considering any claims of environmental benefits by the solar advocates, the Commission must recognize that the utility receiving energy from those net-metered facilities obtains none of the RECs associated with energy produced by those facilities – the RECs that represent the environmental attributes (*i.e.*, the "solar-ness" of that energy). Unless the customer agrees to retire the RECs or assign them to the utility receiving the energy, EAL asserts, the utility cannot claim the environmental attributes of the net-metered energy, because the customer or the developer (depending on the arrangement between the two) can sell or transfer the REC to another customer outside of Arkansas, who will then claim credit for the renewable aspect of the renewable attribute of the energy produced. And, EAL states, to the extent the RECs are not retained by the net-metered customer, the facility does not qualify for net-metering under AREDA. *Id*. at 9-10.

EAL cites Scenic Hill Solar's contract with the City of Hot Springs, which was made public by the city, as providing an example of the type of arrangement that does not qualify as solar net-metering under Arkansas law and for which the Commission should adopt rules to prohibit. EAL states that the contract also illustrates the potentially misleading claims of solar developers regarding the product they are selling and potential need for consumer protections. According to EAL, that contract provides not only that the City of Hot Springs receives none of the RECs created by the solar projects, but also that if Hot Springs ever receives other environmental attributes from the solar projects, it must assign them to Scenic Hill Solar. Without Scenic Hill Solar receiving any and all RECs from the City of Hot Springs under the agreement that was executed, EAL asserts that the purported net-metering arrangement violates AREDA, and indeed, it cannot reasonably be asserted that the city is actually receiving solar/renewable energy at all. Yet, according to EAL, after the contract was entered, Scenic Hill Solar claimed in a media report – apparently falsely – that the contract would provide Hot Springs with environmental benefits. EAL argues that it is not only consistent with AREDA, but also in the public interest for the Commission to regulate net-metering activity in a manner that preclude arrangements such as this, whose renewable status is dubious, but also safeguards against Arkansas electric customers from being misled in this fashion. *Id*. at 10-12.

EAL states that the Commission's NMRs are very clear, as is AREDA, that a retail electric customer can qualify for net-metering if <u>and only if</u> it is using (or in this case purchasing under a long-term PPA) renewable energy from certain qualifying technologies like solar and wind. If the customer is not actually using (or purchasing) renewable energy, EAL argues, that customer is simply ineligible for net-metering. Further, EAL states, under the Commission's current rules, the solar developer that retained the solar RECs may decide to sell those RECs to a business or organization several states away that in turn claims those RECs for their own compliance or sustainability purposes. According to EAL, the Commission should consider such scenarios and establish rules, consistent with AREDA, to regulate the treatment of RECs that is required for a facility to qualify for net-metering. *Id*. at 12-13.

Rate Structure Issues

<u>Cost Shifting Under 1:1 Full Retail Credit</u>

EAL argues that net-metering results in cost shifting when a 1:1 full retail credit is provided to the net-metering customer. For this reason, EAL recommends that the long-term rate structure for net-metering facilities be addressed at the outset of Phase 3. EAL states that if the intended objectives of Act 464 are to be achieved, modifications to the net-metering rate structure and rules are needed to prevent or reduce the current subsidies for sub-scale solar, and associated cost shifting. EAL cites the testimony of the Commission Chairman in support of Senate Bill 145 (which became Act 464) as acknowledging that the bill advocated by the solar advocates has a compensation level that is lower than the utilities' position at the Commission.[56] According to EAL, the Chairman stated that the current level of compensation of 10 cents per kWh "comes straight from retail and nobody is saying that's what we should do." Additionally, the Chairman stated that the "solar folks" urged the "status quo" while "the utilities are in the 5-cent range," whereas "[t]his bill starts at 3.3 cents with a 40 percent cap." *Id*. at 13-16.

Economies of Scale

Citing the testimony of Mr. Schnitzer, EAL argues that, owing to economies of scale, larger "grid-scale" facilities have lower installed costs and higher capacity factors than smaller "distributed-scale" facilities, including behind-the-meter and other distributed-scale facilities. Even though grid-scale solar is more advantageous, EAL asserts, the current 1:1 full retail credit framework promotes development of smaller distributed-scale solar. EAL contends that this means EAL is forced to pay inflated rates for solar energy injected into the grid from facilities eligible for net-metering – far more than it pays for solar obtained through integrated resource planning and competitive procurements – and well in excess of the cost of energy in the MISO day-ahead and real-time markets. *Id*. at 17-21.

Ownership of RECs

EAL recommends that the Commission adopt rules – consistent with AREDA – requiring that, to qualify for net-metering, the RECs associated with the energy from a net metering facility must be assigned to the customer whose energy usage the facility will offset (and not to the solar developer). Absent such a requirement, EAL argues that there is reasonable cause to question whether the energy from the facility qualifies as solar

[56] Testimony of Chairman Ted Thomas in support of Senate Bill 145 on February 14, 2019 before the Insurance and Commerce Committee (quote from audio transcript at 10:24:04).

energy at all and whether the facility qualifies for net-metering under the Commission's existing NMRs and Arkansas law. EAL points out that the Commission, in approving EAL's solar energy tariff in Docket No. 18-037-TF, adopted a requirement that the RECs from EAL's grid-scale solar facilities be retired on behalf of the customer who is purchasing renewable energy under that tariff. *Id.* at 21-26.

Fewer Grid-Scale Solar Facilities

EAL argues that continuing the non-market subsidy reflected in the current 1:1 full retail credit rate structure for net metering will likely foreclose development of more economic grid-scale solar facilities. EAL explains that there are physical and operational constraints that limit the amount of solar capacity that EAL's system can absorb irrespective of whether its distribution or grid-scale solar. For example, without energy storage, the amount of solar generation that can be absorbed into the grid during the mid-day hours is limited to demand net of generation from non-solar resources – any generation in excess of demand must be curtailed. EAL explains that some forms of generation (*e.g.*, baseload nuclear) do not make economic sense to curtail, while other forms of generation (*e.g.*, combined-cycle gas turbines) cannot be fully curtailed because they must remain online, operating at minimum levels, to be available to ramp up during the afternoon and early evening hours as the sun goes down and solar production fades. *Id.* at 26-28.

Grandfathering

EAL argues that grandfathering projects under the current 1:1 rate structure will produce long-term harm for customers. EAL further argues that net-metering facilities grandfathered under the current framework would be approved as a long-term resources for which all customers are effectively required to pay with no review of the economic benefits of those resources to customers. EAL points out that this approach contrasts sharply with the lengthy, thorough reviews conducted by the Commission in the case of a utility proposing a new, long-term generating resource for customers. EAL's currently pending proceeding seeking approval to acquire the Searcy Solar facility is one example. EAL acknowledges that customers should have the right to interconnect a generator to meet their own needs and to export energy to the grid provided such exports do not shift costs to other customers. EAL disagrees with the intervenors that believe that Act 464 requires the Commission to grandfather. EAL points to language in the statute that states "subject to approval by a Commission" and recommends the Commission clarify that point now to assure that absolutely no questions on this topic remain. *Id.* at 28-31.

<u>2-Channel Billing or Grid Charge</u>

EAL recommends the Commission adopt a more market-driven rate structure that sends proper pricing signals to net-metering customers. EAL recommends two alternative rate structures: 2-Channel Billing and a Grid Charge.

A. Under 2-Channel Billing, the rate charged for energy recorded on 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. The rate charged for the excess energy (kWh) exported to the grid from the net-metering facility would be measured through Channel 2 and be based on EAL's avoided cost. EAL states that the most appropriate credit rate is the MISO real-time hourly locational marginal price (LMP) within Arkansas. EAL states that an alternative would be to use the National Renewable Energy Laboratory's (NREL), PVWatts model to calculate a more appropriate avoided cost-based credit rate that can then be applied to any excess generation delivered to the grid. EAL is proposing that the credit rate for excess energy recorded on Channel 2 be approximately $0.033 per kWh. EAL notes that the statute permits up to a 40% additional sum if certain conditions are met, but takes no position as to the appropriateness of an additional sum. EAL states that the 40% additional sum would be $0.013 per kWh and would be the upper range of the credit rate that could be applied to Channel 2. EAL notes that 2-Channel Billing, combined with an appropriate avoided cost-based credit rate for excess energy, mitigates, but does not eliminate, the cost shifting from net-metered to non-net-metered customers. *Id.* at 31-35.

B. EAL's second option, a Grid Charge, is a monthly fee that can take various forms, but fundamentally is designed to recover fixed costs that are not avoided by virtue of a customer that self-generates electricity. With a Grid Charge, a net-metering customer would be billed as they are today with a 1:1 full retail credit for any excess energy delivered to the grid, and the Grid Charge would be an additional charge on the bill. The Grid Charge would be calculated based on the utility's most recently approved COS study adjusted, if necessary, to account for a Formula Rate Plan if one were in place, as with EAL. The Grid Charge would then be applied to the installed nameplate capacity (expressed in kW_{DC}) of the customer's net-metered facility. At a minimum, EAL states that the $/kW-month Grid Charge should be developed based on the distribution unit cost (converted to $ per kWh) from the most recent COS Study and the expected typical annual output measured in kWh per kW_{DC} capacity of a typical installed solar facility in Arkansas. EAL has calculated a Grid Charge for each of its rate classes as follows: $2.52 for Residential, $1.98 for SGS, and $0.96 for LGS. *Id*. at 35-37.

Policy Issues to be Decided

EAL asserts that the net-metering rate structure is the most critical issue facing the Commission, but there are a number of policy issues with long-term implications that also must be considered by the Commission in developing the necessary revisions to the current NMRs contemplated in Order No. 22. According to EAL, key issues requiring guidance from the Commission include basic matters such as the definition of a net-metering customer and a net-metering facility, as well as what type of arrangement qualifies for net metering. As with the rate structure issue, EAL submits that these policy issues should be guided by the aim of protecting the public interest and ensuring that the policy objectives of the General Assembly and the Commission are achieved. EAL asserts that these policy issues also implicate the need for revisions to the current interconnection process, as well as consumer protections and rules limiting opportunities for gaming the NMRs to circumvent their requirements. *Id*. at 37-38.

<u>Defining Net-Metering Customers and Net-Metering Facilities</u>

EAL states that up until Act 464, AREDA defined a net-metering customer as "the owner of a net metering facility." Under the pre-Act 464 AREDA NMRs, a customer may only aggregate accounts, which are under "common ownership," which EAL defines as accounts under a common tax identification number (a residential customer's social security number or a non-residential customer's federal Employer Identification Number (EIN)). However, EAL states that Act 464 expanded the definition of a customer eligible for net-metering to include customers that lease a net-metered facility and qualifying non-taxable entities purchasing energy under a long-term PPA, described as a "service contract" in Act 464. Despite expanding the definition of a net-metering customer, EAL states that Act 464 did nothing to expand the definition of "common ownership" required for meter aggregation. EAL further argues that it is critical that those parameters remain to ensure that net-metering operates as contemplated by the General Assembly and to prevent the opportunity for gaming the rules. As an example of potential gaming, EAL states that the developer Scenic Hill Solar is proposing a project for the City of Stuttgart that combines three separate legal entities with separate federal taxpayer identification numbers (*i.e.*, the City of Stuttgart, Stuttgart Municipal Waterworks, and the Stuttgart Public Library) as one customer. EAL argues that the City of Stuttgart's arrangement appears in violation of Ark. Code Ann. § 23-18-603(7)(C), which permits a service agreement for a single tax-exempt entity and does not appear to contemplate a service agreement comprised of multiple tax-exempt entities. In looking at Act 464, EAL argues that the General Assembly did not modify the aggregation language in AREDA, nor did it expand the definition of a net-metering customer beyond the additions noted earlier (*i.e.*, a customer that has entered into a lease or "service contract"). Given that nothing in AREDA or Act 464 states how a customer should be defined for purposes of meter aggregation, EAL argues that no basis exists for altering the factors that always have defined what constitutes a net-metering customer -- *i.e.*, possessing a unique tax ID number. *Id.* at 38-41.

Signatures to the Interconnection Agreement

Act 464 expanded the availability of net metering to now allow a customer to lease the solar facility from the solar developer/provider, or, for eligible customers, execute a long-term PPA to purchase electricity from a solar facility that will be constructed, owned, and operated by a third-party. Given this important change, EAL argues that it is critical to identify which parties will be required to sign the interconnection agreement due to the liability provisions, indemnities, terms of payment of costs, and other items affecting service in the interconnection agreement. EAL recommends that the Commission require both the owner of the facility (*e.g.*, the solar developer) and the customer taking advantage of net-metering to execute the interconnection agreement to properly protect all parties, which means it is essential that the customer identify for the utility the type of arrangement being contemplated so that the appropriate obligations and commitments are obtained. EAL argues that this is of particular concern where the service agreement customer or lessee is a government entity that asserts it is unable to sign the indemnity provisions of the interconnection agreement, which may leave no party responsible for damages or injuries caused by the customer's net-metering system unless appropriate language is inserted to address those circumstances. The interconnection agreement must be updated to properly reflect the roles and responsibilities of all parties involved. *Id.* at 42-44.

Defining a Net-Metering Facility

EAL recommends that the Commission adopt rules that clarify the type of facilities to which net-metering will apply in a manner consistent with the arrangements contemplated in AREDA that were not modified by Act 464. EAL's position is that the

General Assembly contemplated and that AREDA requires net metering facilities to be located behind a customer's meter where there is actual usage to record and where the flow of the net-metered generation can offset the customer's load at that location. However, EAL states that it is seeing arrangements that involve distributed-scale solar generation facilities located not on the same premises as the load they serve but instead remote (in some cases many miles away) from that load. EAL argues that these customers seek to engage in "retail wheeling" by using the utility's distribution system to wheel power from the generator to the customer's load. In summary, EAL argues that this type of arrangement runs afoul of AREDA and Act 464 and does not qualify for net-metering. *Id.* at 44-46.

Sizing a Net-Metering Facility

EAL states that developers are asking EAL to consider a customer's usage based on future hypotheticals that EAL has no way to verify. EAL disagrees with this approach and recommends the Commission clarify its existing rules that uphold the General Assembly's intent on this issue by allowing customers (or solar developers) to install net-metering facilities that will be designed to produce no more electricity than the customer actually consumes (*i.e.*,. customer's usage for the 12 months prior to interconnection). *Id.* at 46-48.

Interconnection Rules and Policies

EAL states that it previously has discussed the flood of interconnection requests that it has received since Act 464 was adopted by the General Assembly, particularly for larger projects that require additional study and consideration, and this significant change warrants further revisions to the Commission's NMRs and the utility's respective tariffs to ensure that net-metering customers are responsible for the additional costs that are incurred to meet their requests. Namely, EAL recommends that Preliminary Site Reviews be required for all facilities. *Id*. at 48-49.

Further, EAL states, as discussed by its witness J. David Palmer, the expanded net-metering options under Act 464 have caused not only an increase in the number of requests received, but also an increase in the size of projects that must be evaluated for technical and reliability implications as well as the variety of scenarios being proposed by solar developers for net-metering facilities that they are trying to sell. EAL asserts that some solar developers are seeking to obtain net-metering treatment for customers for a variety of scenarios that are not contemplated under AREDA or Act 464, many of which are outlined in the discussions above. As discussed in Mr. Palmer's Direct Testimony, EAL states that this is not a scenario where EAL is attempting to foreclose interconnection of qualifying net-metering facilities, but rather a situation where EAL cannot approve certain interconnection requests that have been submitted to it without clear direction from the Commission on these issues. *Id*. at 49.

Given the changed circumstances and the workload associated with these requests, EAL states that rule and tariff changes are needed to assure that customers seeking to interconnect a net-metering facility are paying the administrative and other costs associated with studying their requests. According to EAL, such changes are also needed to ensure that customers are adequately protected in their investment, and that the utility has an opportunity to review the proposed facility before it is installed. One such change recommended by EAL should be to require a Preliminary Site Review for all net-metering facilities. Additionally, EAL argues that the Commission should carefully consider additional rules regarding interconnection that should be required in the event the

Commission expands what facilities are permitted to net meter as discussed by Mr. Palmer in his testimony. *Id*. at 50.

Interconnection Charges

EAL states that since Act 464 was adopted, EAL has received a flood of interconnection requests particularly for larger projects that require additional study and consideration. Therefore, EAL recommends that Preliminary Site Reviews be required for all new facilities, which would be paid for by the net-metering customer – a practice consistent with cost causation principles. Charging a fee would ensure that net-metering customers are responsible for the additional costs that are incurred to meet their requests EAL suggests that a one-time fee should be associated with each Preliminary Site Review, and a one-time fee should be associated with the interconnection request to change the meter. *Id*. at 50-51.

Additional Billing Charges

At present, EAL states that its billing process for meter aggregation customers has been and continues to be a manual, labor-intensive process that must be conducted each month to assure that proper credit for the customer is made and in the proper order. Up until Act 464, EAL states that it has determined that the cost to modify its billing system to automate meter aggregation functions outweighed the cost of continuing to bill such customers manually. EAL states that it may be unrealistic or even infeasible to continue the current practice of manual billing. As such, EAL argues that any costs needed to upgrade EAL's billing system solely to accommodate meter aggregation should be borne by net-metering customers that use meter aggregation and not by all customers, who derive no benefit. *Id*. at 52-53.

Penalties for Unapproved Interconnections

EAL recommends that the Commission adopt a policy that unauthorized interconnections do not qualify for net-metering and thus are foreclosed from receiving any benefits of net-metering for the life of the unapproved system, in addition to having responsibility for any damages resulting from the unauthorized interconnection. *Id.* at 53-54.

Updated Rules for Leases and Service Agreements

According to EAL, Act 464 amended AREDA to allow leases and for qualifying non-taxable entities to enter into "service contracts" (effectively PPAs). EAL states that, for leases, certain restrictions must be met for the arrangement to be eligible for net-metering treatment. EAL states that in both cases, the Commission will now be required to review each lease and "service contract" and determine whether it actually meets the requirements established by Act 464. To help facilitate the review of leases, EAL proposes two options:

- The Commission could establish a review process for lease agreements to be submitted to General Staff and the utility to ensure compliance; or
- The Commission could establish a form agreement that either must be used or that, if used, would allow the net-metering customer to forgo APSC review.

With respect to reviewing "service contracts," EAL also recommends two options:

- The net-metering customer could submit legal analysis confirming eligibility for safe-harbor treatment, including a detailed explanation of the basis for that opinion (*e.g.*, a detailed review of contract terms and specific pricing provisions contained in the purported service contract); or

- The Commission could develop a standard form contract.

Id. at 54-57.

Gaming

EAL provides the following are examples of gaming activity that may be occurring under the Commission's current NMRs:

- Breaking up a larger solar project into smaller projects to stay below thresholds for Commission review (*e.g.*, multiple < 1 MW solar projects even though the customer has executed a single lease or service agreement where the aggregated capacity would trigger Commission review and approval; a similar situation would occur if the customer proposes multiple < 5 MW solar projects that in aggregate exceed the 5 MW threshold for review).
- Aggregation gaming (*i.e.*, meter aggregation where the expected solar production will provide energy for only a fraction of the customer's total metered usage, but where the customer has listed all of their accounts that will have to be manually billed but only the first few are likely to receive any credit against their billed actual usage).
- Grouping together individual meters, including, but not limited to, residential meters that exceed in total allotted thresholds (*e.g.*, 1 MW) and are not tied to any actual load (*i.e.*, so-called "community solar" projects seeking to utilize meter aggregation).
- Submission of multiple preliminary site reviews for the same customer for the same location simultaneously, when in fact the customer only intends to install one system.

- Submission of Preliminary Site Reviews without an actual customer associated with them and that are only intended to "scout out" the potential for a site for a new solar facility.

Id. at 58-60.

Consumer Protection Rules

EAL recommends that the Commission develop consumer protection rules that will assure that Arkansas consumers are not entering into long-term contracts or leases for solar generating facilities based on misleading or false claims and representations by solar developers with respect to the product they are selling to customers. Such rules should include mandatory minimum disclosures outlined by the Commission such as:

- Information includable in rate comparisons and savings estimates presented to customers (*e.g*., inappropriately using national averages for electric rates rather than utility-specific electric rates; estimates of future escalation of utility rates that far exceed the actual rate increases from the utility in question; other assumptions);
- Minimum requirements for disclosure of technical information, such as
    - Expected lifetime operational performance; warranties; annual degradation; expected future costs including equipment replacement (*e.g*., inverters); preventative maintenance and associated costs;
    - Origin of solar panels (*e*.g., Germany, China, U.S.);
- Required/minimum disclosures for lease arrangements (*e.g*., ownership of RECs);
- The extent to which the Commission may require a contract to describe the allocation of risk to the customer, such as the risk of Commission non-approval of

the applicable net-metering arrangement and the potential for future changes that influence the value the customer will receive from net-metering; and

- An explanation and timeline of the process so that customers are not misled into thinking that the minute their facility is built, it will begin providing value. The interconnection agreement must be submitted to the utility at least 30 days prior to anticipated interconnection in order to facilitate review by the utility and allow time for the utility to identify any issues. Developers appear to be telling some customers that they may miss out on current federal tax credits because the utility is taking too long, when instead the developer has failed to timely submit a complete interconnection application and then somehow expects instantaneous interconnection.

Id. at 60-65.

ii. EAL Witness J. David Palmer – Supplemental Testimony

Purpose of Testimony

Mr. Palmer explains the issues EAL is encountering with the current net-metering site review and application processes in light of Act 464. EAL has notified three potential net-metering customers of such issues related to Act 464 and Mr. Palmer discusses each case. Palmer Supplemental at 3.

Case # 1

Mr. Palmer explains that the City of Stuttgart, Arkansas, submitted a Preliminary Site Review that included a request to aggregate more than 75 individual accounts. The issue EAL has with Stuttgart's application is that the 75 meters are associated with three different tax identification numbers, in other words, three separate net metering customers. EAL states that the rules on meter aggregation require all the accounts to be under common ownership. If the Commission decides to allow multiple non-taxable entities to be considered a single net-metering customer (*e.g.*, a city that pays the bills for two or more entities/tax IDs), Mr. Palmer argues that the Commission would also need to establish clear direction to customers and developers for the size of facilities associated with any service contract that would require Commission approval and under which section of the statute that approval is required. *Id.* at 4-6.

Case # 2

Mr. Palmer explains that a solar developer has identified property near Fountain Lake, Arkansas, and plans to co-locate multiple meters with a total capacity of 500 kW. To date, EAL has received Preliminary Site Reviews from three residential customers and two commercial customers. Mr. Palmer has identified several issues with this project. First, he states that a facility of that size would require additional engineering feasibility studies and review. Second, Mr. Palmer states that this project appears to be a community solar arrangement and neither the current net metering rules nor AREDA clearly allow for such a facility to interconnect. EAL recommends that the Commission establish specific parameters to ensure each participating customer shares in any upgrade costs to the transmission and distribution system necessitated by the total facility as well as the costs of any additional studies caused by the interconnection request. *Id.* at 6-9.

Case # 3

Similar to Case #2, Mr. Palmer explains that a solar developer has identified property near Dumas, Arkansas, with the intent to have 1 MW in total capacity installed by multiple customers who would all co-locate but who have not yet been identified. Mr.

Palmer points out that this project also appears to be a community solar arrangement. Mr. Palmer notified the customer that the project would require additional engineering feasibility studies and review. *Id.* at 9.

iii. EAL Witness Andrew Owens – Direct Testimony

Purpose to Testimony

Mr. Owens describes two proposed long-term rate structures: 2-Channel Billing and a Grid Charge, as EAL recommended alternatives to the current 1:1 retail credit. Owens Direct at 4.

2-Channel Billing

Mr. Owens states that there is extensive testimony already in the record discussing 2-Channel Billing; therefore, he only addresses calculating the appropriate credit rate consistent with Act 464 that should be applied to any excess energy delivered to the grid by a net-metered system. Mr. Owens explains that Act 464 provides that the bill credit for any excess energy delivered to the grid by a net-metering facility under a 2-Channel Billing framework shall be based on the utility's "avoided cost plus any additional sum." *Id.* at 7-8.

Mr. Owens testifies that EAL proposes to use the historic MISO hourly real-time LMPs as the basis to credit excess energy. He states that EAL has created an Excel model to calculate an appropriate credit rate; in that Excel model, the expected hourly output from PVWatts for a 1 kW_{DC} rooftop-mounted solar PV system located in Little Rock, Arkansas, is multiplied by the corresponding MISO hourly real-time LMP for energy for the Arkansas load zone (avoided cost). The resulting dollar ($) value for each hour, he notes, represents the relative value of solar PV energy based on the actual avoided cost that the Company incurs operating within the MISO market. He states that this calculation is done for every hour of the year, then summed to arrive at a total dollar value, which is then divided by the expected energy output for every hour to calculate a weighted average credit rate of $0.0331/kWh. According to Mr. Owens, that resulting weighted average credit rate would be applied as-is going forward under 2-Channel Billing to any excess energy delivered by a net-metering facility to the grid. *Id*. at 9-11. As an alternative, Mr. Owens states that the calculation could be done using more recent data such as the trailing twelve months. Mr. Owens states that if historic LMPs are used, then EAL recommends that the credit rate be updated once each year based on the prior year's actual MISO real-time LMPs for Arkansas coupled with an updated use of the PVWatts model. Mr. Owens states that the "additional sum" is calculated by simply applying 40 percent to the avoided cost credit rate, which for EAL amounts to an additional $0.0133/kWh. Accordingly, he states, the total credit rate ($0.0331/kWh plus $0.0133/kWh) of $0.0464/kWh would be paid for the excess energy recorded on Channel 2. *Id*. at 12-14.

Grid Charge

Mr. Owens explains that the two main inputs necessary to calculate a Grid Charge for each rate class are the last Commission-approved unit cost-of-service (COS) study coupled with the output of the PVWatts model described in the 2-Channel Billing calculation. He states that EAL's calculation starts with the Commission-approved COS, and converts the demand costs broken out by function (generation, transmission, and distribution), energy costs (which exclude fuel and purchased power), and customer-related costs for three rate classes (Residential, SGS, and LGS) into volumetric values (expressed in $/kWh) by dividing each cost by test year sales. He states that the resulting numbers (again expressed in $/kWh) represent EAL's total revenue requirement broken out by function and cost driver and expressed as volumetric values. Next, Mr. Owens applies the current Formula Rate Plan (FRP) percentages, which are specific to each rate class, to the distribution-related demand costs that are now expressed as volumetric values for each of the three rate classes. This step is necessary to reflect cost changes that have occurred since the COS study was last performed and approved by the Commission. Mr. Owens makes an additional adjustment for the residential rate class to account for the portion of distribution costs that are recovered through the volumetric rate and not the fixed customer charge. The final step in calculating the Grid Charge for each rate class, he notes, is to multiply the expected annual energy output of a 1 kW$_{DC}$ solar PV system per PVWatts by the distribution cost values that are expressed volumetrically and further dividing by 12 to calculate the monthly value (expressed in $/kW$_{DC}$-mo and applied to the net-metering facility nameplate size). *Id.* at 16-18.

Mr. Owens states that EAL's Grid Charge could also be billed under more than one rate schedule: for example, an EAL customer with multiple accounts taking service under both SGS and LGS could decide to take advantage of net-metering coupled with meter aggregation. According to Mr. Owens, prior to interconnecting a new generator that qualifies for net metering, the customer would provide EAL with a list of its electric accounts in priority order. To calculate the appropriate Grid Charge, EAL would use the list of the customer's accounts in priority order and determine the actual billed usage for the prior 12 months for each account starting with the generation meter first (*i.e.*, providing an "annualized" view of usage for each account). Mr. Owens states that the total annualized usage for each of the accounts under SGS and LGS, respectively, would be summed and then would be divided by the expected annual energy output of the customer's net-metering facility to determine the relative proportion for each rate schedule. *Id.* at 19-20.

iv. EAL Witness Michael M. Schnitzer – Direct Testimony

Purpose of Testimony

Mr. Schnitzer describes the negative consequences of the existing 1:1 full retail credit rate structure and also addresses the negative consequences of grandfathering all projects that submit an Interconnection Agreement prior to December 31, 2022, under the existing 1:1 full retail credit rate structure. Schnitzer Direct at 4.

Summary of Conclusions

First, Mr. Schnitzer states that there are significant economies of scale in solar. He argues that larger, "grid-scale" facilities have lower installed costs and higher capacity factors than smaller "sub-scale" facilities, including behind-the-meter and other sub-scale facilities eligible for net-metering. Second, he states, the existing 1:1 full retail credit rate structure for net-metering customers subsidizes sub-scale solar by forcing the utility to in effect pay an inflated rate for solar energy from these facilities, through volumetric bill credits for every kWh generated by the facility. He asserts that this bill credit is far more than the costs the utility incurs for solar obtained from grid-scale facilities through resource planning and competitive procurements. Mr. Schnitzer argues that the result is a cost shift, with net-metering customers better off and non-net-metering customers funding the bill savings of participants through higher electric rates. Third, Mr. Schnitzer argues that there is an operational and economic limit on how much solar can be absorbed by EAL. In the long run, he states, the continued subsidization of sub-scale solar through net-metering could eventually leave less room for more economic grid-scale solar, which would be to the detriment of all customers. Fourth, he contends that absent a requirement by the Commission that any RECs associated with net-metered solar production be retired, and not sold off-system, then the power that is generated cannot validly be considered "renewable" because the renewable attributes have been separated from the power and can be counted by another party. *Id.* at 4-6.

Economies of Scale in Solar

Mr. Schnitzer states that the installed cost per unit of solar generating capacity ($/kW) decreases as a function of size. He states that this relationship is well documented in numerous studies by groups such as the NREL. He also explains that grid-scale solar systems generally have higher capacity factors than smaller facilities -- one reason for this is that grid-scale solar is more likely to incorporate single-axis trackers that allow the angle of the panel to change during the course of the day to follow the sun, increasing the energy generated from the same installed capacity. He notes that rooftop facilities may also be subject to space and angle limitations and therefore be sub-optimally oriented towards the sun resulting in a lower capacity factor. To highlight the cost difference, Mr. Schnitzer provides two examples of recent solar procurements in Arkansas. He states that AECC has entered into an arrangement for solar power sourced from a 100 MW facility at a cost less than 3 cents/kWh. In contrast, Mr. Schnitzer states that the City of Hot Springs signed a 28-year PPA in September 2019 for the output of a 12.75 MW solar project at an escalating price starting at 5.9 cents/ kWh, twice the price of AECC's grid-scale project. *Id.* at 7-11.

The 1:1 Credit Rate Promotes High-Cost, Sub-Scale Facilities

Mr. Schnitzer testifies that in the case of non-behind-the-meter distributed solar, where the facility is not actually behind a meter with retail electric load, the customer is not using any of its own solar produced. Instead, the customer is simply injecting solar power into the grid at one location and consuming grid power at a different location (or locations). Every kWh is a net injection into the grid, he states, but under 1:1 net metering, for every kWh injected, the customer would receive volumetric bill credits to use against its consumption at a different location (or multiple locations). Mr. Schnitzer argues that such a structure is completely divorced from the original policy behind net metering. If all the power from a net-metered facility is injected into the grid, he says, and 1:1 net metering is applied, this is essentially retail access for a subset of customers, with no rate unbundling. He argues that this leads to a substantial shift of transmission, distribution, and generation costs to non-participants. Mr. Schnitzer asserts that the existing 1:1 full retail credit billing framework has the effect of reducing a customer's volumetric billing determinant by an amount equal to the kWh output of its net-metering facilities. Therefore, he states, a customer has an incentive to pursue net-metering if the cost of the net-metered energy is less than the customer's overall volumetric rate, which includes the base rate plus applicable riders, fees, and sales taxes. For example, he notes that the average volumetric rate paid by EAL's SGS customers is currently approximately 7.9 cents/kWh. In comparison, NREL estimates the cost for small commercial rooftop solar is 7.3 cents/kWh. *Id.* at 13-18.

Inflated Rates for Solar and Subsidization

Mr. Schnitzer argues that under the existing 1:1 full retail credit billing framework developers do not have to compete against other grid-scale solar resources that could supply EAL and its customers at lower cost. Current net-metering customers save money on their electric bills because their cost incurred to source sub-scale solar is less than the cost of the volumetric rate that would otherwise be paid to EAL that they avoid for their consumption. Therefore, he states, non-net-metering customers end up funding those bill savings via higher electric rates. Mr. Schnitzer states that the cost shift caused by 1:1 full retail credit net-metering is due to the utility's rate structure, since the volumetric portion of the retail rate is designed to recover the majority of costs incurred by the utility. In the case of a rate schedule like Residential Service or SGS, Mr. Schnitzer states, the volumetric portion of the rate represents the vast majority of the rate. He states that this volumetric rate covers far more than the costs that the utility avoids as a result of the energy produced by net-metered facilities. He notes that the volumetric part of the rate pays for a large portion of "fixed costs" for wires and generation that do not change with volume. He states that the fixed costs that are no longer being recovered from customers that take advantage of 1:1 full retail credit net-metering must ultimately be recovered from non-participating customers instead. As an example, Mr. Schnitzer states that the City of Hot Springs is contemplating a 28-year solar PPA arrangement for 12.75 MW that would trigger a cost shift of approximately $900,000 in the first year. *Id*. at 24-27.

Mr. Schnitzer also argues that benefits such as reduced line losses and avoided transmission and distribution investment are highly site-specific and only occur when the solar facility is located with the customer (*i.e.*, behind the meter). For example, he states that studies for other utilities have shown that 80 to 90% of distribution feeders are not fully loaded, and thus there are no capital costs to be avoided. *Id*. at 28-30.

Grandfathering

Mr. Schnitzer argues that the Commission should not grandfather any project under the existing 1:1 full retail credit rate structure without first evaluating the impacts, including cost shifts, of grandfathering that project and determining that it is in the public interest. Mr. Schnitzer warns that grandfathering all projects that submit an interconnection request prior to December 31, 2022, will trigger a significant long-term cost shift. *Id.* at 30-33.

Sub-Scale Solar versus Grid Scale Solar

Mr. Schnitzer explains that the amount of solar generation that can be absorbed by EAL during the solar production hours is limited by generation from non-solar resources on the system that must also run during those hours. In particular, he notes, nuclear generation will generally run all hours, for economic and operational reasons, and other forms of generation (*e.g.*, combined-cycle gas turbines) cannot be fully curtailed during solar hours because they must remain online, operating at minimum levels, to be available to ramp up during the afternoon and early evening hours as the sun goes down and solar production fades. He points to the need to keep some other forms of generation online to meet ramping and states that other reliability requirements limit the "space" available on the system to absorb solar. Energy storage can make more space available; he notes that it is currently expensive. *Id.* at 33-35.

d. Oklahoma Gas and Electric Company

Rate Structure

OG&E acknowledges that Staff's proposed NMRs allow for utilities to submit individual utility-specific net-metering solutions that will balance the interests of both its participating and non-participating customers. OG&E supports this approach, as it will allow the Commission to develop experience with multiple net-metering solutions that can assist future refinements that improve the balance of interests for both participating and non-participating customers. OG&E attaches its proposed redline refinements to the Staff's proposed rule changes. OG&E Initial Comments at 1-2.

OG&E requests that the Commission approve a rate structure to replace the current 1:1 rate structure. OG&E recommends that any new rate structure approved by the Commission be based on each utility's cost of service. Of the three new rate structure options allowed for by Act 464 (2-Channel billing, grid access charge (or similar), and three-part rates that include a demand charge, or a hybrid thereof), OG&E's preference is the adoption of a grid access charge rate structure for all applicable net-metering customers. OG&E believes such a rate structure is the most effective mechanism to mitigate the current unreasonable allocation of costs to non-net-metering customers. OG&E Initial Comments at 2-3. OG&E also responds to the potential rate structures listed in Order No. 22. *Id*. at 2.

<u>Current 1:1 rate</u>

OG&E states that the current rate structure leads to unreasonable allocations of costs to non-participating customers because the net-metering customers are no longer paying for the customer- and demand-related services that are embedded in the credit they are receiving. Additionally, OG&E states, under a 1:1 net-metering rate structure, non-participant customers are required to pay far more than market rates (SPP and MISO Day-Ahead) for unscheduled excess energy delivered onto the utility grid by net-metering customers. *Id*. at 3.

<u>2-Channel Billing</u>

OG&E notes that 2-Channel Billing was a compromise among Sub-Group 2 parties and OG&E did not oppose it. If 2-Channel Billing is adopted, OG&E recommends that that each utility be allowed to set its own rate structure components (grid access charge, demand charge, etc.) at a level that limits unintended subsidies and minimizes above-market payments for excess energy. If the Commission were to determine that utility-specific net-metering rules are not desirable, OG&E requests that the Commission approve a grid access charge mechanism for net-metering customers. OG&E states that a grid access charge should be designed to recover the costs that are not avoided by a net-metering facility, at a minimum including the cost of utilizing the distribution grid. OG&E states that under the current 1:1 credit mechanism, a net-zero kWh customers will avoid all costs of utilizing the distribution grid, which means all other customers are footing the bill for these costs. Under an unavoidable grid access rate structure, any net excess energy within the billing cycle would be credited at the rate of the utility's avoided cost. *Id*. at 3-4.

Avoided Cost Plus an Additional Sum

OG&E notes that under Act 464, the burden of proof for any "additional sum" up to 40 percent of avoided costs is on the party seeking the sum. OG&E states that the evaluation of an additional sum should be based on quantifiable benefits and should also consider the impact on non-net-metering customers. OG&E urges caution in including any Quantifiable Benefits that cannot be tied to an accounting or market mechanism, or any amount not currently included in a utility's cost of service. *Id*. at 4-5.

Benefits Related to RTO Market Mechanisms

OG&E states that it is unaware of any explicit RTO (SPP) market mechanism that measures the utility distribution benefits provided to a utility by the use of net metering.

OG&E further notes that the grid provides a substantial benefit to distributed energy resource customers equal to battery backup storage within varying time intervals and urges the Commission to consider those benefits in the calculation of any Quantifiable Benefits. *Id*. at 6.

Customer Protections

Protections for Non-Net-Metering Customers

OG&E states that either a grid access charge or 2-Channel Billing would reduce the unreasonable allocation of costs to non-net-metering customers. OG&E also suggests adopting a three-part rate structure with an appropriate level of demand charge, and treating net-metering customers as a separate rate class. OG&E asserts that this will provide more accuracy and granularity into cost allocation to increase protections to non-net-metering customers. *Id*. at 6-7.

Gaming

OG&E supports developing a regulatory mechanism to guard against the gaming of new 1,000 kW threshold net-metering projects. OG&E also requests the Commission take administrative notice of the FERC Notice of Proposed Rulemaking in Docket Nos. RM 19-15-000 and AD 16-16-000 in which, in part, FERC is proposing to increase its protections against gaming. OG&E proposes as an additional step to mitigate the potential for gaming, that the contact information for the owner of a facility needs to be listed on any interconnection agreement, and all solar lessors and aggregators should be required to register with the Commission, so as to establish mechanisms for enforcing common ownership rules. OG&E recommends establishing a process to allow utilities and/or other parties to file a complaint regarding any potential gaming, as third-party solar installers are not regulated. In addition, OG&E urges, penalties for gaming should include, but not be limited to, forfeiture of ability to participate in net metering. *Id*. at 7-8.

e. Southwestern Electric Power Company

Staff's Strawman

SWEPCO supports Staff's revisions to the NMRs with one exception: Rule 2.03 - New or Additional Charges. SWEPCO suggests that the language from Ark. Code Ann. § 23-18-604(a)(4) be incorporated in the Rule rather than just referring to the section. SWEPCO Initial Comments at 2. SWEPCO next discusses the contested issues.

Rate Structure: 2-Channel Billing

SWEPCO supports the adoption of the 2-Channel net excess generation credit because it appropriately recognizes the utility's costs that the net-metering customer avoids and provides for an additional credit of up to 40 percent of the utility's avoided costs. SWEPCO discusses other benefits that make this method a fair and reasonable choice for all parties. *Id*. at 2-3.

Quantification of Additional Sum

SWEPCO points out that the utility must be able to actually quantify the benefits based upon cost-based ratemaking already approved by the Commission and not by subjective "societal" benefits which may be claimed by the net-metering customer. The quantifiable benefits can also consist of benefits from RTO market mechanisms, but SWEPCO is unaware of any such market mechanisms in SPP. *Id*. 3-5.

Rate Structure: 1:1 Approach

SWEPCO does not support the existing 1:1 rate structure because it shifts costs to non-net-metering customers. SWEPCO argues that the current full retail rate credits the net-metering customer for investments in embedded costs that the customer is not avoiding by merely reducing their consumption. SWEPCO notes that in the first seven months of 2019, the Company issued 263 "net kWh zero bills" in Arkansas. These are bills that reflect a net-zero kWh usage for the month which means the only payment made by the customer is the fixed customer charge, which typically recovers the cost of meters and billing. The customer does not pay for fuel, energy efficiency programs, or any factor that is based on kWh usage. *Id*. at 6-7.

SWEPCO notes that the number of net-metering facilities in Arkansas has been increasing dramatically, noting that according to annual filings with the Commission, there were 1,500 net-metering facilities – both residential and commercial – among utilities with customers in Arkansas in 2018. This, SWEPCO states, was a 52 percent increase in the number of facilities from 2017. Furthermore, SWEPCO states, in 2017 there was a 53 percent increase in the number of facilities from 2016. SWEPCO itself issued over 200 "net kWh zero bills" in Arkansas in 2018 for net-metering customers, and for the first seven months of 2019, SWEPCO issued 263 "net kWh zero bills" in Arkansas. Like all Arkansas utilities, SWEPCO states that it is experiencing an increase in the number of residential and commercial net-metering customers, as well as full-blown marketing campaigns to schools, cities, and other municipal entities. SWEPCO states that as of its October 15, 2019 filing, it had received 62 net-metering applications and interconnected 68 new net-metering facilities in 2019 and is forecasted to receive another 90 applications and interconnect 84 new facilities before the end of the year. Given this unprecedented growth, SWEPCO asserts that the existing 1:1 rate structure is unsustainable. *Id*. at 6-8.

Current Demand Tariffs (GS Tariff)

SWEPCO recommends that the Commission should make an exception to the NMRs regarding the continuation of the existing 1:1 net excess generation credit approach for net-metering customers who receive service under a rate that includes a demand component for any current demand tariff under which the Company is not fully recovering its cost to serve. As an example of such a case, SWEPCO points to customers under its General Service (GS) tariff that do not meet the 6 kW demand charge threshold. SWEPCO notes that a significant portion of the Company's costs for such customers under the GS tariff are thus achieved through the energy charge. SWEPCO argues that while the proposed NMRs are a reflection of the statutory provisions of Act 464 for customers with a demand component, it believes that the statutory language does not properly take into consideration the new rate structure on current demand tariffs. Therefore, SWEPCO urges that the 2-Channel Billing approach should be extended to net-metering customers on the General Service tariff, as well as any current demand tariff under which the Company is not fully recovering its cost to serve, as an exception to the Commission's NMRs. *Id*. at 8-9.

Gaming/Oversizing Facilities

SWEPCO notes that while Act 464 provides limits for the size of net-metering facilities for residential customers, it does not have a mechanism for "policing" customers who oversize their systems. SWEPCO states that Ark. Code Ann. § 23-18-603(8)(E) provides that a net-metering facility is "intended to primarily offset *part or all* of the net-metering customer requirements for electricity."[57] SWEPCO notes that while Commission review is required for interconnection of a net-metering facility over 1,000 kW_{AC} for a

[57] Emphasis added.

commercial or industrial net-metering customer, there is currently no disincentive for commercial of industrial net-metering customers to oversize a system. Rather, SWEPCO states, conditions have changed in a way that makes 1:1 netting and cost payment an inducement to oversizing. Therefore, SWEPCO supports the adoption of rules that specifically define a level of "over-sizing" and provides either penalties or terminates the Standard Interconnection Agreement and removes the customer from net-metering service until the size of the net-metering facility is reduced to comply with the Ark. Code Ann. § 23-18-603(8)(B)(i). To guard against gaming, SWEPCO also recommends developing rules or guidelines to define a level of "over-sizing" and provides either penalties or terminates the Standard Interconnection Agreement and removes the customer from net-metering service to that of a cogeneration facility until such time as the size of the net-metering facility is reduced to comply with Ark. Code Ann. § 23-18-603(8)(B)(i). SWEPCO also urges the Commission to develop rules or guidelines to guard against the possibility that a large net-metering facility that would otherwise exceed the new 1,000 kW threshold is not broken into multiple small net-metering facilities under common ownership to avoid Commission review. *Id.* at 9-10.

Data Sharing

SWEPCO points out that the Commission is currently addressing issues related to data privacy, data access, and data sharing in Docket No. 16-028-U. Therefore, SWEPCO believes it is premature to attempt to define and establish a market-based incentive for credit for data sharing until those data issues are addressed in Docket No. 16-028-U. SWEPCO also notes that it has not deployed AMI meters or separate production meters, both of which are necessary to gain increased visibility into the distribution grid. SWEPCO states that production meters are owned by the customer and are installed behind the customer meter in such a fashion that they are capable of directly measuring the output of a customer's net-metering facility. Production meters, in conjunction with AMI meters, thus allow a utility to completely understand consumption, generation, import from the grid, and export to the grid in such a way that the true costs and load impacts to the grid by that customer can be quantified definitively. Because SWEPCO has an obligation to serve and the customer's production data is necessary to provide that service, SWEPCO does not believe it should have to pay for such information from the customer. SWEPCO states that, at this time, there is little incentive for the utility to provide distribution system information in exchange for a customer's data information or develop market-based incentives to increase net excess generation credits in exchange for information from net-metering customers. *Id*. at 10-12.

Grandfathering

SWEPCO believes Act 464 requires the Commission to approve net-metering facilities that seek to be grandfathered. SWEPCO also believes that Act 464 did not supersede Order No. 10, which provides that grandfathering will be determined based upon the date of the Commission's order, which has yet to be issued, adopting a new net-metering rate structure. SWEPCO notes that Act 464 provides that net-metering customers who sign a Standard Interconnection Agreement (SIA) between July 24, 2019, and December 31, 2022, will be subject to the rate structure in effect at the time they sign the SIA. Therefore, SWEPCO argues, it would seem logical that the date of the Commission's order adopting a new net-metering rate structure will be date upon which ALL net metering customers at the time of the order would be grandfathered. For example, SWEPCO states, if that date is January 1, 2020, then all net-metering customers who are current customers, or have signed an SIA, will be grandfathered at the current 1:1 rate structure, and there would be no more grandfathering after that date. Additionally, SWEPCO contends that, as written, the Act 464 requirement for Commission approval[58] applies only to the net-metering customers who submit an application between July 24, 2019 and December 31, 2022, or to any customer who has submitted a signed SIA prior to the date of the order adopting a new net-metering rate structure. Thus, SWEPCO states, the application of the grandfathering provision will also require the distinction of rates applicable to grandfathered customers versus new net-metering customers who will be subject to the rate structure as determined by the Commission. SWEPCO believes that the NMRs need to reflect and address these issues. *Id*. at 12-14.

Third-Party Leasing

SWEPCO believes that the addition of third-party leasing of a net-metering facility may require the Commission to adopt additional rules or guidelines regarding eligibility and criteria for such leases, beyond the listed limitations in Ark. Code Ann. § 23-18-603(7)(B)(i)-(ii). *Id*. at 14.

<u>f. The Empire District Electric Company</u>

Definition of Net Metering Facility

Empire cites Proposed Rule 3.02(C), which states that "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." Empire states that the NMRs should also clarify that the intent is to restrict the initial sizing of the

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[58] Ark. Code Ann. § 23-18-604(b)(10).

net-metering facility to ensure that those facilities are not intended to generate electrical energy in excess of the amount necessary to offset all of the Net-Metering Customer requirements for electricity. Additionally, Empire states that the Commission should ensure that the NMRs address the potential disqualification of a facility as a net-metering facility if its production level becomes excessive as a result of the reduction of the electricity requirements of the Net-Metering Customer. Empire Reply at 1-3.

Rate Structure

Empire recommends that each utility be given a range of options for its proposed rates, terms, and conditions for net metering within its service territory. Empire argues that a single prescriptive rate structure solution applicable to all utilities requires that all utilities have sufficient technical capabilities to implement the prescribed solution which is not the case in Arkansas. Empire contends that a prescriptive one-size-fits-all solution would, by default, limit itself to the "lowest common denominator" or be limited to the technical capabilities of the least advanced utility. Empire suggests that as utilities implement new metering and billing technologies which support better solutions, those utilities should be encouraged to incorporate those advanced capabilities into their rates. *Id*. at 3.

Aggregation of Meters

Empire notes that the Proposed NMRs address meter aggregation in Rule 2.04(C) and in Rule 2.05 and recommends that the Commission consolidate the meter aggregation rules into a single rule for brevity and clarity. *Id*.

g. Arkansas Electric Cooperative Corp.

Introduction

AECC explains that it is imperative that the Commission exercise flexibility given the vast diversity among the electric cooperatives in Arkansas. If, however, the Commission adopts a uniform rate structure, AECC recommends a rate based on wholesale rate for energy (kWh) – *e.g.*, the avoided cost, noting that it is also the rate recently used by several states, including the neighboring state of Louisiana. AECC Initial Comments at 1-3.

Staff's Strawman

AECC proposes changes to Staff's Strawman, which are attached as AECC Initial Exhibit-1, in order to help clarify certain ambiguities or unintentional errors, and to better protect non-net-metering customers against the potential for unreasonable cost shifts.

Definitions – Additional Meter

AECC suggests a change to the Strawman definition for "additional meter." Specifically, AECC states that the Strawman's language does not reflect that Ark. Code Ann. § 23-18-604(c)(2)(A)(ii) prohibits, rather than promotes, meter aggregation. By focusing on singularly on common ownership, AECC asserts that Staff's Strawman's proposed language opens the door to limitless aggregation amongst different governmental or tax-exempt owners within a single service territory. *Id*. at 4-5.

Applicable Period

AECC recommends that the term "applicable period" be defined to avoid confusion. AECC suggests the definition read as follows: "The period of time used by the Electric Utility to determine Net Metering or Net Excess Generation." AECC argues that to avoid creating a cost shift that becomes a subsidy for net-metering customers, excess generation must be accounted for anytime a net-metering facility feeds energy back to the utility. Otherwise, AECC asserts, the net-metering customer receives more than the avoided cost – *i.e.*, a non-market based rate, for generation it sells to the utility. Such a result, AECC contends, is contrary to the existence of wholesale power markets and negatively affects non-net-metering customers. AECC contends that the reality is that most utilities have the ability to measure energy flow both to and from customers. Because a net-metering facility provides energy only, AECC argues that its excess generation is effectively purchased as additional wholesale energy by the utility. By contrast, AECC argues, the energy a utility customer (including a net-metering customer) consumes comes with the infrastructure required to deliver it, on demand, and as much as is needed. AECC asserts that the distinction between the energy flowing to and from the utility means that excess generation from a net-metering facility has a distinctly lower value than the retail energy flowing to the consumer. AECC thus argues that continuing to compensate lower-value energy at an artificially inflated price does not serve the public interest. *Id*. at 5-6.

Applicable Rate

AECC recommends adding a definition for "Applicable Rate" and suggests it read as follows: "The Net-Metering tariff rate filed by the Electric Utility that is multiplied by the kilowatt hours generated by the Net-Metering Facility and fed back to the Electric Utility."

AECC recommends that Commission adopt rates that are tailored to each public utility's approved cost-of-service and system characteristics. In the absence of a utility-specific rate, the Commission should adopt the utility's annual avoided cost rate for wholesale energy. Payments in excess of avoided cost should be based on a customer- and facility-specific determination and supported by substantial evidence. AECC argues that paying for excess generation at any rate above the utility's avoided cost also requires all other customers to pay premium prices for energy that is (1) non-dispatchable, (ii) unable to be scheduled when needed, and (iii) not subject to the control of the utility. *Id*. at 6-7.

Net Excess Generation Credits

AECC recommends that Staff's Strawman's proposed definition for Net Excess Generation Credits be deleted because it is unnecessary to carry out the law or to clarify the current Net Metering Rules. *Id*. at 7.

Quantifiable Benefit

AECC believes there is a legal question as to whether the Commission is preempted to implement a rate for the purchase of energy above the utility's average annual avoided cost of wholesale energy under federal law – specifically, the Federal Power Act and the Public Utility Regulatory Policies Act. Subject to this argument, AECC suggests a procedural modification to the term Quantifiable Benefits to make it more consistent with Act. 464. AECC's proposed definition includes additional language, as follows:

> (u) Quantifiable Benefits
> As defined in Ark. Code Ann. §23-18-603(9) and determined on a case by case basis upon the filing of a formal Application by the Net-Metering Customer. Any such Application must include evidence to demonstrate benefits to the utility from the Net-Metering Facility to merit compensation greater than market-based energy.

Id. at 7-8.

Rule 2.04 - Billing for Net Metering

Rates with and without Demand Components

AECC notes that Act 464 distinguishes between rate structures with and without demand components based on a distinction between the recovery of a utility's fixed (demand) costs versus variable (energy) costs. AECC asserts that the objective is to ensure that a utility's fixed costs are not left stranded by excess generation is accomplished only if the allocation of fixed costs is sufficiently compensatory. AECC states that there is a question (raised by at least one party, AAEA) as to whether the Commission has the discretion to establish a rate structure for demand-metered customers beyond the current full retail credit (such as a 2-Channel Billing approach). AECC argues against this theory by pointing out that Act 464 allows "net excess generation" to be measured in kilowatt hours or kilowatt hours multiplied by the applicable rate. AECC also points out that "applicable rate" is not defined, nor is it mentioned in Act 464 that demand-metered customers are guaranteed a full retail credit. Finally, AECC points out that facilities larger than 1 MW are reviewed under section (b)(9) instead of section (b)(6). Under section (b)(9), neither a rate nor a rate structure is prescribed, and therefore something entirely different than the full retail credit could be chosen by the Commission. AECC thus proposes that in recognition of the legal limitations of Act 464, the Strawman Rule 2.04(A)(2) should be modified as follows:

> Except as provided in Ark. Code Ann. §23-18-604(b)(9), Net-Metering Customers who receive service under a rate that includes a demand component, the Electric Utility shall credit the net-metering customer with any accumulated net excess generation in the next applicable billing period and base the bill of the net-metering customer on the net amount of electricity that the net-metering customer has received from or fed back to the electric utility during the billing period.

Id. at 8-9.

Demand Component Rates with Unique Characteristics

AECC urges the Commission to be flexible and consider alternate rate structures, including the phase-in of demand billing for certain Net-M customers with unique characteristics. For example, AECC submits, customers with seasonal accounts for irrigation, poultry houses, and other agricultural accounts should not receive full retail credit. *Id*. at 10.

Rule 2.07 – Grandfathering Rate Structures

AECC believes the Commission has the discretion to approve the grandfathering on a case-by-case basis. AECC also suggests that the language in the Strawman at Rule 2.07(A) should be corrected from the plural to the singular language, as shown below:

> The net-metering facility~~ies~~ of a net-metering customer~~s~~ who submits a standard interconnection agreement, as referred to in these Net Metering Rules, to the electric utility after July 24, 2019, but before December 31, 2022, is allowed to remain under the rate structure in effect when the agreement was signed, for a period not to exceed twenty (20) years. Such treatment must be approved by the Commission.

Id. at 10-11.

Gaming and Consumer Guidance

AECC recommends adding a gaming section to the NMRs and offers an example in AECC Initial Exhibit 1:

> Any facilities used for Net-Metering being credited to a customer's account, regardless of the location of the facility and its aggregation, will be treated as a single facility and must comply with the imposed capacity and/or sizing limits under these Rules.

AECC also argues that gaming would diminish if not disappear once the Commission establishes a just and reasonable credit for excess generation, noting that gaming is only incentivized when a substantial benefit attaches to excess generation payments as a result of inaccurate price signals. In other words, AECC argues, gaming serves no purpose when over-generation competes on price with the markets in which power is currently purchased. *Id*. at 11.

AECC asserts that developing a Consumer Guide could also help address gaming. A good example is the *Solar Consumer Protection Guide* recently issued by the California Public Service Commission. In addition to a Consumer Guide, AECC recommends developing a Customer Bill of Rights and Code of Ethics, which would limit the consumer's exposure for the purchase of a system during the utility's review of the Preliminary Interconnection Site Review Request. AECC further recommends that third-party developers be required to, at a minimum, register with the Commission and agree to comply with these requirements. AECC asserts that this will provide visibility into those businesses and allow the utility to deny interconnection when a developer does not comply with the Bill of Rights and Code of Ethics. Finally, AECC states that the Bill of Rights could be used to provide a consumer with the common language to understand what part of their utility bill they might avoid with net-metering projects and those billing elements which are, or might be, unavoidable. *Id*. at 11-13.

Clarification in the Rules

Avoid Unreasonable Allocation of Costs

Because the term "unreasonable allocation of costs" is used throughout Act 464, AECC recommends the NMRs define the term or explain how allocation of costs will be evaluated. *Id*. at 13.

Metering is Needed to Monitor Larger Projects

AECC points out that FERC recently issued a Notice of Proposed Rulemaking on PURPA which provides for the possibility of the "Rebuttable Presumption" being reduced from 20 MW to 1 MW. AECC suggests the possibility that future federal law may require these large facilities to participate in the market to make the market more efficient and bring benefits to all. With this in mind, AECC recommends that net-metering facilities greater than 1 MW be required to meter their total production. *Id*. at 14.

Exceeding the Statutory Limit Requires Heightened Scrutiny

AECC recommends re-evaluating the minimal standards that a facility must meet to exceed the statutory limit of 1 MW. *Id*. at 14.

Distribution System Saturation

AECC proposes that net-metering saturation be addressed, in the NMRs, by stating the utility will prioritize net-metering projects based on the date the Preliminary Interconnection Site Review Request is completed and submitted for review to the utility. AECC proposes new language for Rule 3.01(G) to address this concern:

> Rule 3.01(G)
> The Electric Utility shall review, and process all completed Preliminary Interconnection Site Review Requests in the order they are received. If the Electric Utility's existing facilities are not adequate to interconnect with the proposed Net-Metering Facility, the Electric Utility shall not be required to proceed with interconnection until:
>
> (i) the Net-Metering Customer ~~shall~~ pays for the cost of additional or reconfigured facilities, or
>
> (ii) a mutual agreement is made with the Electric Utility that equitably addresses the risk of interconnecting a Net-Metering Facility at a location where system capacity is likely to be exceeded.
>
> After interconnection, the Electric Utility may interrupt a Net-Metering Facility or facilities that exceed system limits. However, these interruptions may be addressed by the mutual agreement referenced above.

AECC provides a couple of examples of why this is needed. *Id*. at 15.

h. Carroll Electric Cooperative Corp.

Rate Structure

Carroll supports the comments provided by AECC and notes that it has the highest concentration of net-metering customers (relative to total customers) of any utility in Arkansas. In Exhibits A through F, Carroll provides extensive evidence of the growth of net-metering in Arkansas and its own service territory, as well as examples of poor solar installations and a proposed Customer Bill of Rights and Code of Conduct. Carroll states that the total number of net-metering customers reported to the Commission has grown from 24 in 2007 to 1,507 in 2018. Carroll Initial Comments at 2. Carroll supports grandfathering of net-metering customers. Carroll's most recent internal report shows a total of 459 net-metering customers (primarily residential) are interconnected or pending interconnection to its distribution grid. *Id*. Exhibit B at 8. Carroll recommends that the SIA be clarified so that both AC and DC ratings of net-metering proposals are listed with the limiting rating highlighted. *Id*. at 2-3.

Carroll recommends adopting a flexible, utility-specific Floor and Ceiling approach for setting a new rate structure. Carroll states that a reasonable Floor would be Avoided Cost, since net-metering facilities lack dependable capacity. An appropriate Ceiling would be the 1:11 full retail rate. *Id*. at 3 and 5.

Consumer Protections

Carroll recommends developing a Customer Bill of Rights, a Code of Conduct for Utilities, and a Code of Conduct for Net-Metering Vendors. In Exhibit D, Carroll provides the following examples:

- *2019 Solar Consumer Protection Guide*, California PUC
- *Consumer Guide to Rooftop Solar PV*, Arizona Residential Utility Consumer Office (RUCO)
- Consumer Complaints with Solar Installation Companies, Webpage of the NPUC's Consumer Complaint Resolution Division

Carroll also provides Exhibit E which is the sworn affidavit of Joey Magnini, Carroll's representative for all net-metering interconnection agreements. Mr. Magnini provides numerous examples with pictures of faulty installations. In addition, Carroll provides a proposed Net Metering Customer Bill of Rights and related Codes of Conduct for utilities and Net-Metering vendors. *Id*. at 5.

i. Five Joint Electric Cooperatives: Ashley-Chicot Electric Cooperative, Inc.; Clay County Electric Cooperative Corporation; Craighead Electric Cooperative Corporation; Farmers Electric Cooperative Corporation; and South Central Arkansas Electric Cooperative, Inc.

Rate Structure

These five distribution cooperatives filed a one-page comment supporting the comments and recommendations submitted by AECC in the filing of their Initial Comments. Additionally, each of the cooperatives listed above has a goal to implement cost-of-service based rates and rate structures for net metering customers that are tailored to the unique characteristics of their individual cooperatives and are consistent with Commission approved cost-of-service principles.

j. Arkansas Electric Energy Consumers

Introduction

AEEC explains that the NMWG met only one time following the issuance of Order No. 22 and found little or no consensus on any issues. AEEC also notes that Staff's Strawman failed to provide a recommended resolution of the major contested net-metering issues or even a list of the contested issues. Therefore, AEEC limits its comments to criticism of Staff's suggested red-line amendments to the NMRs, and a summary of AEEC's general position on some of the contested issues. AEEC Initial Comments at 2.

Staff's Proposed Amendments to the NMRs

Rule 1.01 and Rule 2.04

AEEC states that Staff's proposed amendment to Rule 1.04(n) in the definitions section is inappropriate and suggests an edit to the existing definition of "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 as set forth in Rule 2.04, or, pursuant to Rule 2.04, purchased by the utility in a future billing period.

Likewise, AEEC states that Staff's amendments to Rule 2.04(A) through (C) are incorrect and recommends the Commission replace them with language that actually establishes the rates, terms, and conditions under which a net-metering customer can take service. *Id*. at 3-4.

Rule 2.07 Grandfathering

AEEC states that Staff's amendment merely adds the language from Act 464 verbatim to the NMRs. AEEC recommends the Commission reject Staff's amendment and replace it with language that actually resolves the controversy surrounding the meaning of Ark. Code Ann. § 2318-604(b)(10)(A). *Id*. at 4.

Rate Structure

AEEC opposes the 1:1 rate structure and argues that the current rate structure is shifting costs to other customers. AEEC further argues that the shift is large enough to be problematic in rate classes where the rate design recovers a significant portion of fixed costs through a volumetric charge. AEEC supports 2-Channel Billing for net-metering customers in classes without a demand charge. AEEC also supports the concept of a Grid Usage Charge along the lines suggested by EAL in its September 23 Motion. *Id*. at 5-6.

Interconnection

AEEC recommends that the Commission establish new guidelines for interconnection of net-metering facilities to include provisions for larger net-metering facilities, and leasing of the facilities for certain customers. In doing so, AEEC recommends the Commission resolve the following issues:

- How does the current standard contract need to be revised to accommodate a lessor, rather than an owner?
- Are the current time frames sufficient, given the larger sized projects?
- Should penalties be imposed for customers who interconnect without utility authorization?
- Are new rules needed to clarify aggregation issues?

Id. at 6.

Gaming

AEEC agrees that the Commission needs to promulgate rule changes to guard against gaming, but makes no other suggestions. *Id*. at 6-7.

Lease and Service Agreements

AEEC recommends that the Commission clarify questions regarding whether a service contract for a net metering facility qualifies for safe-harbor protection as provided under § 26 USC 7701(e)(3)(A), as required by Ark. Code Ann. §23-18-603(7)(C). AEEC has provided the following issues it believes need clarification:

- Is the safe-harbor provision set forth in the Arkansas statute applicable to entities other than federal agencies?
- Section 26 USC 7701(e)(4) outlines several circumstances in which the safe-harbor protection under § 26 USC 7701(e)(3)(A) shall not apply. Should confirmation be required from the appropriate federal agency that none of those conditions exist with respect to the service contract at issue?
- Analysis of these issues will require review of contract terms and specific pricing provisions contained in the purported service contract. How will contract compliance be determined?

Id. at 7.

Grandfathering

AEEC supports the interpretation of Ark. Code Ann. § 23-18-604(b)(10)(A) that the Commission must determine whether a particular net-metering customer will be grandfathered under the current rate structure. AECC argues that rules of statutory construction suggest that the phrase in this new grandfathering subsection of Act 464 applies to all of § 23-18-604(b)(10)(A), and not merely to the last antecedent clause ("for a period not to exceed twenty (20) years"). Additionally, AEEC argues that none of the Commission actions contemplated by § 23-18-604(b) can occur without "notice and opportunity for public comment." AEEC asserts that such notice and comment would be a meaningless, hollow exercise if it could not influence the outcome of the Commission. Hence, the Commission may decide not to grandfather any of the customers after receiving "public comment." Since in its view, a decision to grandfather would effectively enshrine a significant subsidy in rates for a period of time, AEEC thus recommends that the Commission choose not to grandfather additional net-metering customers. Alternatively, AEEC recommends that the Commission not grandfather customers for a lengthy period of time, insofar as such action will effectively enshrine a subsidy in rates for a lengthy period. *Id*. at 7-9.

k. Walmart

Changes to the NMRs

Walmart supports changes to the Net-Metering tariff that are applicable to net-metering customers receiving service under a rate schedule that includes a demand component. Walmart proposes the following revisions:

- In order to ensure that net-metering billing aligns with changes in customer billing demand, for net-metering customers who receive service under a utility rate that includes a demand component, in addition to crediting the net-metering customer for any net excess generation as set forth in Staff's Strawman at Sections 3.5 and 3.6, the electric utility should also reduce the net-metering customer's billing demand to reflect any applicable reduction in demand resulting from the net-metering facility; provided, however, that billed demand cannot be reduced below zero.
- Walmart proposes the following revision to Staff's Strawman at Section 3.2 to clarify that a net excess generation credit is not the only bill reduction available to net-metering customers with a rate that includes a demand charge:

> 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 schedule. Under net-metering, the kilowatt hour (kWh) and kilowatt (kW) units of a net-metering customer's bill are netted.

Walmart Initial Comments at 1-2.

l. Distributed Solar Advocates: Arkansas Advanced Energy Association, National Audubon Society, Inc., and Sierra Club

i. Initial Joint Comments

Introduction

Joint Initial Comments are provided by Arkansas Advanced Energy Association, Inc. (AAEA), National Audubon Society, Inc., and the Sierra Club (Distributed Solar Advocates). Distributed Solar Advocates generally support Staff's Strawman but offer several amendments that further support implementation of Act 464. Distributed Solar Advocates attach the testimony of Thomas Beach of Crossborder Energy LLC, which provide updated results to the 2017 cost-benefit analysis that Crossborder Energy undertook for the service territory of EAL in Phase 2 of this Docket (Crossborder Study). Distributed Solar Advocates state that the updated analysis demonstrates that retaining the full retail rate for non-demand-metered customers will not result in unreasonable cost shifting to non-net-metering customers. Distributed Solar Advocates state that the evidence demonstrates that it is in the public interest and will not result in an unreasonable allocation of costs for the Commission to retain full retail net metering for non-demand-metered customers, while undertaking a considered and gradual transition to a rate structure that could better align incentives for the utility and net-metering customers to maximize the long-term system benefits offered by net-metering customers. Distributed Solar Advocates Initial Comments at 1-2.

Grandfathering

Distributed Solar Advocates support Staff's incorporation of Ark. Code Ann. §23-18-604(b)(10)(A) in its entirety as NMR Rule 2.07(A), with slight modifications to honor legislative intent and promote efficiency. Specifically, Distributed Solar Advocates recommend striking "subject to approval by the Commission." According to Distributed Solar Advocates, this edit makes it clear the Commission is not required to engage in case-by-case grandfathering adjudication, but has issued its approval by establishing generally applicable rules for grandfathering. Distributed Solar Advocates thus argue Ark. Code Ann. § 23-18-604(b)(10)(A) is not a mandate to create needless docket activity, but that Commission approval is implicit once a rule is adopted. Distributed Solar Advocates also advocate that the NMRs solidify the grandfathering period at twenty years. Distributed Solar Advocates state that this interpretation is also consistent with the Commission's decision in Order No. 10. Distributed Solar Advocates' proposed amendments to the rule are shown below:

> Rule 2.07 Grandfathering Rate Structures
> A. The net-metering facilities of net-metering customers who submit a standard interconnection agreement, as referred to in these Net Metering Rules, to the electric utility after July 24, 2019, but before December 31, 2022, are allowed to remain under the rate structure in effect when the agreement was signed, for a period of ~~not to exceed~~ twenty (20) years~~, subject to approval by the Commission~~. B. A net-metering facility under subdivision(A) of this section remains subject to any other change or modification in rates, terms, or conditions.

Distributed Solar Advocates argue that although some parties have asserted that the statute gives the Commission the authority to approve grandfathering on an individual basis, this is a misreading of the intent of the statute, as such a practice is inefficient, unnecessary, and undermines the stability and predictability that the Commission previously identified. For similar reasons, Distributed Solar Advocates urge the Commission to exercise its authority to definitively state the twenty-year grandfathering period in the NMRs, rather than the range permitted by the statute, so as to provide customers with certainty regarding the time period over which they can ascertain the return on their investment, consistent with Order No. 10 and the stated intent of AREDA. *Id*. at 3-5.

Meter Aggregation

Distributed Solar Advocates support an amendment to the NMRs that establishes an easy, clear, and non-controversial means for customers to establish common ownership of multiple accounts for purposes of meter aggregation. Distributed Solar Advocates' proposal would require that the customer provide only their name and account numbers and a signature affirming that the accounts are under common ownership. Distributed Solar Advocates believe it is unnecessary to require customer tax IDs to confirm common ownership. Distributed Solar Advocates' proposed addition to the NMRs reads as follows:

<u>Rule 2.05 - Meter Aggregation</u>

> . . .
> <u>D. A customer seeking to aggregate multiple accounts under common ownership shall submit a request to their Electric Utility identifying the accounts that are under common ownership. Electric utilities shall develop and provide a form for this purpose. The form may require submission of the following information relating to accounts that the customer seeks to aggregate: Customer name, customer account number. The form may require a signature affirming that the accounts for which aggregation is sought are under common ownership.</u>

Id. at 5-6.

Rate Structure for Demand Billed Customers

Distributed Solar Advocates support the way in which Staff's Proposed NMR Rule 2.04(A)(2) reflects the difference in permissible rate structure for demand- and non-demand billed customers, noting that Act 464 establishes a bright-line distinction between customers that receive a bill that includes a demand component and those that do not. Distributed Solar Advocates believe that Act 464 grants the Commission authority to modify net-metering rates for customers that do not receive a bill with a demand component, but does not give the Commission the authority to modify the rate structure for customers on demand component bills. Distributed Solar Advocates argue that the Commission is required to follow Act 464's prescriptive language for demand billed customers, which is in sharp contrast to the Act's grant of discretion to the Commission regarding how crediting shall occur for non-demand-billed customers. *Id.* at 6.

Rate Structure for Non-Demand-Billed Customers

Distributed Solar Advocates acknowledge that Act 464 (Ark. Code Ann. § 23-18-604(b)(2)(D)) gives the Commission ample discretion to design rates that promote the public interest and avoid unreasonable allocations of costs. Distributed Solar Advocates go on to describe the various rate structures spelled out in Act 464. Distributed Solar Advocates urge the Commission to consider the longer-term benefits that a robust distributed generation market can provide to the utility's system. Distributed Solar Advocates note that, critically, the statute gives the Commission authority to maintain the status quo, or take gradual and incremental steps toward a different rate structure, citing Subsection (D) in particular. Distributed Solar Advocates point out that Act 464 does not define "unreasonable allocation of costs," thereby leaving the Commission discretion to design rates that allow *de minimis* shifting of costs, as it traditionally has done in rate making to maintain simplicity, fairness, gradualism, and other principles of rate design. Distributed Solar Advocates state that the broader standard provided in the statute, which also directs the Commission to consider the "public interest" in designing rates, invokes the wide-ranging policy goals of AREDA expressed in Ark. Code Ann. § 23-18-602. Thus, Distributed Solar Advocates assert, the Commission's decision regarding the public interest should be informed not merely by immediate cost-of-service considerations, but also by the longer-term benefits that a robust distributed generation market can provide to the utility's system. *Id.* at 7-8.

Distributed Solar Advocates state that Act 464 substantially departs from several Act 827 provisions that were previously discussed in this Docket, noting that Act 464 clearly establishes that the Commission may move away from 1:1 kWh netting, which was previously required by the definition of net metering and which precluded an approach such as 2-Channel Billing. Distributed Solar Advocates point out that Act 464 also provides a more specific definition for quantifiable benefits than was suggested in the prior statute, but notes that the Act requires the use of "quantifiable benefits" only in the case where the Commission elects to implement 2-Channel Billing or a grid charge, not where the Commission chooses to pursue any of the other rate structures within its authority. Most importantly, AAEA state, Act 464 specifically repealed the previous provision, added to AREDA by Act 827, that rates must recover the entire cost of providing service to a net metering customer. Distributed Solar Advocates argue that the General Assembly's elimination of that requirement and substitution of a standard based on the public interest and no unreasonable allocation of costs among ratepayers is a clear sign of legislative intent to move away from a rigid cost-based rate structure. *Id.* at 8-9.

Distributed Solar Advocates state that Mr. Beach's testimony and the updated Crossborder Study continue to show that (1) "solar DG is a cost-effective resource," and (2) "net metering does not cause a cost shift to non-participating ratepayers," and "[m]odifications to net metering are not needed to recover the utility's full cost of service over time from net metering customers." Mr. Beach's testimony also explains why a long-term evaluation of the costs and benefits of distributed generation is the preferred tool for informing rate design, rather than cost-of-service studies that look only at historic, embedded costs. Distributed Solar Advocates assert that Mr. Beach's testimony establishes that solar distributed generation provides significant, quantifiable social benefits, including local economic benefits and public health improvements from reduced air pollution, which are relevant to the public interest as set out in AREDA. *Id.* at 10-11.

Distributed Solar Advocates assert that there is no imperative for the Commission to change the net-metering rate structure, or to do so in a precipitous manner as encouraged by other parties, adding that while the Commission may ultimately conclude that a rate structure other than the status quo would best promote the objectives of AREDA and improve efficiency through transparency and market-based incentives, it has discretion to shift utilities gradually to any new rate structure. Distributed Solar Advocates state that if the Commission determines that a change in the rate structure is needed, they recommend that the new rates be determined in a general rate case or other utility-specific proceeding. Distributed Solar Advocates believe this method is necessary because several of the rate structure options available in Act 464 require updated cost-of-service information and other utility-specific information such as the value of avoided costs and other benefits. *Id*. at 11-12.

Distributed Solar Advocates state that a gradual, data-drive approach to designing a rate structure is not only permitted by AREDA, but consistent with guidance in the National Association of Regulatory Utility Commissioners' (NARUC) DER Manual:

> For the jurisdictions with low DER adoption and growth, there is time to plan and take the appropriate steps and avoid unnecessary policy reforms simply to follow suit with actions other jurisdictions have taken. Reforms that are rushed and not well thought out could set policies and implement rate design mechanisms that have unintended consequences such as potentially discouraging customers from investing in DER or making inefficient investments in DER. That is not to say a jurisdiction should ignore the issue. Understanding how its existing rate design interacts with its compensation may be worthwhile to consider at any time. The important point is that a jurisdiction be situated to analyze, plan, and be prepared for its next steps before the market and customer adoption rates overtake its ability to respond.[59]

Distributed Solar Advocates suggest that the Commission should consider exploring alternative rate designs through pilot programs or offer alternatives on an opt-in basis, which would allow the Commission to see how the new rates affect solar adoption and influence other key features such as system size, orientation, storage integration, and use of advanced inverters. Distributed Solar Advocates cite the New Hampshire Public Utilities Commission as a state taking this approach, noting that among the pilot programs to be implemented were time-of-use rates, real-time pricing, and monetary bill credits to expand DG ownership to low- and moderate-income customers. *Id*. at 13-14.

A third option recommended by Distributed Solar Advocates is combining net-metering with time-of-use rates (TOU net-metering), which they suggest should be

[59] NARUC DER Manual at 62.

introduced gradually and conditionally, with net-metering customers first being offered the chance to elect TOU net-metering, and the success of the program being evaluated carefully prior to any decision to require TOU net-metering for new net-metering customers. Distributed Solar Advocates describe how TOU net-metering could work and the benefits to customers and utilities, noting that netting would still occur across the billing period (one month), but net-metering customers would receive different levels of credit for their exports, which would roughly track the value of the exports to the utility under the TOU rate. Distributed Solar Advocates also point out that California's three investor-owned utilities have TOU net-metering, having been implemented in 2014 under the California PUC's "NEM Successor Tariff."[60] Distributed Solar Advocates note that under state law, the state's investor-owned utilities were required to switch to TOU net metering when solar DG penetration reached five percent of aggregated customer demand, or by July 1, 2017, whichever came first. By the sake of comparison, Distributed Solar Advocates note that solar DG penetration in Arkansas is still less than 0.1 percent. *Id.* at 15-16.

Distributed Solar Advocates argue that TOU net metering can provide benefits for a utility's system once solar becomes more prevalent, leading the net load peak hours to shift to later in the afternoon or early evening hours. These benefits arise, Distributed Solar Advocates state, because TOU net-metering incentivizes customers and third-party developers to install systems that maximize production, and therefore system benefits, during utility peak load hours. For example, Distributed Solar Advocates note, if the customer's utility peaks in late afternoon, rather than midday, then the customer may be

[60] *See* Calif. Pub. Util. Comm'n, Decision Adopting Successor to Net Energy Metering Tariff, at Rulemaking 14-07-002 (July 10, 2014); *see also* Calif. Pub. Util. Comm'n, Net Energy Metering (NEM), at https://www.cpuc.ca.gov/General.aspx?id=3800.

incentivized to install a system with some components facing the west or southwest. According to Distributed Solar Advocates, TOU net metering also strengthens the incentive for customers to reduce their energy usage during peak hours, noting that the TOU rate has this effect directly on consumption, as consumers seek to shift their energy usage away from high-cost periods, but the higher price for exports during the peak enhances the incentive, as net-metering customers realize the value they can capture for exports if they are not using the energy behind the meter. *Id.*

According to Distributed Solar Advocates, because the time when net load peaks can shift later in the day as solar penetration on the system increases, TOU net metering automatically adjusts to reflect the gradually reduced value of solar to offsetting system peak. In this way, say Distributed Solar Advocates, TOU net metering would also incentivize the development of hybrid solar and storage facilities, so that customers can continue to offset as much of their high-cost usage as possible, even if and when system peaks shift into the early evening hours. To be clear, Distributed Solar Advocates state, Arkansas utilities are far from having the degree of solar penetration where there is an observable effect on net load, but TOU net metering would put in place a durable structure to reflect the changing value of solar as the installed solar capacity in the state increases. Distributed Solar Advocates note that several Arkansas utilities already have opt-in TOU rates for residential or small commercial customers, the joint parties recommend that those rates be comprehensively revisited in light of any new intended purpose, and to ensure that the on-peak windows selected, and the rates imposed for usage (and exports) during different periods, accurately reflect the cost to the utility of providing service during peak times. Distributed Solar Advocates recommend that any transition to TOU net metering should be gradual, and suggests that the Commission consider a pilot period in which net-metering customer can opt into TOU net-metering, as was the case in California. Distributed Solar Advocates also suggest that the Commission consider piloting rate structures that can provide a vehicle to incentivize customers to install and enable the capabilities of advanced inverters, to allow DG systems to provide ancillary services to the grid and integrate higher levels of DG without requiring distribution system upgrades. This incentive, Distributed Solar Advocates assert, could take the form of an adder to the net excess generation credit or any rate that specifically applies to exports, in order to reflect the value of those ancillary services or the value of the visibility to the utility. *Id.* at 16-18.

Finally, Distributed Solar Advocates believe that transparency into the hosting capacity on the utility's distribution system is vital to streamlining and facilitating the interconnection process, optimizing the value of customer investments in DG, and enabling customers and DG developers to avoid proposing projects in congested areas of the distribution system, or at least be aware of the potential interconnection costs associated with doing so. Distributed Solar Advocates state that the Commission can help realize the highest level of benefits envisioned by AREDA by proactively pursuing policies, supported by well-designed pilots, to lay the foundations of utility transparency and willingness to help maximize the benefits of DG, as the Commission is currently evaluating in Docket No. 16-028-U. *Id.* at 18-20.

ii. Corrected Direct Testimony of R. Thomas Beach

In Corrected Direct Testimony filed on October 21, 2019, Mr. Beach, principal consultant of the consulting firm Crossborder Energy, testifies on behalf of the Distributed Solar Advocates and provides an updated and corrected benefit/cost analysis of net-metering on the EAL system in 2019, based on the 2017 Crossborder Study that he previously submitted in Phase 2 of this Docket, with updates to the key numbers for 2019.

According to the Executive Summary of Mr. Beach's recommendations, the Corrected Direct provides an updated benefit/cost analysis of the cost effectiveness of net-metering on the EAL system in 2019, based on the 2017 study that he previously submitted in Phase 2 of this Docket, with key numbers for 2019. This study examines the benefits and costs of net metered solar DG using the full set of cost-effectiveness tests for demand-side resources that are standard practice in the utility industry. The tests examine the benefits and costs from the multiple perspectives of all key stakeholders, using a comprehensive set of costs and a long-term time frame that considers the full economic life of solar DG systems. Mr. Beach states that this update of the 2017 study uses current forecasts of avoided energy costs (based on an updated natural gas forecast), avoided generation capacity costs (from EAL's 2018 integrated resource plan (IRP), avoided long-term transmission and distribution (T&D) costs (by extending the 2017 study's analysis), carbon emission costs (from the 2018 EAL IRP), and other minor updates. Beach Corrected Direct at 3. The results of Crossborder's updated analysis are shown in his tables and are similar to the results of the 2017 study. *Id*. at 3-4.

Based on these results, Mr. Beach testifies that the principal conclusions of Crossborder Energy's prior analysis remain valid today:

- Solar DG is a cost-effective resource for EAL, as the benefits equal or exceed the costs in the Total Resource Cost (TRC), Program Administrator (PAC), and Societal tests. As a result, in the long-run, deployment of solar DG will reduce the utility's cost of service.

- Net metering does not cause an unreasonable allocation of costs to non-participating ratepayers, as shown by the result above 1.0 for the Ratepayer Impact Measure test.

- The economics of solar DG are marginal for EAL's residential customers, as shown by the Participant test results just above 1.0 and the modest amount of solar adoption to date. The Commission should be mindful of this result as it considers any proposed change in the compensation provided to solar DG customers.

- There are quantifiable societal benefits from solar DG, including local economic benefits and public health improvements from reduced air pollution, that are of comparable size to the direct economic benefits to ratepayers.

Id. at 4.

Mr. Beach testifies that 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 that can provide uninterrupted power when the utility grid is down. Distributed generation also enhances customers' freedom, he states, 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. He notes that 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.

According to Mr. Beach, Solar DG is not the only new DER technology that is on the horizon. For example, battery storage paired with other types of DERs promises to increase substantially the value of DERs to the utility system. The best approach to ensure that demand-side programs such as NEM continue to maintain an equitable balance among all stakeholders, he states, is to develop cost-based, TOU rates. TOU rates will signal more accurately to customers the cost consequences of the changes that DERs will produce in the hourly profiles of the loads that the utility serves with power delivered from the grid. Mr. Beach states that such a time-sensitive rate design, in conjunction with net metering, is the best and most cost-based means to accommodate the expected diverse combinations of DER technologies. In his opinion, such a rate design should be developed in a rate case where the most information relevant to making rate design changes is available. *Id.* at 5.

Mr. Beach describes the 2017 Crossborder Study filed in Phase 2 of this Docket, stating that it examined the benefits and costs of net metered solar DG using the full set of cost-effectiveness tests for demand-side resources that are standard practice in the utility industry. He notes that EAL regularly does similar analyses of the cost-effectiveness of its portfolio of demand-side programs – *i.e.*, energy efficiency (EE) and demand response (DR) programs – that focus on encouraging customers to conserve energy and reducing their use of the grid during peak demand periods. Mr. Beach testifies that the 2017 study provided a comprehensive benefit-cost analysis of demand-side solar in EAL's service territory, noting that the analysis had the following key features:

1. **Multiple perspectives.** The study examined 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 in the development of solar DG. To capture all of these perspectives, Crossborder Energy examined 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.** Crossborder's approach to valuing solar DG began with the same direct benefits to ratepayers that EAL employs to evaluate its other demand-side programs. These are the standard "avoided costs" for electric service that a utility like EAL saves when a customer installs behind-the-meter (BTM) solar generation that largely serves the customer's own load. Then Crossborder

added certain other avoided costs from solar DG that also directly benefit EAL ratepayers – such as lower market prices and reduced exposure to volatile natural gas prices. This comprehensive analysis drew upon similar 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.

3. **Use a long-term, life-cycle analysis** that covers the full economic life of a solar DG system, which is at least 25 years. This is standard practice for these analyses, and a long-term, life-cycle analysis is also standard practice when a utility wants to build and then charge its customers for a new plant that will last for decades, thus treating solar DG on the same basis as other utility resources, both demand- and supply-side.[61]

Id. at 10-11.

Mr. Beach states that the direct benefits to ratepayers of net-metered solar DG are the savings that EAL realizes in its energy, generating capacity, delivery, and environmental costs when customers install solar to serve a portion of their own load and then export power that serves their neighbor's load. He states that EAL's own analyses for its EE and DR resources include these benefits. He testifies that Crossborder Energy also included certain additional direct benefits for ratepayers from distributed solar that have been widely recognized and used in similar analyses:

- the benefit that solar displaces natural gas generation, thus reducing ratepayers exposure to volatility in natural gas prices;
- the benefit that solar adds to the state's energy supplies, thus reducing prices in the state's electricity and natural gas markets; and
- the benefit that solar will reduce the utility's long-term need to expand its transmission and distribution wires.

[61] Mr. Beach points out the asymmetry of a utility's use of cost-of-service analysis to evaluate net-metering by looking only at benefits and costs over a short, historical one-year test period compared to how the utility assesses the cost-effectiveness of utility-owned plant.

Mr. Beach adds that finally, there clearly are additional, indirect, or "societal," benefits from rooftop solar, such as the local economic benefit from new solar installation activity and the public health improvements from reduced air pollution. He states that these benefits accrue to all residents and ratepayers in EAL's service territory. Further, he states, these benefits can be quantified – not necessarily for the purpose of increasing compensation to solar customers, but so that decision-makers understand the magnitude of these additional benefits. He urges the Commission to weigh these additional benefits, as it sees fit, in determining the overall public interest. *Id.* at 11-12.

Mr. Beach explains how the Crossborder Study examined the cost-effectiveness of net metering form a variety of perspectives, by comparing the direct benefits of net-metered solar for ratepayers to several different sets of costs:

- To look at the perspective of all ratepayers and the utility system as a whole (the Total Resource Cost (TRC) test), the costs are the costs to install a solar system and then integrate it into the utility grid.
- To look at the perspective of those ratepayers who do not install solar, Crossborder examined two tests. In the most stringent test – the Ratepayer Impact Measures (RIM) test – the costs are the revenues that the utility will lose because solar customers will be supplying their own loads with their own power, instead of buying from the utility. Mr. Beach notes that the RIM test often is criticized because it is not forward-looking – the lost revenues consist mostly of "sunk," already-incurred costs. He states that another perspective the Program Administrator Cost (PAC) test, avoids this problem and considers only the utility's going-forward costs to

implement the net-metering program. The PAC test measures whether the program will reduce future bills on average across all utility customers.

- To look at the benefits and cost of solar DG from the perspective of customers who install the resource (the Participant test). In this test, he states, the costs are the installation cost of a solar system (incurred by the customer) and the benefits are the savings that the solar customer realizes from a lower utility bill.
- To look at the broadest perspectives for the benefits and costs of solar DG, Crossborder added the societal benefits to the direct benefits in the TRC test, in a Societal test.

Id. at 12-13.

Mr. Beach testifies that the updated results of these tests are shown on Figure ES-1 and Table ES-1 from Crossborder Energy's 2017 Study. He states that the results of the TRC and RIM tests conducted in 2017 were that net metering was cost effective from both of these perspectives. He states that the benefit/cost ratio above 1.0 in the TRC test meant that net-metered solar provided an overall benefit to all ratepayers in Arkansas. Likewise, he states, the perspective of the stringent RIM test was important because it meant that installing solar in 2017 did not cause any kind of long-term cost shift to the "non-participating" ratepayers who do not install solar. Crossborder Energy's analysis showed that for customers who installed net-metered solar in 2017, the economics of that decision were marginal in Arkansas, with the long-term costs higher than the benefits. This, Mr. Beach states, certainly accounted for the modest amount of solar DG adopted to that date.

Id. at 13-14.

Interestingly, Mr. Beach states, the economic and health benefits of solar were significantly greater than Crossborder Energy's calculation of the benefits of rooftop solar in combating climate change. Overall, he states, these quantifiable societal benefits are similar in magnitude to the direct benefits to ratepayers. Mr. Beach testifies that Crossborder Energy concluded in its 2017 study that net metering was cost-effective in Arkansas, such that it was fair to continue to compensate net-metered solar customers at the full 1:1 retail rate. *Id*. at 14.

According to Mr. Beach, the 2017 study discusses other benefits of distributed solar resources that are difficult to quantify, but the Commission should acknowledge and consider them qualitatively. These additional benefits include:

- Rooftop solar enhances the 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 solar also enhances customers' freedom, choice, and engagement, allowing them to choose the source of their electricity and resulting 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 full advantage of federal tax incentives for solar that will begin to phase out in 2020.

Id. at 14-15.

Mr. Beach testifies regarding the updates to the key assumptions used in the Crossborder Study, to use current information. These include:

- **Avoided energy.** Crossborder Energy updated its forecast of avoided energy costs for solar DG using (1) hourly MISO day-ahead market prices for the Arkansas hub from a recent 12-month period from September 2018 to August 2019 and (2) the Energy Information Administration's (EIA) *2019 Annual Energy Outlook* (*2019 AEO*) forecast of natural gas prices at the Henry Hub, Louisiana as the basis for the long-term escalation in avoided energy costs. The result is a 25-year levelized avoided energy cost for a typical solar output profile of $44.90 per MWh. This is lower than the avoided energy costs in the 2017 Study, as a result of lower current and forecasted natural gas prices.
- **Avoided generation capacity.** Crossborder Energy reviewed the *2018 EAL Integrated Resource Plan* (*2018 EAL IRP*) to update its understanding of the utility's capacity position and avoided generation capacity costs. The *2018 EAL IRP* includes three scenarios. All of the scenarios include EAL continuing to add demand-side resources each year, as well as new solar resources in 2021. These near-term additions suggest that EAL has a current and continuing need for capacity. Two of the three scenarios show that the utility's first major capacity addition is a new combustion turbine (CT) in 2025. Crossborder has modeled EAL's avoided generation capacity costs assuming the addition of a CT in 2025, using the CT costs from the *2018 EAL IRP*. The result is a 25-year levelized avoided generation capacity cost of $31.70 per MWh. Crossborder also estimated EAL's avoided generation capacity costs using a forecast of capacity prices in MISO Zone 8, assuming that Zone 8 capacity prices increase to the cost of new entry (CONE) by 2025. The result was slightly higher than Crossborder's calculation using the CT

costs in the *2018 EAL IRP*. See *Direct Testimony of Kenneth K. Collison, Vice President ICF on behalf of Entergy Arkansas, LLC*, at Figure 1. Crossborder assumed 8% marginal capacity losses and 7% marginal energy losses. For example, Entergy Arkansas joined MISO after 2013, and EAL's FERC Form 1 data changes on that date. Crossborder performed linear regressions of distribution system and transmission system additions as a function of annual peak loads, both for the period prior to MISO integration (*i.e.*, 1996-2013), and for the period since then (2014-2018), including a dummy variable to indicate MISO participation.

- **Avoided T&D line losses.** Crossborder Energy updated the distribution line loss factors for energy and capacity to use the marginal losses cited in testimony filed by EAL on March 15, 2019 in Docket No. 07-085-TF.
- **Avoided T&D capacity.** Crossborder Energy's 2017 Study used EAL's FERC Form 1 load and cost data to calculate long-term avoided T&D capacity costs. Crossborder updated its analysis to use more years of available data. Its updated analysis results in a long-term avoided T&D capacity value of $21.70 per MWh, which is similar to the results in the 2017 Study.
- **Avoided carbon costs.** The scenarios in the *2018 EAL IRP* include three different scenarios for carbon costs. In Crossborder's judgment, the carbon cost profile in the Future C scenario is the most realistic, although it is conservative in not including any carbon costs until 2027. EAL is procuring new solar capacity today in recognition that renewables provide a hedge against the costs of carbon emissions, which indicates that there is value today in avoiding emissions of CO2.

- **Other benefits.** The fuel price mitigation and market price suppression benefits are derived from Crossborder Energy's forecasts for natural gas prices and avoided energy costs. Crossborder has updated these benefits based on its revised forecasts.

Id. at 15-16.

Mr. Beach states that Table 1 summarizes Crossborder Energy's revised calculations of the direct ratepayer benefits of solar DG. *Id*. at 16.

Mr. Beach explains how he has updated the costs used in the cost-effectiveness tests:

Cost of Residential DG Solar. The costs in the TRC and Participant tests are the LCOE of residential distributed solar systems in Arkansas. Crossborder updated these costs using the most recent data for residential systems (2Q 2019) from the Solar Energy Industries Association and Wood MacKenzie's latest *U.S. Solar Market Insight* report. This is a national average cost for residential systems; Crossborder Energy expects that costs in Arkansas may be lower than the national average.

Bill Savings / Lost Revenues from Residential DG Solar. The benefits in the Participant test are the bill savings realized by residential customers who install solar DG; these are also the costs in the RIM test, because the bill savings are the revenues lost by the utility. Crossborder updated the bill savings calculation from the 2017 Study to use today's EAL rates, including applicable riders.

Integration Costs. The 2017 Study assumed that the utility incurs integration costs of $2 per MWh to cover the higher ancillary service costs expected to result from the addition of variable solar generation. This estimate was based on a number

> of solar integration studies performed by other major utilities in the 2012-2014 time frame. More recent solar integration analyses have calculated substantially lower integration costs; this includes studies by utilities with increasing penetrations of solar resources. For example, recent solar integration studies from PacifiCorp and Idaho Power have reported integration costs of about $0.60 per MWh. In addition, Crossborder recently analyzed ancillary service costs on the California Independent System Operator's grid and have found no increase in these costs, as a percentage of wholesale market costs, over the last 15 years (2014-2018), despite the addition in this period of 20 GW of solar resources to a grid in California that has a peak demand of 50 GW. These lower integration costs are attributable to (a) methodological improvements in the studies themselves, (b) reduced market prices, (c) "learning by doing" experience operating the grid with solar resources, and (d) the increased availability of regulation-capable gas-fired resources displaced by new renewables (*i.e.*, a greater supply of ancillary services). For this update, Crossborder has reduced integration costs to $1 per MWh.

Id. at 17-18.

According to Mr. Beach, the updated results shown at in Figure ES-1 and Table ES-1 at the beginning of this summary of his testimony are similar to the 2017 Study results, and the principal policy conclusions of Crossborder Energy's prior analysis continues to apply:

> 1. Solar DG is a cost-effective resource for EAL, as the benefits equal or exceed the costs in the TRC, Program Administrator, and Societal tests. 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 "an unreasonable allocation of costs" to non-participating ratepayers, as shown by the results for the Ratepayer Impact Measure and Program Administrator Cost tests.

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 remain marginal for EAL's residential customers, as shown by the Participant test results just above 1.0 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 further as solar costs 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 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 1 advantage of federal tax incentives for solar that will begin to phase out in 2020.

Id. at 20-21.

Mr. Beach comments on why the approach he has used in analyzing the cost effectiveness of net-metered solar DG is superior to approaches based on the utility's cost of service. He states that there are numerous reasons why COS analyses are inappropriate for evaluating the benefits and costs of DERs – be they EE, DR, or net-metered solar DG. He asserts that COS analyses have the following limitations for this purpose:

> Limited to a single test year. DERs are long-term resources. Other resources with long useful lives are not judged based on their impacts on ratepayers in a single year. For example, a new utility generating plant or transmission line with an economic life of 30-50 years is not judged based solely on its impact on the first-year revenue requirement.
>
> The benefits of DERs are avoided costs; these are not the embedded, historical costs used in COS studies. Avoided costs are, by definition, counterfactual – they are costs that the utility never incurs because it procures a service from another source. In the well-known formulation of avoided costs in PURPA, "avoided costs mean the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." As a result, it is questionable whether avoided costs can be measured accurately by the utility's embedded costs, which are not counterfactual but are the historical costs which the

utility actually has incurred. Basic economics informs us that the more accurate way to measure avoided costs is to calculate the utility's long-run marginal costs, which measure how the utility's costs vary with the change in demand or supply that result from the addition of a 1 new long-term resource such as DERs.

DERs produce certain direct, quantifiable benefits (avoided costs) for ratepayers that are not included in embedded cost rates. These include avoiding the risk of volatile natural gas prices. Another such benefit is avoiding future costs associated with reducing carbon dioxide emissions. This is an avoided cost that is included in utility IRPs and in the cost-effectiveness evaluations of other types of demand-side resources.

Multiple perspectives. An embedded COS analysis focuses solely on whether net metering is an equitable short-term allocation of existing costs among different classes of ratepayers.[62] It does not consider other important perspectives – including the key long-term perspectives of whether DG is a reasonable long-term investment for the DG customer, for the utility system, and for society as a whole. It is the combination of all of these perspectives that constitutes the public interest in net metering.

Id. at 21-22.

[62] Mr. Beach states that it is possible and even likely, that a detailed cost-of-service analysis conducted in a rate case will show that DG customers are less expensive to serve than standard customers. He states that this is what he showed in his earlier critique of the Study Group 2's COS analysis of solar DG in Phase 2 of this Docket. He notes that the installation of solar DG can result in reductions in the DG customer's delivered loads in system coincident peak hours in the summer months that are 40% to 60% of the DG system's nameplate, even though the annual capacity factor for the solar array is much lower, about 20%. This results in a much lower allocation of production and transmission costs, per kWh, to solar DG customers than to standard customers. He states that there also can be substantial reductions in DG customers' usage in the hour of the class coincident peak, resulting in a reduced responsibility for distribution costs.

Mr. Beach makes recommendations regarding the appropriate process for making changes to net-metering or to any type of compensation or incentives for customers who install DERs. The first analysis, he says, should be a long-term benefit/cost analysis to determine whether DERs are a cost-effective resource under current net-metering policies. If they are, he states, then there is no need for a near-term change in the compensation for DER customers. Clearly, he states, conditions in energy markets and on the grid will change over time – for example, due to increases in the penetration of new types of generation, such as solar. He states that there is likely to be a proliferation of many types of DERs that customers can use to serve their own loads, to shift in time their usage from the grid, and – with DG and storage DERs – to export excess power to the grid. He contends that if there is a need to adjust the rates applicable to DER customers to restore an equitable balance among participating and nonparticipating customers, a rate case would be the correct forum in which to make such rate design changes. *Id.* at 22-23.

Mr. Beach argues that rate cases also will be the correct forum to respond to the growth of the many types of DER technologies or potential combinations of DER technologies. Different DERs or combinations of DERs can produce significantly different load profiles and annual usage. For example, he states, the pairing of solar with storage can shift the output of the DER system to exactly the time period when this output is most valuable to the utility system, increasing the value of the DER output. He asserts that the best approach to accommodate the full range of possible DER technologies will be to develop, in rate cases, cost-based TOU rates that signal accurately to all customers the cost consequences of any possible change to the hourly profiles of their loads that are served by the utility from its grid. Such a time-sensitive rate design, in conjunction with net metering, is the best and most cost-based means to accommodate the wide range and combination of DER technologies.

m. Scenic Hill Solar

Introduction

Scenic Hill Solar notes that it does not serve the residential market, so although it supports the joint filing on the Strawman NMRs by Distributed Solar Advocates, it has limited its comments to how Act 464 impacts demand-metered customers. Scenic Hill Solar Initial Comments at 1.

Staff Strawman

Scenic Hill Solar supports Staff's changes to the NMRs that incorporate the uncontroversial provisions of Act 464. *Id*. at 2.

Meter Aggregation and Applicable Billing Period

Scenic Hill Solar supports the joint comments of Distributed Solar Advocates, Audubon, and Sierra Club regarding Act 464's provisions for meter aggregation and the applicable billing period. *Id*.

Demand Metered Customers

Scenic Hill Solar asserts that Act 464 does not give the Commission the authority to modify the rate structure for customers on demand component bills. Instead, Act 464 provides prescriptive language for net-metering demand billed customers. Scenic Hill Solar points out that during Phase 2, there was agreement within the NMWG that demand-metered customers are only netting the energy portion of their consumption, and are not causing any significant cost shifting. Scenic Hill Solar quotes from the NMWG Final Report, prior to the enactment of Act 464, wherein the utilities in Sub-Group 2 explicitly stated, "Sub-Group 2 recommends that demand-billed tariffs continue to be billed as they are today."[63] *Id.* at 3.

Grandfathering

Scenic Hill Solar recommends a modification to Rule 2.07 that strikes the phrase "subject to approval by the Commission" to make it clear that the Commission is not required to engage in case-by-case grandfathering adjudication, but has issued its approval by establishing generally applicable rules for grandfathering. Scenic Hill Solar also argues that statute itself provides an inherent limitation to the applicability of a general grandfathering period by specifying that it applies only during the time period beginning with enactment of Act 464 and ending at December 31, 2022, the date at which federal tax credits expire. Scenic Hill Solar argues that Act 464 granted automatic approval for projects greater than 300 kW, but less than 1 MW in size, and thus the Act cannot reasonably be interpreted to delay these projects for a case-by-case grandfathering review, when such review would essentially subject them to the same delays that the General Assembly sought to eliminate by automating their approval. Scenic Hill Solar further argues that it cannot escape notice that the General Assembly applied uniform grandfathering language to all projects – making no distinction for a grandfathering decision (as was the prior practice of the Commission) between automatically approved projects and those subject to project-by-project approval. Scenic Hill Solar asks the Commission to maintain 1:1 net metering for demand-metered customers in its NMRs, as required by Act 464, and take all actions allowable under Act 464 to foster the distributed

[63] NMWG Final Report, September 15, 2017, at 156, and Attachment B-5, Sub-Group 2's redline of the Commission's NMRs, retaining 1:1 Net-Metering for demand-metered customers.

solar energy market in Arkansas to allow the state to achieve significant penetration, as intended by Act 464. *Id.* at 4-12.

2. REPLY COMMENTS

a. Staff

i. Reply Comments

Introduction

Staff filed its Reply Comments and the Direct Testimony and Exhibits of Kathleen Kelly. Staff has revised its proposed amendments to the NMRs and has included them as Exhibit A. Staff states that its comments and the proposed NMRs have been drafted with the goal of promoting the public interest and public policy goals of AREDA, as spelled out in Section 2(a) of AREDA (Ark. Code Ann. § 23-18-602). Staff attaches as Exhibit B a Report of Net-Metering Adoption Percentages in Arkansas, reflecting extremely low levels of Solar PV penetration, both as a function of percentage of customers and total utility capacity as of December 31, 2018.

The Report shows the following as a percentage of customers: EAL – 0.06%; SWEPCO -- 0.10%; OG&E – 0.07%; Empire – 0.24%; all electric cooperatives – 0.17%; and Grand Total of all utilities – 0.11%. The Report shows the following as a function of total utility capacity: EAL – 0.12%; SWEPCO – 0.26%; OG&E – 0.05%; Empire 0.08%; all electric cooperatives – 0.21%; and Grand Total of all utilities – 0.24%. Staff Reply Comments at 1-2 and Exhibit B.

Staff recommends that the Commission regulate in a way that encourages solar development to the maximum extent authorized by law until solar penetration reaches a more significant level. Staff further recommends that utilities be allowed to propose alternative rate structures in a general rate case, so as to allow the Commission to address concerns unique to each utility's service territory and customer population. *Id.* at 3.

Rate Structure

Staff repeats its observation in its Initial Comments that Act 464 provides a continuation of the current 1:1 full retail rate structure for net-metering customers who receive service under a rate that includes a demand component, but grants the Commission the discretion to alter the current 1:1 full retail rate structure for net-metering customers who receive service under a rate that does not include a demand component and for customers who propose to build facilities that exceed the statutory limits as provided in Ark. Code Ann § 23-18-604(b)(9). *Id.* at 3-4.

Staff states that several utilities have pointed to the lost contribution to fixed costs (LCFC) caused by the installation of solar in the SGS class, and notes that EAL has gone even further and flooded the record with unrealistic projections of what the LCFC would be if 100 percent of its customers in the SGS and LGS rate classes were to adopt solar PV. Staff states that despite reciting this speculation over and over again, these hyperbolic projections do little to inform the Commission and do not provide substantial evidence of any unreasonable customer cost shifting of the solar installations currently on their system for classes over which the Commission has discretion to choose the "net-net" energy metering rate structure – such as the residential class or demand-metered customers with net-metering facilities over 5 MW. Staff states that at least one utility (SWEPCO) has recognized that the Commission lacks discretion to alter the statutory rate structure of 1:1 for net-metering facilities in classes with a demand component under 5 MW and has therefore asked the Commission for an "exception" for this class in the NMRs. Staff notes that the fact that the Commission lacks discretion to alter the rate structure precludes it from granting the requested exception. *Id.* at 4 and fn 10.

For those classes without a demand component – such as the residential class – Staff notes that the Commission is granted the authority to select from a range of rate structures for net-metering customers. Staff continues to support the adoption of NMRs that permit each utility to propose a unique rate structure that is consistent with Act 464 rather than a "one-size-fits-all" approach. Staff cites Carroll's Floor-to-Ceiling approach[64] as a helpful metaphor, with avoided cost as the Floor and 1:1 retail rate as the Ceiling. Staff states that at this time, the law has only authorized the Commission to lower the ceiling for non-demand-metered customers. Staff and the AG propose setting a default Net-Metering rate structure that can be modified upon a utility's demonstration of actual rate and bill impacts as a result of net metering. Based on the plain text of Act 464, Staff believes the default rate should be 1:1 net metering. *Id.* at 4-5.

<u>Demand Component Billed Rate</u>

Staff does not believe Act 464 gives the Commission the authority to apply different rate structures to customers who receive service under a rate that includes a demand component, even if a large portion of fixed cost is collected in the energy component. Based upon its reading of Ark. Code Ann. §§ 23-18-604(b)(9) and 23-18-603(8)(B)(ii) and (iii), Staff summarizes the rate structure options for demand-metered customers and the Commission's discretion to approve a different rate structure as follows:

a. Up to 1,000 kW net-metering facility = Continued 1:1 net-metering rate structure for demand-metered customers;

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[64] Carroll Initial Comments (Doc. No. 366) at 5.

b. 1 MW to 5 MW net-metering facility = Continued 1:1 net-metering rate structure for demand-metered customers;

c. 5 MW to 20 MW net-metering facility = Net-metering rate structure for demand-metered customers must not result in an unreasonable cost shift to other utility customers.

Staff believes the only options for relief from the 1:1 retail rate structure for demand-metered customers are to allow utilities to propose modifications to the three-part rate design for these classes in a general rate case or to seek changes from the General Assembly to grant the Commission the authority to change the rate structure for such customers. *Id.* at 5-6.

Rate Structure for Non-Demand Customers

As noted above, Staff recommends that the Commission continue the current 1:1 full retail rate structure for non-demand-metered customers as a general rule and allow new and different rate structures on a utility-specific basis. More particularly, Staff recommends that if electric utilities choose to propose a new and different rate structure option for non-demand-metered customers as authorized by Act 464, they be required to file an application for a general change in rates to request that the Commission review and address any unreasonable cost shifting and rate design issues as a result of net metering. Staff states that the Commission should require the application to include a cost-of-service study, substantial evidence that net metering has reached a significant penetration level of the electric utility's metered customer load, and substantial evidence that the electric utility's proposed rate structure is in the public interest and will not result in an unreasonable allocation of, or increase in costs to, the electric utility's other customers.

According to Staff, this utility-specific case-by-case approach would allow utilities to address any rate design issues in the context of a general rate case. *Id.* at 6-7.

Staff discusses the potential rate structure options that the Commission may consider under its recommended approach:

- **2-Channel Billing**: Staff does not oppose the AG's proposal to phase in 2-Channel Billing for those utilities that have demonstrated significant solar PV penetration and unreasonable cost shifting in the 1:1 full retail rate structure for non-demand-metered classes.
- **Grid Access Fee**: Staff does not object in theory to a grid access fee for non-demand customers, if a utility can present substantial evidence showing that it is in the public interest.
- **Fixed Costs**: Staff notes that several utilities have indicated that a portion of their fixed costs are recovered in the energy component of a customer's bill – contrary to the cost-of-service results. Staff state that this issue is better addressed in a general rate case than with a one-size-fits-all net-metering rate structure. While current rate designs may have been appropriate at the time they were adopted, Staff states that this misalignment of rate design and the cost-of-service study may result in unreasonable cost shifting when net-metering reaches certain penetration level. Staff notes that the underlying rate design issue arose from and is more appropriately dealt with in a general rate case.
- **Cost Shifting**: Staff recommends that any alleged cost shifting as a result of LCFC be addressed on a utility-by-utility basis pursuant to the procedures

proposed above for different rate structures. Staff states that it will be the burden of the utility requesting the change to demonstrate reasonableness and points out that no cost-shifting impacts would be experienced by customers without Commission approval of a change in existing rates in a general rate case.

Id. at 7-8.

Reporting Requirements

In order to allow the Commission to better assess renewable energy penetration on a utility-by-utility basis, Staff recommends that the Commission adopt additional requirements for the annual report on Net-Metering Facilities that utilities are required to file in Docket No. 06-105-U. In particular, in addition to requiring utilities to report net-metering adoption percentages based on the utility's number of customers, the Commission should require reporting on the following metrics:

1. Adoption of net-metering facilities as a percent of the utility's total production capacity in kW and kWh by rate class;
2. Net-metering as a percentage of the utility's peak demand;
3. The solar PV installation information by rate class;
4. The kW and kWh of each installation by rate class; and
5. The monthly peak demand by rate class.

Id. at 9.

Grandfathering

Staff states that the General Assembly enacted Act 464 for the purpose of reducing barriers to solar development. Since economic risk is a barrier to solar development, Staff asserts that grandfathering is a form of consumer protection that reduces the economic risk of investing in solar generation. To promote administrative efficiency and effectuate the policy goals of Act 464, Staff states that the Commission should make some grandfathering automatic, as it did in Order No. 10 in this Docket, issued on March 8, 2017. However, Staff does not agree with comments that propose grandfathering of net-metering rate structures be automatic for 20 years for all customers without Commission approval. More particularly, Staff addresses the following categories of grandfathering:

1. **Case-by-case Grandfathering for Net-Metering Facilities (NMFs) 1,000 kW or more:** Staff quotes from Order No. 10 regarding proposed grandfathering for customers who petition for permission to exceed the size limits set by statute:

> The Commission finds that because Waivers by definition are to exceed statutory limits, and because larger NMFs potentially have more effects (costs or benefits to other customers) on the system, each request for a Waiver should individually address whether it is in the public interest for that Waiver to be grandfathered, to the extent it meets all other criteria for grandfathering.[65]

Consistent with Order No. 10, Staff recommends that the Commission continue to consider and approve grandfathering on a case-by-case basis for net-metering facilities whose customers request to exceed the statutory limits for net-metering facilities pursuant to Ark. Code Ann. § 23-18-604(b)(9).

2. **Automatic Grandfathering for Net-Metering Facilities below 1,000 kW:** To promote administrative efficiency, Staff recommends that the Commission not require individual review and approval of grandfathering for facilities that are within the limits of Ark. Code Ann. § 23-18-603(8)(B)()(b)(i) and (ii), and thus do

[65] Docket No. 16-027-R, Order No. 10 at 150.

not already require Commission review and approval. Staff states that this includes: (a) Residential facilities pursuant to Ark. Code Ann. § 23-18-603(8)(b)(i); and (b) Non-residential facilities below 1,000 kW pursuant to Ark. Code Ann. § 23-18-603(8)()(b)(ii).[66]

Staff states that Commission Order No. 10 provides that "[e]vidence also supports a 20-year life for Net-Metering Facilities and a common warranty period of 25 years." Therefore Staff recommends that the Commission approve grandfathering of these facilities for the statutory maximum period of twenty years. *Id.* at 10-11.

Meter Aggregation

On the subject of meter aggregation, Staff agrees with the initial comments of Distributed Solar Advocates that "customers seeking to aggregate meters should be allowed to indicate common ownership." However, Staff suggests that this be through a sworn affidavit. Staff's proposed NMR amendments support inclusion of the Rule 2.05(D) proposed by those Parties in their initial comments, with additional revisions proposed by Staff. In particular, Staff recommends that Net-Metering customers be required to complete and submit a standard application form approved by the Commission and a sworn affidavit by a person with personal knowledge affirming that the customer is in fact the legal owner of all accounts listed in the meter aggregation application form. Further, Staff recommends that electric utilities be prohibited from requiring common tax ID numbers as proof of common ownership, since more than one tax ID number can be under common ownership. Based on comments regarding delays in the interconnection process,

[66] The Commission notes that Ark. Code Ann. § 23-18-603(8)(B) sets the limit at "not more than" 1,000 kW rather than "below 1,000 kW."

Staff strongly supports that a clear, streamlined, auditable and therefore readily enforceable approach is essential. *Id.* at 11-12.

Renewable Energy Credits

Staff states that AREDA provides that "[a] renewable energy credit ("REC") created as the result of electricity supplied by a net-metering customer is the property of the net-metering customer that generated the renewable credit."[67] Staff notes that development of clean and renewable solar energy provides broad benefits to society regardless of who retains the RECs that are produced by solar development. However, Staff states, as EAL correctly points out, RECs have value.[68] Staff states that although Arkansas does not currently have renewable energy standards or goals that are tied to the accounting of RECs, any ability for the customer, utility, or the state to count these net-metering facilities as "renewable energy" lies with the holding or retiring of the REC. Therefore, the Net-Metering Consumer Guide should inform net-metering customers that they are not required to simply hand over any RECs that they own to the utility or third-party developer. Staff states that the sale or trade of the REC should be conducted in an arm's length transaction. Further, Staff states, the Net Metering Code of Conduct should require compliance with the Federal Trade Commission's *Guides for the Use of Environmental Marketing Claims*, as codified in 16 C.F.R § 260.15(d). *Id.* at 12-13.

Distributed Solar vs. Utility-Scale Solar

Staff states that Act 464 encourages distribution non-utility-scale solar and it also includes requirements for large-scale facilities to seek specific approval, and for governmental entities to meet certain requirements in order for them to be considered net

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[67] Ark. Code Ann. § 23-18-604(b)(8)(B).
[68] EAL Initial Comments at 10.

metering. Staff states that whether such solar installation proposals meet the specific requirements of Act 464 remain fact-specific and are more appropriately dealt with in dockets seeking approval – not this rulemaking docket. *Id.* at 13.

Interconnection

Staff states that there are concurrent discussions about the interconnection procedures in relation to DERs in Docket No. 16-028-U and supports a single solution for both DER and net-metering facilities that recognizes new ownership structures and new technologies associated with Act 464. To that end, Staff suggests that adoption of a single set of procedures such as those included in *IREC's Model Interconnection Procedures, 2019 Edition* submitted as an Attachment to Staff's Initial Comments would be reasonable. Staff states that while no other party has suggested a wholesale change in the current interconnection procedures contained in the existing NMRs, several Parties have suggested changes to the current forms to recognize the new ownership structures and new technologies allowed by Act 464. Staff does not oppose these suggested modifications until such a time that a single set of procedures can be developed to apply to DERs and Net-Metering Facilities and has incorporated those changes in the Net-Metering Rules. *Id.* at 13-14.

Customer Protections, Code of Conduct, and Consumer Guide

Staff agrees with the many comments suggesting that all net-metering participants would benefit from certain customer protections and codes of conduct, as well as the development of an informative Consumer Guide to net-metering in Arkansas. Staff recommends that the Commission establish a working group to develop and submit for Commission approval the following:

1. As noted in Staff's Initial Comments, Staff continues to support the creation of a Code of Conduct as critical for both the solar provider and the public utility. Areas to be considered include, while not exhaustive, mandatory procedures and requirements, including disclosure requirements that must be followed by solar developers and utilities in connection with the construction, ownership, lease, interconnection, or operation of a net-metering facility in Arkansas. Staff notes that it continues to research existing resources, which should be of benefit.
2. An informative Consumer Guide or Customer Bill of Rights as a tool to assist customers in evaluating net-metering options. Staff has identified ample existing resources to draw upon and is willing to lead or participate in an effort to develop the resource and would also continue to work collaboratively with the Parties to produce a well-informed educational tool. Staff continues to support inclusion of the following non-exhaustive list of topics:
    - How Solar Power Works
    - Generating Electricity
    - Life-Span of Solar Equipment
    - Ownership Options in Arkansas
    - Purchase
    - Lease
    - Know Your Situation (usage, roof, finances, weather)
    - Do Your Homework (best deal, research the solar company, understand any tax credits or incentives, insurance)

- Understand the Agreement (terms, ask questions, estimates versus guarantees, warranties, property insurance)
- Understand the Interconnection Process (your responsibilities, installer responsibilities)
- Key Questions to Ask
- Working Out Differences
- Understanding what happens to your Solar Facility during a utility outage (safety)
- Understanding Renewable Energy Credits (RECs) and how to avoid deceptive practices

Id. at 14-15.

ii. Direct Testimony of Kathleen Kelly

Kathleen Kelly testifies in support of Staff's Reply position on grandfathering, including information on the extent to which grandfathering has been utilized by commissions in other states; and states that, given the low penetration of solar PV in Arkansas, the Commission need not rush to implement changes to net-metering rates within this proceeding in response to concerns that that rapid penetration of net-metered solar in Arkansas is causing a cost shifting that burdens non-participating customers. Ms. Kelly also comments on the opportunity for the Commission to use gradualism when making rate changes in response to increased net-metered solar systems within this or subsequent proceedings, and points to the benefits of such a determination being made in the context of a general rate case proceeding.

Ms. Kelly's testimony is based on her review of the comments by the Parties and, in summary, her comments are as follows:

- Grandfathering of the ratemaking that existed/exists when customers invested/invest in net-metering qualified facility should be approved as it is clearly allowed by statute in Arkansas and is a widely used practice by commissions across the country.
- The current low level of penetration for net-metered solar systems in Arkansas affords the Commission the opportunity to implement rate design changes over time, and on a utility-specific basis while incorporating what the Commission decides are the appropriate use of gradualism and grandfathering. Other states, including Rhode Island, Massachusetts, Arizona, Utah, Kansas, and Montana, have successfully opted to use utility-specific processes to assess the rate implications rather than an immediate establishment of rates through a state-wide rulemaking mandate.
- The current rate regulation in Arkansas requiring Commission approval of rate changes means that to date customers have not been impacted as a result of any speculations of alleged cost shifting, regardless of whether utilities may have experienced some level of reduced revenue collection from net-metering solar customers. Any measurable shifting that might occur in the future can only be determined by a thorough review of utility costs, marginal costs, the value ascribed to solar by policymakers in Arkansas, a new cost-of-service study and rate designs, and subsequent changes in rates approved by the Commission. Whether cost shifting is reasonably known and measureable, the foundational cost recovery

standard in Arkansas can best be addressed in the context of a comprehensive general rate case proceeding.

- Adopting an implementation of Act 464 of 2019 through a rulemaking that incorporates gradualism is good for customers, the solar industry, **and** the electric utilities.

Kelly Direct at 6-7.

Ms. Kelly recommends that the Commission utilize grandfathering of existing rules and rates for existing net-metering customers, and provides Exhibit KK-2 to show how widely grandfathering has been approved. Some states have considered creating a separate rate class and/or a different rate structure for net-metering customers, as well as implementing an alternate compensation and/or billing mechanism for net-metering customers. Her review of dockets in these states leads her to conclude that grandfathering is a means to enable rules and rates to evolve while still treating existing net-metering customers fairly. *Id*. at 7.

According to Ms. Kelly, given the unique service territories, penetration levels, and current rate designs, there is merit to considering rate design issues in a proceeding outside of this Docket. She suggests that the Commission consider the benefits of each utility developing its own specific proposals in separate proceedings, such as a general rate case, compared to utilizing a single set of rules and rates for all utilities immediately in this proceeding. She states that the ratemaking process in Arkansas accommodates a utility-specific process, noting that a general rate case is based on a test year that is most commonly comprised of history and six months of projection, or forward-looking information. Additionally, she notes, the twelve months after the test year can be adjusted based on reasonably known and measurable changes. This results in up to 18 months of forward-looking data, she states, which will allow a utility to incorporate in its load forecast for the penetration of solar PV systems with various rate designs, including the design it is proposing. This approach also ensures the same reasonably known and measurable standard in establishing rates in conjunction with net metering and is the statutory framework for general rate determination in Arkansas. *Id.* at 8-9.

Ms. Kelly testifies that the comments in this proceeding have shown that there is relatively low penetration of solar PV systems in net-metering applications in Arkansas and thus no urgency to establish specific changes in rates for net metering. She states that the existence or magnitude of cost shifting associated with each net-metering installation can be debated. She notes that even if there is a reduction in utility revenue that is greater than the cost savings of the utility when a solar PV system is operating in net metering, the formula ratemaking process that three of the four investor-owned utilities have elected means that customers will not see their class allocation change unless a general rate case is initiated and the Commission approves changes. Thus, she states, there is no cost shifting imperative for the Commission to act quickly within this proceeding to set new net-metering rules and regulation. She suggests that the Commission could take advantage of this to set up a process where no changes are made until a utility files a general rate case, which would allow the Commission to avoid establishing an order based on dated cost-of-study proceedings, without an Arkansas-specific view on the value of solar, the lack of established marginal costs for the utility that results from net-metering solar PV systems being installed or considered being installed, and a reasonably known and measurable project of expected net-metered solar penetration and impact. She states that all of this is necessary to establish just and reasonable rates that capture any cost shifting. *Id.* at 9-10.

Ms. Kelly recommends that the Commission should make minimal to no changes to the existing 1:1 retail rates for net-metered customers and have those remain in effect until a utility files a general rate case to make changes. She further recommends that the Commission amend the reporting requirements in NMR Rule 4.02 to require utilities to file solar PV installation information by rate class, include the total number of net-metering customers within each rate class, include the kW and kWh of the installation by rate class, and include the monthly peak demand by rate class. With this information, she states, the Commission could then periodically and more readily monitor the penetration levels by rate class and consider establishing a penetration limit for the amount of installed net metering that could then trigger the Commission initiating a review of the impacts of net metering and solar PV installations. *Id.* at 10-11.

Ms. Kelly testifies that her Exhibit KK-4 shows that, as of 2017, various limits for the amount of solar that can utilize net-metering rules and regulation had been established in other states – several of which used a percent of peak demand. Her intent in presenting this information is to show that limits are established and vary from very limited to as large as 20 percent of the energy in the system. *Id.* at 12.

Ms. Kelly summarizes the benefits of addressing rate design in utility-specific general rate cases:

- There are benefits to the Commission itself in that there is now a window of opportunity to incorporate gradualism and grandfathering.

- There are benefits to the existing net-metering customers who have made investments based on Commission ratemaking and legislative policy by allowing them the opportunity to realize the savings they expected.
- There are benefits to non-net-metering customers because a determination of any cost shifting will be reviewed and addressed in a comprehensive and more thorough ways not possible outside the context of a general rate case.
- There are benefits to the solar industry in that they can continue to develop local business capability to deliver solar systems and establish the infrastructure to make their businesses sustainable.
- There are benefits to the utility in that it can develop the forecasts of solar penetration consistent with its total and marginal cost trends to better support any case for cost shifting. In addition, the utility can evaluate its proposed actions in a way that responds more comprehensively with evaluations of its customer value proposition and its distribution system design and planning rather than focusing solely on rates as its competitive lever.

Ms. Kelly concludes by observing that the utilities, stakeholders, and the Commission will likely find that the best path forward to further AREDA is a utility general rate proceeding that ensures comprehensive consideration of all data and policies, enabling a fair balancing of everyone's interests, including determining the pace of change that serves Arkansas best. *Id*. at 12-13.

b. Attorney General

In Reply Comments, the AG addresses rate structure, grandfathering, customer protections, leasing, and draft rules.

Rate Structure

Gradualism. The AG reiterates her support for a transition to 2-Channel Billing that would move closer to an excess generation credit based on avoided costs as net-metering penetration increases. This transition would balance the AG's goal to move towards a more equitable allocation of costs while being sensitive to the market disruption net-metering developers could experience from an abrupt and dramatic change in rate structure. The AG's review of Initial Comments does not change the AG's position that a gradual change of the rate structure is necessary. The AG notes that Staff came to the same conclusion regarding gradualism and the concern regarding cost shifting. However, the AG does not believe it is reasonable to downplay the subsidization concerns of the utilities, especially when planning for the future of net-metering in Arkansas. The AG is working informally with EAL to gather information specific to EAL's system that will further inform the AG's view regarding the magnitude of the cost shifting and assist in crafting reasonable solutions within reasonable time frames. Therefore, the AG continues to support a long-term policy that mitigates subsidization, or eliminates it if possible, while seeking a reasonable gradual transition to a rate structure that accomplishes this policy goal. AG Reply at 2-4.

Flexibility. The AG supports flexibility for the utilities in how net-metering is implemented and, to some degree, in how net-metering rates are set, citing Empire and AECC as advocates for flexibility, given the diversity of the utilities' abilities to implement technologies capable of supporting advanced solutions and the material differences between electric cooperatives and investor-owned utilities. Notwithstanding this, the AG continues to support a standard rate structure as the default, such as the 2-Channel Billing rate structure. However, the AG agrees that there may be utility-specific circumstances where a 2-Channel Billing rate structure is not feasible or is overly burdensome for some or all of its rate classes. The AG would thus support a mechanism whereby any utility that desires to deviate from the standard 2-Channel Bill approach can make a filing with the Commission requesting an exemption or variation, and propose and alternative net-metering rate structure that it believes is more reasonable for its customers and its customers' specific circumstances and is likewise in the public interest. *Id*. at 4-5.

Quantifiable Benefits. The AG states that numerous Parties addressed the term "Quantifiable Benefits" as it relates to setting a reasonable net-metering rate structure, noting that Distributed Solar Advocates asserted in their combined Initial Comments that while Act 464 does provide a more specific definition of the term than was suggested in the prior statute, the use of Quantifiable Benefits is not required when the Commission chooses to pursue any of the other rate structures within its authority, and as such "is a clear sign of legislative intent to move away from a rigid cost-based rate structure." On the other hand, the AG states, Carroll argues in its Initial Comments that Act 464 provides the Commission discretion to consider Quantifiable Benefits and costs associated with net-metering customers, seeing the application of Quantifiable Benefits as an area where the Commission can foster flexibility and the use of utility-specific information. According to the AG, OG&E also states that it is of the utmost importance to develop net-metering rates that are reasonable and based on truly Quantifiable Benefits, urging caution in including any such benefits that cannot be tied to an accounting or market mechanism or any amount not currently included in a utility's cost of service. *Id*. at 6.

The AG agrees with OG&E and believes that any additional monetary benefits included in net-metering rates must be quantifiable. The AG asserts that the term Quantifiable Benefits has been sufficiently defined in Act 464 and as reflected in the AG's draft NMRs.[69] The AG urges the Commission to consider establishing a standard formula to calculate Quantifiable Benefits to eliminate ambiguity on what can and cannot be included in net-metering rates. The AG also support's Carroll's desire for flexibility and the need to use utility-specific information and data when setting net-metering rates, and believes a standard formula to calculate Quantifiable Benefits will achieve this goal. *Id*. at 6-7.

Grandfathering. The AG reiterates her Initial Comments interpretation of three levels of grandfathering created by Act 464 and notes that there seems to be a significant divergence of views on grandfathering within the Phase 3 comments filed by others. At one end of the spectrum, the AG observes, the view is that there should be no grandfathering at all. On the other end, says the AG, the view is that the rate structure at the time of interconnection should be grandfathered in for the life of the net-metering facility. The AG states that it and some other commenters fall somewhere in between. *Id*. at 8.

The AG recounts the positions of the Parties on this topic, and then repeats her original position that Act 464 gives the Commission authority to grandfather net-metering customers who fall into Level 2 (net-metering customers submitting an interconnection agreement between the effective date of Act 464 and December 31, 2022) on a case-by-case basis, noting that the specific language of Act 464 supports a case-by-case determination.

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[69] AG's Phase 3 Initial Comments, Appendix A at 21-22.

The AG points out that the statute clarifies that any possibility for grandfathering can only occur "following notice and opportunity for public comment."[70] That AG believes that all grandfathering, both Level 1 (net-metering customers established before the effective date of Act 464 – July 24, 2019, who are automatically grandfathered into the current rates at that time: 1:1 Billing) and Level 2, should be limited to twenty years, as described by Act 464, beginning from the date the interconnection agreement is signed. The AG argues that its current recommendation on grandfathering would fall squarely within the plain language of Act 464. *Id*. at 8-10.

Customer Protections

Code of Conduct. The AG states that there seems to be general agreement in the Initial Comments that a code of conduct for net-metering participation should be developed to protect customers, citing proposals from AECC and Carrol, which actually included a Proposed Customer Bill of Rights and Code of Conduct. The AG repeats her original suggestion that customer protection issues, including discussion of Carroll's proposal, should be addressed through a separate working group that allows for flexibility as issues arise. The AG recommends that such a working group should consist of Staff, the AG, net-metering providers, and the utilities. The AG cites the successful PWC on matters related to energy efficiency programs as an example of a successful working group in Arkansas. However, the AG suggests that additional parameters be established for the net-metering customer protections working group, including a deadline for filing a Net-Metering Code of Conduct for Commission approval. In addition, the AG recommends that the working group should be required to meet at least semi-annually to address any

[70] Ark. Code Ann. § 23-18-604(b)(10)(A).

new issues that need to be added to the Code of Conduct or revisions to be approved by the Commission. The AG suggests that more frequent meetings can also be set to deal with urgent issues. *Id*. at 11-12.

Regulation of Non-Utility Providers. The AG recounts her concerns in her Initial Comments that the Commission does not have statutory authority to regulate certain non-utility providers and notes that other Parties share this concern. The AG agrees with some of those Parties that net-metering providers should be required to register with the Commission prior to installing net-metering facilities in the State and be subject to program suspension or expulsion due to non-compliance with a Commission-approved Code of Conduct. However, the AG observes that to gain such authority for the Commission, legislation would be required. Without such legislation, the AG recommends that the Commission craft rules and regulations in such a way that utilities, which ultimately hold the responsibility for net-metering interconnection and which are strategically placed to protect the net-metering customer, bear the responsibility of customer protection. *Id*. at 12-13.

The AG asserts that it is reasonable for the Commission to enact rules such that if an unregulated third-party net-metering provider or participant does not adhere to the Code of Conduct, interconnection will not be completed or allowed to continue by the utility. The AG comments that this approach puts more burden on the utilities, which is not preferable, but absent legislation that gives the Commission general direct oversight of net-metering providers, there are limited options that will properly protect customers. The AG encourages the Commission to seek appropriate legislative changes that would place enforcement of the Code of Conduct where it belongs rather than punishing utilities for failing to adequately police unregulated third-party participants. *Id*. at 13.

Consumer Rights and Consumer Education. The AG agrees with numerous other Parties that there is a need for both a Consumer Guide and a Customer Bill of Rights and recommends that one of the assignments given to the customer protections working group include their development. The AG suggests that the Commission explore requiring the submission of a customer acknowledged copy of the Consumer Guide and Customer Bill of Rights with any net-metering interconnection request forms. The AG believes that the submission requirement is an appropriate term and condition for net-metering under Act 464. *Id*. at 13-14.

Leasing. In keeping with her recommendations regarding customer protections, the AG states that necessary legislative changes may be required to compel net-metering leasing providers to register with the Commission prior to installing net-metering facilities in the state and be subject to program suspension or expulsion due to non-compliance with a Commission-approved Code of Conduct. The AG expresses appreciation to EAL for suggesting that either a review process be established for lease agreements to be submitted to Staff and the utility, or the creation of a form agreement that net-metering providers would be required to use for leasing options. The AG states that this is also an issue best handled in the context of a customer protections working group. *Id*. at 14-15.

Net-Metering Rules. The AG reiterates her argument that it would be more administratively efficient to begin with the language of Act 464, as that represents the current public policy of the State of Arkansas and that draft rules be narrowly tailored to the statute. This, she asserts, is preferable to shoehorning Act 464’s fundamental alterations to net metering into the existing NMRs. The AG continues to urge caution due to the dictates of Ark. Code Ann. § 25-15-220 requiring rules to be narrowly tailored to only that which is absolutely necessary to affect the statute. *Id*. at 15-16.

c. Entergy Arkansas

Introduction

Primarily addressing the comments from Staff and the Distributed Solar Advocates, EAL states that according to those Parties, there are no concerns that the Commission needs to address with any urgency, and most surprisingly, nothing that the Commission has any authority to address in several key areas. EAL argues that the Distributed Solar Advocates and Staff are misguided, and EAL submits that the Commission's swift action is needed for the protection of all customers. EAL Reply Comments at 1.

First, EAL asserts, there is a very real problem and the Commission should be concerned that:

- Contrary to the erroneous and patently self-serving claims of the Distributed Solar Advocates, sub-scale net-metered solar is clearly uneconomic, and the Commission can and should reach that conclusion readily, without the need for further study.
- The 1:1 full retail credit rate structure creates a significant incentive for customers to pursue uneconomic sub-scale solar, at the expense of non-participating customers – this too, requires no further study or analysis.
- Cost shifts are occurring now. There is urgency for the Commission to act, given the magnitude of the subsidy under the current 1:1 full retail credit rate structure and the volume of projects that have sought Preliminary Site Review and/or been

announced. Claims that cost shifts currently are, and will continue to be, *de minimis* are false.

Second, EAL states that claims that the Commission lacks authority to address the problem in certain key areas are incorrect in that:

- The Commission retains the authority to modify the rate structure applied to customers with demand charges, either by eliminating the 1:1 full retail credit or by imposing an additional charge.
- The Commission retains the authority to determine whether a proposed generation facility actually qualifies for net-metering.
- Requests to grandfather the rate structure applied to a net-metering facility remain subject to review and approval on a case-by-case basis by the Commission.

EAL argues that, in short, the Commission faces an urgent choice between two very different futures: one – the preferred course – where grid-scale solar is aggressively pursued at economic prices yielding the twin benefits of economic capacity and energy for all customers as well as economic development and environmental benefits for the region; or the other – contrary to the public interest – where misguided net-metering policies result in substantial investment in uneconomic sub-scale solar for the benefit of the very few at the expense of the many. EAL urges the Commission to choose the first path and act now to ensure that its promise is realized. To be clear, EAL states, it is not advocating in any way, shape, or form that customers should not have the opportunity to install their own self-generation; rather, the Commission's net-metering policies and rules must ensure that other customers are not made to subsidize that choice by having to pay higher electric rates, which is the current path for the State of Arkansas in the absence of immediate action by the Commission. *Id*. at 2-3.

EAL summarizes its request that the Commission take the following actions in an order addressing the issues raised in Order No. 22:

- Implement 2-Channel Billing for non-demand billed customers (e.g., residential and certain small commercial customers);
- Implement either 2-Channel Billing or a grid charge for customers who pay a demand charge;
- Confirm that, in order to qualify for net-metering, the renewable generating facility must be physically attached to the customer's load (i.e. behind-the-meter), with appropriate sizing and aggregation requirements;
- Confirm that grandfathering, given its cost-shifting and distortive effects, will not be available for a customer unless approved for the customer through a specific order from the Commission

Id. at 3-4.

Rate Structure Issues

EAL states that the Commission can and should act now to implement a rate structure that sends the correct pricing signals to customers considering investing in a net-metering facility. EAL argues that the predictable consequence of leaving the 1:1 full retail credit rate structure in place is a vastly more significant problem that will only become more difficult to address with the passage of time. EAL further states that the Commission has the opportunity and the duty now to design an appropriate rate structure, given the proliferation of solar opportunities now enabled by Act 464, that satisfies the "apples to apples" comparison that was presented to the Senate Committee as the overarching goal when the General Assembly was considering the Senate Bill that ultimately became Act 464. More particularly, EAL states:

A. Arkansas is not a "low penetration state." EAL disagrees with Staff's assertion that net metering is "underdeveloped" in Arkansas or that Arkansas is a "low adoption state." EAL asserts that this mischaracterization forms the basis for Staff's advocacy of several positions that would promote further net metering in Arkansas, including an assertion that the current 1:1 full retail credit framework may be acceptable for the time being and that, as a consequence, some level of cost shifting that inevitably will follow may be reasonable. EAL points out that Staff' asserts,[71] without any quantification or substantiation, that because of low penetration of net metering today, "there is minimal to no measurable cost shifting occurring between customers within and between customer classes, particularly in light of unrecognized benefits" of net metering. EAL argues that Staff's perspective fails to give sufficient consideration to the fact that Act 464 stands to enable a significant near-term increase in the level of net metering in Arkansas, which depends in significant part on the outcome of this rulemaking. EAL notes that Distributed Solar Advocates make arguments similar to those of Staff, but responds that the Commission should reject these arguments as self-serving and instead balance several competing objectives, as discussed in EAL's Initial Comments. EAL states that the Commission should not, as Distributed Solar Advocates argue, adopt a "tunnel-vision" focus on the single objective of promoting additional net-metering opportunities, to the sole benefit of the Distributed Solar Advocates and customers who avail themselves of net

[71] Staff Initial Comments at 4.

metering (and to the significant detriment of all other customers and Arkansas generally). EAL references the lessons learned from Hawaii and Arizona, which it cites as jurisdictions that waited until net-metering penetrations were at more critical, saturated levels to enact needed policy reforms. EAL urges the Commission not to "kick the can down the road" under the erroneous basis of "low penetration," which it says may be politically expedient. EAL states that the issue of unfair cost shifting will continue to grow, likely dramatically based on recent media reports involving tax-exempt entities pursuing larger net-metering projects. *Id.* at 5-7.

B. Current 1:1 full retail credit rate structure creates an unreasonable cost shift. EAL critiques the testimony and analysis of Distributed Solar Advocates witness Beach and the accompanying updated Crossborder Study, stating that the assertions by Mr. Beach that (1) "solar DG is a cost-effective resource" and (2) that 1:1 full retail credit "net metering does not cause a cost shift to non-participating customers." EAL asserts that both of these assertions depend on the existence of large offsetting benefits from distributed solar (with avoided costs now estimated by Mr. Beach at 15.7 cents/kWh), that rely on numerous "inaccurate and inflated assumptions" as well as methodology issues that were addressed extensively in Phase 2 of this proceeding. EAL states that some of the benefits that Crossborder attempted to quantify are wholly unrealistic and not credible – in particular Crossborder's conclusions regarding the existence of avoided T&D costs. *Id.* at 7-8.

EAL asserts that the simplest way to illustrate the unreasonableness of Crossborder's overall benefits estimates (*i.e.*, avoided costs) is by comparison to the cost of grid-scale solar, which it states is in the range of 3.5 cents/kWh in Arkansas. EAL asserts that grid-scale solar can provide at least the same, if not greater, economic and environmental benefits as distributed solar, citing to the testimony of its witness Mr. Schnitzer.[72] *Id*. at 8.

EAL states that the value of distributed solar in Arkansas, which may avoid a small amount of transmission line losses in relation to grid-scale solar when sited behind-the-meter, simply cannot be 15.7 cents/kWh when the cost of grid-scale solar, which provides the same or higher benefits is 3.5 cents/kWh. EAL argues that sub-scale solar is not cost effective as a resource to serve customers since the current net-metering rate structure provides a subsidy that promotes the development of high-cost, sub-scale solar instead of low-cost, grid-scale solar and is not paid by the participating customer – it is ultimately paid by non-participants. EAL quotes the 2016 dissent of California Public Utility Commissioner Michael P. Florio on this point:

> 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 not correct; the utilities are just a conduit. Other customers – the people who do not or cannot even have solar – pay the compensation 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...."[73]

Id. at 9.

C. Additional Studies are unnecessary and a needless delay. EAL argues that Staff's Initial Comments' recommendations[74] to perform more studies is unwarranted, since the existence of a cost shift is readily apparent and can be reliably and objectively

[72] Schnitzer Testimony at 9-11.
[73] California Public Utility Commission Decision 16-01-044, Adopting a Net Energy Metering Successor Tariff, Feb. 3, 2016.
[74] Staff Initial Comments at 4 and 7.

quantified as the difference between lost revenues and the cost of grid-scale solar, as described by Mr. Schnitzer.[75] EAL asserts that additional studies are unnecessary to quantify exactly how worse off non-participants are, as the important facts were established in Phase 2 and have not changed since then. EAL responds to Staff's arguments (1) that a certain level of cost shifting is "part and parcel" of ratemaking based on grouped classes of customers and (2) it is not practical to set individual rates for customers. According to EAL, while some amount of cost shifting is unavoidable within grouped classes of non-homogeneous customers (e.g., residential customers in different geographic locations or with different consumption patterns), this does not imply that cost-shifting should be encouraged. EAL further asserts that there is no practicality concern where there is an identifiable group of net-metering customers that, given the existing 1:1 full retail credit rate structure, is causing a large and rapidly growing cost shift. EAL notes that it has proposed two alternative rate structures to mitigate the cost shift, both of which it asserts can be readily implemented. *Id.* at 10-11.

D. The cost shift is already significant and growing rapidly. EAL responds to Staff's premise that the penetration of net-metering resources is currently low and its recommendation that the Commission consider retaining the 1:1 full retail credit rate structure until net-metering penetration increases "to a threshold that might result in more substantial cost shifting." EAL states that this premise is incorrect – the size of the cost shift is already significant and has been growing rapidly, especially following the passage of Act 464. EAL states that the explosive growth that is now occurring across the state – in actual installation, in new Preliminary Site Reviews, and in news reports of

[75] Schnitzer Direct at 25-26.

proposed large projects – all lead to the conclusion that what had been a potentially manageable issue is quickly spiraling into a major problem that, if left unaddressed, will lead to a large, long-term cost shift that will adversely impact the rates all customers pay and may affect the State of Arkansas's economic competitiveness via impacts to its significantly lower than nation average electric rates. *Id.* at 12.

EAL points to the testimony of Mr. Schnitzer as quantifying that the cost shift associated with the net-metering arrangement announced by the City of Hot Springs is approximately $29 million over the thirty-year life of that arrangement and that the cost shift associated with a different PPA with Pulaski County is $11 million over twenty years.[76] EAL notes that media announcements demonstrate that other similarly large arrangements are being negotiated, but no such arrangements by any entity (including the City of Hot Springs and Pulaski County) have been presented to the Commission for review and potential approval. EAL asserts that the State of Arkansas has reached a threshold where the amount of cost shifting is rightly characterized as "unreasonable." *Id.* at 13.

According to EAL, if the Commission does not implement a new rate structure, the only reasonable expectation is that the acceleration of private solar development activity will continue, and the problem will become larger and increasingly difficult to address. EAL states that, as explained by Mr. Schnitzer, "customers in each of EAL's major rate schedules already have, or could soon have, actionable incentives to pursue net-metering under the 1:1 full retail credit rate structure. EAL asserts that this is especially true following Act 464, because of the ability to lease solar facilities and, for tax-exempt customers, to source solar using long-term PPAs." Importantly, EAL asserts, each new net-

[76] Schnitzer Direct at 26-28.

metering arrangement increases the size of the cost shift, and the longer the 1:1 full retail rate structure is left in place, the more private solar developers will come to depend on it for their financial gain, and the more difficult it will be for the Commission to address later for the protection of non-participating customers.[77] *Id.* at 12-13.

Commission Authority to Reform Net Metering

EAL states that the Commission has authority to modify NMRs and should use that authority to avoid gaming and assure that rates for all customers remain just and reasonable. EAL asserts that Distributed Solar Advocates, as well as Staff in several instances, advocate strained interpretations of Act 464 language that would limit the Commission's authority to make certain determinations and assert incorrectly that Act 464 dictates particular outcomes on several critical issues. For example, EAL states that Staff and Scenic Hill Solar assert that Act 464 requires that a 1:1 full retail credit be provided to demand-metered customers, recommending that no other rate structure modifications be incorporated into the NMRs for such customers. In addition, EAL states, Distributed Solar Advocates contend that the Commission should adopt rules that impose little to no review of net-metering by the Commission, particularly with respect to issues such as grandfathering, determining whether facilities actually are eligible for net metering, and questions involving "common ownership." EAL argues that these positions should be rejected, as they not only are inconsistent with the statutory provisions of Act 464 but also limit arbitrarily the Commission's ability to regulate the development of net metering in Arkansas, as well as its ability to assure that rates are just and reasonable for all customers. *Id.* at 13-14. More particularly, EAL asserts that:

[77] *Id.*

A. Under Act 464, the Commission retains the authority to modify the rate structure for net-metering for demand-metered customers, either by eliminating the 1:1 full retail credit or by imposing an additional charge. EAL states that Act 464 provides the Commission with a specific overarching directive, i.e., that the Commission "shall establish appropriate rates, terms, and conditions for net metering."[78] EAL argues that this grant of authority to the Commission aligns with the specific powers and duties that the General Assembly has provided the Commission, i*.e.*, the authority to "find and fix just, reasonable, and sufficient rates to be thereafter observed, enforced, and demanded by any public utility."[79] EAL notes that Staff and the Distributed Solar Advocates agree that Act 464 grants the Commission authority to modify net metering rates for customers taking service under a rate that does not include a demand component. However, EAL states, the Distributed Solar Advocates contend incorrectly that the language in Ark. Code Ann. §23-18-604(b)(6) forecloses any option for the Commission to modify the rate structure for customers taking service under a rate schedule that includes a demand charge, claiming that this provision "is in sharp contrast to the Act's grant of discretion to the Commission regarding how crediting shall occur for non-demand-billed customers."[80] *Id.* at 14-15.

EAL asserts that this is a flawed interpretation that ignores the Commission's overall grant of authority referenced above, which provides the Commission with the clear authority to assure that the NMRs are appropriate and to assure that rates for all customers are just and reasonable. In this respect, EAL argues, the language in §23-18-604(b)(6) is silent regarding the rate at which the customer is to be credited, only that they

[78] Ark. Code Ann. § 23-18-604(b)(1).
[79] Ark. Code Ann. § 23-2-304(a)(1).
[80] Audubon Initial at 6, Scenic Hill Initial at 2-3.

are to be credited. In addition, EAL asserts, the "sharp contrast" between subparts (b)(5) and (b)(6) noted above overlooks the fact that the purported language in (b)(5) that the Distributed Solar Advocates contend "grants the Commission authority to modify net metering rates for customers that do not receive a bill with a demand component" (i.e., "as measured in kilowatt hours or kilowatt hours multiplied by the applicable rate") is included in the definition of "net excess generation," which appears in both (b)(5) and (b)(6). In support of its assertion that the Commission is foreclosed from addressing the net-metering rate structure for customers with a demand charge, EAL notes that Scenic Hill Solar further states:

> [T]he reason and justification for this difference is clear and was roundly debated in many parts of this proceeding: the argument that non-demand bill customers might not pay a cost-of-service level of charges to cover demand-related costs simply does not apply when demand-related costs are recovered through a demand component in the rate.[81]

Based upon this erroneous assertion, EAL contends, Scenic Hill Solar should agree that the inverse is also true, *i.e.*, where there are demand-related costs to serve a demand-metered customer that are *not* recovered through the demand component of the rate, i.*e.*, they are recovered through the volumetric portion of the rate, also known as the energy charge, then the argument that demand-billed customers are not paying the costs incurred to provide them electric service, in fact, does apply and should be irrefutable. *Id.* at 16-17.

EAL states it has already has provided evidence in this proceeding to demonstrate that a significant portion of the fixed costs incurred to provide service to demand-billed customers on the SGS rate schedule is recovered through the volumetric rate. EAL notes that its witness, Ms. Talkington, has explained in Docket No. 19-042-TF that there are

[81] Scenic Hill Solar Initial at 3.

significant fixed costs recovered through the SGS volumetric rate. EAL argues that the only evidence that Scenic Hill Solar can rely upon is the position taken by Sub-Group 2 in Phase II of this proceeding that omits important context, as well as an incorrect assertion that "EAL Arkansas ultimately supported Act 464."[82] In making this assertion, EAL states that Scenic Hill Solar attempts to relegate to a footnote EAL's overarching concern that Act 464 be implemented in a manner that ensures that cost shifting would not occur. As reflected in the actual recording of the statements before the Senate Committee on February 14, 2019, EAL states, its concerns, as well as those of other investor-owned utilities and AECC, were that Senate Bill 145 be implemented in a manner that would not produce cost-shifting and that would not dictate a particular result, to avoid the potential for cost shifting.[83] *Id.* at 17-18.

EAL cites the following comments of Commission Chairman Thomas before the Senate Committee as reflecting the intent to avoid the cost shifting produced by the 1:1 credit:

> [W]hat we want is not the option to leave it at the retail rate. We want the option to choose what the utilities have advocated, two-channel billing. And, what the solar advocates have added, advocated, monthly net. Now, you think those things would average out to be pretty close, but the way they are fighting I know there's some money there. So, what we want is options...we are not asking to keep the option of retail 1:1. We are asking within the context of the bookends between the two positions, to make the choice of the options between those and that's what this bill does.[84]

Id. at 18.

EAL asserts that Act 464 was designed to provide the Commission with options for altering the rate structure associated with net metering, not to limit its authority to

[82] *Id.*
[83] Testimony of Chairman Ted Thomas in support of Senate Bill 145 on February 14, 2019 before the Insurance and Commerce Committee (quote from audio transcripts at 11:00:42m 11:06:43).
[84] *Id.* (audio transcript at 11:26:58).

establish a reasonable rate structure for net metering in Arkansas. In the event that the Commission were to determine that demand-metered customers must continue to receive a 1:1 full retail credit for the energy produced by a net-metering facility, the Commission should approve the grid charge concept discussed by EAL witness Andrew Owens to assure that those demand-metered customers are not avoiding paying their reasonable share of the fixed costs for the electric system that they continue to use and upon which they continue to rely, a significant portion of which currently is recovered through those customers' volumetric rates. *Id.* at 19.

B. Grandfathering should be adopted only where specifically granted by the Commission. EAL asserts that grandfathering is another area where the Distributed Solar Advocates want to eliminate Commission review, noting that they recommend what they claim to be "a slight modification," namely to remove "subject to approval by a Commission," which is express language under Act 464. This, EAL states, would eliminate the General Assembly's express directive to the Commission to evaluate whether grandfathering is appropriate. EAL states that while none of these Parties nor Scenic Hill Solar makes an outright request for the Commission to adopt universal grandfathering, they admit that their proposed rule effectively authorizes grandfathering for <u>all</u> net-metering projects for a period of twenty years until the statutory period ends. In other words, EAL argues, they would bind the Commission with their suggested "slight" modification to provide 1:1 full retail credit net metering for all customers that submit a complete interconnection request prior to December 31, 2022, which EAL asserts cannot possibly be what was envisioned by the General Assembly when they included the term "subject to approval by a Commission." *Id.* at 19.

EAL argues that the plain language making grandfathering subject to Commission approval is there for a reason, noting that the objective of Act 464 is to promote cost-effective net metering, providing the Commission with the tools necessary to ensure that appropriate price signals are being sent to customers contemplating a net-metering investment. EAL asserts that grandfathering would limit the Commission's ability to modify the price signals that are being sent to those customers, and the Commission similarly would be limited in its ability to avoid or mitigate the unfair cost-shifting effects of net metering on non-participants. *Id.* at 20.

According to EAL, the support that the Distributed Solar Advocates offer for their position on grandfathering is not compelling, noting that those Parties assert that grandfathering is appropriate for purposes of administrative efficiency and to provide certainty that will promote increased development of net metering. Yet, EAL asserts, their recommendations would serve to promote all net metering, *i.e.*, that which is economically inefficient as well as efficient, which is inconsistent with the Commission's and the General Assembly's objectives. *Id.*

EAL notes that both Scenic Hill Solar and the Distributed Solar Advocates are frank about the problematic economics associated with net-metering facilities, with the latter admitting in its comments that "the economics of residential solar DG are currently marginal – that is, residential customers who install solar DG are barely able to recover their costs over the life of the system in most cases."[85] Similarly, EAL states, Scenic Hill Solar claims that "litigation time and expense will overwhelm project economics for many projects."[86] EAL argues that if the prospect of an administrative review of their project is

[85] Audubon Initial Comments at 12.
[86] Scenic Hill Solar Initial Comments at 5.

enough to "overwhelm" the project's economics, or if project economics are marginal even where an above-market credit is provided that far exceeds the costs to the utility to acquire renewable capacity and energy, the Commission should question whether allowing such a project to go forward with an explicit and substantial subsidy from non-participating customers is sound policy, or consistent with maintaining just and reasonable rates in Arkansas. *Id.* at 21.

EAL further argues that these Parties' interpretation limits the Commission's ability to regulate the development of net metering, noting that as EAL demonstrated in its Initial Comments and as the Commission has recognized previously, there is a physical limit to the amount of solar generating capacity that can be absorbed by Arkansas utilities. EAL asserts that if the Commission wants to obtain the maximum benefits of grid-scale solar development for Arkansans, it must retain the ability to manage the development of net-metering facilities to avoid foreclosing the development of much more economic, grid-scale solar development for the benefit of all customers. *Id.* at 22.

EAL agrees with Staff's recommendation that the Commission consider its current practice of approving grandfathering on a case-by-case basis,[87] as reflected in EAL's proposed modifications to the NMRs attached to its Initial Comments.[88]

Gaming Issues

A. The Commission's NMRs should limit, to the greatest extent possible, gaming opportunities by clarifying qualifications for net-metering treatment.

EAL argues that the comments submitted by the Distributed Solar Advocates reflect those Parties' singular focus on promoting net metering at any cost and in any conceivable

[87] Staff Initial Comments at 8.
[88] See Attachment to EAL's Comments on October 15, 2019 Net Metering Rules – Redline Version at 2-7.

manner, rather than in a manner that is economic, that ensures the legitimacy of proposed facilities and arrangements, and that is subject to clear rules. EAL asserts that those Parties' comments pay little to no attention to the Commission's request for rules addressing gaming opportunities, and a number of their respective positions actually would serve to promote gaming, with net-metering being available to facilities or arrangements well beyond those contemplated by the Commission or the General Assembly. Based upon the positions advocated by those Parties, EAL asserts that if adopted by the Commission, the following would occur:

- No meaningful review of "common ownership" would be required, with the customer merely needing to assert common ownership in some unverified writing;
- No contract review would occur to verify that a lease does not contain the statutory restrictions;
- No reviews would be required to confirm that a PPA (also known as a "service agreement") qualifies for safe harbor protection under federal law;
- No confirmation would occur that a tax-exempt entity even is qualified under the federal safe harbor language to enter into a PPA;
- The definition of "net-metering facility" relative to "net-metering customer" means that, for example, an application for Commission approval from the City of Hot Springs for 12.75 MW from five separate solar PV projects each with capacity between 1 to 5 MW may assert that review should occur under (b)(9)(A) (in other words, the overall capacity of 12.75 MW being proposed by City of Hot Springs greater than 5 MW is irrelevant relative to which provisions of Act 464 would apply);

• No criteria beyond that specified in (b)(9)(A) would be applied to net metering facilities between 1 and 5 MW (in other words, according to Scenic Hill Solar' strained reading of the statute, cost-shifting or any other issue not enumerated in that section is not to be addressed by the Commission in any manner during the review process); and

• Limited reviews would be conducted on any project exceeding 5 MW up to 20 MW (for those facilities unable to circumvent these size limitations altogether through the potential maneuvering described above), with the scope of those reviews limited by the purported statutory issues.

Id. at 23-24.

EAL states that in the paradigm confected by those Parties, the customer would be presumed to have an appropriately-sized facility based upon accounts that are aggregated, with the Commission not exercising any review and not determining whether the project complies with Act 464 and the Commission's NMRs. If those proposals were to be adopted, EAL argues, the Commission would have no way of assuring that net-metering is being implemented in a manner consistent with the General Assembly's directives or the Commission's NMRs and would simply take it on faith that the statutory framework is being respected. EAL states that the Commission should not adopt the approach these Parties advocate and instead should take this opportunity to utilize the tools provided by the General Assembly in Act 464 to assure that net-metering further develops in an appropriate manner. *Id.* at 24.

B. Determining common ownership for purposes of meter aggregation. EAL states that, consistent with a position that advocates few to no checks on net-metering installations, Distributed Solar Advocates and Scenic Hill Solar urge the Commission to establish "an easy, clear, and non-controversial means for customers to establish common ownership of multiple accounts for purposes of meter aggregation."[89] EAL asserts that the "elegantly suited" approach they advocate merely would have customers "indicate common ownership through the submission of a signed form to their electric utility."[90] Thus, EAL states, in order for a customer to aggregate additional meters to its account, Distributed Solar Advocates and Scenic Hill Solar would have the customer be required only to recite the fact of common ownership in writing. Thus, says EAL, these advocates contend that this approach "avoids unnecessary intrusions into customer tax IDs or other defining traits."[91] *Id*. at 25.

EAL responds that this recommendation is an absurd approach to resolving a real problem, noting that the fallacy of the advocates' position is demonstrated by the fact that they provide no acknowledgement of or response to the potential for gaming under this approach, much less any provisions to prevent gaming. EAL states that utilities, and the protection of the interests of their non-participating customers, require the establishment of a method to be able to confirm common ownership to avoid customer's claiming "common ownership" where none exists. Otherwise, EAL states, customers may be able to aggregate limitless accounts which share no common ownership, defeating the purpose of this statutory requirement, noting that this issue is critical for the aggregation provisions of Act 464 not to be abused. *Id*. at 25-26.

EAL observes that customers and developers are incentivized, through the far-above-market value provided by 1:1 full retail credit net-metering, to construct the largest

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[89] Audubon Initial at 5, Scenic Hill Initial at 2.
[90] *Id*.
[91] *Id*.

facility possible in order to maximize the subsidized bill savings that they will receive from the utility's non-participating customers, associated with a net-metering facility. As EAL reiterates its position that the question of what constitutes "common ownership" is not a simple one. EAL states that the methods used by utilities, including EAL, to confirm common ownership (e.g., tax ID numbers) are a reasonable approach to confirming that accounts proposed to be aggregated are, in fact, under common ownership consistent with the aggregation rules established in AREDA. EAL's use of taxpayer IDs is not an unreasonable "intrusion" and, indeed, such IDs are already commonly used by EAL and other APSC-jurisdictional utilities as the primary method to confirm customer identities for creation of accounts and for a host of other reasons, such as protecting against customer avoidance of unpaid charges for electric service simply by creating a new account for electric service under a different name. According to EAL, using taxpayer IDs for the purpose of ensuring common ownership is a natural extension of this type of existing usage of that information. Absent a systematic way to verify common ownership of accounts for aggregation under net-metering, EAL argues that utilities and the Commission are left with no way to verify that the statutory provisions are being followed and the process is not being gamed. EAL states that this is particularly concerning given the new provisions of Act 464 that permit service agreements for tax exempt or governmental entities. Without a means to confirm that the accounts are under common ownership and are all tax exempt, EAL contends that utilities will have no way to verify that the participating entities participating in these service agreements are qualified to do so. EAL recommends that the Commission adopt EAL's proposed modification to Rule 1.01

(b) to clarify that common ownership shall be verified by tax identification number. *Id*. at 26-27.

C. Determining whether a remote generator qualifies for net metering.

EAL notes that in its Initial Comments, Staff expressed "concerns with the ability for consumers to enter into agreements for larger facilities that will by their nature appear to be small power producers" because "the facilities will not physically serve a customer's load."[92] EAL strongly agrees with and shares Staff's concerns. Setting aside aggregation for the moment, EAL argues that net-metering contemplates facilities that are behind the customer's meter, just as the Crossborder Report assumed in its analysis. Indeed, EAL notes, the current NMRs and Staff's proposed Strawman both contemplate that arrangement, defining "Generation Meter" as "the meter associated with the Net-Metering Customer's account to which the Net-Metering Facility is physically attached."[93] EAL states that Act 464 itself clearly contemplates such physical attachment through its retention of the statutory requirement in AREDA that the "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" – there being no such bi-directional flow absent load and generation located at the same premises.[94] EAL repeats its position in its Initial Phase 3 Comments that permitting physical separation of the generator and the load against which it is net-metered would open the door for retail wheeling in potential violation of applicable FERC rules and federal law. For these reasons, EAL argues that the Commission should retain the definition of Generation Meter currently included in the Commission's NMRs and clarify in its next order that a net-metering facility must be

[92] Staff Initial at 8.
[93] Net Metering Rules, Rule 1.01(i) (emphasis added).
[94] Ark. Code Ann. § 23-18-604(a).

physically attached to the customer's load in order to qualify for net metering. EAL states that it has seen a proliferation of Preliminary Site Reviews that propose solar facilities that are remote generators tied to no customer load, including over 30 MW in aggregate since February 2019.[95] As such, consistent with Staff's recommendation, EAL states that it is critical that the Commission provide guidance in this docket that these facilities do not qualify for net-metering. EAL states that sizing of the net-metering facility is another matter where gaming can occur absent clear direction from the Commission. EAL notes that Act 464 provides that the net metering facility is "intended primarily to offset part or all of the net-metering customer requirements for electricity," adding that the Commission Chairman's statements regarding Act 464 echo this intent:

> The key legislative limitation on net metering is the quantity. What you are supposed to do is build for your load. You're not supposed to build more than you need and finance that by selling to others. To me, the balance struck in this legislation, is correct because it maintains that.[96]

Id. at 27-28.

EAL agrees with SWEPCO's statement in its Initial Comments that "there is no disincentive at this time to oversizing a system. Rather, conditions have changed in a way that makes one-for-one netting and cost payment an inducement for oversizing."[97] EAL agrees with SWEPCO and the Chairman that the Commission should clarify the manner for determining the appropriate size for a customer's facilities to avoid the result noted by the Chairman, *i.e.*, where the net-metering customer winds up exporting a substantial amount of energy to the grid. EAL notes that it discussed in Phase 2 of this proceeding as

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[95] *See, e.g.*, Supplemental Testimony of J. David Palmer at 7-9 (describing exemplar applications EAL has received for large-scale remote facilities and the concerns therewith).
[96] Testimony of Chairman Thomas in support of Senate Bill 145 on February 14, 2019 before the Insurance and Commerce Committee (quote from audio transcript at 10:39:38).
[97] SWEPCO Initial at 9.

part of Sub-group 2, that the majority of the excess energy from a net-metering customer is provided to the grid between 9 a.m. and 3 p.m.[98] EAL states that these hourly patterns of usage and generation can result in over half of the solar generation produced by such a facility being exported to the grid rather than used by the customer in the hour it is produced. EAL asserts that absent clarifications to the methodology for calculating the maximum size of a facility, the very circumstance sought to be avoided will materialize (i.e., a customer or developer building more than the customer needs to offset the customer's own usage and financing that oversizing through bill credits provided for that excess energy). *Id.* at 29.

D. Reviews are needed to confirm that leases and PPA (service agreements) comply with the statutory provisions. EAL states that several parties recognize that the Commission needs to institute a process to determine whether net-metering facilities obtained through one of the two new options provided by Act 464 (*i.e.*, leases or long-term PPAs/service agreements) meet the requirements set forth in that act. EAL's Initial Comments outlined the prescriptive terms set forth by the General Assembly for each added option. EAL states that in its comments on the Interconnection process, Staff noted that the process should be expanded to encompass leases, but it provided no insight into the manner in which confirmation of compliance with the lease provisions will occur. Similarly, EAL states that Staff has not offered any proposals for the Commission to determine whether PPAs/service agreements qualify for the safe harbor provision as required by in Act 464. Although not specifically addressed in their comments, EAL asserts that Distributed Solar Advocates and Scenic Hill Solar's positions

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[98] *See* Sub-Group 2 Surreply Comments at 33-34. *See also*, Joint Report and Recommendations of the Net-Metering Working Group, Attachment B, Sub-Group 2 Recommendations at 164-171 (September 15, 2017).

on the need for Commission reviews, if adopted, would ensure that little, if any, review would be required to determine these important issues. EAL urges the Commission to implement a process to ensure that only agreements and facilities that meet the statutory requirements are eligible for the benefits of net-metering. *Id.* at 30.

E. Structuring projects with multiple facilities in order to avoid Commission review. EAL states that the Distributed Solar Advocates and Scenic Hill Solar both advocate that the Commission's eventual NMRs adopt a very limited review process, relying upon a skewed interpretation of Act 464:

> [Act 464] specifies that the Commission must take into account reasonable cost allocation as part of the decision to approve or not approve 5 to 20 MW net metered projects.[99]

EAL argues that duplicate consideration of the issue for grandfathering is unnecessary and not indicated by the language of the statute, which defines the criteria for approval of such projects.[100] With this unreasonable interpretation of Act 464, EAL asserts that Scenic Hill Solar advocates the establishment of Commission rules that would adopt a review process whereby cost shifting is a consideration only for net-metering facilities over 5 MW up to 20 MW. According to EAL, this interpretation, if it were enacted, effectively expands the 1 MW threshold for Commission review to 5 MW, as the Commission would only be authorized to take into account negative cost-shifting impacts on non-participating customers for projects exceeding the 5 MW threshold. Yet, EAL asserts, the plain language of Act 464 states that any project subject to Commission review must be "in the public interest"[101] – an inquiry by the Commission that necessarily must include consideration of cost shifting to non-participating customers. In addition, EAL argues, this interpretation,

[99] Scenic Hill Solar Initial at 6.
[100] Ark. Code Ann. § 23-18-604(b)(9)(A)(iii).
[101] *Id.*

and others similarly limiting the Commission's authority over net metering, promotes gaming, providing an additional incentive, as SWEPCO noted in its Initial Comments, to pursue the practice of breaking projects into smaller pieces to circumvent and evade Commission review.[102] *Id*. at 31.

EAL states that AECC has submitted a reasonable approach to addressing this concern and eliminating potential gaming opportunities.[103] AECC's proposed rule 5.03(E)(1) provides:

> Any facilities used for Net-Metering being credited to a customer's account, regardless of the location of the facility and its aggregation, will be treated as a single facility and must comply with the imposed capacity and/or sizing limits under these Rules.

EAL states that AECC's recommendation provides a clear and concise statement of the requirements that should be applied to net-metering projects, and EAL recommends that the Commission adopt this recommendation in its final rule. *Id*. at 32.

d. Oklahoma Gas and Electric Company

Cost Recovery and Rate Structure

OG&E states that contrary to the opinions of the Distributed Solar Advocates, Act 464 should not be interpreted as an attempt to maintain the status quo for net-metering rate structures in Arkansas, noting that while the Act may allow for the continued use of the 1:1 crediting structure, it does so with the provision that any rate structure should be in the public interest. To date, OG&E argues, no Party to this Docket has presented viable evidence to counter the overwhelming support that the 1:1 crediting structure unfairly burdens the non-participants of the current net-metering program with costs that are unreasonably allocated to them by the participants. OG&E Reply at 1-2

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[102] SWEPCO Initial at 10.
[103] AECC Initial at 11.

OG&E asserts that the position held by some Parties that because of low penetration levels or potential impacts to existing customers with net-metering facilities, only a small step be taken now toward a more appropriate net-metering rate structure be taken at this time is in direct conflict with the Act's intention to promote a net-metering rate structure that is more in line with the public interest. OG&E states that this position would be to say that a known problem should be allowed to fester until becomes a more serious one. OG&E argues that it is not the intent of Act 464, nor should it be the intent of this process, to artificially support an industry on the backs of non-participating customers. OG&E states that an advantage Arkansas currently has is that it can establish rules that are sustainable and do not create subsidy issues that will have to be addressed in the future. *Id*. at 2-3.

OG&E observes that those Parties supporting 2-Channel Billing, grid access charge, or utility-specific solutions are the same Parties (the utilities) supporting the Act's intent to promote a net-metering rate structure that is more in line with the public interest. While OG&E maintains its support that net-metering solutions should be utility-specific due to unique operating and consumer circumstances, absent a utility-specific solution, it recommends a grid access charge as the most reasonable path forward for all customers. OG&E states that support for this proposal was laid out in its Initial Comments as well as those EAL and AEEC, and it was acknowledged as a potential path forward by Staff, the AG, and AECC. *Id*. at 3-4.

OG&E states that, in conjunction with the changes outlined in the Act for net-metering, it would be supportive of separating net-metering customers into their own class in a cost-of-service study to analyze and design an appropriate rate structure specific to these customers, whether it be TOU rates or otherwise. OG&E notes that taking service under a TOU rate structure would allow net-metering customers to realize the time-specific value of the energy that they produce. If this process is undertaken, OG&E states, it should be intended "to ensure that the on-peak windows selected, and the rates imposed for usage (and exports) during different periods, accurately reflect the cost to the utility of providing service during peak times," citing Initial Comments by the Distributed Solar Advocates.[104] To aid in reducing the current unreasonable allocation of costs to non-net-metering customers, OG&E suggests, a transition to net-metering-specific TOU rates could be addressed by all utilities in their next proceeding in which a new cost-of-service study can be presented and net-metering customers can be analyzed in a standalone class of customers. *Id*. at 4.

With respect to customers served under a demand rate, OG&E acknowledges that the law certainly allows for maintaining the current 1:1 rate structures, but states that there is a need to ensure that the demand rates being charged to these customers are set at an appropriate level to fully recover the demand portion of the cost to serve. Otherwise, OG&E states, it will result in an unreasonable allocation of costs to non-net-metering customers under the 1:1 net-metering structure. OG&E supports a process going forward that allows for the examination of the current price level of demand charges to ensure each utility is recovering the appropriate level of demand-related costs to mitigate unreasonable allocations of cost to non-net-metering customers. *Id*. at 5.

Finally on the subject of rate structure, OG&E opposes inclusion in any part of the NMRs or utility tariffs in Arkansas Walmart's proposal that "[u]nder net metering, the

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[104] Distributed Solar Advocates Initial at 17.

kilowatthour (kWh) and kilowatt (kW) units of a net metering customer's bill are netted."[105] OG&E cites to the express language of AREDA and Act 464 providing for the netting of kWh or kWh multiplied by the applicable rate of a net-metering customer's bill, and thus does not allow for netting of kW.[106] *Id*. at 5-6.

Aggregation

OG&E references Distributed Solar Advocates' support of an amendment to the NMRs that establishes an "easy, clear, and non-controversial means for customers to establish common ownership of multiple accounts for purposes of meter aggregation," but replies that it is unclear how the provision of a tax ID or other defining trait could possibly be intrusive or unnecessary, citing the benefits of using such an ID. OG&E requests that the Commission implement a means for establishing common ownership that includes, but is not limited to, the provision of a customer's tax ID. OG&E also supports EAL's Initial Comment that defining common ownership is a significant issue that still remains to be addressed. OG&E agrees with AECC's Initial Comment that the Staff Strawman does not reflect the following found in Ark. Code Ann. § 23-18-604(c)(1), "an 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." While OG&E agrees that there are exceptions for how net-metering credits are applied to common ownership facilities, it recommends the implementation of rules that reflect the law's prohibition on <u>meter</u> aggregation. *Id*. at 6-7 (emphasis added).

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105 Walmart Initial at 1-2.
106 Ark. Code Ann. § 23-18-603(6).

Grandfathering

OG&E notes that grandfathering under the current net-metering rate structure, not price level, ends on December 31, 2022. OG&E asserts that the purpose of grandfathering is to acknowledge that customers who construct facilities under prior rules/statutes may have made different decisions than under new rules/statutes, which means it only applies to the net-metering customer and not the facility. OG&E states that it should not be tied indefinitely to a customer or a facility as changes in ownership should take into consideration the rules/statutes in place at the time of that change. *Id*. at 7.

OG&E contends that the approach taken by Distributed Solar Advocates and Scenic Hill Solar to strike "subject to approval of the Commission" is in direct contradiction to the Act and is inherently flawed, arguing that the choice and length of time for any grandfathering decision should be based on a public interest finding in accordance with the Act. OG&E argues that there is currently no evidence to support the maximum allowable length of time as being in the public interest and, to make these findings, the Commission needs to have the ability to appropriately review the net-metering structure and price levels for each situation to determine if grandfathering is in the public interest. These determinations should remain subject to the approval of the Commission, according to OG&E, and made on a case-by-case basis. OG&E adds that this position is clearly supported by Staff when it states, "Prior to Act 464 the Commission has allowed grandfathering on a case-by-case basis. The Act requires no change to this practice."[107]

OG&E supports the second and third level of the 3-Level explanation of grandfathering provided by the AG, as it is reasonable and captures the language and spirit

[107] Staff Initial at 7.

of Act 464.[108] In addition, OG&E encourages the Commission to reject Distributed Solar Advocate's revision to Rule 2.07, to extend the grandfathering exemption to December 31, 2022, stating that had the General Assembly intended to extend the exemption until that date, it would have omitted the language permitting Commission approval on a case-by-case basis, as identified by Staff in its comments. OG&E also reiterates comments made by AECC, that "[t]he Commission's discretion to disallow grandfathering must be protected when it is evident that the proposed activity at the current rate structure does not protect other utility customers from unreasonable cost shifts. To hold otherwise would render the discretionary approval grant to the Commission meaningless."[109] *Id.* at 8.

Data

OG&E disagrees with Distributed Solar Advocates regarding the topic of data and visibility into the distribution system, asserting that they are inappropriate for inclusion in this Docket and not based on any factual evidence. OG&E notes that the Commission is explicitly considering these issues in Docket No. 16-028-U and agrees with SWEPCO that attempting to define and establish a market-based incentive before these data issues are addressed in that docket seems premature. OG&E asserts that hosting capacity access is not a net-metering issue, but is a business request of third-party solar providers that would be paid for exclusively by all Arkansas customers, both net- and non-net-metering. *Id.* at 9.

Interconnection

OG&E states that the *IREC Model Interconnection Procedures for 2019* proposed by Staff for consideration by the Commission need to be more thoroughly vetted prior to any

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[108] AG Initial at 13.
[109] AECC Initial at 11.

potential adoption, and that the appropriate docket in which to review it is Docket No. 16-028-U, where this specific issue is already being addressed. *Id*.

Consumer Protections

OG&E cites and supports the AG's proposals to protect consumers from predatory practices by third-party solar developers that are unregulated entities, noting that while the Commission may not be able to regulate the prices set by third-party providers, it certainly has the authority to impose certain requirements in accordance with the rules and statutes. For example, OG&E states that the Commission has the authority to determine if net-metering lease arrangements qualify to participate in net metering. If a customer enters into an arrangement that the Commission determines is not permitted under net metering, OG&E states that it is still able to participate under the small power producer rates (*e.g.*, OG&E's COG-1 rate). OG&E supports the AG's suggestion of the formation of a working group to address "setting terms and conditions for participation in net-metering, including suspension or expulsion from the program, basic requirements and prohibitions for marketing materials, and customer contract requirements. OG&E supports the inclusion of utilities in such a working group if it is formed. OG&E also fully supports EAL's recommendation that the Commission address consumer protection rules that will assure that Arkansas consumers are not entering into long-term contracts or leases for solar generating facilities based on misleading or false claims and representations by solar developers with respect to the product they are selling to consumers. *Id*. at 9-10.

Leasing

OG&E recommends that the Commission adopt rules regarding third-party leasing of net-metering facilities and make explicit the types of facilities and agreements that will qualify for net-metering eligible leasing. OG&E supports statements by EAL, which states that these rules should (1) establish a review process for lease agreements to be submitted to Staff and the utility to ensure compliance; or (2) establish a form agreement that either must be used or that, if used, would allow the net-metering customer to forgo APSC review. Additionally, OG&E supports EAL's recommendation that the Commission clarify the standards that each net-metering customer will be required to meet to confirm their leased facilities or the energy purchased under a "service contract" are actually eligible for net metering. OG&E also supports EAL's recommendation when it states in part, "...the addition of third party leasing of a net-metering facility may require the Commission to adopt additional rules or guidelines regarding eligibility and criteria for such leases, beyond the listed limitations."[110] OG&E supports the statements made by both EAL and SWEPCO and recommends that the Commission establish clear guidelines and rules for the definition, eligibility, limitation, form, and review of all third party net-metering lease proposals in an effort to protect all customers. OG&E recommends that the Commission establish clear guidelines and rules for the definition, eligibility, limitation, form, and review of all third-party net-metering lease proposals in an effort to protect all customers. *Id*. at 11.

[110] SWEPCO Initial at 14.

Gaming

OG&E agrees with EAL's recommendations to the Commission around gaming, including a requirement that any net-metered facility must be behind the customer's meter and must displace some amount of electricity that the customer consumes. In particular, OG&E urges the Commission to establish rules that recognize Ark. Code Ann. § 23-18-604 requirement that net-metered facilities register the flow of a net-metering facility in two directions. In accordance with this law, OG&E states that rules should be established that prohibit facilities from qualifying specifically for net-metering (OG&E notes that they can potentially qualify as a Small Power Producer) if said facility is not located behind a customer meter in which load is offset. OG&E expands on this, by asking that the rules further clarify the restrictions for what qualifies as a proper account which a net-metering facility can appropriately be placed behind. OG&E cites as one example that should be avoided, the placing of a net-metering facility behind a security light to establish an account in which load would be offset. *Id*. at 12.

Other Issues

OG&E agrees with EAL's position that because Act 464 promotes the production and use of renewable energy, a customer that obtains energy from a facility but does not retain the renewable attributes through RECs, that customer is not receiving renewable power and is therefore not qualified for net metering. OG&E states that Ark Code Ann. § 23-18-603 (7) is clear in this regard. *Id*. at 14.

e. Southwestern Electric Power Company

Rate Structure

While it is SWEPCO's position that the 2-Channel approach for net-metering customers who receive service under a rate that does not include a demand component is the most effective mechanism to mitigate the current unreasonable allocation of costs to non-participating customers, SWEPCO would also support the recommendations of AECC, Empire, and OG&E that the Commission consider rules that would allow for utility-specific rate structures. This, SWEPCO asserts, would allow each utility the flexibility to select the best available option for proper rates based on long-standing cost-of-service principles, individual needs, and implementation of new metering and billing technologies. Additionally, SWEPCO endorses changes to the net-metering rate structure for demand-billed customers where current rate schedules do not recover the majority of fixed, functionalized costs through existing demand charges. SWEPCO does not support the continuation of the existing 1:1 credit rate structure for all the reasons included in its previous comments, but rather continues to support the adoption of the 2-Channel Billing approach. With regard to net-metering customer compensation in addition to the utility's avoided cost, SWEPCO reiterates that quantifiable benefits are defined as "[r]easonably demonstrated costs that: (i) are related to the provision of electric service and based on the utility's most recent COS Study filed with the Commission; and (ii) will be avoided by the utility by use of net metering."[111] Therefore, as cautioned by OG&E, SWEPCO argues that the utility must be able to actually quantify the benefits based upon cost-based ratemaking already approved by the Commission or be tied to an accounting or market mechanism

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[111] Ark Code Ann. § 23-18-603(9)(A).

and not by subjective "societal" benefits or future, estimated long-term "values" that may be claimed by the net-metering customer. SWEPCO Reply at 2-3.

Gradual/Phased-Approach

SWEPCO notes that Staff, the AG, and the Distributed Solar Advocates believe that changes to the current net-metering rate structure in Arkansas should be gradual or tiered to ensure that private distributed generation development is not discouraged, which is of particular concern in a low adoption state. SWEPCO responds that Arkansas added the 18th most solar projects among the 50 states last year, adding 118 MW of solar generation.[112] SWEPCO adds that Arkansas, which had a meager 22 MW of solar power at the end of 2017, saw its total rise 552%, ranking it 33rd among solar states in 2018, up 13 spots from a year before.[113] As stated in its Initial Comments, SWEPCO argues that, given the unprecedented increase in the number of applications received for residential and commercial net-metering customers, the existing rate structure is not sustainable. SWEPCO remains concerned about the continued use of the 1:1 credit rate structure and the unreasonable allocation of or increase in costs to non-participating customers. Further, SWEPCO states that Arkansas ranks among the top five states with the lowest average electricity price in the United States, with the state's average price for residential electricity (10.18 cents/kWh) falling 3.09 cents/kWh below the national average.[114] SWEPCO asserts that Arkansas's low electricity rates are likely the leading cause of the state's historically low solar adoption rates, which make adoption of distributed generation resources much less cost effective than in states with higher average electricity prices. SWEPCO states that

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[112] SEIA/GTM Research U.S. Solar Market Insight Report (Lasted Updated: Sept. 17, 2019).
[113] *Id.*
[114] 7 U.S. Energy Information Administration, Arkansas State Energy Profile (Last updated: February 21, 20 19).

it is proud to be able to provide reliable electric service to its customers in Arkansas at such reasonable rates. However, SWEPCO asserts that it is not the responsibility of the state's utilities, or the state's non-participating customers, to advocate ratemaking that justifies investments on behalf of solar customers. Additionally, a tiered or phased-in approach that would move towards a credit based on the utility's avoided costs, as suggested by the AG, would be complicated for customers and the utilities, and is unnecessary as the grandfathering approach discussed below would eliminate the potential rate shock to existing net-metering customers. *Id*. at 4-5.

SWEPCO states that apprehension regarding an immediate change in the rate structure is unfounded, as the recommendations regarding the EGCR received in this Docket over the last three years are data-driven and evidence based. SWEPCO's COS Study and SPP Market data serve as the basis for the Company's recommendation of the 2-Channel Billing approach. SWEPCO states that the COS Study and SPP Market data encompass the full quantifiable costs and benefits of the utility's generation capacity, system reliability, and its distribution and transmission systems, as well as the full costs and quantifiable benefits of serving a net-metering customer. SWEPCO asserts that this approach is consistent with Act 464 and the framework upon which rates are set in Arkansas. Furthermore, SWEPCO says its determination of the EGCR includes actual, quantifiable costs and benefits in contrast to the Distributed Solar Advocates' recommendation to maintain the status quo using an analysis based on assumed and speculative information regarding the hypothetical future value of solar generation. SWEPCO states that quantifiable costs and benefits provide the foundation for proper economic price signaling that will aid in customer decision-making and also provide a basis for a net-metering program that will benefit participating customers, nonparticipating customers, the utilities, and the State of Arkansas. Moreover, SWEPCO agrees with AECC that potential gaming is addressed if cost-based economic price signaling is the standard. *Id*. at 5.

Quantifiable Benefits/Crossborder Report

SWEPCO argues that Arkansas ratemaking policy does not consider hypothetical future societal or other non-quantitative benefits in setting rates. SWEPCO urges the Commission to avoid engaging in any discussion or dispute resolution about the inputs and values for the Crossborder Report study because it is inherently flawed by its questionable assumptions. Furthermore, SWEPCO asserts that the Distributed Solar Advocates' continued reliance on the Crossborder Report's long-term analysis of costs and benefits to support retaining the current net-metering policy of crediting excess generation at the full retail rate is not consistent with the requirements of Act 464 or the statutory framework that supports ratemaking in Arkansas. SWEPCO urges the Commission to reject it. *Id*. at 5-6.

SWEPCO notes that the Distributed Solar Advocates also state that Act 464 only requires the use of "quantifiable benefits" for the rate options that implement the 2-Channel Billing approach or a grid access charge and not for any other rate structure within its authority. According to SWEPCO, they interpret this and the elimination of the requirement in Act 464 that rates must recover the entire cost of providing service to a net-metering customer as a clear sign of legislative intent to move away from a rigid cost-based rate structure. While SWEPCO appreciates the recognition that only benefits that are quantifiable and correlated to the utility's COS studies are appropriately included in a 2-

Channel or grid access charge rate structure as a benefit, SWEPCO strongly disagrees that these rate structures are the only instances where benefits have to be "quantified" to be included to adjust the rate at which net-metering customers are compensated. SWEPCO states that the utilities have clear indication throughout the instructions of the Commission's RPPs, that there are specific requirements to identify, allocate, and functionalize the utility's costs through jurisdictional and class COS studies. The required COS studies are used to determine rates that are just and reasonable for all classes of customers, SWEPCO states. Undetermined benefits, without a firm tether to the utility's COS studies, are in SWEPCO's view, fictional at best and not measurable in determining just and reasonable rates. Moreover, SWEPCO does not agree that by mentioning the two suggested rate structures for non-demand billed customers, the statute intended to treat quantifiable benefits differently for other rate structures (including the rate structure for demand-billed customers). SWEPCO states that clearly this is also recognized in the fact that the definition of "quantifiable benefits" requires a basis in reasonably demonstrated costs that are "based upon the utility's most recent cost-of-service study filed with the Commission."[115] *Id*. at 6-7.

Cost Shifting/Class-of-Service Basis

SWEPCO is in agreement with AEEC's Initial Comments that the current rate structures encourage cost shifting between participating and non-participating customers in classes that recover a substantial portion of fixed costs through variable charges, and can also occur in rate classes that are demand-billed, but still have a portion of fixed costs not recovered through the demand rate component. SWEPCO also agrees with AECC's

[115] Ark. Code Ann. § 23- 18-603(9)(A).

comments that there are situations where net-metering customers have unique characteristics that should be considered on a class-of-service basis. SWEPCO would extend this recommendation to certain rate classes where there is a mix of demand-billed and non-demand billed customers and where a rate class, through its approved rate schedule, is not fully recovering its fixed COS through fixed charges but through variable rates. SWEPCO states that these rate schedules have large portions of functionalized fixed costs included for recovery through variable kWh rates and notes that these rate classes are vulnerable to extending current subsidies or putting non-participating customers at risk of being asked to subsidize customers who choose to participate in net metering by shifting the allocation of fixed costs to non-participating customers via the next class COS study. *Id*. at 7-8.

Demand Reduction

SWEPCO states that Walmart proposes in its comments that current net-metering tariffs be revised to reduce the net-metering customer's billing demand to reflect any applicable reduction in demand resulting from the net-metering facility. Walmart also proposes a rule change to include that kWh and kW units of a net-metering customer’s bill are netted. SWEPCO disagrees with this suggestion, noting that billing demand (kW) is measured based on actual customer capacity requirements from the utility and serves as the basis for a demand-billed customer’s billing demand charge. SWEPCO states that demand charges are typically determined based on functionalized fixed generation, transmission, and distribution service costs in order to recover the costs to serve customer class load requirements that are recovered through approved demand rates. SWEPCO argues that to net a customer’s measured demand would serve to artificially reduce the customer's actual capacity requirements requested from the utility, resulting in reduced recovery of fixed costs set in place to serve the load required and actually used by the customer, as measured at the meter. Furthermore, SWEPCO states, the net-metering customer has already reduced its demand based on the output of the net-metering facility. SWEPCO notes that demand-billed customers with net-metering facilities will already benefit through reduced reliance on the utility resources, but will continue to be served by the utility's generation, transmission and distribution systems as indicated by demand (kW) measured at its meter. Also, SWEPCO argues, because solar generation is not typically available at the time of the system peak, any netting of demand will actually exacerbate any issues associated with subsidization of the net-metering customers. According to SWEPCO, these customers will still be using SWEPCO's system at the time of the system peak and contributing to peak load demand, yet could be paying even less for it than they currently pay. Finally, at this time, SWEPCO states, utilities do not have visibility into a customer's production behind the meter. Therefore, any billing adjustment associated with reduced demand would not be feasible. *Id*. at 8-9.

SWEPCO states that Distributed Solar Advocates suggest that the Commission examine the transitioning to TOU rate structures for net-metering customers. SWEPCO would reiterate the caution, as expressed by Empire, that some utilities do not necessarily have sufficient technology to implement a prescribed solution (such as TOU or other interval-type solution). SWEPCO states that it does not currently have TOU rates already designed for all classes of net-metering customers based on its most recent class COS study, nor does it have advanced meters which record interval data. While SWEPCO is not opposed to a TOU suggestion, it argues that the Commission should consider adopting this approach only on a case-by-case basis. Furthermore, while there is potential in determining delivered and received kWh within intervals of TOU to develop a rate structure that is based more on cost causation for net-metering customers, SWEPCO states that it has started to see 5-minute interval nodal locational marginal prices in the SPP reach negative amounts. SWEPCO states that the Commission will need to be mindful about any policies developed related to TOU pricing due to changing markets from increased renewable penetration. *Id*. at 8-10.

Grandfathering

SWEPCO points out that Distributed Solar Advocates argue that the rules should not contain language requiring Commission approval for the grandfathering of net-metering customers, believing that Commission approval is implicit once a rule is adopted, and therefore, approving grandfathering on an individual basis is inefficient and unnecessary. Conversely, SWEPCO supports EAL and AEEC's view that Act 464 explicitly provides that grandfathering is "subject to approval by a commission." Thus, SWEPCO asserts that the Commission must determine whether a particular net-metering customer or group of customers will be grandfathered under the current rate structure. Further, SWEPCO notes, AEEC urges the Commission not to grandfather additional net-metering customers, or alternatively, to grandfather customers for a period less than 20 years, believing that a decision to grandfather would effectively enshrine a significant subsidy in rates for a period of time. Notably, SWEPCO states, Act 464 provides that net-metering customers are to be grandfathered "for a period not to exceed twenty (20) years."[116] Thus, SWEPCO states, the statute clearly vests the Commission with discretion to grandfather

[116] Ark. Code Ann. §23- I 8-604(b)(I O)(A).

customers for a shorter period of time, asserting that the statutory language supersedes the Commission's decision in Order No. 10 to adopt a grandfathering term of 20 years. Accordingly, SWEPCO suggests that the Commission choose not to grandfather customers for a lengthy period of time, as doing so would continue to preserve the unreasonable allocation of or increase in costs to non-participating customers. *Id*. at 10.

Additionally, SWEPCO notes, Order No. 10 states that the grandfathering period will be determined based upon the date of the Commission's Order adopting a new net-metering rate structure, which has yet to be issued. However, SWEPCO states, Act 464 provides that net-metering customers who sign an interconnection agreement between July 24, 2019, and December 31, 2022, will be subject to the rate structure in effect at the time they sign the interconnection agreement. SWEPCO asserts that determining a grandfathering period from the time of signing of an interconnection agreement would result in a different date for each customer, which would be difficult to manage from a customer service standpoint. Accordingly, SWEPCO recommends that the date of the Commission's Order adopting a new net-metering rate structure will be the date upon which all net-metering customers at the time of the Order would be grandfathered. For example, if that date is January 1, 2020, then all current net metering customers, or customers who have signed an interconnection agreement, will be grandfathered at the current 1:1 credit rate structure. SWEPCO notes that there would be no additional grandfathering after that date. SWEPCO asserts that Act 464 does not seem to supersede Order No. 10. In fact, according to SWEPCO, the only changes from Order No. 10 versus Act 464's language are the requirement for Commission approval for those customers seeking to be grandfathered and the grandfathering term. SWEPCO states that grandfathering perpetuates the substantial cost-shifting to non-participating customers of the 1:1 credit rate structure currently in effect and is, therefore, not in the public interest. SWEPCO states that harm is presently occurring from the lack of clarity on this issue. Thus, SWEPCO believes that the NMRs need to reflect and address these concerns. *Id.* at 11.

Larger Facilities/Oversizing/Gaming

SWEPCO states that gaming potential is material and significant and should be addressed by the Commission in the NMRs, urging respect for the sizing limits imposed by Act 464. SWEPCO points out the Order No. 10 states that rather than strictly prohibiting overproduction, AREDA looks to the customer's intent in sizing the net-metering facility, which may be reasonably discerned by comparing the customer's usage with the size of the intended net-metering facility at the time the facility is installed and the interconnection agreement is signed. Therefore, SWEPCO support's EAL's recommendation that sizing of net-metering facilities should be limited to what is necessary to meet no more than the customer's usage for the 12 months prior to interconnection. *Id.* at 12.

To provide better protection, SWEPCO agrees with EAL, OG&E, AEEC, and AECC's suggestion that a new gaming section should be included in the NMRs and recommends the rule language proposed by AECC in AECC-Initial Exhibit 1. SWEPCO cites one particularly important provision, which states:

> Any facilities used for Net-Metering being credited to a customer's account, regardless of the location and its aggregation will be treated as a single facility and must comply with the imposed capacity and/or sizing limits under these Rules.

As an additional step to mitigate the potential for gaming, SWEPCO recommends that all solar lessors and aggregators should be required to register with the Commission and a process established to allow utilities and/or other parties to file a complaint regarding potential gaming, as third-party solar developers are not regulated. SWEPCO states that penalties for gaming should include, but not be limited to, forfeiture of a customer's ability to participate in net metering. *Id*. at 12-13.

SWEPCO also supports development of customer protections such as a Customer Bill of Rights and Code of Ethics and notes that it is important for utilities to play a role in the consumer protections considered by Staff and discussed by the AG. SWEPCO notes that customers are being approached with long-term contracts or leases by solar developers and could greatly benefit from having a guide to help them through the process. SWEPCO states that utilities currently do not have input into the portion of the marketing materials provided to their customers based on the utilities' rates, terms, and conditions. Including utilities as part of a future consumer protection process will make for a better-informed customer, SWEPCO states, especially in light of grandfathering rules that are introduced to protect a consumer's investment, which is based on an estimate of a utility's rates and is devoid of any verification from the utilities. SWEPCO believes that it would benefit all parties if the utilities could provide guidance, through some formalized process, in the rates used to determine pay-back periods for potential net-metering customers. *Id*. at 13.

SWEPCO notes that Staff has observed that the NMRs do not address whether larger facilities that are not directly connected to a customer's load should be more appropriately be consider a Distributed Energy Resource. SWEPCO is in "strong agreement" with EAL that facilities located solely on remote "generation-only" sites utilize the utility's distribution and transmission systems to wheel power from the generator to the customer's load (one or more other meters). SWEPCO states that these installations run afoul of AREDA, are inconsistent with cost causation principles, increase costs to non-participating customers, and potentially implicate FERC rules and/or federal law. Accordingly, SWEPCO believes that such facilities should not qualify for net metering. *Id*. at 14.

Leasing

SWEPCO states that Act 464 fundamentally altered net metering in Arkansas by enabling customer access net metering through leasing of facilities rather than only through direct ownership, so long as the lessor does not sell electricity to the lessee. According to SWEPCO, the leasing arrangement allowed by the statute would permit a customer to make monthly payment to a solar developer without purchasing the actual panels. SWEPCO shares the AG's concern that this could easily result in misleading contract terms for customers accessing this leasing option. SWEPCO states that the NMRs should specifically address Commission oversight of solar developers, including net-metering facility owners who offer leasing options to customers. *Id*.

SWEPCO states that the new leasing option creates a circumstance where the Commission will be required to review each lease and determine whether it meets the requirements established by Act 464. SWEPCO agrees with the AG and EAL that a review mechanism is needed, noting that leasing terms should be clear and conspicuous, and leasing providers should be subject to the same program suspension/termination rules it discussed above. SWEPCO supports EAL's proposed review option establishing a form agreement that, if used, would allow the net-metering customer to forgo Commission review. *Id*. at 14-15.

Interconnection

SWEPCO observes that the current interconnection process does not contemplate a leasing ownership structure, and thus agrees with Staff and EAL that the interconnection rules will need to be amended. SWEPCO recognizes that the interconnection process must be updated to properly reflect the roles and responsibilities of all parties involved, and thus it supports EAL's recommendation that the Commission require both the owner of the facility (*e.g.*, the solar developer) and the customer taking advantage of net metering to execute the interconnection agreement to properly protect all parties. SWEPCO cites EAL's explanation that without this additional protection, if a problem were to arise, the utility may find itself in a position of being responsible for any costs or damages, while the customer and lessor assert lack of responsibility due to either not having signed the agreement or not having control over the net-metering facility. *Id*. at 15.

SWEPCO states that, like EAL, it has charged customers for certain feasibility studies, but has not charged customers for any Preliminary Site Reviews or for interconnection requests. However, SWEPCO states, the recent influx of new interconnection requests has placed an administrative and cost burden on the Company to review and process these requests. SWEPCO asserts that charging a fee associated with Preliminary Site Review and interconnection requests is consistent with cost causation principles and will help assure that only legitimate requests for interconnecting a net-metering facility are submitted. Accordingly, SWEPCO believes that a one-time, cost-based fee should be associated with each Preliminary Site Review and interconnection request. *Id*. at 16.

f. Arkansas Electric Cooperative Corp.

Introduction

AECC asserts that the 1:1 full retail rate is overly compensatory, unduly preferential, and is against the public interest, noting that wholesale energy markets allow utilities to purchase generation for approximately 3 cents per kWh, on average. By contrast, AECC states, the current NMRs and conforming tariffs require utilities to pay net-metering customers between three and four times more than the market rate for generation. AECC Reply at 1.

Rate Structure

AECC notes that it has been argued by Staff[117] that Act 464 does not require a change in the current net-metering rate structures currently established by the Commission. If true, AECC responds, the corollary is that Act 464 does not require retention of the current net-metering rate structures, either. AECC cites testimony of the Commission Chairman at a Senate committee hearing in support of its position that it has been acknowledged – even as the basis upon which Act 464 was passed – that the current, full-retail rate regime is unsustainable.[118] AECC thus argues that now is the time for Arkansas to move away from over-compensating end-use generators who are neither operating in the wholesale energy markets nor complying with the same dictates that

[117] Staff Initial at 3.

[118] Testimony of Chairman Ted Thomas, Arkansas Senate Insurance and Commerce Committee meeting at 11:25:54 through 11:27:55 (February 14, 2019). Stating "the main point I wanted to make was this bill doesn't advocate continuation of one for one retail—which is where this 9 or 10 cents comes from. There has been an evolution in position such that what they fought about at the PSC was between 9 cents and 4 or 5 cents. . . . What we are fighting for here is maybe $.03- to .04 [cents]. So the goal posts have moved. . . . What we want is not the option to leave it at the retail rate. We want the option to choose what the utilities have advocated—2 channel billing—and what the solar advocates have added—monthly net[ting.] . . . We are not asking to keep the option of retail one-to-one. . . . If we throw out our order and the appeals court takes it, we might be two years with one-to-one. There will be an order within 6 to 8 months, if the bill passes."

wholesale generators must satisfy. AECC states that such compensation is also contrary to well-established principles of ratemaking and public utility service. *Id*. at 1-2.

a. Demand Component Customers. AECC asserts that Act 464 does not require continuation of the current 1:1: rate structure. More particularly, AECC notes that Act 464 does not use the terms "demand billed" or "demand metered," but instead uses the phrase "demand component," which it states has a different meaning. AECC responds to Staff's assertion that Act 464 "continued the current 1:1 rate structure,"[119] stating that to the contrary, Ark. Code Ann. § 23-18-604(b)(6) does not mention, much less require, that the Commission maintain the current rate or rate structure for such customers (or any customers). Instead, AECC states, that Section states that:

> (6) Except as provided in subdivision (b)(9) of this section, for net-metering customers who receive service under a rate that includes a demand component, shall require an electric utility to credit the net-metering customer with any accumulated net excess generation in the next applicable billing period and base the bill of the net-metering customer on the net amount of electricity that the net-metering customer has received from or fed back to the electric utility during the billing period;

AECC states that 604(b)(6) only requires crediting "net excess generation in the next applicable billing period," and adds that "net excess generation" is a defined term under the laws and can be "measured in kilowatt hours or kilowatt hours multiplied by the applicable rate....[.]"[120] According to AECC, there are thus two separate options for measurement, which means the General Assembly left the decision to the Commission, through its review of the individual utilities' respective tariff filings, to decide the proper mechanism for crediting. AECC thus argues that the 1:1 full retail credit for all customers, including those with a demand component in their rate structure (including seasonal

[119] Staff Initial at 3.
[120] Ark. Code Ann. § 23-18-603(5).

accounts, such as irrigation, poultry houses, and other agricultural accounts that are offline part of the year), must be evaluated under the amended law using statutory construction principles. AECC asserts that, quite simply, the General Assembly does not, and neither did Act 464, set rates for net metering: that is the Commission's purview and Act 464 requires the Commission to do that for all net-metering classes. *Id.* at 3-4.

b. Prior Recommendations in Phase 2: AECC is not bound by settlement positions made under an entirely different law. AECC states that as support for retention of a subsidy to certain net-metering customers, Staff suggests that maintaining the current 1:1, full-retail credit rate structure for demand-metered customers was recommended previously by certain Parties to this Docket.[121] AECC responds that this suggestion ignores the salient fact that a compromise struck, under a very different fact scenario and before a massive overhaul of the law, cannot possibly be used to bind any Party during Phase 3 of this Docket. AECC states that it no longer agrees, or identifies, with the compromise reached by Sub-Group 2 in Phase 2 of this Docket and does not support rates or rate structures that over-compensate customer-owned, net excess generation. *Id.* at 5.

c. Burden of Proof: Net-Metering Customers bear the burden of proof for adders in excess of the filed rate. AECC states that it appears, but is not entirely clear, that there might be an expectation by Staff that utilities will bear the burden of proof to demonstrate that a net-metering facility creates an unreasonable allocation of costs, rather than the net-metering customer demonstrating the opposite.[122] If this is the case, AECC asserts, a shift of this magnitude creates precedent about which AECC reserves all of its

[121] Staff Initial at 3.
[122] Staff Initial at 7, which states: "A company-specific demonstration of all relevant factors, including unreasonable cost shifting and quantifiable benefits should further the Commission's determination in this regard."

rights to address in a later filings. For now, AECC offers that, when a utility files a tariff, the approval of that tariff is a decision by the Commission that the utility has met its burden and the filed rate is just and reasonable. Said another way, AECC argues, if a net-metering customer wants to be paid more than the filed rate allows, the net-metering customer must prove that any additional compensation they are requesting "will not result in an unreasonable allocation of or increase in costs to other utility customers....[123]" AECC contends that if, and only when, that showing is made should the burden of proof shift to the utility for rebuttal purposes. According to AECC, to hold otherwise creates a rebuttable presumption that all cost allocations stemming from a net-metering facility are reasonable unless the utility shows otherwise, which would result in a burden of proof contrary to Act 464. *Id.* at 6.

d. Cost Shifting

e. Timing: Cost shifting of any magnitude resulting from overpayment for net excess generation should be addressed on a tariff and/or facility-specific basis. AECC applauds and shares Staff's recognition of the importance of a utility-specific approach in net-metering ratemaking and the position that cost shifting is a concern. With the uptick in scale of net-metering facilities from 300 kW to as large as 20 MW, AECC asserts that the potential cost shifting impacts have increased exponentially and waiting for an increase in severity to address the matter only courts trouble. Despite the claim by Staff that there "is minimal to no measurable cost-shifting occurring between customers within and between customer classes...,"[124] AECC states that at least one electric utility (EAL) has already quantified, through filed evidence, a loss in revenue of $75 million to $126 million from a

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[123] *See, e.g.,* Ark. Code Ann. §23-18-604(b)(2)(B).
[124] Staff Initial at 4.

net-metering single facility.[125] Further, AECC cites to EAL's assertion in this Docket that "...approximately 70 - 75 percent of [its] fixed costs in base rates are recovered through the volumetric charge – not through the demand charge component — thus, allowing a customer to avoid not only variable costs but also the majority of the fixed costs that are incurred ... to serve them – costs that, importantly, are not reduced by the installation of a net-metering facility."[126] AECC points out that EAL's evidence was "neither refuted, either with comments or data, proving there is, in fact, minimal to-no-measurable cost shifting." *Id*. at 6-7.

AECC argues that procrastination on action now, because it is perceived to be a minor issue, exacerbates the problem in the future. AECC adds that different rate structures and rules for net metering for different customers create confusion, inefficiency, and complication that could have unintended consequences on current and future net-metering customers and the utilities to whom they are selling their generation. Plus, AECC asserts, ignoring how difficult, and likely non-qualitative, a wait-and-see approach would be, if implemented, the General Assembly did not establish a penetration level for the Commission to evaluate when cost shifting should be addressed. To the contrary, AECC states, Ark. Code Ann. §§ 23-18-604(b)(2)(B), 604(b)(2)(D), and 604(b)(9) require a net-metering benefits analysis be determined on a tariff and/or facility-specific basis, regardless. AECC notes that AREDA was created in 2001, with several goals stated in the preamble, including to increase the consumption of renewable resources. Presumably, AECC states, that goal still drove Act 464, and in the almost twenty years since AREDA was passed, AECC has been able to acquire, on market-supportable, market-based and price-

[125] APSC Docket No. 19-042-TF, Direct Testimony of Myra Talkington at 16-17.
[126] APSC Docket No. 16-027-R, Motion for Interim Net-Metering Rate Structure at 18-19.

advantageous terms, enough capacity and energy to the point that nearly 1 of every 5 kilowatt hours AECC generates – on an energy basis – comes from hydro, solar, wind, or biomass resources. In short, AECC contends, it has achieved, without inaccurate price signals or subsidies, what AREDA was intended to capture. According to AECC, this demonstrates that net-metering is not the only vehicle to achieve AREDA's goals, and continuing to force payments for generation at above-market prices is no longer necessary to encourage a diverse generation mix. *Id*. at 8.

f. Cost-of-service studies are not needed to value compensation for excess generation. AECC quotes Staff for the proposition that "foundationally a certain level of cost-shifting is part and parcel of ratemaking based on grouped classes of customers[]" and, therefore, it is necessary to review a utility's most recent cost-of-service study to assess whether there is a subsidy.[127] AECC counters that this suggestion misses the mark when it comes to remediating net-metering cost shifting, asserting that net-metering policy is about how much is paid by non-net-metering customers for the generation net-metering customers want to sell to the utility. AECC states that the comparator for that inquiry is unrelated to billing determinants in a cost-of-service study and, instead, should be measured against the price paid for generation in the relevant wholesale energy markets. Generation is generation, AECC argues, and the wholesale avoided cost comprehends the fact that generation is homogeneous, on an energy basis, *i.e.* net-metering power is no different than any other power, renewable or otherwise, that can be purchased in the market. Making rates for generation the same, regardless of the origin of the generation, AECC asserts, balances the General Assembly's aim to promote renewable

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[127] Staff Initial at 5.

energy through net metering without unduly burdening non-net-metering customers. AECC points out that this very balance was recently recognized by the Louisiana Public Service Commission when it reduced the net-metering rate paid for customer-owned generation to the wholesale avoided cost, determining that any other result would abdicate its obligations to the public interest. In fact, AECC states, that Commission held that forcing a payment of greater than avoided cost would be an inherent subsidy by non-solar customers.[128] *Id*. at 8-9.

AECC states that Act 464 created, for the first time since AREDA was passed nearly 20 years ago, a unique opportunity to adopt a market-based approach in the customer-generator space. According to AECC, the wholesale energy markets, managed by independently-operated, FERC-designated RTOs, set the energy price based on sophisticated computer models and a footprint-wide, multi-state view, which also capture the accompanying regulatory and federal oversight that ensure generation availability and relatability. AECC argues that to continue to pay a higher price for non-market energy perpetuates a false economy, negatively affects the markets' value under federal regulation and deprives market participants of efficiencies the markets are designed to capture. *Id*. at 9-10.

g. Grandfathering is not required by law. AECC states that grandfathering is a point of contention in the net-metering space because an uneconomic, inflated price is being paid for customer-owned generation. If the Commission lowers the price utilities are ordered to pay for customer-owned generation to a market-based rate, then, AECC says, the deleterious financial effects of grandfathering are lessened to a point that the concern

[128] Louisiana Public Service Commission Docket No. $33929, General Order at 3 (September 19, 2019).

is no longer acute. AECC argues that grandfathering should not be approved by the Commission for any net-metering facility, absent the case-by-case, Act-464-required individual facility/customer showing, that a guaranteed, long-term, higher energy payment will serve the public interest. Absent a change in the price paid for customer-owned generation, AECC asserts that grandfathering the price paid to net-metering customers locks in place an over-compensatory rate to the detriment of all other ratepayers, which runs afoul of Commission-approved standard interconnection agreements and net-metering tariffs.[129] AECC argues that guaranteeing a customer-generator a fixed, unsustainable rate to be captured at their election, at the expense of other ratepayers, violates the public interest. *Id.* at 10.

h. Distributed Energy Resources and Interconnection Matters: Action should be taken in this Docket. AECC shares Staff concerns with the ability for consumers to enter into agreements with solar developers for larger facilities that will, by their nature, appear to be small power producers.[130] AECC also agrees with Staff that "DER should [not] be treated the same as a net metering facility."[131] In addition, given their interrelationship to net-metering, AECC argues that these substantial matters should be decided in this rulemaking, not a different docket, noting that Docket No. 16-028-U is an educational proceeding with no defined timelines or finite objectives. In addition, AECC argues, that Docket is not a rulemaking, and the rigors required by due process for state action are not present in that forum. Assuming small power producers are going to receive net-metering treatment, even though they are facilities with no load, AECC asserts that any

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[129] AECC notes that since they were first implemented and approved by the Commission, the Standard Interconnection Agreement and Net-Metering Tariffs put all net-metering customers on notice that their rates were subject to change.
[130] Staff Initial at 8 (noting "[t]hese facilities will not physically serve a customer's load").
[131] *Id.*

accompanying rules or regulations for such facilities should be decided in this Docket as part of the ongoing Phase 3. In addition, AECC argues that any changes to the interconnection processes and timing should be decided here, based on evidence of needed changes, including the timing of interconnection and any accompanying rights and obligations for interconnecting facilities. *Id.* at 11.

g. Joint Cooperatives: Arkansas Valley Electric Cooperative Corporation, C & L Electric Cooperative Corporation, Carroll Electric Cooperative Corporation, Mississippi County Electric Cooperative, Inc., North Arkansas Electric Cooperative, Inc., Petit Jean Electric Cooperative Corporation, Rich Mountain Electric Cooperative, Inc., Southwest Arkansas Electric Cooperative Corporation, Woodruff Electric Cooperative Corporation

Nine electric distribution cooperatives filed Rebuttal [Reply] Comments pertaining to Staff's Strawman NMRs and point out issues with the current 1:1 full retail rate structure for demand-billed tariffs as discussed in Staff's Initial Comments. The Joint Cooperatives respond to Staff's Initial Comments stating that "[f]or customers with a demand component, the Act continued the current 1:1 rate structure, which the parties recommended for demand-metered customers." The Joint Cooperatives state that in those Initial Comments, Staff is relying on comments made in the Joint Report filed in Phase 2 of this Docket on September 15, 2017, by Sub-Group 2, where Sub-Group 2 recommended 2-Channel Billing to non-demand billed tariffs. While Sub-Group 2 recommended that demand-billed tariffs continue to be billed as they are today, the Joint Cooperatives note that there were a lot of assumptions and a vastly different statutory framework under which the Parties were collaborating to reach a settlement in Phase 2. Joint Cooperatives Reply at (unnumbered) 1-2.

According to the Joint Cooperatives, the challenge with that compromise, particularly given the increased facility size (from 300 kW to as large as 20 MW) allowed under Act 464, makes the deficiencies in existing 3-part rate structures more difficult to navigate. For the distribution cooperatives, the Joint Cooperatives assert, it is simple to determine whether the existing 3-part structure is overly compensatory to net-metering customers: Each cooperative has a Cost of Energy Adjustment, which passes through inflation in fuel cost and TO/RTO charges billed to the cooperatives by their power supplier, AECC. Except for the TO/RTO demand-related charges, the Joint Cooperatives state, the pass through of these costs plus AECC's energy charge represent volumetric energy-related costs. The Joint Cooperatives state that to determine the fixed costs recovered in the volumetric base energy charge, an individual could find the difference between the energy charge for demand-billed tariffs and the cost of energy embedded in the cooperatives' base energy rates. For example, Rich Mountain's Large Power Service rate has an energy charge of 3.862 cents per kWh. The cost of energy embedded in the energy charge is 2.8264 cents per kWh. The difference of components is 1.0356 cents, which would represent fixed costs embedded in the volumetric energy charge instead of the customer or demand charge. *Id*. at 2.

The Joint Cooperatives provide Exhibit 1 showing fixed costs embedded in the energy charges for demand billed tariffs for the nine cooperatives. According to the Joint Cooperatives:

- Fixed costs embedded in the volumetric energy charge range from $0.00081 to $0.14237 per kWh sold. While there are demand-billed tariffs that align closely to cost of service, there are many that do not. C & L Electric

Cooperative Corporation, Woodruff Electric Cooperative Corporation, and Mississippi County Electric Cooperative, Inc. have irrigation class tariffs that would be crediting to a net-metering customer as much as an additional $0.14237 of fixed cost per kWh sold under the existing 1:1 rate structure, which would create significant subsidies between net-metering and non-net metering customers.

  - Another example is Southwest Arkansas Electric Cooperative Corporation's rural three-phase rate. This rate's demand is currently being phased in as it previously did not have a demand component. The current energy charge is $0.08232 per kWh sold, which is $0.04447 per kWh sold above the cost of energy embedded in the energy charge.

- Each of the nine cooperatives listed reserves the right to address over-compensation for net-metered generation due to fixed cost recovery shifts between net-metering and non-net-metering customers.
- The cooperatives should be able to develop net-metering rate tariffs consistent with the present tariff revenue requirements as approved by the Commission by shifting costs to the customer and demand charges while lowering the existing energy charges.

Id. at 2-3.

h. Arkansas Electric Energy Consumers

Rate Structure

AEEC disagrees with Staff's contention that changes to the current net-metering rules should not be rushed absent a showing of unreasonable cost shift or increase in costs and its questioning whether the current 1:1 credit for net-metering customers results in cost shifting from net-metering customers to other electric energy customers. AEEC points to the Comments of Sub-Group 2 (which included Staff as a member) in Phase 2 of this Docket, stating that the Comments establish the opposite – that the 1:1 netting in rate classes that recover most of their fixed costs through volumetric rate components allows participating net-metering customers to avoid paying their fair share of fixed costs, thereby shifting those costs to other customers and creating a subsidy. AEEC asserts that Staff's "wait-and-see" approach is wrong and states that good public policy demands addressing the cost-shifting issue now – before the subsidy gets much larger and harder to address. AEEC Reply at 1-2.

With respect to the contention of the Distributed Solar Advocates that no subsidy or cost shifting exists, AEEC asserts that the Comments and testimony of Sub-Group 2 in Phase 2 of this Docket discredited Mr. Beach's Crossborder Report and that these same contentions are also refuted by the Initial Comments filed in Phase 3 by EAL, SWEPCO, OG&E, and AECC. AEEC states that significantly, neither Staff nor the Distributed Solar Advocates and Scenic Hill Solar refute the fact that the expansion of the opportunity for net metering made possible by Act 464 (primarily achieved through the raising of the caps and the loosening of the definition of "owner") will exacerbate the cost shift to non-participating customers, unless the Commission modifies the current rate structure. *Id.* at 2-3.

AEEC continues to support 2-Channel Billing (with an appropriate credit for excess energy) for net-metering customers in classes without a demand charge, or the concept of a Grid Usage Charge, and suggests that the Commission enact changes to create a reasonable net-metering rate structure as soon as possible, consistent with due process. However, AEEC opposes a phased-in approach, as suggested by the AG, and instead supports the approach to setting net-metering rates advocated by EAL, SWEPCO, and OG&E. *Id*. at 3.

Grandfathering

AEEC reiterates its Initial Comments position that the Commission must determine, on a case-by-case basis, whether a particular net-metering customer (or potentially a group or groups of customers) will be grandfathered so as to utilize the current rate structure. AEEC notes that its position is supported by Staff, the AG, AECC, EAL, and SWEPCO. In view of its Initial Comments and those of all non-solar parties in this Docket, AEEC urges the Commission to exercise the discretion afforded by Ark. Code Ann. § 23-18-604(b)(10)(A) and choose not to grandfather additional net-metering customers, asserting that a decision to grandfather would effectively enshrine a significant subsidy in rates for a period of time. Alternatively, AEEC suggests that the Commission exercise its discretion to grandfather customers for a short period of time (such as six to twelve months). *Id*. at 4.

Comments on Staff's Proposed Amendments to the NMRs

AEEC reiterates its suggested changes to Staff's proposed amendments to the NMRs made in its Initial Comments and, in addition, specifically support two AECC recommendations as alternatives to AEEC's: (a) Eliminating the definition of "Net Excess Generation Credits" and (b) Adding a clause to Rule 2.04(A)(2).[132] AEEC also supports AECC's recommended edit to Rule 2.07, to clarify that the Commission must determine on

[132] AECC Initial at 7 and 9 respectively.

a case-by-case basis, whether a particular net-metering customer (or potentially a group or groups of customers) will be grandfathered so as to utilize the current rate structure. AEEC specifically opposes the changes to Rule 2.07 recommended by Scenic Hill and the Distributed Solar Advocates to eliminate the clause "subject to approval of the Commission" from Rule 2.07, as it contends such an edit would clearly contradict Act 464. *Id*. at 5.

i. William Ball

Mr. Ball submits his observations and beliefs from a broad perspective, stating that the current net-metering rate structure and level of penetration do not significantly risk cost shifting to non-net-metering customers. He cites the testimony of Mr. Beach as demonstrating that the benefits of net metering equal or exceed the retail value of a kWh purchased from a utility in Arkansas: some benefits are realized by the utilities, some by utility customers, and some are universal benefits. He asserts that the utilities have largely refused to acknowledge a number of environmental, societal, and life cycle values that cannot be denied, and notes that California utilities have been forced to cut power to millions of customers to avoid potential fires that are now the new normal brought on by climate change. He cites this as an example of costs/benefits that are not recognized in a typical cost-of-service assessment. Ball Reply at (unnumbered) 1-2.

In response to EAL's Initial Comments contention that the benefits asserted by the Crossborder Report and other proceedings around the country have largely been challenged by the emergence of low-cost, grid-scale solar facilities, which deliver the same environmental benefits at a fraction of the cost, Mr. Ball states that it makes no sense to compare an investment made by a utility with funds that are ultimately derived from ratepayers, to an investment made by private capital. He notes that EAL in the same Comments minimizes the benefit of large projects being pursued by customers because they are injecting solar power into the grid at one location and consuming grid power at a different location or locations. Mr. Ball notes that every large commercial solar facility that has been installed in Arkansas, or is currently being pursued, is now serving or will serve customers that pay a demand charge. The result, he says, is that the customer is helping reduce demand for the utility at the solar facility while still paying demand charges at the locations(s) they consume grid power. Additionally, he asserts, meter aggregation is not retail wheeling, since the customer's facility is offsetting part or all of their energy requirements, whether their facility is located behind their meter or at a location with no customer load. *Id*. at 2.

With regard to RECs, Mr. Ball states that the NMRs are clear – RECs belong to the customer, not the developer nor the utility. He notes that Arkansas does not have a renewable portfolio standard and RECs have little economic value; that they can only be sold by the owner, whether with the help of a developer or not; and that if they are sold, neither the owner nor any other person except the purchaser can claim the environmental attributes of RECs. He asks, rhetorically, whether if the customer decided to give the RECs to the utility, would the utility claim the customer is not actually using (or purchasing) renewable energy and that the customer is thus simply ineligible for net metering? He states that he knows of no RECs that have been sold by Arkansas customers and that their minimal economic value is not being realized. He thus has no problem with the transfer of REC ownership to the utilities at the discretion of the net-metering customer. *Id*. at 2-3.

Mr. Ball states that if the Commission decides to alter the rate structure for net metering, he believes there are more equitable methods than using 2-Channel Billing, noting that net metering constitutes a kWh-for-kWh exchange, and that the utility does not purchase kWh from a net-metering customer. He considers the 2-Channel Billing method outlined in Act 464 to be too prescriptive and states that the limits listed in the Act are likely the reason the utilities supported the legislation. He states that limiting the value of net excess generation to avoided cost plus an adder not to exceed 40 percent of avoided cost would turn what is currently a marginal return on investment into an investment that most would not make. Mr. Ball states that if changes to net metering are necessary, he believes a grid access charge applied to <u>all</u> volumetric rate customers to be a preferable option. He submits that such an approach would consider impacts to all volumetric rate customers and be less likely to target only net-metering customers. He states that the grid access charge, if any, should be based on the size of a customer's electric service and if they are a net-metering customer, it should not be based on the size of their net-metering facility. *Id*. at 3-4.

Mr. Ball believes that EAL's request that all meters aggregated for the purpose of net metering should be under a common tax ID is a red herring. He notes that the rule states that all meters aggregated must be in the same account name and within the utility's service territory. He considers a requirement that all accounts be under one tax ID to be an attempt to suppress net metering. Mr. Ball states that in the case of third-party ownership where the net-metering customer is leasing the system, the developer provides numerous guarantees and insurance coverage that is in excess of the mutual indemnification requirement currently in place. He states that this is especially true in the case of government or other entities where the requirements for mutual indemnification are already waived. *Id*. at 4.

Mr. Ball asserts that it is disingenuous for utilities to accuse renewable energy developers of gaming a system in which the utilities hold all of the cards. He cites an example of a solar company that submitted a Preliminary Site Review to a utility on behalf of a customer and within twenty-four hours a utility-affiliate solar entity contacted the customer and informed them that "the interconnection would cost a lot less if they did the project instead of the private solar company." Mr. Ball supports the idea of including consumer protection language in the NMRs and suggests that there is also a need for language protecting renewable energy developers from utilities. *Id*. at 4-5.

Mr. Ball states that even if the utilities projections of lost revenues in the many millions of dollars are accurate, they represent revenue lost to competition that will affect their shareholder's bottom line and not lost revenues that they would otherwise invest in maintaining the transmission and distribution infrastructure and that the utilities therefore need to replace those losses by shifting costs to non-net-metering customers in order to support the grid. *Id*. at 5.

Mr. Ball observes that grandfathering is the only certainty in an uncertain renewable energy market. He states that Act 464 has increased the number of larger scale and third-party applications, but the increase in rooftop solar installations has not been as significant. He asserts that if new net-metering rules following utility recommendations are implemented, coupled with declining federal tax credits, investment in rooftop solar will be non-existent. He submits that even if 1:1 net-metering credit continued for many years, it is not certain that significant cost shifting would occur. He believes that the existing plan to extend grandfathering of net-metering facilities under the 1:1 rule until December 31, 2022, is prudent and consistent with the scheduled decline in the federal tax credit. *Id*. at 5-6.

j. Distributed Solar Advocates (AAEA, Audubon, Sierra Club)

In introductory Reply Comments, the Distributed Solar Advocates note that the most contentious topic for the Commission to resolve is how residential customers who install solar for their own on-site use should be credited for any renewable energy that they incidentally send to the utility's grid. These advocates assert that net-metering customers' reduced on-site usage and exports reduce the overall distribution system load, thereby enabling the utility to avoid many costs that would otherwise be incurred over the lifetime of the net-metering system. They state that from the perspective of all customers, the long-term reduced system costs enabled by these customer-financed systems outweigh reduced revenue recovery in the short-term – asserting that there is a net benefit to all ratepayers. In addition, the advocates state, the unique nature of the benefits provided by net-metered systems further countenances the Commission's support of these valuable resources. The solar advocates note that net-metered solar systems and other renewable distributed generation provide long-term, low-maintenance climate and other environmental benefits, job creation and system resilience and diversity benefits, among others – all based on significant private investment and federal tax credit leverage by customer generators. They point out that these customer generators maintain the systems, insure them, and enhance the value of the real estate where those systems are sited. Distributed Solar Advocates Reply at 1-2.

The Distributed Solar Advocates submit that valuing net-metering systems based on their ability to avoid costs already incurred is a completely illogical concept and will not create the proper incentives for private investment that benefits all customers by avoiding costly new utility investment. As such, they say, it is not consistent with the public interest to compensate net-metering customers at levels that do not reflect the value of their investment, and will not support further investment. The solar advocates reiterate their position that the Commission should determine that under the very low levels of distributed solar generation currently installed in Arkansas, the existing full retail net-metering framework is in the public interest and does not result in unreasonable allocations of costs to other customers. However, they state, to support development of this resource in a way that maximizes benefits to other customers, the Commission should establish a process to consider and evaluate alternative rate designs in a gradual manner. *Id*. at 2.

Rate Design

Net Metering for Demand-billed Customers. Distributed Solar Advocates state that Act 464 definitively requires 1:1 kWh netting for customers taking service on a rate that includes a demand charge, citing Ark. Code Ann. § 23-18-604(b)(6), and declaring that there is simply no rate design issue for the Commission to resolve in this proceeding as it relates to demand-billed customers.[133] The advocates state that the General Assembly's foundation for this decision stems from the fact that even Arkansas's

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[133] Distributed Solar Advocates state that while the statute requires the Commission 1:1 net metering for demand-billed customers, it does permit the Commission to "authorize an electric utility to assess a net-metering 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." Ark. Code Ann. § 23-18-604(b)(4). The advocates note that none of the Parties that have proposed a fee or charge in this proceeding that may apply to demand-billed customers have attempted to support its request with reference to subdivision (b)(4).

electric utilities had very recently taken the position that there is simply no reasonable claim of a cost shift caused by net metering when customers are on a rate that charges for demand-related costs directly. Despite clear statutory language, the advocates state, several parties (EAL, AECC, and SWEPCO) specifically advocate for the Commission to alter net metering for demand-billed customers, or argue with the General Assembly's judgment in maintaining the status quo for such customers. *Id*. at 3.

Distributed Solar Advocates state that among those Parties taking issues with net-metering for demand-billed customers, AECC attempts to interpret the statutory language to offer the Commission some discretion regarding rate structure for demand-billed customers, but to no avail. The advocates contend that AECC asserts that Act 464 provides discretion through the definition of net excess generation, which is defined as an "amount of electricity as measured in kilowatt hours or kilowatt hours multiplied by the applicable rate."[134] However, Distributed Solar Advocates argue, the use of the term "net excess generation" in Ark. Code Ann. § 23-18-604(b)(6) does not introduce the ambiguity or flexibility that AECC suggests, because that section otherwise mandates the Commission to require utilities to "base the bill of the net-metering customer on the net amount of electricity that the net-metering customer has received from or fed back to the electric utility during the billing period." Thus, the advocates claim, this section is unambiguous as to whether "net excess generation" should be credited to demand-billed customers based on kilowatt hours or "kilowatt hours multiplied by the applicable rate." Distributed Solar Advocates assert that only the former is permitted. *Id*. at 3**.** Distributed Solar Advocates state that in their Initial Comments, some Parties cite evidence regarding the

[134] Ark. Code Ann. § 23-18-603(5)

scale of an alleged cost shift based on examples from demand-billed customers as part of their case to urge the Commission to move away from net-metering generally, or not allow grandfathering. While the advocates disagree that net-metering of demand-billed customers results in any cost shifting, they argue that any cost shifting that *may* result from kilowatt-hour netting of demand-billed customers is irrelevant to the separate question of what constitutes a reasonable rate structure for non-demand-billed customers, or how grandfathering should apply to such customers. They further state that if there were such cost shifts due to lost revenues from demand-billed net-metering customers, those costs would generally be borne by others within the same rate class, not shifted to other classes. Notably, the advocates state, AEEC, which represents demand-billed customers, acknowledges that cost shifting concerns among that group are not problematic.[135] Distributed Solar Advocates state that the Parties who attempt to alarm the Commission about the consequences of grandfathering residential net-metering customers by referring to large potential systems installed on behalf of demand-billed customers are "unhelpfully conflating these issues." For example, the advocates contend, EAL witness Schnitzer calculates cost shift associated with large-scale projects for demand-billed customers. Such a calculation is irrelevant to the issue at hand, the advocates assert, and misleadingly suggests that the scale of distributed generation development in the residential market is anywhere near as significant as what has been proposed in the commercial and public sector entity markets. *Id*. at 4-5.

Net Metering for Non-Demand-Billed Customers. Distributed Solar Advocates state that residential customers take service on tariffs without demand charges

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[135135] AEEC Initial at 5.

and Act 464 leaves the Commission with significant discretion in how to design net-metering rates for such customers. According to the advocates, Act 464 requires the Commission to select a rate design that is "in the public interest and do[es] not result in an unreasonable allocation of costs to other utility customers."[136] The advocates state that in determining what constitutes the public interest, the Commission should consider the purposes of AREDA, to promote distributed renewable energy resources, for the attendant health, resilience economic development, and consumer choice benefits. Distributed Solar Advocates state that in determining what allocations or increases of costs are "reasonable," the Commission should consider changes to rates over a planning time horizon, not based simply on a snapshot of embedded costs. They assert that just and reasonable rates not only recover prudently incurred costs; they also send price signals supporting economic efficiency and policy implementation. According to the advocates, "reasonable" allocation of costs include practices that tolerate *de minimis* cost shifts that are favored by public policy or could only be eliminated through measures that would result in rate shock or other disruption. What is a "reasonable" allocation of costs, the advocates assert, must also consider the public interest and AREDA's purposes – the two parts of the standard work in tandem. Although AECC urges the Commission to define "unreasonable allocation" in this proceeding, and the advocates agree that the Commission will need to interpret this term in order to adopt NMRs on rate design, they urge the Commission not to adopt a rigid definition that would preclude its ability to modify the rate design as the market and technologies mature. *Id*. at 5-6.

[136] Ark. Code Ann. §23-18-604(b)(2)(D),

Reasonable Allocation of Costs and Cost Shifting. Distributed Solar Advocates state that Parties who argue that residential net metering shifts costs to other customers take a restrictive view of the question before the Commission and that their arguments boil down to a comparison of the retail rate (credited to consumers for exports under the current 1:1 approach) and either the cost of utility-scale solar or other measures of avoided cost for energy. The advocates assert that these frames ignore the cost and challenges of delivering wholesale generation to load, as well as system savings associated with slower peak load growth, and overlook other benefits of distributed generation including resiliency and consumer choice.[137] As a foundational matter, Distributed Solar Advocates state, the Commission should recognize that net-metered customers do not *create* any costs by reducing their dependence on utility-provided electric service. They assert that the cost-shift issue is about allocations of costs and the efficient and policy-justified design of rates. *Id.* at 6-7.

Distributed Solar Advocates agree with Staff's Initial Comments[138] that the time frame for the Commission's analysis matters, stating that if one looks solely at whether certain embedded costs can be avoided instantaneously as a result of distributed generation, then distributed generation appears to offer more limited benefits. However, the advocates contend, this myopic view treats all costs other than energy as fixed and unavoidable and leads to a result where a private investment that reduces system costs over the long run would be discouraged if it results in any costs to other ratepayers in the

[137] Distributed Solar Advocates cite to the Corrected Prepared Direct Testimony of R. Thomas Beach on Behalf of National Audubon Society, Inc. and the Sierra Club (hereinafter "corrected Beach Testimony") at 15-21. They note that an error was identified in the updated Crossborder Energy study following their initial filing on October 15, 2019, and a corrected version was filed on October 21, 2019. *See* Errata filing of that date. The advocates state that these corrections were minor and did not change any of Mr. Beach's conclusions.

[138] Staff Initial Comments at 6.

short run. They quote from Mr. Beach's Corrected Testimony finding that "Solar DG is a cost-effective resource for EAL, as the benefits equal or exceed the costs in the TRC, Program Administrator, and Societal tests. As a result, in the long run, deployment of solar DG will reduce the utility's cost of service."[139] Distributed Solar Advocates state that the Crossborder Energy analysis uses a "long-term, life-cycle analysis that covers the full economic life of a solar DG system, which is at least 25 years."[140] Mr. Beach explains that this is standard practice for these analyses and a long-term, life-cycle analysis is also standard practice when a utility wants to build and then charge its customers for a new plant that will last for decades. He adds that the benefits of DERs are avoided costs and not the embedded, historical costs used in COS studies. He states that avoided costs are by definition counterfactual – they are costs that the utility never incurs because it procures a service from another source.[141] He quotes the economic axiom he believes to be useful here: -- Over the long run, all costs are variable – but notes that likewise, over the very short-run, all costs are fixed. Just and reasonable rates, he states, strike the right balance in addressing both short- and long-run cost impacts. Distributed Solar Advocates argue that every utility cost is fixed only on a short time-horizon and can be avoided if utilities engage in more comprehensive and integrated planning, including at the distribution system level, that includes forecasts of distributed generation development and output. *Id*. at 7-8.

Distributed Solar Advocates state that fortunately, AREDA gives the Commission flexibility to interpret the public interest and reasonable allocations of costs using a longer-term view of the utility's system. Doing so, they contend, is consistent with the

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[139] Beach Corrected at 20.
[140] *Id*. at 11.
[141] *Id*. at 20-21.

Commission's approach to energy efficiency, which requires utility expenditures on measures that will cost effectively allow customers to reduce their usage, on the basis that these measures will ultimately avoid more costs than they impose in the short run. The advocates argue that the conceptual similarity to energy efficiency is why Crossborder Energy and countless other net-metering cost-benefit studies utilize the same framework for analysis of how system costs and other ratepayers will be affected.[142] *Id*. at 8.

Distributed Solar Advocates state that the updated Crossborder Energy analysis filed with their Initial Comments shows that over a 20-year period, net-metered distributed generation avoids more costs than it shifts to other customers. They note that while they anticipate responding to additional critiques that may be made in the Reply Comments, the testimony of EAL witness Schnitzer contains a limited rebuttal of the methodology in the Crossborder Energy study. They also note that the study comprehensively addressed previously filed criticisms of its study in an attachment to the Surreply Comments of Sub-Group 1 to Joint Report and Recommendations of the NMWG in Phase 2 of this Docket. Distributed Solar Advocates then undertake an extensive review and response to Mr. Schnitzer and EAL's arguments. *Id*. at 9.

First, Distributed Solar Advocates state, Mr. Schnitzer agrees with Crossborder Energy that avoided line losses are a benefit of distributed generation.[143] They state that the study's analysis employs line losses developed by EAL, which increase the energy value of distributed generation by seven percent and its capacity value by eight percent. Second, the advocates state, Mr. Schnitzer begins to rebut the concept of avoided transmission costs, but ultimately takes issue only with valuing avoided transmission in cases of meter

[142] *Id*. at 4.
[143] Schnitzer Testimony at 29.

aggregation, where the generation is remote from some portion of the load offset on behalf of the net-metering customer.[144] The advocates state that even this limited critique falls apart as a matter of common sense about grid operations since a net-metered resource is still behind a meter on the distribution system and close to other loads, so any exports will flow directly to the closest load on that distribution feeder, whereupon the utility will charge full retail despite not having provided any transmission service associated with that particular kilowatt-hour. They argue that the assertion that the energy exported from a net-metering system would use the transmission to reach other meters associated with that customer account rests upon an inaccurate description of how electrons flow and is irrelevant to the analysis of avoided costs. *Id*. at 9-10.

Distributed Solar Advocates next respond to Mr. Schnitzer's contention that Crossborder Energy's valuation of avoided distribution costs relies on unnamed "studies for other utilities that have shown that 80 to 90% of distribution feeders are not fully loaded, and thus there are no capital costs to be avoided."[145] The advocates state that while it is challenging to address Mr. Schnitzer's concern given the lack of citation to these studies, it also appears that he misses a core concept with avoided distribution costs. They state that it is unsurprising and reflects conservative distribution system management as well as typical patterns of system use, for most feeders not to be fully loaded. If a distribution feeder is already fully loaded, they note, it is likely too late to avoid any costs associated with an upgrade of the feeder's components. According to the advocates, distributed generation *prevents* a feeder from becoming fully loaded, which is how it avoids expensive incremental distribution system costs (that in turn may have low asset

[144] Beach Corrected at 16, fn 6.
[145] EAL Initial at 17-18; Schnitzer Direct at 7-11.

utilization rates) over the 20-30 year life of these generation systems. For this reason, Crossborder Energy estimates avoided transmission and distribution costs based on the relationship over a 10 to 20 year period between load growth and transmission and distribution system investments.[146] *Id*. at 10.

Next, Distributed Solar Advocates address the subject of Mr. Schnitzer's testimony and EAL's comments regarding the relative costs of utility-scale and distributed generation.[147] They state that simple economies of plant scale are widely understood, so it is unclear why EAL spent ratepayer dollars on an expert to establish that distributed generation is more costly to install than utility-scale solar. Moreover, they assert, this comparison misses the point and is irrelevant to implementation of Act 464. They note that EAL argues that AREDA is intended to promote economic renewable energy resources broadly, but argue that in doing so misreads the statute.[148] Distributed Solar Advocates observe that AREDA is specifically about customer-sited and customer-financing renewables, not renewable energy generation more broadly. They note that Ark. Code Ann. § 23-18-602(a), stating the purposes of AREDA, refers specifically to net metering as a mechanism to reduce barriers to entry for customer-financed renewables, and the statute focuses exclusively on policies for development, administration, and compensation of customer-financed solar. They state that were AREDA intended to incentivize efficient utility-scale renewable energy development, it should be considered by the Commission as part of its review process for every resource planning decision by the utilities. The advocates argue that the added jobs and local economic benefits of distributed generation are the reason for higher *prices of* and higher *benefits* from distributed generation.

[146] Distributed Solar Advocates Initial at 64.
[147] EAL Initial at 17-18; Schnitzer Direct at 7-11.
[148] EAL Initial at 15-16.

Distributed Solar Advocates assert that AREDA does not permit the Commission to make a policy choice that because utility-scale renewable energy may be less expensive to install than distributed renewable energy resources, distributed generation should no longer be facilitated through utility net-metering tariffs. Doing so, they argue, would undermine the purpose of AREDA to facilitate the exercise of consumer choice and local economic development. *Id*. at 11.

Moreover, Distributed Solar Advocates assert, the cost of a value provided by utility-scale renewables are not directly comparable to that of distributed generation. They state that Mr. Schnitzer asserts that all benefits of distributed generation can be obtained from utility-scale installations, which they contend is a blinkered perspective that ignores not only the avoided line loss benefit of distributed generation that Schnitzer otherwise acknowledges, but also the avoided transmission and distribution costs associated with generating electricity close to load. Unlike utility-scale systems, the advocates state, distributed generation avoids the need to acquire land and possibly expand the transmission system, both of which can be costly and face community opposition. Additionally, the advocates state, citing the Crossborder Energy study, distributed generation also lays the groundwork for a more resilient grid as it is the foundational technology for hybrid distributed generation-storage resources that can ultimately allow vulnerable customers or those offering critical services to ensure continued service during transmission and distribution outages. Distributed Solar Advocates argue that utility-scale solar, or any remotely located generation, will never provide that benefit. *Id*. at 11-12.

Finally, Distributed Solar Advocates note that EAL makes the strange argument that the utility and its customers must choose between utility-scale and distributed renewable energy, and that net metering is somehow deterring the utility from investing in utility-scale solar they acknowledge is extremely affordable.[149]

The advocates declare that there is no such trade-off and cite EAL's postulation that there is a limit on how much solar can be integrated on the system, but cites no study establishing what such a limit might be. The advocates note that in California, nearly 20 percent of energy production, on average, is from solar resources, and the state plans to add substantial amounts of new solar as part of its goal to achieve 100 percent clean energy by 2045. Distributed Solar Advocates state that as complementary resources such as storage and demand response become more widely available, any current engineering cap on the amount of solar the grid can accommodate, will increase. They cite a recent NREL study that shows that with increased grid flexibility, 25 percent or higher penetrations of solar can be achieved at low cost. The advocates contend that the question of what any cap might be is practically irrelevant in the state of Arkansas, which currently produces less than 3 percent of its energy from all non-hydroelectric renewable energy sources combined.[150] They state that EAL eventually acknowledges the supposed ceiling on solar is a long-run problem.[151] The advocates state that should EAL or other utilities accelerate their procurement of utility-scale solar to the point where it faces challenges managing this resource become a practical reality, they would welcome a reconsideration of the public interest in further incentives for distributed solar generation. They contend that the fact many customers are choosing to install distributed generation because utilities are not moving quickly enough to satisfy consumer preferences for less polluting generation

[149] EAL Initial at 26-28.
[150] *See* U.S. Energy Information Administration State Energy Profiles, Arkansas, Electricity (July 2019), available at https://www.eia.gov/state/?sid=AR#tabs-4.
[151] EAL Initial at 28 ("In the long run, the continued subsidization of small-scale solar would likely eventually crowd out more economic grid-scale solar. . .").

resources, because customers value non-monopoly solutions, and intrinsically understand the benefits of distributed energy resources. Here, they state, a utility is seeking to squelch consumer choice simply because the utility could – but is not – giving those customers what they want, even though it would be quite affordable to do so. Distributed Solar Advocates assert that is precisely the consumer choice gap that AREDA aims to address. *Id*. at 12-13.

Proposed alternative rate designs will not achieve objectives of the statute.

Distributed Solar Advocates state that Parties advocating for immediate changes to the net-metering rate design for residential customers generally call for two types of changes: imposition of a 2-Channel billing rate design with Channel 2 compensation at the utility's avoided cost of energy, or imposition of a grid charge. They respond that neither of these proposed rate designs meets the standard of consistency with the public interest and avoiding unreasonable allocations of costs. *Id*. at 13.

2-Channel Billing proposals. Distributed Solar Advocates state that Parties who propose 2-Channel Billing call for compensation of excess energy exported to the distribution system at the utility's avoided cost of energy only. They respond that compensation at this extremely low avoided cost rate inadequately credits consumer-generators for the value that distributed generation offers the grid. Put another way, they assert, 2-Channel Billing *overcorrects* for a perceived shifting of costs to other customers that does not exist, especially if one considers the full spectrum of costs that distributed generation avoids. In doing so, they argue, it also fails the public interest prong on the Act 464 standard because export rates at avoided energy costs will not be sufficient to cover costs for systems that would be installed by most, if not all, residential customers. This rate design would devastate the residential distributed generation market in Arkansas, they state, and not only be contrary to the General Assembly's objectives to promote customer choice, avoid imports of out-of-state fuels, and the many other state interests in distributed generation, but it would also increase system costs in the long run as costs that distributed generation would have avoided are instead incurred. *Id.* at 14.

Distributed Solar Advocates note that, as the AG's Initial Comments aptly describe, an immediate shift to avoided cost-only generation would likely lead to the loss of jobs at solar installation companies in Arkansas. The advocates urge the Commission to consider the experience in Michigan as it decides what course of action to take, noting that in 2018, the Michigan Public Service Commission switched from full retail net metering to a compensation scheme based on LMPs.[152] They note that this created significant uncertainty and a fall-off in solar adoption in the state, and Michigan lawmakers are beginning the process of adopting a new law to switch back to a rate structure that will better support the residential solar market.[153] *Id.* at 14-15.

Distributed Solar Advocates observe that none of the proposed export rates includes avoided line losses, despite EAL witness Schnitzer's admission of this benefit. To the extent that the Commission concludes that it is unable to consider the full spectrum of avoided costs due to the definition of "quantifiable benefits" in Ark. Code Ann. § 23-18-603(9), then the Commission should decline to redesign net metering for residential

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[152] Balaskovitz, Andy, 2018, Energy News Network, *Michigan to replace net metering program with avoided-cost tariff, available at: https://energynew.us/wp18/04/18/midwest/michigan-to-replace-net-metering-program-with-avoided-cost-tariff/*

[153] Walton, Robert, 2019, Utility Dive, *DTE, Consumers Energy push back on Michigan legislators' plan to rewrite 2016 energy law*, available at: https://www.utilitydive.com/news/dte-consumers-energy-push-back-on-michigan-legislators-plan-to-rewrite-20/575642/

customers in line with the process set out in Ark. Code Ann. § 23-18-604(b)(2)(B). *Id*. at 15.

Distributed Solar Advocates state that while the most important problem with the proposed 2-Channel billing net excess generation rate is the exclusion of avoided costs other than energy costs, another matter for the Commission to consider is that LMPs do not accurately reflect utilities' avoided cost of energy due to many utilities' practice of uneconomically dispatching coal units. The advocates note that a recent paper published by the Sierra Club shows that LMPs may be suppressed by nearly one-third due to excessive uneconomic generation, primarily by utility-owned units.[154] Distributed Solar Advocates contend that although utilities that engage in self-scheduling practices may be able to buy power at these suppressed rates, their customers are effectively charged more for the utility's own generation when the utility's units operate at a loss, but they recover their production costs in excess of LMP from customers through their approved revenue requirement. The advocates state that it would require further investigation by the Commission to determine the utilities' actual avoided cost of energy, when factoring in any uneconomic dispatch practices by utility-owned generation in Arkansas. For the purposes of their comments, the Distributed Solar Advocates simply note that this would be a topic for further consideration if the Commission were to go the route of compensating residential net-metering customers based substantially on LMP. For the foregoing reasons, the advocates argue that the Commission should not pursue 2-Channel Billing. *Id*. at 15-16.

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[154] Fisher, Jeremy, Al Armendariz, Matthew Miller, Brendan Pierpont, Casey Roberts, Josh Smith, Greg Wannier, *Playing with Other People's Money: How Non-Economic Coal Operations Distort Energy Markets*, at 5 (2019), available at: https://www.sierraclub.org/sites/www.sierraclub.org/files/Other%20Peoples%20Money%20Non-Economic%20Dispatch%20Oct%202019.pdf .

Distributed Solar Advocates address an argument advanced by certain parties that interprets Ark. Code Ann. § 23-18-604(b)(2)(B)(iv) to require that the net-metering customer demonstrate quantifiable benefits as part of establishing the rate for net excess generation. This section of the statute states: "the additional sum added to the avoided cost of the electric utility may be applied after the demonstration of quantifiable benefits by the net-metering customer and shall not exceed forty percent (40%) of the avoided cost of the electric utility." Distributed Solar Advocates assert that the phrase "by the net-metering customer" refers to the benefits provided by that customer, not a showing that must be made by the net-metering customer. They state that to interpret this provision otherwise would require the Commission to conclude that the General Assembly intended individual residential customers who wish to net meter to present a case before the Commission for such benefits, after hiring an attorney and expert witness, and for the Commission to consider separate evidence and issue separate orders in each such case. Fortunately, say the advocates, the statute can be read to avoid such an inefficient process by placing the burden of establishing rates on the utility.[155] They argue that the Commission can avoid this thorny issue entirely by declining to adopt 2-Channel Billing. *Id*. at 16-17.

Distributed Solar Advocates also urge the Commission to reject OG&E's argument that integration or "storage service" costs should be netted out of quantifiable benefits, suggesting that this approach appears to be a holdover from the prior version of Ark. Code Ann. § 23-18-604(b)(2)(B), but is not permitted by the current definition of quantifiable

[155] The advocates note that Carroll suggests establishing a rebuttable presumption regarding quantifiable benefits that could facilitate consideration of the issue in future utility-specific cases. The advocates believe this approach may have some merit in streamlining the Commission's consideration while still allowing for the use of utility-specific data, as appropriate.

benefits. Moreover, the advocates assert, integration costs are negligible when solar penetration is low, and the notion of the utility providing a storage "service," while good storytelling, is a complete fiction. *Id*. at 17.

Grid charge. Distributed Solar Advocates note that several Parties advocate that the Commission impose a grid charge on residential net-metering customers, acknowledging that such a charge is among the options specifically permitted by AREDA. Ark. Code Ann. § 23-18-604(b)(2)(C) permits the Commission to:

> Authorize an electric utility to assess a net-metering customer that is being charge a rate that does not include a demand component a per-kilowatt-hour fee or charge to recover the quantifiable direct demand-related distribution cost of the electric utility for providing electricity to the net-metering customer that is not:
>
> (i) Avoided as a result of the generation of electricity by the net-metering facility; and
>
> (ii) Offset by quantifiable benefits[.]

Notably, the advocates state, the only cost that may be recovered through such a fee are the utility's demand-related distribution costs, and only if those costs are not actually avoided by generation from the net-metering facility, and also not offset by quantifiable benefits. Distributed Solar Advocates argue that understanding whether demand-related distribution costs are avoided by the net-metering customer requires an understanding, among other things, of the net load profile of that customer, which could well reflect lower demand during the times that determine the residential class's share of those distribution system costs. The advocates contend that a fee imposed on net-metering customers for demand-related distribution costs, when they likely have lower peak demands than others in their class, does not reflect cost-based ratemaking and is not consistent with cost-based ratemaking nor considerations of the public interest. *Id*. at 18.

Distributed Solar Advocates assert that an example provided by EAL in the testimony of Mr. Owens illustrates the unfairness of applying a grid charge to many net-metering customers. That example shows a customer who, after netting their excess generation, still pays for 700 kWh a month.[156] The advocates ask: Is such a customer really not making a reasonable contribution to paying the demand-related distribution costs associated with serving them for that month? They note that while some net-metering customers may occasionally have bills consisting of only the customer charge, many others continue to have significant bills, yet would still be imposed an additional fixed charge that is likely more than $10 a month. The advocates argue that such an additional charge cannot be supported without a better understanding of how residential net-metering customers contribute, on average, to the demand-related distribution costs, or reductions in those costs, fairly allocated to the residential class. *Id.* at 18-19.

Distributed Solar Advocates assert that the proposed grid charges would also significantly undermine the market for residential solar by increasing the payback period for net-metering systems. They state that the revised Crossborder study shows that the economics for residential solar on EAL's system are already quite marginal under the Participant Test, which shows a result of just barely above 1.0.[157] This indicates that any additional charges could tip the balance where such systems are no longer installed and, the advocates assert, would likely lead to significantly reduced business for residential solar installers in the state. While acknowledging that this consequence is not dispositive of the Commission's decision in this rulemaking proceeding, the advocates state that it is a

[156] Owens Direct at 14.
[157] Beach Corrected at Table at ES-1.

component of the public interest that the General Assembly has directed the Commission to consider when rendering a decision. *Id.* at 19.

Transition to a new rate structure. Distributed Solar Advocates assert that the Initial Comments from the Parties confirm that there is no urgency to change the rate design for residential net-metering customers, pointing out that Staff Exhibit A, examining data from the utilities' March 2019 filings shows extremely low adoption rates: Only 1,493 customers participate in net metering out of 1.4 million customers – about 0.1 percent of all customers on average. At these levels of adoption, any cost shift is *de minimis*, they assert, even if viewed in the inaccurate framing advanced by certain utilities, which ignores all avoided costs other than avoided energy. *Id.* at 20.

While the Distributed Solar Advocates disagree with the AG's preference to move toward avoided cost-based compensation, they strongly agree with the AG's recommendation that any transition must be gradual. They note that the AG makes a compelling case regarding the impacts on solar businesses of an abrupt transition and notes that a transition period will give those businesses time to scale up, for technology costs to come down, and for other market factors to evolve in a way that enables these businesses to thrive even with lower compensation rates. The advocates agree with the AG that such a transition is similar to gradual movements made in the context of ratemaking to eliminate cross-subsidization while avoiding rate shock. They note that tolerance of *de minimis* cost shifting and gradual elimination of any identified cross-subsidization is a well-established practice at the Commission, and thus no abrupt transition away from full retail net metering is needed to avoid "unreasonable allocations or increases in costs to other consumers." *Id.* at 20.

Distributed Solar Advocates note that multiple electric cooperatives along with Empire contend that the Commission should provide some flexibility for utilities at different stages of solar penetration and with different metering technologies. They agree that some flexibility of this type could be valuable and is consistent with the principles they have set out concerning the public interest in avoiding over-corrective measures to address *de minimis* cost shifting. They state that if the Commission were to determine that some move away from full retail net-metering is needed, it could specify different thresholds of solar penetration at which each utility would progress toward a new rate structure. This, they state, would be similar to the approach taken in California, where utilities transitioned to TOU net metering when the solar penetration on their specific systems reached five percent of aggregated customer non-coincident peak load. They note that Carroll acknowledges that full retail net metering is acceptable for utilities with very low solar penetration.[158] *Id*. at 20-21.

Grandfathering

Distributed Solar Advocates argue that the Commission should allow any residential customer who submits a signed interconnection agreement before the end of 2022 to continue to take service under the current net-metering rate design for a set period of time over which the Commission has discretion, up to twenty years. They assert that allowing customers to continue receiving compensation under the rate structure in place at the time a net-metering contract is signed is critical to the ability of customers to assess the likely payback period on their investment and avoid abrupt changes that leave customers unable to recover their investment. They contend that investments in long-lived assets are very

[158] Carroll Initial at 16.

challenging to support without some certainty regarding the revenues to be earned. They note that Carroll acknowledges that utilities are allowed such certainty regarding recovery of costs for their own investments.[159]

Distributed Solar Advocates state that the justifications for grandfathering identified by the Commission in Order No. 10 remain valid, and the small increases in the amount of net-metered generation since then does not change those equities. The advocates observe that several Parties attempt to point to significant increases in interconnection requests from demand-billed customers to support an argument that, although the Commission allowed grandfathering two years ago, circumstances have changed enough that it must not do so again. However, the advocates note, these Parties almost universally point to growth in net-metering installations by demand-billed customers rather than in *residential* net-metering systems. They state that the record shows that Arkansas was in 2017, and remains today, an extremely low-solar-penetration state, despite AREDA's success in stimulating economic development associated with net metering. The advocates contend that the number of residential customers who utilize net metering or might submit signed interconnection agreements in the next several years will not cause more than a *de minimis* amount of cost shifting, even if one accepts a "cramped, backward-looking definition of cost shifting." *Id*. at 22.

In response to AEEC's contention that the statute would allow the Commission not to grandfather at all – resting its argument upon the "subject to approval by a commission" language, Distributed Solar Advocates state that interpreting Ark. Code Ann. § 23-18-604(B)(10)(A) to give the Commission complete discretion regarding grandfathering

[159] *Id*. at 2.

would give no meaning to the word "shall," which begins that section. The advocates call for the Commission to avoid reading the statute in a way that gives no meaning to a particular part, particularly where the part that would be disregarded is a mandatory term. The advocates state that the presence of the term "shall" in the statute demonstrates such an intention contrary to entirely permissive construction that AEEC advances. *Id*. at 22.

Distributed Solar Advocates assert that the statute can be read to avoid such an anomalous interpretation, by interpreting the phrase "subject to approval by a commission" to refer only to the term of years the customer can remain under the rate structure in effect when the net-metering contract is signed. In contrast to the overarching mandate signified by "shall" at the beginning of the section, the advocates state that the statutory language regarding the length of time for grandfathering clearly delegates some discretion to the Commission, further establishing that the "subject to approval" language applies to the duration decision, not the initial decision to grandfather. *Id*. at 22-23.

Distributed Solar Advocates urge the Commission to make an across-the-board determination regarding grandfathering for residential and small commercial customers, as it did in Order No. 10. They agree with Scenic Hill Solar's observation that case-by-case adjudication would be incredibly inefficient, and such a scheme would, practically speaking, deter most projects from ever getting off the ground. This would be especially true, they assert, if the Commission were to adopt EAL's position that the scrutiny involved in each grandfathering determination should amount to a full-blown cost and benefit analysis akin to what the Commission would require from a utility seeking to enter into a PPA.[160] *Id*. at 23.

[160] EAL Initial at 29.

According to Distributed Solar Advocates, several Parties read Order No. 10 and Ark. Code Ann. § 23-18-604(b)(10)(A) together in unnecessarily complicated and ultimately incorrect ways. They cite SWEPCO's contention that under Order No. 10, after the date of a Commission order in Phase 3 of this proceeding, no further grandfathering is permitted.[161] The advocates state that this would be directly contrary to the statute, which states that the Commission shall allow customers to be grandfathered if they submit interconnection agreements before 2023 (though with discretion as to the duration of the grandfathering period). It is true, however, the advocates state, that customers submitting interconnection agreements after a Commission order but before 2023, would be grandfathered under any new rate structure that the Commission's order may place into effect within that time frame. They note that the AG contends that the statute "does not contemplate grandfathering" for those customers who submit interconnection agreements after December 2022.[162] The advocates state that it is unclear from this statement whether the AG considers the statute to be silent as to grandfathering these customers or prohibits grandfathering. The advocates believe that because § 23-18-604(b)(10)(A) is silent as to the Commission's obligation to grandfather customers who interconnect after 2022, the Commission may exercise its inherent authority to do so, as demonstrated in Order No. 10. Distributed Solar Advocates state that this continued authority could be important should the Commission choose to engage in the type of extended and flexible transition period that the advocates have recommended. For example, they state, if the Commission were to gradually modify the net-metering rate structure once the distributed generation on a utility's system reaches a certain level, that threshold could be reached for some utilities in

[161] SWEPCO Initial at ¶ 24.
[162] AG Initial at 13.

2025, and the Commission may wish to ensure that customers who interconnect in 2024 are able to do so with a full understanding of the likely return on their investment. *Id.* at 24.

Interconnection.

Distributed Solar Advocates agree with Staff that, given the changes made by Act 464, the interconnection rules need to be amended. In addition, they fully support Staff's recommendation that the IREC Model Procedures be used as a guide for updating interconnection in Arkansas, noting that these procedures standardize and streamline interconnection of DERs, synthesize best practices, save all stakeholders time and resources, maintain grid safety and reliability, and improve efficiency and affordability. The advocates note that, for example, under the IREC Model Procedures, preliminary site review (PSRs) are only required for larger projects. This, they note, is in stark contrast to the proposal by EAL in this Docket, which advocates for PSRs for all facilities regardless of how small the project. The advocates state that requiring PSRs for small facilities creates an unnecessary barrier in the residential solar market. *Id*. at 25.

In addition to using the IREC Model Procedures as a guide for updating interconnection in Arkansas, Distributed Solar Advocates support a general inquiry into specific utility practices that unnecessarily delay interconnection and, accordingly, support Staff's recommendation of the creation of a code of conduct critical for both the solar provider and the utility.[163] The advocates also support Staff's recommendation of the development of a Consumer Guide to assist consumers in evaluating net-metering options.

[163] Staff Initial at 10.

They are willing to participate collaboratively with all Parties in the development of this guide. *Id.* at 26.

Meter Aggregation

Distributed Solar Advocates state that Act 464 made no significant changes to meter aggregation, which was introduced to AREDA through Act 827, and allows customers to apply credits from a net-metering system to additional meters beyond the one directly connected to the net-metering system.[164] They note that the sole change was a new section, Ark. Code Ann. § 23-18-604(c)(2)(A)(ii), which states that "[s]ubdivision (c)(2)(A)(i) of this section does not apply if more than two (2) customers that are governmental entities or other entities that are exempt from state and federal income tax defined under § 23-18-603(7)(C) co-locate at a site hosting the net-metering facility."

The advocates note and disagree with AECC's contention that subdivision (c)(2)(A)(ii) prohibits, rather than promotes, meter aggregation for governmental and other tax exempt entities. The advocates support Staff's proposed revisions to the net-metering rule. They note that the subdivision refers to governmental and tax-exempt entities that co-locate and that such entities are not necessarily under common ownership, in which case they would not be eligible for meter aggregation under subdivision (c)(2)(A)(i). The advocates argue that it would make no sense for the General Assembly to add a new section saying that a provision allowing aggregation among meters under common ownership does not apply to entities that are not under common ownership. Instead, they contend, subdivision (c)(2)(A)(ii) should be read to say that the restriction on net metering to meters under common ownership does not apply to governmental and

[164] Ark. Code Ann. § 23-18-604(c)(2)(A)(i).

other tax-exempt organizations, so long as they co-locate at a site co-hosting the net-metering facility. Such an expansion makes good sense from a policy perspective, in that it expands access to net metering to such organizations and governmental entities, allowing them to take advantage of some economies of scale in installing a larger system, while maintaining a tight link between the generation and the customer load it is offsetting due to the co-location requirement.[165] *Id.* at 26-27.

Distributed Solar Advocates note that EAL proposes that the Commission define "common ownership" to mean customers with the same tax identification number. While the advocates agree that the Commission should provide some definition for common ownership to ensure that disagreement over it does not become a roadblock in project development, as it has. The advocates do not agree with EAL's more narrow proposal; instead, they propose that the Commission deem sufficient a statement by a customer seeking to engage in meter aggregation that the accounts it seeks to aggregate are under common ownership. However, the advocates state that in order for customers to understand what would constitute common ownership, the Commission should clarify that it includes partial ownership arrangements, combined budgeting and operational control, and other indicators of interest or control over the account in question. *Id.* at 27.

Distributed Solar Advocates note that EAL asserts that a tax identification number is the "existing basis used to define a customer," but provides no examples of how the tax identification number has been used in this way. The advocates contend that this failure is odd considering that such examples should presumably be readily within EAL's control were this an established practice. They assert that EAL does not explain why an identifier

[165] *Id.* at 26-27.

used in the context of defining a customer is necessarily determinative in defining "common ownership," as there is no definitional overlap between the qualifications and requirements to secure a tax identification number and the characteristics of common property ownership, interest, or control. In fact, the advocates assert, EAL's use of a tax identification number as denoting common ownership is without support in corporate and governmental common ownership structures. For example, they note, two corporate subsidiaries of a common parent corporation are under common ownership, yet they still have separate tax identification numbers from each other and from the parent company. In a governmental example, they note, a municipality may have its own tax identification number, yet it may have an electric company and a water company each with separate tax identification numbers. Distributed Solar Advocates argue that it is nonsensical to assert that the water company and the electric company are not under common ownership by the municipality. The advocates state that many farmers and other sole-proprietors in Arkansas would unnecessarily be barred from meter aggregation by adoption of EAL's overly restrictive proposal. For example, they note, a residential customer and her farm LLC should be regarded as being commonly owned, but would likely have separate tax identification numbers and customer accounts. *Id.* at 28.

Distributed Solar Advocates note that EAL challenges meter aggregation on a number of grounds beyond simply refining the expansion provided for in Act 464: *e.g.*, EAL asserts that meter aggregation is a violation of FERC rules and constitutes retail wheeling.[166] However, the advocates state that these arguments are not fully developed, are outside the scope of this proceeding to update the NMRs in response to Act 464, and

[166] EAL Initial at 8.

appear to be legal challenges to the statute. As such, the advocates do not address them but reserve their right to do so at a later time should the Commission determine that these issues are within the scope of this Docket. *Id.*

Distributed Solar Advocates note that EAL also contends that meter aggregation does not offer the avoided transmission and distribution system benefits as net-metering facilities co-located with load.[167] The advocates respond that this ignores that net-metering facilities are located on a distribution feeder near *some* loads, even if not some portion of the system owner's load. Thus, they state, the utility is still able to serve those other customers without incurring transmission and distribution costs, and without line losses. *Id*. at 29.

The solar advocates note that EAL asserts that net-metering customers who utilize meter aggregation should bear the costs of upgrading EAL's billing system to one that can handle aggregation without the need for manual billing. The advocates state that EAL presents no evidence of how much manual billing costs or how those costs might increase in the near future, and how such costs compare to the billing system upgrade EAL says would be required. The advocates state that such an upgraded billing system would likely create administrative cost savings to EAL, which would benefit all customers. Under such circumstances, the advocates assert, it would be manifestly unfair for net-metering customers to bear all of those costs. They contend that one effect of net metering may be to expose inadequacies in utility billing systems – inadequacies that could constitute a barrier to efficient and economic adoption of a wide range of DERS. Ultimately, they state, this proceeding is the wrong one for the issue EAL raises. If EAL believes this new billing

[167] See. *e.g.*, *id*. at 44.

system is a prudent investment, the advocates state, it should buy the system and then seek to include the cost in its rate base. They state that the need for the system and appropriate cost allocation should then be worked out in proceedings designed for those purposes. Finally, Distributed Solar Advocates note that EAL asserts that meter aggregation customers with too many accounts listed as eligible for having credits applied to them are engaged in "gaming" that the Commission must address in this proceeding. The advocates state that gaming implies attempts to circumvent rules, whereas the behavior EAL describes sounds simply like excessive optimism on the part of the net-metering customer. They state that it is unclear how listing additional accounts that will rarely if ever receive bill credits harms anyone or undermines the Commission's rules. *Id.* at 29-30.

Gaming

Distributed Solar Advocates state that in Order No. 22, the Commission prompted parties to address measures to address potential gaming of the 1 MW threshold in Ark. Code Ann. §23-18-603(8)(b)(ii). They note that several parties propose definitions of circumstances that would constitute gaming. For example, SWEPCO contends that it constitutes gaming to have multiple facilities under 1 MW under common ownership at the same location. The advocates agree that co-location of facilities could be an indicator of intention to game the 1 MW threshold, but only if those facilities have an aggregate capacity of more than 1 MW. Furthermore, the advocates state, "common ownership" of the co-located systems would need to correspond to how common ownership is defined for purposes of meter aggregation. In other words, they state, if a collection of entities are not deemed commonly owned such that they can aggregate across meters, then they should not be deemed commonly owned for the purpose of gaming rules around co-located facilities. The advocates note that AECC proposes a new section of the NMRs – Section 5.0 – to address various concerns it has around gaming. However, the advocates respond, most provisions of AECC's proposed NMR 5.0 do not concern the 1 MW threshold, but instead other types of misleading statements, unpermitted actions, or crimes of omission by net metering customers. For example, AECC proposes terminating net-metering privileges and subjecting a customer to the penalties associated with "tampering" under the General Service rules, for such infractions as changing the service contact of a net-metering facility without notifying the utility. Absent more information about how pervasive the conduct listed in proposed rule 5.03(A)-(F) is, and the utilities' inability to address it through existing process, Distributed Solar Advocates do not believe such harsh remedies are appropriate. *Id*. at 30-31.

The advocates note that AECC proposed rule 5.03(E)(1) does relate to the 1 MW threshold and states that "Any facilities used for Net-Metering being credited to a customer's account, regardless of the location of the facility and its aggregation, will be treated as a single facility and must comply with the imposed capacity and/or sizing limits under these Rules." Thus, they state, AECC's proposed rule is broader than SWEPCO's in that it would aggregate the capacity of all facilities credited to a customer's account, regardless of location. In the advocate's view, such a rule might prohibit legitimate arrangements where a customer has behind-the-meter systems at multiple locations that it owns (such as multiple shops or offices associated with a single business) and links those Net-Metering Facilities to meters at other properties owned by the customer. They acknowledge that this would be an unusually complex meter aggregation arrangement, to be sure, but raise the possibility to illustrate a circumstance where having Net-Metering Facilities linked to a single customer account, but not co-located, and exceeding the 1 MW threshold, does not appear to be motivated by an attempt to game the threshold, but simply the result of a customer taking advantage of multiple rooftops and seeking to maximize the value of those credits. *Id*. at 30-31.

Distributed Solar Advocates assert that EAL likewise seeks to shoehorn into the "gaming" inquiry a wide range of behaviors it views as troublesome relating to Preliminary Site Reviews. They urge the Commission to hesitate to prohibit what appear to be reasonable commercial behaviors without better understanding the motivations behind them. From EAL's description of how Preliminary Site Reviews help solar developers understand the feasibility of interconnecting at different locations, the advocate state that these issues are likely to be addressed through measures to improve transparency regarding utility hosting capacity, as being explored in Docket 16-028-U. *Id*. at 31.

Leasing

Distributed Solar Advocates note that several parties suggest changes needed to the Net Metering Rule to implement the Act 464 provisions expanding net-metering eligibility to leased facilities or those managed under service contracts. For example, they state, EAL asks the Commission to establish a process for reviewing lease agreements to ensure that they qualify for net metering, or alternatively to allow for use of a form agreement. The advocates note that AEEC raises a similar concern with respect to service agreements, noting the need to assess whether the exclusions from the safe harbor provision at 26 U.S.C. §7701(e)(4) are applicable before determining whether a facility is eligible for net-metering. Distributed Solar Advocates agree that there should be a streamlined process for determining eligibility for net-metering of facilities utilizing these kinds of arrangements, but that process need not involve the Commission; instead, they argue, the Commission could consider designating a staff member to review such agreements and attempt to resolve any disputes with the utility regarding eligibility. The advocates assert that any such process should have the objectives of allowing consumers seeking to utilize lease or service contract arrangements to confirm early in the process that their system will be eligible for net metering, while not requiring those customers to jump through countless hoops or initiate a Commission proceeding in order to get approval for net metering. To that end, the advocates could support EAL's suggestion that a form contract or lease agreement be developed which could be used to eliminate any kind of uncertainty or case-by-case review, though they state that the use of such a form agreement should not be compelled. *Id.* at 32.

On the issue of the eligibility of a consumer for the safe harbor provision at 26 U.S.C. §7701(e)(4), the advocates note that AEEC suggests that the Commission might require confirmation by the appropriate federal agency (presumably the IRS), of the applicant's eligibility. The advocates believe such a requirement would be unnecessarily burdensome, especially considering that in most cases, the face of the service contract should generally resolve whether the safe harbor applies. Distributed Solar Advocates assert that since many of the utility commenters in this Docket have taken a hostile stance towards these express expansions of net metering rights under Act 464, there is a real concern that a utility might utilize a "legal" review of a lease or service agreement as a means to delay or derail proposed net metering facilities. *Id.* at 32-33.

Consumer Protection and Related Issues.

Distributed Solar Advocates support the recommendation of the AG that the Commission establish a working group to develop measures intended to protect consumers, which could include a code of conduct for utilities and solar installers, general consumer protection information, and possibly a process to certify providers. The advocates state that it is critical that the code of conduct apply to both utilities and solar installers, so that the process can truly be as smooth as possible for consumers. To that end, they propose that any such working group that the Commission may establish should include, or at least seek input from, representatives of different consumer classes. They suggest that the working group could consider already available resources such as the California Public Utilities Commission Solar Consumer Protection Guide recommended by AECC to determine applicability and comprehensiveness from an Arkansas perspective. The advocates note that a number of parties have suggested that the Commission should have a process to receive complaints against or otherwise discipline solar installers. Distributed Solar Advocates contend that the Commission's jurisdiction to do so is not clear, given that these installers are not public utilities. As such, the advocates suggest that this working group should examine what tools the AG and the Commission have under their existing authority to enforce the code of conduct or otherwise hold companies interacting with ratepayers accountable for any misleading statements. They state that those discussions can inform recommendations that might be made to the Commission or General Assembly, as appropriate, regarding consumer protection in this area. *Id.* at 33-34.

Miscellaneous Provisions

Distributed Solar Advocates note that EAL contends that in order for a facility to qualify for net metering, the net-metering customer must hold the RECs, because if the customer does not hold these credits then the facility cannot be counted as "renewable generation" eligible for net metering. EAL asserts that "AREDA requires that customers retain the RECs associated with the energy provided by the net-metered facility in order for the generator to qualify as 'renewable' and the customer be eligible to take net-metering service."[168] But the advocates assert that this is not what Ark. Code Ann. §23-18-604(b)(8)(B) says, noting that the section states: "[a] 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" (emphasis added). According to the advocates, AREDA does not say the REC is inalienable property, as EAL asserts. The advocates suggest that EAL's concern appears to be that the net-metering customer may transfer its property (the REC) to a solar developer as part of a negotiation of the contract. According to the advocates, the implication of EAL's argument is that the net-metering customer can never sell the RECs their system generates to anyone without losing eligibility for net-metering. That would, they note, of course, include any sale of the REC to the utility, which would seem problematic given EAL's suggestion that it might one day seek to claim the RECs of net-metering facilities on its system for compliance with a renewable portfolio standard or similar policy. Distributed Solar Advocates argue that EAL's proposal to restrict net-metering customers' right to sell their property, including an upfront sale to a developer in order to obtain more favorable installation terms, has no

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[168] EAL Initial at 8-12 and 21-26.

precedent among state net-metering policies as far as they are aware. While RECs are essential to ensuring that multiple entities do not make renewable energy claims regarding the same kWh, the advocates assert there is no indication in AREDA that the General Assembly was concerned that distributed renewable energy systems be strictly "additional" in order to be eligible for net-metering. Instead, the advocates assert, the General Assembly seemed particularly focused on the economic development benefits of distributed generation development, which is enhanced by the transferability of RECs and the revenues that can thereby be generated. *Id.* at 34.

Distributed Solar Advocates state that EAL and SWEPCO express concerns that net-metering facilities are being oversized, and propose changes to the NMRs to address that problem.[169] However, the advocates respond, neither utility offers any evidence that facility oversizing is a problem, or that attempts by consumers to oversize are not adequately controlled by the existing net-metering rules.[170] The advocates note that in Order No. 10, the Commission addressed concerns about oversizing and concluded that the existing Net-Metering Rules and interconnection procedures were adequate.[171] The advocates state that no Party puts forth evidence that circumstances have changed sufficiently that interconnection procedures are inadequate to resolve these conflicts and that require amendment to the NMRs regarding facility sizing. *Id.* at 35.

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[169] EAL Initial at 47-48 and SWEPCO Initial at 9-10.

[170] Distributed Solar Advocates also note that the federal investment tax credit available to consumers who install solar systems is restricted to systems which "generate electricity for use," 26 U.S.C. §25D(d)(2), thus reinforcing the similar restriction in the NMRs and disincentivizing oversized systems that exceed the demand on-site.

[171] Order No. 10 at 60-63: ("as with the sizing of larger systems, the interconnection process is the right place to make a reasonable decision as to whether a Net-Metering Facility is intended primarily to offset part or all of the NMC's requirements. If there is a later dispute between the utility and the Net-Metering Customer about the size of the systems and whether it meets the statutory definition of an Net-Metering Facility, the Commission has processes in place to resolve such disputes.").

Distributed Solar Advocates note that AECC proposes to define the "applicable period" in a way that would eliminate netting over the billing period.[172] They respond that such a definition would make net metering as it currently exists impermissible under the Commission's rules even during any transition period that the Commission might deem appropriate. They state that this would also take away the flexibility that AECC otherwise says should be available to accommodate diversity among cooperatives. The advocates argue that the Commission should define "applicable period" in a way that preserves its flexibility regarding what it ultimately views as the preferred rate structure, and to provide for a measured transition. As the Commission considers whether to stick with monthly netting or move to a different mechanism, Distributed Solar Advocates note that there is great market value in ensuring that the billing period and the netting period are consistent. They assert that bills and netting arrangements provide price signals to customers and a common temporal platform for evaluating net-metering facility investments, usage patterns, and payback performance. The argue that to have two separate time periods—one for billing and one for net-metering facility netting — will create excess confusion for customers who are merely seeking to manage and reduce their utility bills through Net-Metering Facility investments. *Id.* at 36.

Finally, Distributed Solar Advocates state that EAL raises an issue as to whether certain facilities qualify for net metering if they are not "behind the customer's meter" and do not "displace some amount of electricity that the customer consumes," and requests that the NMRs be clarified to impose such restrictions on facilities that can qualify for net-metering.[173] At the same time that EAL is advocating for this "clarification" to the rules,

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[172] AECC Initial at 5-6.
[173] EAL Initial at 44-45.

the advocates state, and absent evidence that any customer seeking to net meter is actually proposing a facility with no associated load, the utility is providing confusing information to customers about the likely outcome of this proceeding. They note that two of AAEA's member companies who are solar developers recently received the following form email from EAL regarding solar projects they are developing on the EAL system:

> There is a rulemaking currently before the commission (APSC) concerning updates to the net metering rules including whether remote facilities qualify for net-metering. A remote site is an interconnection that does not serve load at the physical location of the solar facility. Therefore, until this rulemaking is complete at the APSC, Entergy cannot move forward with the "insert customer name" net meter installation project since it is a remote site.

Distributed Solar Advocates argue that Act 464 and this rulemaking have nothing to do with whether a remote net metering facility qualifies for net metering, asserting that such facilities qualified for net metering under any reading of AREDA before Act 464, and Act 464 made no amendments to AREDA that changes that fact. They state that such "remote" sites will always have some load associated with them for such things as inverters, night lighting and security, and will be equipped with a meter capable of measuring electricity in two directions. The advocates acknowledge that load associated with the facility will be less than the electricity produced by the facility: however, the excess will be used to offset other meters of the owner of the facility under meter aggregation. The advocates state that the AAEA member companies intend to file a complaint at the Commission to address this issue. *Id.* at 36-37.

Conclusion

Distributed Solar Advocates state that the purpose of Act 464 of 2019 was to remove barriers to access to net metering in Arkansas. They note that it is a reaffirmation of the importance of promoting net metering to ensure the wise use of Arkansas's natural resources. They assert that Act 464 specifically added the availability of leasing for all customers and solar services agreements for non-taxed entities; increased the size limitation for net-metering facilities; codified 1:1 kilowatt hour netting for all demand-billed customers; and struck the overly restrictive language requiring the removal of all cost shifts, and replaced it with a more flexible reasonable allocation of costs standard. Yet, they state, some commenters would have this Commission implement rule changes in response to Act 464 in a manner that would restrict rather than promote net metering in Arkansas. Distributed Solar Advocates request that the Commission implement the changes required by Act 464 in the spirit of AREDA as amended, noting that while the legislature gave broad discretion to the Commission to modify net metering for non-demand billed customers, any potential changes should be viewed through the criteria of promoting net metering as that is the clear and unambiguous legislative intent. To that end, the advocates state that changes should be ordered only if required in order to maintain a reasonable allocation of costs, and implemented in a manner designed to mitigate market disruption. *Id*. at 37-38.

k. Scenic Hill Solar

Scenic Hill Solar's comments address in particular the comments of EAL regarding demand-metered customers, net metering penetration, common ownership, grandfathering, renewable energy credits, and energy storage, and provide correspondence with EAL for the Commission to establish that EAL has routinely delayed the most basic of interconnection reviews on spurious grounds. In addition, Scenic Hill Solar provides a correction to what it calls EAL's completely speculative and premature analysis that finds that a substantial cost shift will occur as a result of Scenic Hill Solar's interconnection of a net-metered system for the City of Hot Springs. As well, Scenic Hill Solar addresses some of EAL's "unsupported" redlines to its net-metering tariff and the Commission's NMRs. Scenic Hill Solar Reply at 1-2.

Further, given EAL's claims of net metering causing a cost shift to non-net-metering customers, Scenic Hill Solar provides as attached exhibits the reports cited in its initial comments, which were reports synthesizing individual studies at the state or utility level, and providing an extensive sampling of those studies. According to Scenic Hill Solar, these studies generally show net metering has either a *de minimis* impact or a net benefit on non-net-metering residential customers, implying that demand-metered customers, which have lower energy rates than residential customers, provided an even greater net benefit according to those studies. According to Scenic Hill Solar, the intent of including these studies is to show that EAL's claims of cost shifting are based on a simple avoided energy cost analysis that ignores other values commonly identified in studies. With Arkansas' low penetration of solar, Scenic Hill Solar asserts that whatever the impact of net metering is, it is certain to be very small as a percentage of retail sales. Scenic Hill Solar states that the Commission has plenty of time to determine the scope of an appropriate study and conduct the study, and expects that such a study will show that net-metering provides a net benefit, as other studies in low solar penetration states have shown. *Id.* at 2.

Demand-metered Customers

Scenic Hill Solar states that, along with EAL's initial comments, its witnesses Schnitzer and Owens filed testimony addressing the purported impact of demand-metered customers and steps that the Commission could take to mitigate these impacts. EAL's comments also incorporate by reference testimony filed by witnesses Castleberry and

Talkington in Docket 19-042-TF regarding cost shifting. For purposes of the present rulemaking, Scenic Hill Solar contends that this blizzard of testimony should not be considered at all with respect to demand-metered customers. *Id.* at 3.

According to Scenic Hill Solar, Act 464 clearly preserves traditional kilowatthour-for-kilowatthour (1:1) net metering for demand-metered customers, so it is out of scope in this rulemaking to address alleged cost shifting caused by these customers. Nonetheless, Scenic Hill Solar questions the conclusions of these EAL witnesses, noting that Mr. Schnitzer provides calculations of the overall impact of net metering, including the "made up" specific example of a net-metering facility that he asserts Scenic Hill Solar may use to provide energy to the City of Hot Springs. Scenic Hill Solar states that Mr. Schnitzer's calculations for Hot Springs are refuted later in its comments, but also questions his overall results in light of the numerous studies attached to its comments that show much greater benefits than just the avoided energy costs that Mr. Schnitzer uses. Most notably, Scenic Hill Solar states, he shows that for LGS customers, the cost shift is just 1.1 cents per kWh using EAL's avoided energy cost as the only benefit.[174] With even the most conservative of approaches acknowledging just over a penny of other benefits, Scenic Hill Solar argues that the cost shift for these customers becomes a net benefit for non-net-metering customers. To be clear, Scenic Hill Solar acknowledges that many of its customers have LGS meters. Most importantly, Scenic Hill Solar states, all that EAL knows about the Hot Springs project is that an agreement exists for a 12.75 MW facility and that neither Mr. Schnitzer nor anyone else at EAL knows anything more about the project, so it is impractical for them to opine on the impact of the project at this time.

[174] EAL Initial at 4-5.

Scenic Hill Solar asserts that it is a free country, so Mr. Schnitzer can speculate all he likes, but the Commission should ignore completely his speculation, as the APSC will have an opportunity to review the future Hot Springs projects when they have been fully developed. This will occur more quickly, Scenic Hill Solar states, if EAL stops its delaying tactics in processing preliminary interconnection site reviews. *Id*. at 3-4.

According to Scenic Hill Solar, Mr. Owens provides extensive testimony on how 2-channel billing can be established to pay for exported energy at avoided cost rates, including an example showing the process and supposed savings of using 2-Channel Billing for a demand-metered customer. Again, Scenic Hill Solar asserts, there is simply no point in providing this example, given that Act 464 preserved 1:1 net-metering for demand-metered customers. According to Scenic Hill Solar, within EAL's comments, the citations to testimony in Docket No. 19-042-TF include a summary of those results, with wildly unrealistic impacts based on all customers that have filed for preliminary review actually installing systems. What matters at the present juncture, Scenic Hill Solar asserts, is that solar penetration in Arkansas is so low that impacts are immaterial at this point, and any reported impacts should be based on an unbiased study that considers more than avoided energy costs. Particularly for demand-metered customers, Scenic Hill Solar states, a reasonable analysis accounting for more than just avoided cost would show a net benefit of the largest customers availing themselves of net metering. *Id*. at 3-4.

Net-Metering Penetration

Scenic Hill Solar asserts that EAL's reported cost-shifting impact raises the issue of when the Commission should perform a study to look at the impacts of net metering from its unbiased perspective. Scenic Hill Solar suggests that the Commission has time to begin to formulate the approach it wants to use for study based on examples from dozens of other states, and hire an expert to perform a study of the impacts for EAL and to develop a model for evaluation of the impacts for other utilities. Further, Scenic Hill Solar suggests that changes to net metering should be based on such a study; at the current low penetration, and that the impact on non-net metering customers is *de minimis*. Scenic Hill Solar poses the question: When is the right time for a study? Scenic Hill Solar responds that looking at all generation in kilowatt-hours, as a percentage of the utility's total customer sales, would be a useful way to establish the timing of a review of net metering, noting that both Minnesota and New Jersey have used this percentage of retail sales approach. According to Scenic Hill Solar, Minnesota uses four percent of utility retail sales, at which point a utility can request to deploy a value-of-solar tariff. New Jersey uses 5.8% of total state retail electricity sales, says Scenic Hill Solar, at which point a supplier can ask that state's commission (the Board of Public Utilities) to let them stop offering net metering. Scenic Hill Solar suggests that to establish net- metering generation, it would be a cumbersome and unnecessary exercise to gather the data for all net-metering systems in Arkansas. Instead, the Commission could use average kWh/kW figures from existing Arkansas systems, together with data from NREL's PVWatts to calculate generation based on installed capacity. According to Scenic Hill Solar, the benefit of using a generation-as-a-percentage-of-sales approach would be that the percentage sets an absolute outer bound on cost shifting. In the example it presents, if the utility sees a reduction of 3.4 percent of its sales due to net metering, the impact on non-net-metering customer bills cannot be any more than that percentage. Even using only avoided energy costs, Scenic Hill states, the impact on non-net-metering customer bills would be in the range of only 2%, and with reasonable accounting for other benefits, argues that the impact would be to reduce non-net-metering customer bills. *Id*. at 5-6.

Scenic Hill Solar asks what the appropriate threshold is for a study using this approach. Given that AREDA has a clear intent to promote distributed renewable energy, and its language regarding avoiding "an unreasonable allocation of or increase in costs to other utility customers," Scenic Hill Solar suggests that the Commission would want to conclude a study before net-metering penetration exceeds five percent, at which point even with only an avoided energy cost approach, the impact of net metering on non-net-metering bills would be no more than perhaps 3%, and a reasonable study would likely show a minimal impact. *Id*. at 6.

Common Ownership

Scenic Hill Solar states that EAL simply ignores AREDA's language of "common ownership" and instead imposes a requirement of customers having the same tax identification number ("tax ID") in its place. Having gone through this discussion with EAL for a specific project, as discussed in both Initial Comments and the supplemental testimony of EAL witness Palmer, Scenic Hill Solar states that it is clear that the tax ID approach is unworkable. *Id*. at 6-7

More importantly to Scenic Hill Solar, the statutory requirement regarding common ownership cannot reasonably be interpreted to mean anything but ownership by the same person or entity. Scenic Hill Solar states that an entity such as a municipality can have more than one tax ID for different city functions, but if the city owns both the water pumping station and city hall, those two city functions with separate tax IDs are nonetheless commonly owned. Mr. Palmer discusses the request of Scenic Hill Solar's client, the City of Stuttgart, and states the crux of the problem as, "because it is reasonable to assume that a non-taxable entity has a single tax ID, EAL considers it clear in the statute that multiple tax ids would constitute multiple net-metering customers."[175] Scenic Hill Solar responds that it is not reasonable to assume that a non-taxable entity has a single tax ID. For the City of Stuttgart, Scenic Hill Solar states that it has clearly demonstrated that the City has more than one tax ID, and has gotten the Mayor on the phone with EAL to affirm that the City has more than one tax ID. Scenic Hill Solar asserts that the effort has dragged on for months, as discussed later in its comments, for absolutely no reason, adding that EAL's response has been to refuse to complete a preliminary technical review based on its position that the City of Stuttgart is not the common owner of its city departments.

Scenic Hill Solar notes that EAL's comments address the Stuttgart example as well, over the course of three pages.[176] Scenic Hill Solar states that it seems audacious that EAL can be aghast that it claims that, "three separate legal entities with separate federal taxpayer identification numbers (i.e., the City of Stuttgart, Stuttgart Municipal Waterworks, and the Stuttgart Public Library) now are "associated with" one customer, i.e., the City of Stuttgart." Scenic Hill Solar states that it does claim that these entities are under the common ownership of the City and asks that the Commission direct EAL to accept that city departments, despite having separate tax IDs, are under the common ownership of the city in question. According to Scenic Hill Solar, EAL goes on to posit that under its line of reasoning, a person who owns multiple businesses might claim common

[175] Palmer Supplemental at 5.
[176] EAL Initial at 38-41.

ownership.[177] Scenic Hill Solar asserts that EAL's presumption seems to be that opening this floodgate will allow untold combinations, possibly even without actual ownership in common. In Scenic Hill Solar's opinion, an affidavit of common ownership would be sufficient, but it would also be feasible to show evidence of common ownership through corporate formation documents showing common ownership. However, Scenic Hill Solar urges the Commission to not apply such a rule to municipalities, arguing that proving that the library and the water department of a city are under common ownership is a frivolous exercise; common ownership in that case is self-evident. *Id.* at 6-8.

Grandfathering

Both Scenic Hill Solar's Initial Comments and the Initial and Reply Comments of Sierra Club/Audubon/AAEA [herein the Distributed Solar Advocates] discuss grandfathering at length, and the need for certainty. In contrast, according to Scenic Hill Solar, EAL asserts that grandfathering will perpetuate the cost shifting that they allege. As noted earlier in these comments, Scenic Hill Solar argues that by only looking at avoided energy costs, EAL is dramatically overstating the potential for cost shifting and asserts that grandfathering is critical for demand-metered customers. Scenic Hill Solar asserts that while 1:1 net metering is preserved by Act 464 for demand-metered customers, laws can change. Scenic Hill Solar asserts that just as a residential customer who installed a net-metering facility before Act 464 reasonably expects the 1:1 net metering that motivated her to install her facility will not be snatched away, a demand-metered customer installing a net-metering facility today should be able to rely on the continuation of 1:1 net metering. *Id*. at 8-9.

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[177] *Id*. at 40.

Scenic Hill Solar states that EAL has redlined the NMRs to add a grandfathering provision as Rule 2.11, providing only that, "Any customer who is already interconnected at the time of the enactment of these Rules may apply for grandfathering by submitting an Application with the Commission." Scenic Hill Solar states that asking every net-metering customer in the state to submit an application to the Commission for an individualized determination of grandfathering creates needless uncertainty and thwarts the goals of AREDA. Scenic Hill Solar asserts that consistency requires that the Commission establish a single period for grandfathering. Given that Act 464 allows for a period of up to 20 years, the Legislature clearly considered that amount of time to be in the range of reasonableness, and Scenic Hill Solar encourages that length to give the prospective net-metering customers the improved certainty that will spur more renewable installations as intended by the Arkansas General Assembly. *Id.* at 8-9.

Renewable Energy Credits

Scenic Hill Solar states that EAL makes the interesting though unsupported argument that net metering customers must retain the RECs associated with their net-metering facility's generation, or else the facility is no longer actually a renewable energy generator. Mr. Schnitzer cites the Energy Services Agreement that the City of Hot Springs has signed with Scenic Hill Solar as an example of a developer retaining RECs.[178] The problem with this argument, according to Scenic Hill Solar, is that AREDA does not require that the net-metering customer retain the RECs associated with her facility, but only that, "[a] 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

[178] EAL Initial at 8-11.

renewable energy credit."[179] Like any property, Scenic Hill Solar observes, RECs can be sold. Scenic Hill Solar state that it does not assume that it owns the RECs, which is the reason that a provision about RECs is in the agreement with the City of Hot Springs cited by Mr. Schnitzer. In practice, Scenic Hill Solar states, it is difficult for an individual net-metering customer to become familiar with the processes for tracking and selling RECs, so the RECs have less value to the net-metering Customer directly than may be achieved by a developer on the net-metering customer's behalf. By taking ownership of the RECs, Scenic Hill Solar contends that it can offer the City of Hot Springs and other customers lower energy rates. Scenic Hill Solar asserts that the argument that selling energy generated by a solar array to a utility customer, while not selling the associated RECs to the customer somehow makes the solar array no longer a net-metering facility is unpersuasive. A net-metering facility is defined in relevant part as a facility that, "[u]ses solar, wind, hydroelectric, geothermal, or biomass resources to generate electricity . . ."[180] Scenic Hill Solar states that it is unaware of any state that requires the net-metering customer to retain RECs -- the common practice is to allow the sale of RECs because it is another revenue stream that helps defray the cost for the customer. Given EAL's alleged intent to delay interconnection approval for the City of Hot Springs based on their assertion that the REC ownership issue creates uncertainty, Scenic Hill Solar requests that the Commission rule on this issue as soon as possible. *Id.* at 9-11.

Energy Storage

According to Scenic Hill Solar, Mr. Schnitzer notes in two instances that energy storage could expand the potential for solar energy penetration, but is currently expensive.

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[179] Ark. Code Ann. § 23-18-604(b)(8)(B).
[180] Ark. Code Ann. § 23-18-603(8)(A).

However, with massive investments in battery technology underway, particularly for electric vehicles, Scenic Hill Solar states that the general speculation is that battery costs will continue to rapidly decline.[181] Scenic Hill Solar suggests that at some point in the coming months, the Commission will need to clarify what types of storage facilities may be considered a part of a net-metering facility, given the changes in Act 464. *Id.* at 11.

Evidence of EAL Delays

Scenic Hill Solar notes that in Mr. Palmer's supplemental testimony for EAL, he states that, "some parties have alleged that EAL is obstructing the preliminary site review process and interconnection process for potential net-metering installations," and, "[t]o date, EAL has only notified three potential net-metering customers of such issues related to Act 464."[182] The City of Stuttgart, a Scenic Hill Solar customer, is the first of the three customers that Mr. Palmer discusses. Scenic Hill Solar states that it has experienced issues with other applications, and attaches to its Reply Comments some of its lengthy correspondence with EAL to seek preliminary reviews, each of which is discussed at the end of this section. For these reviews, Scenic Hill Solar has paid $1,000 each, for a total of $12,000 to date. According to Scenic Hill Solar, the limited and non-binding technical review of whether an interconnection of a MW facility at a particular site will possibly require upgrades appears to require only a few hours of engineering time. *Id.* at 11-12.

Scenic Hill Solar notes that at the October 29, 2019 workshop in Docket No. 16-028-U, EAL clearly explained what is variously referenced in its comments in the present Docket: if it perceives that an applicant would not qualify for net metering, then it will not

[181] *See, e.g.*," Lithium Ion Battery Prices Are Expected to Fall at an Average Annual Rate of 6.5% for the Next Decade", Navigant Research, Aug. 6, 2019, available at www.navigantresearch.com/news-andviews/lithium-ion-battery-prices-are-expected-to-fall-at-an-average-annual-rate-of-65-for-the-next-decade
[182] Palmer Supplemental at 3.

process the preliminary technical review. Scenic Hill Solar asserts that with the stated intent of not misleading customers that they might qualify for net metering, EAL refuses to even provide the most basic technical review of distribution circuit capacity. Scenic Hill Solar contends that the Commission has the sole authority to determine whether a proposed project qualifies for net-metering. Obviously, Scenic Hill Solar states, it would not waste time guiding a customer down a path towards development of a facility if it thought the facility would not qualify. While EAL might have a different opinion, Scenic Hill Solar asserts that it is not their prerogative to decide these issues on their own, especially in the preliminary site review process. *Id.* at 12.

Scenic Hill Solar attaches as Exhibit 1.a correspondence with EAL starting in July 2019 regarding the Stuttgart project. The first page summarizes the 23 major interactions on the pages that follow. Scenic Hill Solar states that the August 15th email from EAL in this Stuttgart correspondence details EAL's refusal to process multiple applications for a project in Camden (each of which Scenic Hill Solar paid EAL to process). As shown by the correspondence, Scenic Hill Solar states, it repeatedly represented that there were only two tax ID numbers associated with the City of Stuttgart, while EAL contended that there were three. After multiple emails over several months, Scenic Hill Solar states that it was finally able to get EAL to identify which meters had tax ID numbers other than the two now known to be associated with the City. The City of Stuttgart has supplied EAL with W-9 forms to correct errant tax ID numbers in EAL's records, per the final correspondence in the record. According to Scenic Hill Solar, this string makes it very clear that tax ID numbers are not a workable method for EAL to establish common ownership. According to Scenic Hill Solar, the common ownership of City of Stuttgart departments could have been accepted as obvious three months ago, and the project could be installed and operational at this point, but for EAL's delay. Scenic Hill Solar also attaches as Exhibit 1.b a timeline and 32 pages of correspondence with EAL regarding applications for multiple net-metering facilities to serve the City of Camden and Ouachita County, starting with initial applications in June. Again, Scenic Hill Solar cites delays based on multiple applications, each of which EAL was paid $1,000 to process, attributable to EAL's opinion that they are not required to undertake more than one study for any given customer at a time. Scenic Hill Solar provides Exhibit 1.c -- a four page email string with EAL regarding multiple applications for preliminary review of facilities to serve Forrest City. According to EAL, these emails also illustrate that EAL is asserting that it will not process more than one application at a time for facilities proposing to offset load at one or more of the same meters. Scenic Hill Solar's purpose in filing the email strings related to Stuttgart, Camden, and Forrest City is to demonstrate the pressing need for Commission direction that a utility cannot rely on tax ID numbers to determine common ownership (at least, not for municipalities), and that a utility should process preliminary technical reviews promptly, without delay based on its interpretation of Act 464 and the net-metering Rules. *Id.* at 12-14.

EAL Testimony Regarding the Impact of the City Hot Springs Utilizing Net-Energy Metering

Scenic Hill Solar states that in the Mr. Schnitzer's testimony, he shows that the energy rates for LGS and LPS customers are mostly comprised of his determination of 3.5 cents of avoided cost, with the remaining 1.1 and 1.0 cents, respectively, of those rate schedules' energy rates attributed to a "cost shift."[183] Scenic Hill Solar asserts that Mr. Schnitzer thereby assumes the conclusion he wishes to achieve. While Scenic Hill Solar vigorously disputes whether there is a cost shift at all, even with Mr. Schnitzer's assumptions, it points out that the cost shift would be a fraction of what he has calculated. Scenic Hill Solar states that it does not wish to expend anyone's resources to review all of EAL's witnesses' calculations. As noted earlier, Scenic Hill Solar notes that the only information that EAL has concerning the Hot Springs project is that an agreement exists with Scenic Hill Solar for a 12.75 MW project; EAL is merely speculating about impacts without knowing any details about the project. According to Scenic Hill Solar, at the appropriate time the Commission will have an opportunity to review the specifics of a "real" project from Scenic Hill Solar for Hot Springs, rather than the "fictional" project examined by Mr. Schnitzer. *Id.* at 13-14.

Miscellaneous EAL Redlines

Scenic Hill Solar states that in EAL's redline of the NMRs, attached to its Initial Comments, EAL includes several provisions that are not supported by AREDA as modified by Act 464. Scenic Hill Solar's attention to these specific redlines is not meant to show support for any other elements of EAL's redlines. In NMR Rule 2.01, EAL adds in redline that a utility, "is not required to interconnect a customer installing a renewable facility that is not connected to its load." Scenic Hill Solar states that it justifies this position in its comments with the logic that AREDA calls for the use of a bidirectional meter, and such a meter would be unnecessary if energy only flowed in one direction, such as at remote

[183] Schnitzer Direct at 26 (Fig. 8).

generation site without load.[184] According to Scenic Hill Solar, this argument suffers from several fatal flaws:

- First, AREDA only says that an electric utility "shall allow" interconnection of a NET-METERING Facility with a bi-directional meter; it does not require the use of a bi-directional meter;[185] accordingly, EAL is free to use a uni-directional meter at a net-metering facility sited remotely;
- Second, nothing in AREDA requires load at the generation site, including the definition of a net-metering facility;
- Third, the concept of allowing generation to offset load at another site was conceived of, and has been discussed throughout workshops in this docket as a way for customers with load at a site with limited potential for solar generation to put an array on vacant [sic] land elsewhere and offset their load; and
- Fourth, a customer can install lighting at a remote generation site and thereby have load at the site.

Id. at 14-16.

Scenic Hill Solar next notes that in NMR Rule 2.09(C), EAL adds redline to prohibit multiple applications to offset the simple, non-binding reviews. As Scenic Hill Solar discussed previously, the customer pays $1,000 for these fairly simple, non-binding reviews. Scenic Hill Solar responds that in the interest of enabling distributed renewable generation, it makes sense for a developer to be able to ask about the potential to install a given net-metering facility on multiple locations and pick the most promising. Importantly, Scenic Hill Solar asserts, requiring sequential rather than parallel

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[184] EAL Initial at 45.
[185] Ark. Code Ann. § 23-18-604(a).

preliminary reviews would needlessly delay projects. In NMR Rule 2.10, EAL's redlines would prohibit applications that cumulatively exceed the 1 MW threshold unless there is Commission approval. Presumably, Scenic Hill Solar asserts, EAL intended this provision to apply to applications to serve the same load, such as three facilities to serve a single commercial customer. However, together with its proposal to have the developer sign an interconnection agreement along with the utility customer, Scenic Hill Solar argues that EAL's redline here would effectively prohibit any developer from having more than a single MW of applications submitted to a utility at any given time. As well, Scenic Hill Solar states, this relates to its discussion in the prior paragraph of the propriety of allowing multiple applications. *Id*. at 16.

Scenic Hill Solar notes that in Section 3.01, EAL's redline would have the developer sign the interconnection agreement along with the host, noting that to its knowledge, this is not done elsewhere. Scenic Hill Solar states that the developer is identified in the agreement and given authority to represent the utility customer, so that the utility can address any issue or emergency with the installer who has a deep understanding of the facility design and the interconnection. However, Scenic Hill Solar states, the utility has an existing relationship with the utility customer, and energy being exported from the site belongs to the utility customer, and therefore that is the appropriate contracting party. *Id*. at 16-17.

Finally, Scenic Hill Solar notes, in EAL's redline of its tariff, it adds in Section 52.1.1 that the threshold size for a commercial NET-METERING facility is the "lesser [sic] of 1) one thousand kilowatts (kW) for non-residential use unless otherwise allowed by the Commission and 2) one hundred percent (100%) of the Net-Metering Customer's highest monthly usage in the previous twelve (12) months of use." Scenic Hill Solar states that there is no such restriction in AREDA, other than a provision that for residential net-metering facilities the customer is restricted to the *greater* of 25 kW or the highest monthly usage in the past twelve months.[186] Scenic Hill Solar asserts that for commercial customers with a fairly steady load, EAL's redline would severely limit the customer's ability to offset consumption: As an example, a customer with a completely steady load of 1 MW would require 8,760 MWh per year, but could only build a 1 MW system that might produce 1,500 MWh per year. *Id*. at 17.

Cost-Benefit Reports and Studies

Given EAL's repeated claims of cost shifting, Scenic Hill Solar puts into the record for the Commission's consideration the reports and many of the underlying studies referenced in its Initial Comments. Attached as Exhibit 2 is the ICF 2018 report commissioned by the Department of Energy that reviewed 15 state studies. According to Scenic Hill Solar, of these studies, six were cost-benefit analyses for net-metering, while others were looking at DER values, and appropriate rates for value-of-solar tariffs, using much of the same methodology used to assess net-metering programs. From Scenic Hill Solar's perspective a particularly notable feature of all of these studies is their focus on residential solar. In all of the states represented in these studies, demand-metered customers pay energy rates that are lower than bundled residential rates, so the comparison to benefits would show a net benefit across all studies (except possibly the SAIC study). *Id*. at 17-20.

[186] Scenic Hill Solar notes that for residential customers, EAL redlines its tariff to remove "greater of" and replace it with "lesser of," despite the fact that the "greater of" language comes directly from Ark. Code Ann. § 23-18-604(b)(8)(B).

Conclusion

For the reasons stated in its Reply Comments, Scenic Hill Solar asks the Commission to maintain 1:1 net metering for demand metered customers in its NMRs, as required by Act 464, and to establish clear provisions in the Rules for demand-metered customers, net-metering penetration, common ownership, grandfathering, REC ownership, and storage provisions. Further, Scenic Hill Solar asks that the Commission establish that utilities be directed to conduct preliminary review of interconnection requests purely on the basis of technical feasibility. And finally, Scenic Hill Solar asks that the Commission find that based on the cost-benefit studies conducted over the past six years across the country that generally show net benefits of net-metering in states with low net-metering penetration, the Commission establish a process for Arkansas utilities to assess their costs and benefits, and establish that given the low net-metering penetration in Arkansas, such studies are not necessary in Arkansas at this time. *Id.* at 20-21.

3. Surreply Comments

a. Staff

Quantifiable Benefits

Staff notes that the term "quantifiable benefits" would only need to be determined if the Commission decides to choose one of the new rate structure or grid charge options outlined in Act 464. Staff agrees with the AG, SWEPCO, OG&E and Carroll that quantifiable benefits must be (1) demonstrated by the Net-Metering Customer, (2) tied to an accounting or market mechanism, or to an amount included in a utility's COS. Staff Surreply at 6-7.

Gaming

Staff agrees with other Parties that the Commission should adopt rules to ensure that a large net-metering facility is not broken down into smaller projects to avoid gaming the 1,000 kW threshold and Commission review. Staff recommends utilizing a broad definition of the term "facility" for the purpose of determining generation capacity limits. To incorporate this protection, Staff proposes the following addition to Net Metering Rule 2.06(A):

> (2) For purposes of Rule 2.06(A)(1), "generation capacity" includes the aggregate ability to produce electricity from all Net-Metering Facilities under common ownership that are located within a single utility's service territory.

Staff also recommends adding "Section 5. Rules to Guard Against Gaming" to the NMRs. This would include defining gaming, prohibition of gaming, and penalties for gaming. Staff also proposes Aggregation Procedures to determine if a net-metering customer has exceeded the 1,000 kW threshold. *Id.* at 7-13.

Common Ownership for Meter Aggregation

Staff strongly supports a clear, streamlined, auditable, and readily enforceable approach for determining common ownership. Staff reiterates its position that common ownership does not need to be verified solely by tax ID numbers, as EAL argues. Staff continues to recommend adopting a standard ownership form and sworn affidavit from the customer. Staff states that the Commission-approved process should allow utilities to seek Commission review by filing a request for declaratory order or filing a formal complaint. *Id.* at 13-14.

Remote Facilities

Staff asserts that the plain text of Act 464 grants the Commission discretion to allow remote generators to qualify for net metering. Staff believes the relevant question regarding the definition of "Generation Meter" is whether the net-metering facility must also be physically attached to the facility using electricity. Staff states that Act 464 only requires this type of physical attachment between the net metering facility and the facility using electricity for governmental entities claiming safe harbor protections. Staff argues that the General Assembly's decision to expand AREDA and allow net-metering customers to lease a net-metering facility demonstrates the legislative intent to allow net-metering for remote facilities. Although Staff supports allowing remote facilities to net meter, Staff points out that net metering customers who have net-metering facilities physically connected to their load clearly avoid more costs to distribution and transmission, since they consume part if not all of their facility's generation. By contrast, a remote facility exports all of its generation to the grid, and therefore would need the grid to provide more transmission and distribution capacity. Staff believes there should be incentives for customers to invest in net metering facilities that are physically connected to their load. In addition, Staff believes utilities could recommend adding a grid charge to customers with remote net metering facilities to account for the use of the grid. *Id.* at 14-16.

Service Contracts and Safe Harbor Provision

Staff proposes that the Commission approve a standard form and affidavit for customers to certify that the service contract meets the specific requirements to qualify for safe harbor, similar in format to the Act 253 Notice and Affidavits used in Energy Efficiency dockets. The Notice and Affidavit should certify that the net metering customer meets the safe harbor requirements as provided by the Internal Revenue Service in Revenue Procedure 2017-1942 and the Office of Management and Budget Memorandum M-12-21. Staff agrees that the Commission should designate Staff to review the agreements and attempt to resolve disputes regarding eligibility, including by confirming whether the agreement meets the eligibility requirements of safe harbor. *Id.* at 17-18.

Consumer Protections

Staff continues to support the development of a Consumer Guide (including a Customer Bill of Rights) and a Code of Conduct. However, several parties have suggested the Commission should regulate non-utility renewable providers, including maintaining a registry of providers, and should review contracts and leases between these providers and customers. However, Staff shares the concerns of the AG that such oversight by the Commission would require legislation. *Id.* at 18.

b. Attorney General

Rate Structure

The AG strongly disagrees with Staff's recommendation to allow utilities to change rate structures for net-metering customers but only after a general rate case in which a full cost of service study is produced. The AG argues that such an approach would be inefficient and not in the public interest. Instead, the AG continues to support adoption of 2-Channel Billing. AG Surreply at 2-6.

Grandfathering

The AG continues to support her interpretation of three levels of grandfathering created by Act 464. *Id.* at 6-7.

Regulation of Non-Utility Providers

The AG continues to express concern that the Commission does not currently have statutory authority to regulate certain non-utility net-metering participants, specifically providers. The AG supports the idea of a working group that would examine what tools the AG and the Commission have under their existing authority to enforce the code of conduct or otherwise hold companies interacting with ratepayers accountable for any misleading statements. The AG states that those discussions could also inform recommendations that could be made to the General Assembly regarding new legislation for consumer protection in this area. *Id.* at 7-8.

c. Entergy Arkansas

Introduction

EAL states that it reached out to various parties informally in an effort to narrow the scope of contested issues that the Commission must resolve. EAL has identified the following areas of potential agreement among the parties:

- the immediate establishment of a 2-channel billing rate structure applied to customers on a rate schedule without a demand component ("non-demand-metered customers") consistent with the requests of several parties;
- the establishment of a grid charge for customers on rate schedules with a demand component ("demand-metered customers") to help mitigate the cost-shift that will result due to those customers avoiding fixed infrastructure costs included in the volumetric portion of certain rates;
- grandfathering provisions to be applied for qualifying net-metering customers;

- an approach to demonstrate common ownership for the purpose of meter aggregation;
- sizing restrictions for net-metering facilities;
- establishing a definition of a generation meter; and
- a process for developing transparent interconnection procedures and consumer protections through the Net-Metering Working Group.

Id. at 1-4.

Rate Structure for Non-Demand Component Rates

EAL recommends the Commission immediately implement 2-Channel Billing for new net-metering customers on rate schedules without a demand component. Upon implementation each utility would make a compliance filing and provide a calculation of the applicable 2-Channel Billing credit rates. Thereafter, each utility would make an annual filing updating the rate with the utility's current avoided capacity and energy costs. For those net-metering customers that are fully interconnected before the Commission issues this Phase 3 Order, EAL recommends grandfathering for no longer than 10 years under the 1:1 retail rate. As an alternative, EAL states that the Commission could incorporate a more gradual, step-down approach, by applying the 40 percent avoided cost adder, with periodic step downs in that adder. *Id.* at 8-10.

Rate Structure for Demand Component Rates

EAL urges the Commission to adopt a Grid Charge for net-metering customers of all sizes that receive service under a rate schedule that includes a demand component. The Grid Charge would be a fixed charge approved by the Commission and based on each utility's cost-of-service. Any net-metering customer that is fully interconnected before the issuance of the Commission's Phase 3 Order would be grandfathered for 10 years. *Id.* at 10-11.

Grandfathering

EAL notes that it previously recommended in Phase 1 of this docket that it could support a reasonable grandfathering period and at that time did not oppose 20 years. EAL explains that the concept of grandfathering is not some automatic right but rather is intended to help ensure that a customer installing a solar facility has a reasonable opportunity to recover a portion of its investment. With that in mind, the grandfathering provision must consider the declining cost of solar facilities that has occurred since Phase 1 of this proceeding. *Id.* at 12-14.

Common Ownership for Aggregation

For any customer under a non-demand component rate schedule, EAL urges the Commission to continue the current practice of requiring a customer to demonstrate that the same tax ID remains in place for any aggregated account(s). With respect to demand-metered customers, EAL urges the Commission to adopt Staff's recommendation requiring an affidavit, supported by appropriate documentation, to demonstrate common ownership, and that is subject to reasonable and justifiable challenges. To avoid gaming, EAL states that any net-metering facilities under common-ownership must be considered a single project for purposes of Commission review and approval. *Id.* at 14-16.

Sizing of Net Metering Facilities

EAL argues that it is not reasonable to allow a net-metering facility to offset 100 percent of a customer's requirements in all hours of the year. The Commission should clarify now that such sizing practices cannot continue. For example, depending upon the specific characteristics of a customer's load profile, a net-metering facility sized to produce 100 percent of the customer's annual energy consumption could result in net exports in excess of 60 – 70 percent of total solar production. To prevent oversizing facilities under a demand component rate schedule, EAL urges the Commission to adopt a maximum size a customer is authorized to construct to remain eligible for net-metering. EAL recommends that the maximum size be set equal to the capacity needed to generate no more than 25% net exports based on the customer's annual solar production compared to annual usage. For customers on a non-demand component rate schedule, EAL continues to support the current rule of using a customer's prior 12 months energy usage as the maximum size for a net-metering facility. *Id.* at 16-19.

Defining Generation Meter

EAL continues to argue that "generation meter" as used in the currently-effective Net-Metering Rules, means the generation meter must be connected to the customer's load. EAL argues that there is no basis for revising the currently effective rule, because Act 464 made no provision authorizing remotely-located generation for purposes of net-metering. EAL states that maintaining the current rule avoids potential claims that the net-metering customer is participating in retail wheeling of energy. *Id.* at 19-20.

Matters to be Addressed by the Net-Metering Working Group

EAL agrees with Staff's recommendation that the Commission direct the NMWG to develop interconnection rules using the IREC uniform interconnection rules as a template. EAL agrees that the NMWG could also be directed to develop a Consumer Guide, mandatory standards for developers, as well as standard templates for Leases and Power Purchase Agreements/Service Agreements. EAL cautions that the IREC uniform rules create a number of requirements for the utilities to implement for purposes of interconnecting customers, the costs of which may be substantial as well as requiring significant time to develop and implement. Prior to implementation of such model interconnection rules, the costs and benefits of those interconnection policies should be evaluated by the Commission in a more thorough review of the implications of such a decision, including allocation of the costs to comply with those interconnection provisions. *Id.* at 20-22.

d. Oklahoma Gas and Electric Company

Cost-Shifting

OG&E provides excerpts of articles from several trade publications that support the existence of cost-shifting under the full retail net-metering rate. OG&E Surreply at 1-3.

Solar Penetration Policy

OG&E is supportive of the development of solar in Arkansas but encourages the Commission to use a reasoned approach that takes into account (1) customer impacts for both non- and net-metering participants, (2) an economical and market-based support for solar in Arkansas, and (3) sustainable long-term solar investment policies. OG&E argues that the current 1:1 rate should not be tied to a certain level of solar penetration. *Id.* at 3-5.

Rate Structure

OG&E disagrees with Staff's proposal that utilities only be allowed to change their net-metering rate structure through a general rate case. OG&E argues that Staff's proposal goes against the intent of Act 464 and is biased against those utilities that have chosen FRPs. *Id.* at 5-7.

Meter Aggregation

OG&E supports Staff's recommendation to require a standard form and signed affidavit to confirm common ownership of meters that are aggregated. However, OG&E does not agree that utilities should be prohibited from requesting a tax ID number as part of a request for service. Common tax ID numbers support an assertion that points of service are under common ownership. If points of service do not have common tax ID numbers, then additional documentation would be required to establish that said points of service are under common ownership and therefore qualify for net metering aggregation. *Id*. at 7-8.

Grandfathering

OG&E continues to argue that Act 464 gives the Commission authority to approve grandfathering on a case-by-case basis. *Id*. at 8-9.

Consumer Protections

OG&E supports the AG's recommendation that net-metering providers be required to register with the Commission prior to installing net-metering facilities in the State and be subject to program suspension or expulsion due to non-compliance with a Commission-approved Code of Conduct. However, OG&E does not agree that utilities should be solely responsible for policing third-party providers. Utilities are not in a position to be the monitors and enforcers of any Code of Conduct that may be adopted. Enforcement of any such Code is more appropriately placed with the Commission or the AG. OG&E also argues that the IREC Model needs to be more thoroughly vetted prior to any potential adoption as a consumer protection guide. OG&E recommends that this issue be taken up in Docket No. 16-028-U where the issue is already being addressed. *Id*. at 9-10.

e. Southwestern Electric Power Company

Rate Structure

SWEPCO continues to argue that the existing 1:1 retail rate structure is not in the public interest. SWEPCO believes the Commission should address the rate structure in this proceeding and not wait until the utility files its next general rate case to alter the rate structure. SWEPCO states that it must serve all its customers at just and reasonable rates. SWEPCO believes that purchasing power from net-metering facilities at retail rates without billing for fixed costs that are recovered through volumetric rates, creates a subsidy from non-participating customers to net-metered customers – not just and reasonable rates. *Id.* at 1-3.

Grid Charge

SWEPCO believes that all net-metering customers that have a demand on the distribution system, whether during the system peak or not, should pay for distribution system costs. SWEPCO argues that some parties have a misunderstanding of how distribution plant costs are allocated. SWEPCO explains that distribution system is not sized to handle the system peak but instead is sized to handle the diversified peak loads of customers in each class for localized areas of the distribution system. Distribution systems must be capable of meeting the sum of each class' maximum demand, irrespective of system peak. This means that net-metering customers that use the system at any time also contribute to the class' maximum diversified demand, no matter when each customer's peak demand occurs, and therefore, contribute to the class' allocation of distribution system costs. *Id.* at 5-7.

Non-Demand-Component Net-Metering Customers

SWEPCO continues to support the 2-Channel approach and requests that the Commission enact changes to create a reasonable and sustainable net-metering rate structure as soon as possible. SWEPCO also supports the recommendation from other parties that the Commission consider rules that would allow for utility-specific rate structures. SWEPCO argues that Staff is incorrect in stating that changing to 2-Channel Billing would require updating COS information and other utility-specific information. *Id.* at 8-10.

Demand-Component Net-Metering Customers

SWEPCO again explains how its General Service tariff is inadequately structured to recover its fixed costs through the demand charge. Therefore, SWEPCO continues to support the 2-Channel Billing approach to net-metering customers on the General Service tariff as well as any current demand tariff under which SWEPCO is not fully recovering its cost to serve. Alternatively, SWEPCO supports a fee or charge be applied to those net-metering customers. SWEPCO states that the additional fee can be charged pursuant to the net-metering tariff and would not require additional tariff or rate changes. In other words, SWEPCO would not need to file a general rate case to effectuate the change. *Id.* at 11-13.

Quantifiable Benefits

SWEPCO states that parties are not in agreement as to whether Act 464 requires a net-metering customer to actually provide evidence of quantifiable benefits. Therefore, SWEPCO requests that the Commission clarify this provision. SWEPCO also supports the AG's recommendation that the Commission consider establishing a standard formula to calculate quantifiable benefits to eliminate ambiguity on what can and cannot be included in net-metering rates. *Id.* at 13-14.

Reporting Requirements

Staff recommends the adoption of additional annual requirements for net-metering facilities in Docket No. 06-105-U for the purpose of assessing renewable energy penetration on a utility-by-utility basis. SWEPCO explains that this could prove problematic for utilities to provide some of the information requested, such as the total production of a net-metering facility in kWh. Total production would have to be estimated as SWEPCO currently does not have an accurate measurement of the production the customer uses behind the meter. Additionally, providing the peak demand by customer on a monthly basis could also be difficult. Staff further requests solar PV installation information by rate class, but does not specify what type of information. *Id.* at 14-15.

f. Arkansas Electric Cooperative Corp.

Rate Structure

AECC argues that a net-metering customer's generation is worth what every other increment of generation is worth in the wholesale energy markets, i.e., the avoided cost. Absent proof that it is more valuable than other generation available to the utility, the price paid for a net-metering customer's generation should not exceed the wholesale avoided cost. For this reason, AECC argues that it is unnecessary to require a general rate case or new cost of service study before approving a new rate structure for individual utilities. AECC believes the Commission has the authority to set new rates and rate structures for each class of net-metering customers no matter whether the customer is a demand component rate or non-demand component rate. AECC Surreply at 1-5.

Solar Penetration

AECC argues that AREDA does not contemplate a minimum solar penetration level. AECC argues that by leaving the current net-metering rate structure in place until a certain penetration level is met is equivalent to imposing a renewable portfolio standard. AECC points out that even with the existence of federal tax credits that subsidize solar, added to an overly-compensatory retail rate in Arkansas for nearly two decades, Arkansas net metering penetration levels remain low because the cost of electricity in Arkansas is also low. AECC argues that perpetuating incentives to increase penetration at some unstated level or time in the future, without regard to the current economic consequences of that price shift, is against the public interest. *Id.* At 5-6.

g. Carroll Electric Cooperative Corp.

Defining Terms in the NMRs

Carroll urges the Commission to define precisely the terms “net energy facility” and “net energy customer” from the language of the Act in the NMRs, with the inclusion by the Commission of specific examples that indicate what does and does not match the definition in the Act. Doing so will resolve much of the confusion and concern regarding both aggregation and gaming. As an example, Carroll points to the language in Ark. Code Ann. §23-18-604 ©(2)(A)(ii), which if taken literally, this means “more than two” qualifying government/tax exempt entities do not have the discretion to apply net-metering credits to a bill for another meter. Carroll Surreply at 1-3.

Rate Structure and Solar Penetration

Carroll continues to support a Floor (avoided cost) and Ceiling (1:1 retail rate) rate structure. The Commission should consider each utility’s cost/benefit analysis of implementing 2-channel billing, utility-specific avoided cost as well as retail cost, and special rate considerations. Carroll urges the Commission not to delay policy action until solar capacity becomes a problem, as has already happened in California, Nevada, Arizona, and Hawaii. *Id*. At 3-10.

h. Arkansas Electric Energy Consumers

Cost Shifting

AEEC continues to believe that the current 1:1 net-metering rate structure shifts costs to non-participating customers. AEEC argues that the cost shifting or subsidies will begin to emerge each time a utility files a new formula rate plan demonstrating a revenue shortfall that then has to be redistributed across all rate classes. AEEC warns that additional cost shifting could likely occur if certain customers in the large industrial rate classes begin to migrate to smaller commercial rate classes where they can obtain service using a favorable net metering rate. AEEC Surreply at 1-3.

Rate Structure

AEEC urges the Commission to adopt new rate structures immediately to address the subsidy before it expands. For non-demand component rate classes, AEEC does not recommend a specific new rate structure, but states that the new rate structure should address the subsidy by reducing the amount of the credit for net excess generation to a more reasonable level. For rate classes with a demand component, AEEC agrees with OG&E that the rate tariffs for those rate classes should be redesigned to recover more of the fixed costs through the demand component. AEEC worries though that adopting this policy would require waiting until a utility files a general rate case which may not happen for several years. *Id*. at 4-6.

Grandfathering

AEEC urges the Commission to choose not to grandfather additional net-metering customers, or at least set the duration for grandfathering at a short period of time. This policy choice will prevent the continuation of subsidies and serves the public interest. *Id.* at 6-7.

RECs and Customer Protections

AEEC agrees that customers should have the freedom to transfer renewable energy credits to another party in exchange for compensation or other things of value. AEEC also supports the recommendations made by the Staff and the AG that customer education measures and other customer protections should be developed. *Id.* at 8.

Reporting Requirements

AEEC agrees with Staff's recommendation to establish certain reporting requirements regarding net metering penetration levels no matter which rate structure the Commission adopts. *Id.* at 8.

i. Arkansas Advanced Energy Association

Introduction

AAEA believes that the following contested issues need not be resolved in this proceeding in order to implement Act 464:

- Consumer protection
- Fees for interconnection or preliminary site review
- Rules regarding retention of renewable energy credits
- Rules regarding "oversized" net-metering facilities

- Changes to net-metering for demand-billed customers other than updating the rules to reflect revised statutory language.

AAEA Surreply at 1-2.

Demand Billed Customers

AAEA believes Act 464 requires the Commission to retain the 1:1 retail net-metering rate for demand-billed customers. AAEA acknowledges that some utilities have provided evidence showing the amount of "fixed costs" that are embedded in volumetric rates even under demand-billed tariffs. AAEA argues such evidence is simply not relevant to the decisions the Commission must make in this case, given the clear statutory mandate regarding demand-billed net metering customers. AAEA also responds to EAL's recommendation to continue the 1:1 full retail credit for demand-billed customers but also adopt a grid charge to recover the fixed costs. AAEA argues that it is also inconsistent with AREDA to impose a grid charge to recover fixed costs. AAEA points out that Ark. Code Ann. § 23-18-604(b)(4) states 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. AAEA argues that EAL has not provided evidence to establish that a grid charge is justified. *Id.* at 4-6.

Net Metering for Residential Customers

AAEA responds to EAL's belief that the benefits calculated by Crossborder Energy are unreasonable because they exceed the cost of utility-scale solar generation. In other words, EAL asks why it should be forced to pay the higher benefit cost for net-metered energy when it can buy utility-scale solar at a lower cost. AAEA argues that EAL's comparison is not apt, because utility-scale solar does not avoid line losses or transmission and distribution investments, nor does it support resilience or consumer choice or economic development to the same degree as distributed generation. *Id.* at 7.

AAEA urges the Commission to consider a long-term view of avoided costs, rather than a static, embedded view of those costs. Adopting such an approach will reduce costs over the long run for all customers, and best promote the purposes of AREDA. AAEA argues that even if the Commission rejects the relevance of long-term costs and benefits, Act 464 allowance for reasonable allocations of and increases in costs clearly permits *de minimis* cost shifting. *Id.* at 8-10.

Grandfathering

AAEA notes that the Commission has not required case-by-case adjudications of grandfathering previously, and should not interpret Act 464 to require such an approach going forward. *Id.* at 14-16.

Consumer Protection

AAEA states that consumer protection measures are not among the issues that the Commission needs to resolve in adopting the next round of Net-Metering Rules. AAEA continues to support the AG's recommendation to form a working group to develop any needed consumer protection measures and determine the appropriate means of implementing and enforcing those standards. AAEA agrees that legislative action will likely be needed for a robust consumer protection framework, but a Commission-initiated working group would be valuable in identifying and characterizing consumer protection issues. *Id.* at 16-17.

Gaming

AAEA agrees with Staff's recommendation to require the net-metering customer to use a standard form and sign an affidavit confirming common ownership of aggregated meters. *Id.* at 18.

Defining Net Metering Facilities and Customers

AAEA disagrees with some parties that argue that remotely located net-metering facilities should not be eligible for net-metering because the facilities are not behind a meter that is attached to the load. AAEA also disagrees with EAL's recommendation to limit the size of a facility to prevent what EAL calls "oversizing." *Id.* at 18-20.

Leasing Facilities and Service Contracts

AAEA recommends the Commission develop a standard form and designate a staff member to review such agreements and attempt to resolve any disputes with the utility regarding eligibility. The process should have the objectives of allowing consumers seeking to utilize lease or service contract arrangements to confirm early in the process that their system will be eligible for net metering, while not requiring those customers to jump through countless hoops or initiate a Commission proceeding in order to get approval for net metering. *Id.* at 22.

j. Scenic Hill Solar

Cost Shifting

Scenic Hill Solar disagrees with EAL's claims that demand-metered net-metering customers are shifting costs to other customers. Scenic Hill Solar agrees with AAEA that the value of distributed solar appears to be above residential rates. Scenic Hill Solar Surreply at 1-3.

Solar Penetration

Scenic Hill Solar disagrees with EAL's assertion that Arkansas is not a low solar penetration state. Scenic Hill Solar states that utilities will likely continue to cite triple digit growth rates in net metered generation. Scenic Hill Solar argues that the utilities should also show analysis of when net metering might provide more than one percent of utility retail sales. *Id.* at 3-4.

1:1 Rate for Demand Metered Customers

Scenic Hill Solar argues that the Legislature, through Act 464, has directed the Commission to establish just and reasonable rates, and that it must have 1:1 Net-Metering for demand-metered customers. Scenic Hill Solar takes that to be a legislative presumption that 1:1 net-metering does not entail a cost shift, and is fully compatible with just and reasonable rates and appropriate net metering. *Id.* at 4-5.

Demand Metered Customer Rate Structures

Scenic Hill Solar explains that the rate tariff design is done in a heavily contested general rate case, therefore, the amount collected in the demand component may not recover all the fixed costs because there were opposing positions in the rate case. Scenic Hill Solar suggest that because this allocation of costs is exhaustively decided in rate cases, the Commission should accept that allocation as settled. The Commission should assume that *energy rates* for demand-metered customers, for the purpose of net metering, reasonably recover the energy and related production costs to serve those customers, and do not recover fixed costs to serve those customers. *Id.* at 5-6.

k. Bill Ball

Mr. Ball made a filing stating that he did not wish to provide Surreply Comments.

4. Commission Public Hearing Testimony, December 5, 2019

a. Staff Testimony: Clark Cotten, Jennifer Hoss, and Kathleen Kelly

Mr. Cotten testifies that in the past, the Commission has ruled on a case-by-case basis to decide the grandfathering of facilities that were larger than 300 kW. T. 540.

Staff recommends implementing net metering rates on a utility-specific basis. Ms. Hoss clarifies that per AREDA, a net metering facility cannot be located in multiple utility jurisdictions and therefore there would not be a problem of aggregated net metering facilities which cross jurisdictional boundaries. T. 542-544. Staff witness Kelly states that Staff recommended implementing net metering rates on a utility specific basis because the underlying cost and benefits may differ by utility. T. 542. Ms. Hoss and Ms. Kelly testify that the rules for all utilities would be set in this proceeding. Ms. Hoss goes on to state that Staff is asking the utilities to present rate design changes in a separate proceeding that would alleviate the cost shifting. T. 544-546.

Ms. Hoss testifies that neither 2-Channel Billing nor grid charges are perfect matches of costs to net-metering and non-net metering customers. Ms. Hoss states that the cost shift will vary by a utility's underlying cost and rate design that the utility has chosen and that the Commission has approved. She states that when and if there is some unreasonable cost shift, it is incumbent on the utility to propose the timing and content of their changes, and typically that has been done in a rate case. Ms. Hoss further testifies that Act 464 does not allow the Commission to modify the demand charge variable for grid charges for a customer on a demand component rate. However, she states that the Commission's authority to change that component is not altered in a general rate case context. Ms. Hoss states that she believes the Commission can consider TOU rates, although some utilities don't have the technological ability to do that to date. Ms. Hoss testifies that utilities can propose specific changes where there are multiple meters being aggregated, so a grid charge is something the Commission can consider for customers who do not have the demand component. She states that Section 604(b)(4) of the Act allows a grid charge or a fee for interconnection and administrative costs. Mr. Cotten adds that utilities already have the ability to recover any costs that are required to accept net metering facilities and they are already doing that. But, he adds, if there are additional administrative costs and billing costs, those aren't being collected from net metering customers today and might be a component of some additional charge. T. 547-550. Ms. Hoss testifies that with regard to Act 464 prohibiting demand customers to be assessed a grid charge outside of a rate case, Staff's position is that it depends on the type of cost inside that grid fee. For example, she states, Section 604(b)(4), which would apply to customers with a demand component, is limited to interconnection and administrative costs. So a customer with a demand component could be charged that fee, but a grid charge that included, for example, lost contribution to fixed costs may not be permissible under Section 604 (b)(4). T. 554.

Ms. Hoss states that it should be each utility's option to propose having a separate rate class. The economics of whether a separate rate class makes sense should be determined in a rate case. Ms. Kelly adds that other jurisdictions have required utilities to bring in cost-of-service based support and any other support to justify a separate rate class. Mr. Cotten states that Arkansas at this time does not have enough net metering penetration to get a statistically important enough signal to be able to establish a separate rate class, and what that cost is for that class. T. 550-551.

Mr. Cotten responds that a working group, not necessarily the NMWG, should be established to address issues such as the code of ethics, consumer protection guide and consumer bill of rights in another phase of this docket. T. 553.

Staff acknowledges that it is possible to use a utility's existing cost of service study with the existing class allocations and portion out the distribution only costs as a grid charge for those net-metering customers that are entirely in front of the meter. T. 557. Mr. Cotten states that a facility installed behind the customer's meter and which provides no excess energy back to the grid at all, probably provides distribution benefits because it reduces the amount of energy the utility had to supply over that distribution system. However, he states, if that same customer provides excess energy back onto the grid from a behind-the-meter, then the customer is relying on that distribution system to have someplace for that excess energy to go. And, he adds, if that customer expects credit back in future months, then the customer is basically using the utility system as a bank. Mr. Cotten states that if, on the other hand, the net-metering facility is remote (in front of the meter) and the customer is not offsetting their own load, then obviously the distribution system is still required to be there and is probably providing energy transport at a location that may be different from what the utility would have normally provided. T. 557-558.

Staff states that a remote facility could provide locational benefits, but it depends on a number of factors such as the specific circuit, location, need, and the utility's planning. For example, according to Mr. Cotten, if the circuit is loaded at a certain level, the utility might get benefits, but if the circuit is lightly loaded, then there may be no benefits. T. 559. Mr. Cotten states that net metering is an energy-only product, and any demand reductions that occur because of a net-metering facility's energy would only accrue to the customer if that facility was installed behind the meter and actually reduces the load on the utility system by the energy that the customer provides. Mr. Cotten states that a customer with a remote facility that aggregates multiple meters is only reducing its energy charge and not reducing its demand. Ms. Hoss states that to the extent the net-metering facility provides capacity that is coincident to utility's peak, the net metering system would be reducing the overall system peak or making some contribution to that. T. 561-562.

Ms. Hoss responds that in general the four California Standard Practice Manual tests used to evaluate energy efficiency programs could be applied to net metering but with some limitations. T. 562-563.

b. EAL Testimony: Andrew Owens, John David Palmer, and Michael Schnitzer

Mr. Owens states that EAL's methodology for calculating its proposed grid charge is consistent with Commission practice for normal ratemaking, and that no distribution costs are avoided. Mr. Owens further testifies that states that EAL's methodology does not assess whether any of those distribution costs are offset by quantifiable benefits from the net-metering facility with respect to the grid charge. T. 1273-1275.

EAL witness Schnitzer testifies that EAL has not calculated the cost shift associated with residential net-metering systems that have been proposed since the passage of Act 464 and that the closest calculation he has done was to compare EAL residential volumetric rate of 10.1 cents versus 3.5 cents, which is the cost for grid-scale solar, resulting in a cost shift of 6.6 cents. T. 1276.

Mr. Owens testifies that 2-Channel Billing or a grid charge do not ensure a perfect match of costs to net-metering and non-net-metering customers and that EAL continues to have a portion of fixed costs that would not be recovered under either of those solutions.

Mr. Schnitzer also states that 2-Channel Billing would mitigate the cost shift but would not eliminate it. T. 1277-1278. Mr. Schnitzer states that paying the 1:1 net-metering credit is effectively asking nonparticipating customers to pay the retail rate for solar kilowatt hours, when as an alternative EAL could be buying grid-scale solar directly at 3.5 cents or less. EAL witness Palmer states that using the cost shift estimates made in EAL witness Myra Talkington's testimony in Docket No. 19-042-TF, the impact may be close to $4 to $5 a month on a residential customer based on 1,000 kWh usage. T. 1278-1280.

Mr. Owens clarifies that the grid charge doesn't modify the customer's existing rate structure, noting that EAL's proposal would also preserve the 1:1 netting that occurs. What EAL proposes, he states, is to take its cost-of-service study and identify the distribution-related costs that are recovered in the volumetric rate that are not recovered in the demand charge and then convert that to a charge that EAL thinks would be very straightforward and simple to implement from a billing perspective. The grid charge would be the same number every month for a customer based on their system size. Mr. Owens states that EAL has other fixed infrastructure costs for generation and transmission that are recovered volumetrically that a customer would still be able to avoid. T. 1280-1281.

Mr. Palmer states that TOU would just be another rate design and asks what value that has to the customer. (Palmer gave a very long explanation and I couldn't decipher what his point was.) T. 1284-1286.

Mr. Palmer states that it is EAL's position that Act 464 either prohibits or otherwise doesn't allow for demand component customers to be assessed a grid charge outside of a rate case. T. 1287.

For 2-Channel Billing, Mr. Owens states that EAL's methodology could be universally applied because all of the Arkansas utilities operate in either MISO or SPP. He explains that EAL's methodology relies on the wholesale energy cost in the RTO. Mr. Owens believes it is the Commission's discretion to apply either a utility- specific or fixed additional sum as consideration for quantifiable benefits. T. 1288-1289. Mr. Owens states that if the rates today that are charged to customers today are assumed to be just and reasonable, then whether the cost of service was done four years, or seven years ago or even longer ago, then those are the rates that could be used to establish a grid charge. T. 1289-1290.

Mr. Palmer states that if a customer sizes his net-metering facility at 100 percent of annual consumption, then that customer is likely going to be exporting 50, 60, or 70 percent of the energy the net-metering facility produces. Mr. Palmer testifies that EAL's proposal to cap the net export based on customer's annual solar production and the annual use at 25 percent just felt like a more reasonable amount for a net-metering customer to be allowed to export. T. 1290-1294.

Mr. Palmer responds that he believes the community solar model used by Mr. Ball and Mr. Kelly is consistent with existing models with respect to the ability to aggregate. He adds that EAL is concerned with issues such as how to establish co-ownership, whether there should be a size limit and meter limitation on community solar projects, and who pays for the incremental upgrades to a circuit as new net-metering facilities are added. T. 1294-1296.

Mr. Owens states that the allocation method that EAL and other utilities use today, in a general rate case, is a methodology under which, generalizing, the closer you get to a customer, (i.e. going from generation to distribution) the less what's occurring (i.e. allocation of costs) has to do with coincident peak. T. 1296-1297. Mr. Owens states that, for example, a nightclub has a peak at 10:00 or 11:00 at night and that has nothing to do with EAL's coincident peak. He states that EAL is sizing its facilities, the transformer, the equipment, the distribution part of serving that customer's needs, based on their non-coincident peak, not EAL's coincident peak. Mr. Owens adds that when EAL allocates distribution costs, demand-related distribution costs, the methodology EAL uses doesn't address and doesn't reflect contribution during that peak hour, whether that's coincidental peak the one time a year or 12 CP over the 12 months. He states that this is the logic that EAL used for its recommendation on the grid charge. T. 1298-1299. Mr. Schnitzer also explains why EAL believes distribution costs are not avoided by net metering customers by stating that there are some empirical studies done by the MIT Energy Institute and others looking at distribution systems and asking the circuit-specific question: Would there be an avoided capital investment, associated with something going in on this circuit that would modify the peak load. Mr. Schnitzer states that if you look at most distribution budgets, they are split between investment required to connect new customers, new service types of things, and rebuilds of old equipment that has to be replaced, neither of which can be influenced by a new solar facility. T. 1300-1301.

Mr. Schnitzer states that because of economies of scale grid-scale solar is cheaper, in the range of $0.03 to $0.036 per kW/h compared to residential or medium-sized commercial systems that are at least twice that price. T. 1303-1304.

Mr. Owens responds that EAL is open to making changes to its SEPO Option B to put everyone on a level playing field but recommends that the question of how a one-year solar contract and a 20-year solar contract should be priced so that the two contracts are equivalent when considering disruption or price change risk should be discussed and addressed in EAL's SEPO Option B docket instead of this docket. Mr. Owens also points out that even under 2-Channel Billing or a grid charge net-metering customers will see significant bill savings. T. 1310-1312.

Mr. Owens states that the question of whether it is reasonable to measure cost shift as a cumulative total or as a percentage of any one transaction really reverts back to what happens with grandfathering. T. 1313.

Mr. Schnitzer states that it is difficult to answer how to design a rate that would incentivize net-metering facilities to correlate their generation more closely to the peak. He explains that experience in other states shows that as solar penetration increases, the peak moves from early evening to later in the evening when the sun has set, so solar cannot solve the problem. In other words, he states, increased solar penetration means solar will have increasingly marginal contributions to capacity over time. Mr. Schnitzer also states that volumetric energy credits of $0.10 kw/h or $0.08 kw/h under net metering do nothing to provide any incentive. T. 1314-1316.

Mr. Owens states that he is uncertain whether customers are aware that it is probably uneconomic to aggregate a large general service meter with other small general service meters. Mr. Schnitzer adds that customers may be able to cover the fixed costs of their net-metering facility and by adding a large general service meter they can make the net-metering facility a little bigger. Mr. Schnitzer also states that adopting 2-Channel Billing would eliminate any incentive to aggregate meters from two rate classes. T. 1318-1321.

c. SWEPCO Testimony: Thomas Brice

Mr. Brice states that 2-Channel Billing does not address the cost shift for the portion of energy that is produced by the net-metering facility and used by the net-metering customer. T. 1374-1375.

Mr. Brice believes that the statute is not clear if Act 464 allows the Commission to modify the demand charge variable. For demand-metered accounts he believes Act 464 describes two different approaches to do (1) billing and (2) calculating the net excess generation. He believes the overall context of Act 464 gives the Commission the flexibility to apply the rate structure it deems best. Mr. Brice recommends the Commission adopt 2-Channel Billing for customers on SWEPCO's General Service tariff. T. 1375-1377.

Mr. Brice states that the Commission has the right to explore TOU rates, but SWEPCO does not have the necessary technology, such as AMI metering at this time. Mr. Brice admits that SWEPCO has AMR technology but adds that it would not be efficient or effective for administering a TOU rate. T. 1378.

Mr. Brice states that SWEPCO is open to a separate rate class for net metering customers, but at this point in time SWEPCO does not have the load data that would be needed to develop that class. T. 1378-1379.

Mr. Brice states that SWEPCO supports an adder if it is specific to the customer and not standard among all customers, and that he believes Act 464 allows customers under the 2-Channel approach to be paid avoided cost plus up to 40 percent of an additional sum if they could show quantifiable benefits associated with the net metering. He states that this additional sum should be considered on a case-by-case basis. T. 1379-1380.

Mr. Brice states his belief that the longer the period of time to measure unreasonable cost shifts, the harder it will be for SWEPCO to deal with the end effects. T. 1380-1381.

Mr. Brice states that SWEPCO could design a grid charge that both recovered that amount when they were under the limit and gave them a credit for what they were paying once they hit the demand charge against the grid charge and it would look similar to a minimum bill. T. 1381-1382.

Mr. Brice states that SWEPCO has explored building a grid-scale facility and seeing if it can sell solar to individual customers to participate in the market in a way that's similar to what EAL is proposing with SEPO B, but based on the Company's circumstances and the RTO they are in, SWEPCO believes there are more viable options. T. 1381-1382.

d. OG&E Testimony: Jeremy Schwartz and William Wai

OG&E witness Schwartz states there are no perfect rates, but 2-Channel Billing or a grid access charge would be an improvement on the current rate structure. He adds that 2-Channel Billing is something that OG&E would consider moving forward with as it is a market-based solution that would be implemented outside of rate cases. T. 1457-1458.

Regarding the grid charge for a customer on a demand component rate, the Commission asks whether Act 464 allows the Commission to Mr. Schwartz states his belief Act 464 gives the Commission discretion to modify the demand charge variable. T. 1458. Mr. Schwartz states that TOU rates are effective in allowing solar customers to realize the time value of the energy they are producing, but OG&E does not believe that TOU rates alone would solve what the Company sees as the current subsidy issue. T. 1458-1459. On the subject of a separate rate class for net metering customers, Mr. Schwartz responds that

TOU rates are something that should happen in the future. He adds that the Company stated in its testimony that putting customers in a separate class in the cost of service enables a more in-depth look at the cost and the load shapes of those customers. T. 1459.

Mr. Schwartz states that based on his non-legal opinion, he believes the statute gives the Commission latitude modify the demand charge variable or assess the grid charge without a rate case, or just assess a grid charge without a rate case. T. 1460.

Mr. Schwartz states that it comes down to size with regards to grandfathering. For example, he states, if you have a residential 10 kW project or a 5 MW project, the impacts of enabling a rate for a ceiling of 20 years, as the statute discusses, could have differing impacts. He adds that if an installation can quantify that they will provide benefits to the system, to the customers, to the public good, then OG&E thinks they have a viable case for proving their grandfathering need. T. 1461-1462.

Asked if OG&E has given thought to offering a grid-scaled solar project as competition with third parties, Mr. Schwartz states that OG&E has been actively investigating this and hopes to be able to share something with the Commission in the next few months. T. 1462.

e. Empire Testimony: Phillip Gillam

Mr. Gillam testifies that Empire does not believe that 2-Channel Billing or a grid charge ensures a perfect match of costs Mr. Gillam believes that the Commission has the discretion to modify the demand charge variable regarding the grid charge for a customer on a demand component rate under Act 464 if warranted and Liberty-Empire would support that change. T. 1473. Mr. Gillam testifies that Liberty Empire currently, at least for the Arkansas jurisdiction, does not have the capability to employ a TOU rate structure.

He adds that TOU rates could get you a more definitive answer with regards to how costs should be allocated. T. 1473.

Mr. Gillam states that Liberty Empire is a small company, so it would take a significant number of customers switching over to net metering to warrant going to a separate rate class for net metering customers. T. 1474.

Mr. Gillam states that Empire would benefit from the Commission not imposing a one-size-fits-all solution to net metering given its low number of customers in Arkansas. T. 1474-1475.

f. AECC Testimony: Robert Shields

Mr. Shields testifies that AECC's 17 distribution cooperatives could possibly file their own net metering proposal using Act 821 nder a utility-specific approach instead of filing a full-blown Section 8 rate case. T. 1537-1538.

Mr. Shields testifies that neither a grid charge or 2 channel billing rate is a perfect match of costs to net-metering and non-net-metering customers, but 2-Channel Billing provides the opportunity to fix the overpayment for generation and is a very close match. T. 1539-1540. He believes that Act 464 allows the Commission to modify the demand charge variable regarding the grid charge for a customer on a demand component rate." T. 1540. Mr. Shields testifies that TOU would be co-op specific and that he did not know who might like to pursue it and who might not. T. 1540.

Mr. Shields states that a co-op could propose a tariff filing that distinguished between a net-metering customer and a non-net metering customer within the same rate class and without establishing a separate rate class for net metering customers. T. 1541-1542.

Mr. Shields believes Act 464 gives the Commission options to decide what the appropriate rate mechanism is. T. 1542.

Mr. Shields states that the age of the cost-of-service study for some of the distribution co-ops, and that those distribution co-ops have sufficient data on distribution costs to reach the right conclusion if the Commission approved distribution-based grid fees. He adds that if rates are considered just and reasonable today, the existing cost of service could be used to determine a grid fee. T. 1543.

g. Carroll Electric Testimony: Joey Magnini

Mr. Magnini with Carroll states that from a high level, he believes you get a lot closer to a perfect match of costs to net-metering and non-net metering customer with 2-Channel than our current structure. T. 1605. Mr. Magnini opines that Act 464 allows the Commission to modify the demand charge variable regarding the grid charge for a customer on a demand component rate. T. 1606-1607. Mr. Magnini states that Carroll has not considered TOU rates internally. Mr. Magnini also states that the Company has AMI metering, but would need other programming mechanisms and processes to be fully equipped for TOU rates. T. 1606. He states that he should not answer whether the Commission should establish a separate rate class for net metering customers. T. 1607.

Mr. Magnini states that almost all of the net metering in Carroll is residential so the Company has not seen penetration that has caused engineering concerns yet. Mr. Magnini states that he does not know that non-participating customers would notice a cost shift because it is not a line item on their bill, and no one has brought it to the Company's attention. T. 1608.

h. Walmart Testimony: Alex Kronauer

Mr. Kronauer with Walmart states that he agrees with previous testimonies -- there is no such thing as a perfect rate structure. He adds that Walmart would prefer single-channel billing (i.e. 1:1 retail). T. 1615. Mr. Kronauer testifies that he believes that TOU rates can result in cost-based rates that reflect the cost of service. Mr. Kronauer testifies that Walmart recommended in testimony that a net metering customer's demand charge should be reduced by whatever the net metering facility's contribution to demand is, which would be measured at peak Mr. Kronauer states that he is not an attorney but he believes Act allows it. T. 1617-1618.

i. Scenic Hill Solar Testimony: Bill Halter

In clarifying the relevance of additional cost-benefit studies that were submitted by Scenic Hill Solar, given that there is already one in the record that is specific to an Arkansas utility, Mr. Halter states that most of these studies were with respect to residential solar, which is to say non-demand charge customers. He explains that it is a mathematical proposition that the net benefits of solar for demand charge customers are materially greater than they are for residential customers. He assumes that if these residential studies show that there is a net benefit to distributing solar deployment, then the net benefit of distributed solar generation for demand metered customers has to be that much larger. T. 2635-2637.

Mr. Halter testifies that neither 2-Channel Billing or a grid charge ensures is a perfect match of costs to net metering and non-net metering customers. He believes the Commission should be looking at the other benefits that are being provided by net metering systems. T. 2645-2646. Mr. Halter states that it is very clear that Act 464 states that the rate for demand metered customers is 1:1. T. 2650-2651. Mr. Halter states that he does not believe customers or various utilities are in a position to implement TOU rates. T. 2648.

The Commission asks Mr. Halter if he thinks. Mr. Halter does not believe the Commission has enough data to assess whether there is currently a cost shift occurring between participants and nonparticipants. T. 2651-2652. Mr. Halter testifies that the Commission should not worry about this as a mathematical proposition until three percent of the number of kilowatt hours in a utility's service territory (*i.e.* utility-specific, not statewide) are provided by third-party distributed generation. T. 2655. Asked if he can point to anything in the studies that he has submitted that specifically support the 3 and 5 percent threshold he has advocated, Mr. Halter states that he can point to multiple states that have much greater penetration than the three and five percent threshold he had advocated. T. 2657-2658.

Mr. Halter responds that his private-sector clients are very savvy about what their goals are and the assessment of risk when considering the hypothetical of how should a one-year solar contract and a 20-year solar contract be priced so that the two contracts are equivalent when considering disruption or price change risk? In other words, if EAL offers solar at one-year increments, and EAL is competing with someone that's offering solar at 20-year increments, should there be some price differential to compensate for the risk that somebody that is signing up for 20-years is undertaking when, if you're signing up on an annual basis and there's price change risk, that risk remains on the nonparticipants? T. 2659-2662.

Mr. Halter responded that he does not know whether the Commission has jurisdiction over non-utility third-party providers, T. 3663. He does not know how he can include what Wal-Mart proposes with respect to also being compensated for the amount of demand reduction provided by the net metering facility if he believes the only compensation for demand charged net metering customers is 1:1. Mr. Halter adds that it is pretty black and white that the statute says 1:1 for demand charge customers. T. 2663-2665.

Mr. Halter responds that under a scenario where the net metering facility is on the same circuit as the load, you could probably move the meter to get it behind the meter. He notes that would be geography-specific and dependent upon the circuit. Mr. Halter describes a net metering facility that was located on a circuit that had load, but not the net-metering customer's load and states that the net-metering facility is providing distribution benefits to the load that is on the same circuit as the facility. T. 2665-2668.

j. AEEC Testimony: Jordan Tinsley

Mr. Tinsley states that AEEC is very supportive, and has been in all phases of this Docket, of 2-Channel billing, as a compromise that would mitigate some of the concern with regard to the cost shift that is occurring in residential rate classes. He states that regarding a grid charge for demand component customers, the best way to address the cost shift concern is to fix the rate design in those classes. T. 2697-2701. Mr. Tinsley also states that AEEC was concerned that some Large General Service customers, by adding a net-metering facility, will reduce their demand to the extent that they migrate to the Small General Service class. He states that this is would increase costs significantly for the remaining customers in the LGS class. T. 2704.

Mr. Tinsley testifies that he does not think TOU rates are a very good solution in the short term, but does think that TOU rates may be beneficial sometime down the road when the technology is more developed and maybe the data is more robust and some of those administrative issues are overcome. T. 2706-2707. Mr. Tinsley states that the amount of granularity or differences between the types of net metering customers, does not lend itself to creating a rate class that is solely dedicated to net metering customers. He thinks that the unifying aspects of the existing rate classes are probably still more salient than the differentiation that occurs when somebody installs a net metering system. T. 2707. Mr. Tinsley states that he thinks Act 464 allows the Commission to approve a tariff for a new grid charge outside a rate case. T. 2712-2714.

k. William Ball

Mr. Ball recommends finding another method besides 2-Channel Billing to try to match costs of net metering and non-net metering customers, because he believes it is too prescriptive. He states, using 2-Channel Billing plus the 40 percent adder to allocate the cost almost cuts in half the value of what net metering means to a net metering customer today on volumetric rates. T. 2716-2717. Mr. Ball states that the Commission must be careful when charging a net metering customer a grid charge when another non-net metering customer within the same rate class is not paying a grid charge because it leaves open the possibility that that net metering customer could be discriminated against or penalized in some way. To prevent such discrimination, he argues that a grid charge should apply to all customers, net metering and non-net metering customers alike. Mr. Ball argues that a grid charge should not be based on the size of their generating facility but the size that they're paying for their access to the grid. For example, if the net metering customer has 200-amp service, or if they have 400-amp service, that is what the customer should pay to support the grid for that access. He states that it would not matter if the customer had one panel or 100 panels -- the customer has paid for their access. T. 2717-2719. Mr. Ball does not support a separate rate class because he believes it would have detrimental effects on net metering customers. T. 2719.

l. AAEA, Audubon, Sierra Club Testimony: Karl Rabago, Gary Moody, and Thomas Beach

Mr. Rabago states that every value-of-solar study that he has seen shows that the value of net metering is higher than the average retail rate. He states that this is especially true in summer-peaking regions, where solar -- while not perfectly coincident -- certainly contributes most of its value during peak or peak-approaching times. So, he states, if a net metering customer exported during that time you would be paying them more and the compensation rate under 2-Channel would be even higher. T. 3029. Regarding a grid charge, Mr. Rabago has not seen any evidence that net metering customers cause incremental demand-related distribution costs. Therefore, he asserts, under traditional cost-of-service ratemaking, which the utilities have often invoked as a reason why they are blind to future benefits, then there is no basis for a grid charge because there is no incurred incremental cost that's not otherwise being recovered by the fully bundled rate that utilities have approved based on what they say are their actual costs of service. T .3030.

Mr. Moody states his belief that there is some fundamental data missing that is needed to evaluate whether or not the 2-Channel system was set up truly. For example, he argues that we need current cost-of- service studies to determine what the cost is to serve a net metering customer and how it differs from other customers within their rate class. He also argues that we do not know what the average load profile is in Arkansas for net metering customers in different rate classes. T. 3031.

On the subject of establishing a separate rate class for net metering customers, Mr. Beach states that there is analysis that was presented in Phase 2 that showed net metered customers are actually much cheaper to server than regular residential customers. For example, he states that if you set up a separate rate class for net metered residential customers on the EAL system, their rate would be 25 percent lower than regular residential customers. T. 3033-3034. Mr. Beach does not recommend a separate rate class for solar customers. He states that solar is just the first of many new technologies coming. He states that if you create a separate rate class for solar customers, you will have to add a class for solar plus storage and another class for solar plus EV, and things will become too complicated. T. 3034-3035.

Mr. Beach testifies that he is a proponent of TOU rates because the cost of electricity does vary throughout the day. He states as you add intermittent resources like solar, it's going to vary more widely during the day. He describes how California has implemented TOU rates, and notes that has shifted the peak period to 4:00 to 9:00 pm and incentivized customers to put in solar plus storage. T. 3036.

Audubon, AAEA and Sierra Club all believe Act 464 does not give the Commission authority to modify the rate structure for customers on demand component rates. T. 3040-3041.

Mr. Beach states that one of the issues he sees with the grid access charge is that it is designed strictly based upon the allocated distribution cost to a customer and there's no recognition that solar customers actually can avoid some distribution cost. He states that his study analyzed 15 years of utility investments in distribution plant as a function of peak demand. He notes that his study found that avoided cost for distribution was 13.5 percent of the marginal distribution cost. T. 3045-3046.

Beach states that the result is the same whether in front or behind the meter for residential customers who are going to be located on a distribution system that has a significant amount of load on it. Those customers are going to provide that benefit, he states, even if the panels are not physically located behind the meter. T. 3046-3047. Mr. Beach states that it is a question of what is the load on the distribution circuit when considering large customers. He states that if the size of the solar system has to be well below the minimum load on the circuit, then he does not believe there is going to be an issue. If, on the other hand, he states, the solar facility is in the middle of nowhere and there is no load nearby and you have to put the output up on to the transmission system to get it to the nearest customers, then the net metering facility is using the utility's system. T. 3047-3048.

m. AG Testimony: Sarah Tacker

Ms. Tacker testifies that the AG opposes Staff's recommendation that new net metering rates be individually set if and when each utility comes in for a general rate case. Ms. Tacker argues that Staff's approach is not practical and would not address quickly enough the subsidizing that is occurring. Ms. Tacker also believes Order No. 4 in Docket No. 19-055-U and the language in Act 464 require the Commission to affirmatively set rates, terms, and conditions after notice and an opportunity for public comment. T. 3120-3122.

Ms. Tacker recommends that a working group be formed, similar to the energy efficiency working group, with the parties working collaboratively to develop both a code of conduct for the participants, as well as a consumer guide. She states that information Carroll presented was an excellent start and that the AG would like to conduct a survey of other states that are farther along in net metering. Ms. Tacker also recommends that legislation be developed to give the Commission jurisdiction over third-party participants. T. 3123-3126.

Ms. Tacker states that the AG's Consumer Protection Division is charged with the enforcement of the Arkansas Deceptive Trade Practices Act. She states that the AG certainly would have enforcement authority over actors who engage deceptive or unconscionable business practices. Ms. Tacker states that the AG does not believe it has the resources to police the third-party participants in an adequate manner considering the increasing penetration of net metering, particularly rooftop solar. T. 3126-3128.

Ms. Tacker states that she does not believe that Act 464 strictly precludes 1:1 billing. Rather, she believes that in this proceeding, the Commission must affirmatively set the rates and that the metric by which the rates are set cannot cause an unreasonable allocation to other customers. Given those facts, Ms. Tacker states that she does not believe that 1:1 is a reasonable allocation based on information the AG has reviewed. T. 3130-3132.

Ms. Tacker testifies that the AG sees a difference in how Act 464 treats demand- and non-demand customers, as it pertains to 1:1 billings. She believes Act 464 specifically designates rate-setting treatment for customers that do not have a demand component. Ms. Tacker also believes that the Commission has the ability to establish rates, terms, and conditions for net metering for both demand and non-demand customers that is specifically authorized in Act 464. T. 3132-3133.

Ms. Tacker responds that the AG's consultant has reviewed preliminary data that indicates there is a trend that would support EAL's contention that subsidization is growing. Ms. Tacker states that the AG may be able to provide a final position in the next month to six weeks if additional information can be obtained from EAL. T. 3134-3135.

Ms. Tacker responds that she believes the 1:1 bill rate is causing a subsidization to occur. She believes that 2-Channel billing or a grid charge would help us move closer to that perfect match of costs to net metering and non-net metering customers. Ms. Tacker also points out that that Act 464 does not necessarily require a perfect match, but simply says that there cannot be an unreasonable allocation. T. 3137-3138.

Ms. Tacker testifies that it is AG's position that Act 464 allows the Commission to approve a tariff or specifically a grid charge for demand customers outside a rate case. T. 3138.

Ms. Tacker stated that the Commission should not treat retail [residential] customers similar to commercial customers and assume that retail customers have sufficient information to take any benefits and risks into consideration when making determinations to lock into a long-term contract T. 3139-3140.

Ms. Tacker states that the working group could begin working on a code of conduct while the Commission worked on legislation with regard to jurisdiction; or alternatively, the working group could begin working on both, with an order from the Commission for it to report to the Commission about legislation that would accomplish what the

Commission's directives are. She states that both are urgent and recommends that they begin immediately, regardless of who the task is assigned too. T. 3140-3141.

Ms. Tacker states that the AG has a good grasp on which activities and which actors the Commission should have jurisdiction over in order to fully protect ratepayers. In short, Ms. Tacker believes the working group can begin assembling language that could address the actors and activities which should come under the jurisdiction. T. 3141-3142. Ms. Tacker states that the new authority that the PSC would have would be more specific to the activities and the actors, and would be better tailored to address what is going on in net metering as compared to the Fair Trade Practice Act. T. 3142-3143.

III. DISCUSSION AND FINDINGS ON MAJOR ISSUES

A. DISCUSSION OF THE EFFECTS OF ACT 464 ON AREDA

The following discussion interprets the language of the Act 464 amendments to AREDA, as informed by the comments, testimony, and exhibits of the Parties to this Docket, and provides the basis for the Commission's adoption of amendments to the NMRs.

Categories of Net-Metering Customers under Act 464

Prior to the enactment of Act 464 there were three reasonably simple categories of Net-Metering Customers permitted under Arkansas law to install Net-Metering Facilities: (1) residential customers with generating capacity up to 25 kW,[187] (2) customers with generating capacity not more than 300 kW for any other use; and (3) non-residential

[187] Or, as provided by Ark. Code Ann. § 23-18-603 (6)(B)(i) prior to the Act 464 amendments, one hundred percent of the residential Net-Metering Customer's highest monthly usage in the previous twelve months.

customers with generating capacity in excess of 300 kW for any other use, which were required to seek a Commission exemption from the 300 kW size limitation.[188]

Today, under Act 464, as illustrated by the following highlighted "ifs," "ors," and "ands," there are four, more nuanced, categories of Net-Metering Customers: (1) residential customers with Net-Metering Facilities having generating capacity up to 25 kW[189] and non-residential customers with facilities having generating capacity of not more than 1,000 kW that are served under a rate without a demand component[190]; (2) non-residential customers with generating capacity of not more than 1,000 kW (1 MW) that are served under a rate with a demand component; (3) non-residential customers with generating capacity of over 1,000 kW (1 MW) but less than 5,000 kW (5 MW) if allowed under Ark. Code § 23-18-604(b)(9) if: increasing the generating capacity limits results in distribution system, environmental, or public policy benefits or allowing the increase would increase the state's ability to attract businesses to Arkansas and "is in the public interest;"[191] and (4) non-residential customers greater than 5,000 kW (5 MW) and up to 20,000 kW (20 MW) if allowed under Ark. Code § 23-18-604(b)(9) if: increasing the generating capacity limits results in distribution system, environmental, or public policy benefits or allowing the increase would increase the state's ability to attract businesses to Arkansas; [and] allowing an increased generating capacity "does not result in an

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[188] Under the previous law, Ark. Code Ann. § 23-18-604(b)(5), the Commission had the authority to increase the 300 kW generating capacity limits for individual non-residential Net-Metering Facilities if doing so "results in distribution system, environmental, or public policy benefits," and, under Ark. Code Ann. § 23-18-604(b)(7)(B), if allowing the increased generating capacity "would increase the state's ability to attract businesses to Arkansas."

[189] Or, as provided by Ark. Code Ann. § 23-18-603(8)(B)(i), one hundred percent of the residential Net-Metering Customer's highest monthly usage in the previous twelve months.

[190] The Commission believes that some utilities serve some Small General Service (SGS) customers under tariffs that do not contain a demand component – primarily very small commercial customers that have load characteristics nearly synonymous with residential customers – *e.g.*, a small storefront office such as a barber shop or a one-person law office.

[191] Ark. Code Ann. § 23-18-604(b)(9)(A).

unreasonable allocation of costs to other utility customers;" and allowing an increased generating capacity "is in the public interest."[192]

The Commission notes that Act 464 has as an overarching "public interest" standard for determining whether there should be changes to the existing 1:1 rate structure for Net-Metering Facilities with demand in excess of 1 MW.[193] In short, the larger the demand-component Net-Metering Facility being proposed for Commission approval above the stated size thresholds, the more requirements an applicant must meet, but in all such cases the public interest must be served if a customer is allowed to exceed the statutory size limits.

Given these differences in statutory conditions for exceeding the Net-Metering Facility size thresholds under Act 464, it is reasonable to conclude that the General Assembly intended for the Commission to have somewhat more discretion in approving projects from over 1 MW to 5 MW than for those between 5 MW and 20 MW. Consistent with its longstanding statutory authority and responsibility and its common practice in ratemaking of mitigation of rate impacts in general rate cases and tariffs, the Commission finds that, in determining what is in the public interest, the unreasonable allocation of costs to other utility customers is always an important consideration. Accordingly, for all such facilities seeking approval to exceed the 1 MW limitation (*i.e.*, from over 1 MW to 20 MW), the Commission will consider whether approval would produce an unreasonable

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[192] Ark. Code Ann. § 23-18-604(b)(9)(B) (emphasis added).

[193] *See, e.g.*, Ark. Code Ann. § 23-18-604(b)(2)(D) for non-demand-component customers falling into Category (1); Ark. Code Ann. § 23-18-604(b)(9)(A)(iii) for demand-component customers falling into Category (3); Ark. Code Ann. § 23-18-604(b)(9)(B)(iv) for demand-component customers falling into Category (4). The Commission notes that neither the public interest standard nor the unreasonable allocation of cost standard is explicitly mentioned in Act 464 for non-residential customers falling into Category (2) but, as discussed further below, finds that the General Assembly has in Ark. Code Ann. § 23-18-604(b)(6) instead declared that customers in this category are required to be retained and grandfathered under the existing 1:1 full retail rate credit.

allocation of costs to other customers and thus not be in the public interest. The Commission further finds that Act 464 requires more rigorous scrutiny of potential cost shifting for proposed Net-Metering Facilities between 5 MW and 20 MW. As discussed below, demand-component Net-Metering Customers who do not seek to exceed the 1 MW statutory limits do not have to apply to the Commission for project approval. This indicates that the General Assembly's intention was to not over-emphasize cost-shifting concerns under the current distributed generation penetration rates for that category of customers.

As outlined below, Act 464 provides, in Ark. Code Ann. § 23-18-604(b)(2)(D), that the Commission may, for Net-Metering Customers receiving service under a rate that does not include a demand component,"[t]ake other actions that are in the public interest and do not result in an unreasonable allocation of costs to other utility customers." This provision preserves the Commission's authority to address cost shifting behavior for residential and some non-residential non-demand component customers in a measured way as distributed energy resources grow in numbers and penetration increases in utility systems across the state.

The Commission reiterates that all facilities in excess of 1 MW of generating capacity must be found to be "in the public interest," which is the overriding condition for approving larger projects, even if all the other conditions are met under Ark. Code Ann. § 23-18-604(b)(9). The public interest standard also applies generally to all decisions the Commission makes in adopting and modifying the NMRs and the Commission notes that Act 464 is suffused with both public interest and unreasonable cost allocation[194] considerations throughout.

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[194] AECC Reply (Doc. No. 384) at 3, fn 4, cites Ark. Code Ann. §23-3-114 regarding prohibition of unreasonable preferences: "(a)(1) As to rates or services, no public utility shall make or grant any

Net-Metering Rate Structure Options for the Commission under Act 464

Before Act 464, when considering rate structure, there was no differentiation based on whether customers were served under a rate with a demand component. Act 464 now provides for different rate structure options depending on whether the Net-Metering Customer receives service under a rate that includes a demand component.

Net-Metering Rate Structure Options for Non-Demand-Component Customers

With respect to Net-Metering Customers below the 1 MW threshold and who receive service under a rate that does not include a demand component, the Commission under Act 464 now has a menu of discretionary rate structure options (A through D below) from which to choose in establishing appropriate rates, terms, and conditions for Net-Metering. Ark. Code Ann. § 23-18-604(b)(2) spells out four options for the Commission, stating that it may:

> A. Require an electric utility to credit the net-metering customer with any accumulated net excess generation as measured in kilowatt hours or kilowatt hours multiplied by the applicable rate in the next applicable billing period and base the bill of the net-metering customer on the net amount of electricity as measured in kilowatt hours or kilowatt hours multiplied by the applicable rate that the net-metering customer has received from or fed back to the electric utility during the billing period.[195]

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unreasonable preference or advantage to any corporation or person or subject any corporation or person to any unreasonable prejudice or disadvantage. (2) No public utility shall establish or maintain any unreasonable difference as to rates or services, either as between localities or as between classes of service…."

[195] The Commission distinguishes Ark. Code Ann. § 23-18-604(b)(2)(A) from the amended provision in Ark. Code Ann. Ark. Code Ann. § 23-18-604(b)(5) that now states: "For net-metering customers who receive service under a rate that does not include a demand component, shall require an electric utility to credit a net-metering customer with the amount of any accumulated net excess generation as measured in kilowatt hours or kilowatt hours multiplied by the applicable rate in the next applicable billing period." (Emphasis added.) The Commission interprets subsection (5) as speaking to the issue of the timing of any credit by providing that any credit must be made in the next billing period rather than at any other time or spread out over more than one billing period. This interpretation is supported when one reads the language of this subsection prior to its amendment by Act 464, Ark. Code Ann. § 23-18-604(b)(3), which states that the Commission "Shall require electric utilities to credit a net-metering customer with any accumulated net excess generation in the next applicable billing period."

The Commission interprets this provision as allowing the Commission to continue the existing 1:1 full retail rate for such customers.

B. Take the following actions if those actions are in the public interest and doing so will not result in an unreasonable allocation of or increase in costs to other utility customers:
   i. Separately meter the electric energy, measured in kilowatt hours, supplied by the electric utility to the net-metering customer and the electric energy, measured in kilowatt hours, that is generated by the net-metering customer's net-metering facility that is fed back to the electric utility at any time during the application period;
   ii. Apply the commission-approved retail rate to all kilowatt hours that are supplied by the electric utility to a net-metering customer by the electric utility during the applicable period determined by a commission;
   iii. Apply the avoided cost of the electric utility plus any additional sum determined under subdivision (b)(2)(B)(iv) of this section to all kilowatt hours supplied to the electric utility by a net-metering customer, during the period determined by a commission, which shall be credited to the total bill of the net-metering customer in a dollar value; and
   iv. The additional sum added to the avoided cost of the electric utility may be applied after the demonstration of quantifiable benefits[196] by the net-metering customer and shall not exceed forty percent (40%) of the avoided cost of the electric utility.

The Commission interprets this subdivision of Ark. Code Ann. § 23-18-604(b)(2) as authorizing the adoption of a form of 2-channel billing for customers served under a rate without a demand component, with flexibility to enhance the avoided cost excess

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[196] Under the new provisions of Act 464, Ark. Code Ann. 23-18-603(9), "Quantifiable Benefits" are defined as the:

"(A) Reasonably demonstrated costs that
(i) Are related to the provision of electric service and based on the utility's most recent cost-of-service study filed with the commission; and
(ii) Will be avoided by the utility by the use of net metering;
(B) Monetary value provided to a utility by the use of net metering as specified by a market mechanism, if any, of the regional transmission organization of which the electric utility is a member; and
(C) Monetary value provided to a utility by the use of net metering as specified by a market mechanism, if any, that measures utility distribution system benefits;"

The Commission interprets this provision as authorizing it to recognize benefits beyond those based on the utility's most recent cost-of-service study if market mechanisms exist that provide value to a utility by the use of net metering. The Commission further interprets this as allowing the forty percent adder to be calculated after the addition of such monetary value from such market mechanisms, if any.

generation credit by up to forty percent of avoided cost, calculated after the customer demonstrates quantifiable benefits, if any.[197]

C. Authorize an electric utility to assess a net-metering customer that is being charged a rate that does not include a demand component a per-kilowatt-hour fee or charge to recover the quantifiable direct demand-related distribution cost of the electric utility for providing electricity to the net-metering customer that is not:
   i. Avoided as a result of the generation of electricity by the net-metering facility; and
   ii. Offset by quantifiable benefits; <u>or</u> (emphasis added).

The Commission interprets this provision as authorizing a grid charge to recover demand-related distribution costs that might otherwise be bypassed through the operation of the Net-Metering Customer's net excess generation credit. The Commission believes it has the discretion, if in the public interest, to employ such a grid charge for this category of customers (non-demand-component customers) when the Commission finds that the utility has demonstrated an unreasonable shift of costs to other utility customers will occur.

D. Take other actions that are in the public interest and do not result in an unreasonable allocation of costs to other utility customers.

The Commission interprets this provision as authorizing the adoption of other options that are in the public interest and that avoid unreasonable cost shifts to other utility customers when customers not served under a rate with a demand component engage in Net-Metering.

<u>Net-Metering Rate Structure Options for Demand-Component Customers at or Below 1 MW</u>

With respect to Net-Metering Customers who receive service under a rate that includes a demand component and are not covered by subdivision (b)(9) of Ark. Code Ann.

[197] *Id.*

§ 23-18-604 – *i.e.*, customers receiving service under a rate that includes a demand component and with generation capacity up to 1 MW – the Commission interprets the statute as requiring the continuation of the existing 1:1 full retail rate for such customers. This interpretation is based upon a comparison of the language of Ark. Code Ann. § 23-18-604(b)(6) – for customers served under a rate with a demand component – with that of Ark. Code Ann. § 23-18-604(b)(2)(A) – for non-demand-component customers. The crediting mechanism language is identical, except that the (b)(6) provision states that the Commission "shall require" what amounts to 1:1 full retail credit for demand-component customers (except for those larger projects covered under subdivision (b)(9)), whereas the subdivision (b)(2)(A) provision provides that the Commission "may require" 1:1 full retail credit as one of the Net-Metering rate structure options for non-demand-component customers.

As explained earlier in this discussion of customer categories after enactment of Act 464, subdivision (b)(9) is a complicated explication of considerations the Commission must apply in deciding whether to approve large (over 1 MW to 20 MW) Net-Metering Facilities. The provisions of subdivisions (b)(9)(A) and (b)(9)(B) are almost identical, with both calling for a public interest finding, but the 5 MW to 20 MW projects addressed by (b)(9)(B) are expressly subject to explicit, enhanced scrutiny under the condition that allowing an increased generating capacity greater than 5 MW and up to 20 MW "does not result in an unreasonable allocation of costs to other utility customers." There is no language in subsection 604(b)(9) or elsewhere in Act 464 that either mandates the retention of the current 1:1 full retail credit or circumscribes the Commission's authority to prescribe a different Net-Metering rate structure for these large customers served under a rate with a demand component.[198] Accordingly, the Commission interprets the exception for large facilities provided in subdivision 604(b)(6) as preserving the Commission's discretion and authority to determine the appropriate Net-Metering rate structure under both "public interest" and "unreasonable allocation of costs" standards, as applicable to these large demand-component customers. The Commission may thus consider and implement various Net-Metering rate structure options, including a grid charge, as a condition for allowing a facility to exceed the statutory limits, if it is found to be an appropriate mechanism to address or prevent unreasonable cost shifting behavior or potential, and is in the public interest. These large Net-Metering Facilities will be subject to case-by-case, project-specific filings by Net-Metering Customers and utility-specific dockets seeking permission to implement a grid charge, with the procedures and guidelines governing each utility's demonstration of unreasonable cost allocations and cost shifting being addressed elsewhere in this Order. Such procedures will include appropriate provisions for notice and public hearing prior to a Commission decision on whether to approve the projects.

<u>Grandfathering under Act 464</u>

A new provision in Act 464, Ark. Code Ann. § 23-18-604(b)(10)(A), codifies the ability of the Commission to grandfather Net-Metering Facilities under an existing Net-Metering rate structure as one of the rates, terms, and conditions of Net-Metering. This provision states that the Commission:

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[198] The Commission notes AECC's observations that nowhere is it mentioned that "demand-metered customers [above 1 MW] are guaranteed a full retail credit," and that "[f]acilities larger than 1 MW are reviewed under section (b)(9). Under that provision, neither a rate nor a rate structure are prescribed, and therefore something entirely different than the full retail credit could be chosen by the Commission." AECC Initial at 9.

> (10)(A) Shall allow the net-metering facility of a net-metering customer who has submitted a standard interconnection agreement, as referred to in the rules of the Arkansas Public Service Commission, to the electric utility after July 24, 2019 but before December 31, 2022, to remain under the rate structure in effect when the net-metering contract was signed, for a period not to exceed twenty (20) years, subject to approval by a commission.
>
> (B) A net-metering facility under subdivision (b)(10)(A) of this section remains subject to any other change or modification in rates, terms, and conditions.

This provision of Act 464 follows Order No. 10 in Phase 1 of this Docket, which adopted provisions governing grandfathering.[199] In that Order, the Commission stated:

> The Commission finds that to be grandfathered under the existing rate structure, a customer must have submitted a signed Standard Interconnection Agreement to the appropriate utility on or before the date of the order, if any, in Phase 2 adopting the new rate structure. The utility need not have approved and signed the Standard Interconnection Agreement by that date; therefore, the customer will not be adversely impacted if the utility delays approving and signing the Standard Interconnection Agreement for whatever reason.

Order No. 10 at 146.

Comparing the two provisions, the Commission finds that Act 464 codified and expanded the grandfathering provision in Order No. 10 by legislatively building on the authority to grandfather enunciated by the Commission in that Order, which found that AREDA, properly construed, allows grandfathering. There, the Commission set forth the rationale for grandfathering Net-Metering Customers on the existing 1:1 rate structure for customers executing a Standard Interconnection Agreement prior to the issuance of an order in Phase 2.[200] The Commission concluded that customers should be eligible for grandfathering for the following reasons:

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[199] The Commission notes that the current NMRs do not contain provisions regarding grandfathering, because grandfathering pertains to rate structure, which was not a part of the Phase 1 proceedings. Accordingly, grandfathering is regulated under Order No. 10, as now supplemented by Act 464.

[200] With respect to grandfathering, it thus appears that the General Assembly in Act 464 de-emphasized the original provision's cost-shifting concerns associated with establishing rates, terms, and conditions for Net-

- To provide a fair, stable, and predictable cost environment, which creates certainty for existing Net-Metering Customers and for the market until new tariffs are established and clarity and simplicity for all parties thereafter;
- To appropriately balance the interests of existing Net-Metering Customers, potential Net-Metering Customers, and other utility customers, along with the interests of the utility;
- To implement the general intent of AREDA to promote the development of renewable energy, which the development of a long period of uncertainty would chill;
- To implement AREDA's general directive and requirement that the Commission "establish rates, terms, and conditions for net-metering contracts...;"
- To provide a period of advance notice to customers commensurate with the useful life of the assets in question (but also balancing questions of administrative efficiency and fairness to all ratepayers), which are "essential in implementing a

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Metering contracts. And it did not include any explicit cost-shifting elements applicable to the Commission's determination of grandfathering eligibility under Ark. Code Ann. § 23-18-604(b)(10). As provided below in Section III.B.1.d., that determination is based solely upon the date of the customer's submission to the Electric Utility of a signed Standard Interconnection Agreement.

Given the change in law enacted by Act 464, which obviated the issuance of an order in Phase 2 that would have implemented Act 827 of 2015, the Commission interprets Order 10's language as substantively providing that the date of issuance of an order changing the rate structure should be the date at or before which eligibility for grandfathering begins – in this case this Order in Phase 3 changing the rate structure.

The Commission further notes that in enacting Act 464, the General Assembly struck language from the provision found in previous Act 827 of 2015 (Ark. Code Ann. § 23-18-604(b)(1)(A)(i)) that, in directing that the Commission "[s]hall establish appropriate rates, terms, and conditions for net-metering contracts," required that the rates charged to each Net-Metering customer "<u>recover the electric utility's entire cost of providing service</u> to each net-metering customer within each of the electric utility's class of customers." (Emphasis added) See Staff Surreply (Doc. No. 400) at 3 and footnotes 10 and 11: "The pre-amendment version of Arkansas Code § 23-18-604(b)(1)(A)(i) required the Commission to establish net metering rates that 'recover the electric utility's *entire* cost of providing service....' Notably, the mandate to establish rates that 'recover the electric utility's entire cost of providing service' was eliminated and replaced with either <u>no</u> such requirement or a requirement in some circumstances that no 'unreasonable allocation' of costs occur. The question, whether an 'unreasonable allocation' of costs would result under the specific circumstances, is a factual one that will vary by utility and rate class." (Emphasis in original.)

statute which has the fundamental purpose of incenting customer investment in such assets."

- To comport with the Commission's general duty to fix just and reasonable rates and with common ratemaking principles, which include gradualism in the introduction of new policies that affect specific ratepayers or classes of ratepayers.
- To make a reasonable distinction among customers who face materially different market and legal conditions over time, based upon fairness to Net-Metering Customers who have signed and submitted a Standard Interconnection Agreement prior to establishment of any new rate structure, upon the different circumstances that face earlier and later investors in generating technologies, and upon changing legislative directives.

Order No. 10 at 142-144.

The Commission reaffirms Order No. 10's ruling that the eligibility for grandfathering is based on the date the customer submits to the Electric Utility a signed Standard Interconnection Agreement to the utility, even though the utility has not approved and signed such Standard Interconnection Agreement. *Id.* at 146. Furthermore, the Commission here implements Act 464's mandate that the Commission "shall allow the net-metering facility... to remain under the rate structure in effect when the net-metering contract was signed." Ark. Code Ann. § 23-18-604(b)(10)(A). However, the Commission recognizes that there are currently several large Net-Metering projects (over the 1 MW limit) in development which have been delayed because of uncertainties over issues such as remote interconnection,[201] common ownership,[202] and the processing of multiple Preliminary Interconnection Site Review Requests (PISRRs) filed with utilities by some Net-Metering Customers.[203] The Commission notes that the filing of a PISRR is required under NMR Rule 3.03 for large Net-Metering Facilities seeking to exceed the 1 MW statutory limit and is thus a preliminary but integral step towards the completion of the Standard Interconnection Agreement.[204] These Net-Metering Customers developing such projects may not have signed a Standard Interconnection Agreement because of these uncertainties and the resultant delays. This order clarifies these issues and establishes more certainty for planned Net-Metering projects. The Commission addresses the treatment of these customers *infra* at Section III.B.1.d.

With respect to the provision at the end of subdivision 10(A) of Act 464 that states "subject to approval by a commission," the Commission interprets this language as requiring Commission approval for the specific terms and conditions of grandfathering, including the appropriate period of years, on a case-by-case basis for customers who petition to exceed the statutory limit.

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[201] Scenic Hill Solar cites EAL's redline of NMR Rule 2.01 where EAL adds in redline that a utility, "is not required to interconnect a customer installing a renewable facility that is not connected to its load." Reply Comments of Scenic Hill Solar, LLC on Staff Strawman Proposal, (Doc. No. 387) at 15.

[202] Scenic Hill Solar provided evidence that EAL delayed a net metering project proposed by City of Stuttgart because the meters being aggregated did not have the same tax ID number. Reply Comments of Scenic Hill Solar, LLC on Staff Strawman Proposal (Doc. No. 387) at 6-8. EAL witness David Palmer testified that EAL informed the city [of Stuttgart] that, in order to proceed with the Site Review pursuant to the Commission's rules on meter aggregation, the accounts the city was seeking to aggregate must be under common ownership. Supplemental Testimony of J. David Palmer, (Doc. No. 369) at 4.

[203] Scenic Hill Solar cites EAL's Initial Comments (Doc. No. 367 at 127) redline of Staff Strawman NMR Rule 2.09(C), where EAL proposes language to prohibit multiple applications to offset the same load. See Reply Comments of Scenic Hill Solar, LLC on Staff Strawman Proposal, (Doc. No. 387) at 16.

[204] Net Metering Rules Appendix A-1, Part II. Terms and Conditions, Sections 2, 3, and 4.

B. DISCUSSION OF ISSUES AND FINDINGS OF THE COMMISSION

The following section sets forth a discussion of the following issues and sub-issues that the Commission will address in making revisions to the NMRs and resolving policy questions. In most cases, the discussion of each issue begins with the Comments and Strawman proposed by Staff in Surreply Comments (Doc. No. 400), followed by the positions of the other Parties. When possible, the positions of Parties that can be grouped together are discussed together (*e.g.*, utilities and AEEC, Distributed Solar Advocates and Scenic Hill Solar). The Commission's findings follow the discussion of each issue.

1. **Net-Metering Rate Structure Options**
   a. **1:1 Full Retail Rate**
   b. **2-Channel Billing and Additional Sum (*i.e.*, Additional Benefits)**
   c. **Grid Charge and Net-Metering Rate Structure Options for Demand-Component Customers with Generation Capacity in Excess of 1 MW**
   d. **Grandfathering of Net-Metering Rate Structure**
   e. **Ownership of Renewable Energy Credits**
2. **Leases, Service Contracts (PPAs), and Safe Harbor**
3. **Common Ownership and Meter Aggregation**
4. **Remote Facilities**
5. **Oversizing of Net-Metering Facilities**
6. **Gaming**
7. **Interconnection Rules**
   a. **Interconnection Rule Amendments**
   b. **Preliminary Interconnection Site Review Request Charge**
   c. **Additional Billing Charges for Net-Metering Customers**
   d. **Penalties for Unapproved Interconnections**
   e. **Signatures on the Standard Interconnection Agreement**
8. **Customer Protection Issues**
9. **Other Issues**
   a. **Unreasonable Allocation of Costs**
   b. **Data Sharing**
   c. **Separate Rate Class for Net-Metering**
   d. **Common Ownership by Tax-exempt Entities**
   e. **Community Solar**
   f. **Annual Reports**

g. Non-bypassable Riders

1. Net-Metering Rate Structure Options

a. 1:1 Full Retail Rate

Staff Comments and Strawman: Staff recommends continuation of the current 1:1 full retail rate structure for non-demand-component billed customers, but would allow different rate structures on a utility-specific basis if justified by the utility in a general rate case. Staff interprets Act 464 as providing an exception to the 1:1 rate structure for customers with a demand component, noting that "if the statute gives the Commission authority to disallow the facility based on the fact that it would result in an unreasonable allocation of costs, it is reasonable to interpret the statute as allowing the Commission to approve a rate structure for the facility (other than 1:1) that avoids an unreasonable allocation of costs." Staff Reply Comments (Doc. No. 388) at 6, 8; and Staff Surreply (Doc. No. 400) at 4-5 and revised Strawman Rule 2.04.

AG: The AG disagrees with Staff's recommendation to adopt new rate structures on a utility-by-utility basis through a general rate case and prefers adopting 2-channel billing and allowing utilities to file a rule-waiver petition for a different rate structure. AG Surreply (Doc. No. 396) at 3-4.

EAL, SWEPCO, OG&E, AECC: These Parties do not support the 1:1 full retail rate credit because they suggest that it results in cost shifting to non-Net-Metering Customers. They believe no general rate case or revised cost-of-service study is needed before setting new rate structures. EAL Surreply (Doc. No. 401) at 11-12; SWEPCO Surreply (Doc. No. 399) at 6-10; OG&E Surreply (Doc. No. 394) at 2-3. AECC asserts that Act 464 gives the Commission the discretion to set different Net-Metering rates for customers with a demand component. AECC Surreply (Doc. No. 398) at 2-4, 8-9.

Empire: Empire takes no position on the current 1:1 full retail credit for net excess generation.

AEEC: AEEC opposes the continuation of the 1:1 full retail rate credit in the current Net-Metering tariffs for customers in rate classes that recover most of their fixed costs through volumetric rates, asserting that the 1:1 rate design creates subsidies and shifting costs to other customer. AEEC continues its Phase 2 position supporting 2-channel billing for Net-Metering Customers without a demand component. Alternatively, AEEC could support in concept a grid charge along the lines suggested by EAL. AEEC Initial (Doc. No. 365) at 5-6.

Distributed Solar Advocates and Scenic Hill Solar: These Parties support 1:1 full retail rate credit and argue that it does not result in unreasonable cost shifting to non-Net-Metering Customers. They support a second option: explore different rate designs through pilot programs; and a third option: combine Net-Metering with time-of-use rates such as that in California. Distributed Solar Advocates Surreply (Doc. No. 404) at 1-2, 15-18 and Scenic Hill Solar Surreply (Doc. No. 403) at 1-6.

Scenic Hill Solar: Scenic Hill Solar argues that Act 464 grants the Commission authority to modify Net-Metering rates for customers that do not receive a bill with a demand component, but asserts that the Act grants no such authority regarding Net-Metering rates for customers on demand-component bills. Scenic Hill Solar notes that the Act specifies prescriptively that the Commission "shall require an electric utility to credit the Net-Metering Customer with any accumulated net excess generation in the next applicable billing period and base the bill of the Net-Metering Customer on the net amount of electricity that the Net-Metering Customer has received from or fed back to the electric utility during the billing period."[205] Scenic Hill Solar asserts that the testimony of Distributed Solar Advocates witness Beach demonstrates that Net-Metering is providing a benefit to ratepayers, even in the case of non-demand-metered customers. In the case of demand-metered customers, Scenic Hill Solar states, this evidence shows an overwhelmingly positive impact on other ratepayers and would be ample justification for the Commission to go beyond 1:1 Net-Metering for demand-metered customers. Scenic Hill Solar Initial (Doc. No. 375) at 4.

William Ball: Mr. Ball favors retention of the 1:1 full retail credit and opposes shifting to 2-channel billing. Ball Reply (Doc. No. 382) at (unnumbered) 3.

Findings:

(1) Residential and Non-residential Customers without a demand component.

Based upon the evidence currently showing very low levels of penetration of renewable distributed generation by solar facilities in Arkansas in the residential class and in any non-residential customers without a demand component,[206] the Commission finds that the current 1:1 full retail credit for net excess generation should be retained for now as the default Net-Metering rate structure. However, after December 31, 2022, a utility may request, in optional utility-specific tariff filings -- using a timely and properly designed cost-of-service study filed with the Commission -- that an alternative Net-Metering rate structure under Ark. Code Ann. § 23-18-604(b)(2)(B) is in the public interest and will not result in an unreasonable allocation of or increase in costs to other utility customers. If the Commission approves an alternative rate structure for this category of customers, it shall be applied going forward from that date of approval for customers in this category who

[205] Ark. Code Ann. § 23-18-604(b)(6).
[206] Exhibit B to Staff Reply (Doc. 388).

seek to Net-Meter. The Commission intends for the utility to demonstrate that cost shifting has occurred or is occurring on a cumulative basis, rather than on the basis of an individual Net-Metering Customer's proposed facility(ies).

(2) Non-residential Customers up to 1 MW with a demand component.

For non-residential customers served under a rate with a demand component up to 1 MW in size, the Commission finds that continuation of 1:1 full retail credit for net excess generation is required by Ark. Code Ann. § 23-18-604(b)(6).[207] However, as provided in Ark. Code Ann. § 23-18-604(b)(10)(B), a Net-Metering Facility remains subject to any other changes or modification in rates, terms, and conditions.

(3) Non-residential Customers Over 1 MW with a demand component.

For demand-component customers installing Net-Metering Facilities with generation capacity from over 1 MW to 20 MW,[208] the Commission finds that there is some evidence of potential cost-shifting[209] which justifies a change in the Net-Metering

[207] However, the Commission agrees with Staff that for demand-component billed customers, the utility would be allowed to seek a different rate structure and to adjust the demand component if justified by the utility in a general rate case in which all rates and tariffs may be examined and altered in the public interest. See Staff Witness Hoss, T2 547.

[208] During Phase 2 of this Docket, the Commission questioned EAL witness Andrew Owens regarding how utilities can ensure that Net-Metering Customers are paying the entire cost of service and whether Sub-Group 2 (the utilities, Staff, the AG, and AEEC) had told the Commission by how much Net-Metering Customers are not paying that entire cost. In short, the Commission asked, How do I guarantee a rate that ensures customers pay the entire cost if I don't know by how much they are not paying it now? Mr. Owens responded at some length, describing the process by which Sub-Group 2 arrived at a consensus through compromise and debate among a diverse group of IOUs, cooperatives, large industrial customers, the AG's Office, and Staff. One of the beginning principles, he noted, was the notion that Sub-Group 2 was not going to unpack for a Net-Metering Customer the need for a higher fixed charge, a demand charge. Transcript Vol. 2 of Phase 2 Evidentiary Hearing, December 1, 2017 (Document 308) T1. 33-35 and T1. 50-51.

[209] See, *e.g*., EAL witness Schnitzer Direct (Doc. No. 372) at 27-28. Mr. Schnitzer estimates that the 12.75 MW Hot Springs net metering arrangement would trigger a cost shift of approximately $900,000 in the first year, with the size of the cost shift increasing over time as the volumetric rate increases to keep up with the cost EAL will incur to provide service. In nominal terms (without discounting), Mr. Schnitzer estimates the size of the cost shift over 30 years at $29 million. Mr. Schnitzer's second example is the announcement by Pulaski County that it has entered into a power purchase agreement with the developer of an 8 MW facility. If this facility was qualified for Net-Metering under the 1:1 full retail rate credit rate structure, Mr. Schnitzer estimates that it would result in approximately $500,000 of cost shifts in the first year and nearly $11 million over the term of the 20-year contract.

rate structure to 1:1 full retail credit for net excess generation plus the adoption of a grid charge. However, there is an absence of utility-specific data and evidence regarding the extent to which any utility is not currently recovering demand-related costs upon which the Commission can establish a utility-specific rate applicable to all of these customers. Therefore, the grid charge will be set at zero unless and until revised by the Commission upon application by a specific utility.

Once the Net-Metering Rules become effective, such data and evidence of cost shifting may be presented to the Commission in optional utility-specific tariff filings by the utilities seeking to demonstrate -- using a timely and properly designed cost-of-service study filed with the Commission -- that an unreasonable cost shift to non-Net-Metering Customers is occurring or has already occurred in the non-residential demand-component category of customers with generating capacity between over 1 MW and 20 MW. The Commission intends for the utility to demonstrate that cost shifting has occurred or is occurring on a cumulative basis, rather than on the basis of an individual Net-Metering Customer's proposed facility(ies).

For demand-component customers with Net-Metering generating capacity from over 1 MW up to 5 MW seeking Commission approval to exceed the 1 MW statutory limit, the Commission may condition a public interest finding on the imposition of measures such as authorizing the utility to implement a properly designed grid charge, as described in c. below, or other measures to ensure the public interest is met.

For demand-component customers proposing a facility with Net-Metering generating capacity greater than 5 MW to 20 MW seeking Commission approval to exceed the 1 MW statutory limit, the Commission may likewise remedy a finding that allowing the facility would result in an unreasonable allocation of costs to other utility customers and would not be in the public interest unless the utility is authorized to implement a properly designed grid charge, as described below, or other measures to ensure the public interest is met.

For all proposed Net-Metering Facilities from over 1 MW to 20 MW, the Commission finds reasonable Staff's interpretation of Act 464 as providing an exception to the 1:1 rate structure for customers with a demand component, including its observation that "if the statute gives the Commission authority to disallow the facility based on the fact that it would result in an unreasonable allocation of costs, it is reasonable to interpret the statute as allowing the Commission to approve a rate structure for the facility (other than 1:1) that avoids an unreasonable allocation of costs." Staff Reply (Doc. No. 388) at 6-8. This, of course, includes the option to prescribe a grid charge, as discussed below.

Given proper notice, other Parties will be able to respond to such data and provide evidence regarding costs and benefits of Net-Metering. The Commission will then decide the proper level of a grid charge and determine the transition or phase-in terms and conditions for implementing such a change.

The Commission recognizes that a utility may, in a general rate case, request to change its overall rate structure, including changes to its customer charge, demand component, and volumetric energy component.

b. 2-Channel Billing

Staff Comments and Strawman: Staff does not recommend that the Commission adopt 2-channel billing or a grid charge at this time. Staff asserts that the Commission needs to define Quantifiable Benefits only if it chooses to adopt one of the rate structure options other than 1:1 full retail (*e.g.*, 2-channel or grid charge) for customers who receive service under a rate that does not include a demand component. Staff argues that Quantifiable Benefits should be determined along with a proposed rate structure on a utility-by-utility basis in a general rate case. Staff agrees in principle with SWEPCO, OG&E, Carroll, and the AG that Quantifiable Benefits should be (1) demonstrated by the Net-Metering Customer if the Commission adopts a Net-Metering rate structure pursuant to Ark. Code Ann. § 23-18-604(b)(2)(B)(iv); and (2) tied to an accounting or market mechanism or to an amount included in a utility's cost of service. Staff shares the AG's desire to avoid ambiguity when defining Quantifiable Benefits, but suggests that flexibility among utilities is needed, and notes that a standard formula for such benefits across utilities may not be appropriate because Act 464 provides that Quantifiable Benefits must be specifically based on "the utility's most recent cost-of-service study filed with the [C]ommission."[210] Staff Surreply (Doc. No. 400) at 6-7.

<u>AG:</u> The AG recommends a "Do No Harm" approach – *i.e.*, a gradual tiered move towards 2-channel billing, while mitigating negative effects, and proposes a phase-in that moves toward a net excess generation credit based on avoided costs, using tiers adopted by the Commission. AG Initial (Doc. No. 362) at 6-7, 9-11.

<u>EAL:</u> EAL recommends adopting either 2-channel billing (and appears amenable to an approved Additional Sum up to 40 percent) or a grid charge, and provides illustrative rates for each approach based on its cost of service. EAL Initial (Doc. No. 367) at 31-37. EAL recommends immediate adoption of 2-channel billing for non-demand component

[210] Ark. Code Ann. § 23-18-603(9)(A)(i).

customers or, as a second option, 2-channel billing with a 40 percent adder that is stepped down annually. EAL Surreply (Doc. No. 401) at 8-10.

SWEPCO: SWEPCO supports 2-channel billing for non-demand-component Net-Metering Customers and for its General Service tariff customers. SWEPCO supports an Additional Sum of 40 percent but states that benefits must be based on cost-based ratemaking, not societal benefits. SWEPCO Initial (Doc. No. 368) at 2-5.

OG&E: OG&E recommends that if 2-channel billing is adopted each utility should be allowed to set its own rate structure components (grid access charge, demand charge, etc.). OG&E argue that the burden of proof for any Additional Sum should be on the party seeking the sum and that it is unaware of any benefits related to regional transmission organization (RTO) market mechanisms. If the Commission should decide that utility-specific rates are not desirable, OG&E requests that the Commission approve a grid access charge mechanism. OG&E Initial (Doc. No. 363) at 3-5; OG&E Reply (Doc. No. 379) at 3-4.

Empire: Empire recommends that because of the differing levels of technology adoption among the utilities, the Commission should avoid prescriptive solutions and give each utility a range of options for its proposed rates, terms, and conditions for Net-Metering within its service territory. Empire Reply [Initial] (Doc. No. 360) at 1-2.

AEEC: AEEC continues its Phase 2 position supporting 2-channel billing for Net-Metering Customers without a demand component. AEEC Initial (Doc. No. 359) at 6.

AECC: With respect to Quantifiable Benefits and the Additional Sum that might be approved under a 2-channel billing approach, AECC argues that Net-Metering Customers bear the burden of proof for adders in excess of the filed rate approved by the Commission.

AECC Reply (Doc. No. 384) at 5. AECC argues that the Federal Power Act and PURPA may preempt the Commission from setting rates for purchasing energy at a rate that is above the utility's annual avoided costs. *Id.* at 9, fn. 23.

Distributed Solar Advocates: Distributed Solar Advocates oppose adoption of 2-channel billing, stating that it overcorrects for a perceived shifting of costs to other customers that does not exist, especially if one considers the full spectrum of costs that distributed generation avoids. They urge the Commission to establish through an order that customers taking service under a rate with a demand component will continue to receive 1:1 kWh offsets for excess generation exported to the grid. Distributed Solar Advocates Surreply (Doc. No. 404) at 21, 26.

Scenic Hill Solar: Scenic Hill Solar opposes 2-channel billing and contends that for demand-metered customers 1:1 full retail crediting is clearly required by Act 464 (Ark. Code Ann. § 23-18-604(b)(6). Scenic Hill Solar cites the results of the Ratepayer Impact Measure test results provided by Distributed Solar Advocates (Crossborder study), as well as 18 similar studies from other jurisdictions, which show that there is much more to an analysis of the value of distributed solar energy than just the spot market energy costs that EAL argues is the only substantive avoided cost. Scenic Hill Solar argues that there is no basis for a grid charge. Scenic Hill Solar Surreply (Doc. No. 403) at 1-5. Scenic Hill Solar takes no specific position on 2-channel billing or a grid charge for non-demand-component customers, but supports the positions of Distributed Solar Advocates on these issues, including the assertion that the value of distributed solar appears to be above residential rates.[211] *Id*. at 3.

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[211] Distributed Solar Advocates Initial (Doc. No. 374) at 2.

William Ball: Mr. Ball opposes 2-channel billing as too prescriptive and opines that limiting the value of net excess generation to avoided cost plus an adder not to exceed 40 percent of avoided cost would turn what is currently a marginal return on investment into an investment that most would not make. Ball Reply (Doc. No. 382) at (unnumbered).

Findings:

Based upon review and careful consideration of the positions of the Parties in Phases 2 and 3 of this Docket, the Commission declines to adopt a 2-channel billing approach at this time and as described in the next section, will afford the utilities the opportunity on a voluntary, utility-by-utility basis to demonstrate how a phased-in grid charge would address any demonstrated unreasonable allocations of costs to non-Net-Metering Customers on the utility's distribution system. Two-channel billing does not provide the same ability to phase-in adoption as does a grid charge. As shown in the previous discussion section of this Order and in the summaries of comments and testimony in the full record of Phases 2 and 3, the Commission notes that most of the investor-owned utilities have expressed support for a grid charge approach as an alternative to 2-channel and none have opposed it. As noted in A, above, the Commission finds that the 2-channel billing approach is not an optional billing structure for non-residential Net-Metering Customers taking service under a demand component and with generation capacity of 1 MW or below, as they are required to continue under the 1:1 full retail rate structure. The same is true with regard to those same demand-component customers with respect to a grid charge under Act 464 – it is not available as an option, but other options may exist in addition to the 1:1 full retail credit,[212] such as those under Ark. Code Ann. § 23-18-604(b)(4).

c. Grid Charge and Net-Metering Rate Structure Options for Demand-Component Customers with Generation Capacity in Excess of 1 MW

i. Grid Charge

Staff Comments and Strawman: As noted above, Staff does not recommend that the Commission adopt 2-channel billing or a grid charge at this time. Staff takes no specific position on a grid charge, but its Strawman provides that the 1:1 full retail credit shall apply to Net-Metering Customers having a demand component and a generating capacity up to 5 MW. For demand-component customers exceeding 5 MW and up to 20 MW, Staff recommends that the Commission require a determination that the Net-Metering Facility and thus the approved Net-Metering rate structure do not result in an unreasonable cost shift to other utility customers and thus base the bill of the customer on the Net-Metering rate structure determined by the Commission at the time it approves the Net-Metering Facility. Staff Surreply Strawman Rule (Doc. No. 400) 2.04.A.2.a. and b.

AG: The AG takes no specific position on a grid charge.

EAL: In its Initial Comments, EAL recommends adopting either 2-channel billing (and appears amenable to an approved Additional Sum up to 40 percent) or a grid charge, and provides illustrative rates for both approaches based on its cost of service. EAL observes

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[212] AECC, on behalf of the state's 17 electric distribution cooperatives, states that the Commission may choose any rate structure option depending on each Net-Metering Customer class, under Ark. Code Ann. § 23-18-604(b)(2) and notes the Commission statement in Order No. 22 that "the General Assembly left entirely to the Commission the decision to choose one of the various options set forth in the Act, or a hybrid thereof." AECC Surreply at 3. On the same page, AECC sets forth four categories of rate structure customer classes and describes for each the Commission's differing levels of discretion in adopting a rate structure. With the exception of demand-component customers up to 1 MW in size, which must remain under the 1:1 credit structure for net excess generation, the Commission finds that this summary is consistent with its description in the preceding section of this Order of rate structure options for differing customer classes.

that 2-channel billing and a grid charge are not mutually exclusive in that they address two different issues – namely, the appropriate value for excess generation to the grid versus recovery of fixed distribution infrastructure costs that are not avoided by virtue of self-generation. In other words, EAL states, with a grid charge Net-Metering billing would occur as it does today, with a 1:1 full retail credit for any excess energy delivered to the grid, and the grid charge would be an additional charge on the bill. EAL Initial at 31-35. EAL witness Owens explains in his Direct Testimony EAL's proposal for calculating a grid charge, and he provides a table showing the resulting grid charge in $/kW-month for each rate class that EAL is proposing as a second option to implement a new rate structure for Net-Metering. The resulting amounts for EAL are $2.52/kW-month for Residential customers, $1.98 for SGS customers, and $0.96 for LGS customers. *Id.* at 36-37.

In Surreply, EAL proposes that the Commission adopt the following rate structure for Net-Metering Customers who receive service under a rate schedule that includes a demand component:

> With respect to net-metering customers of all sizes who receive service under a rate schedule that includes a demand component, the Commission's Phase 3 Order would adopt EAL's proposed Grid Charge and methodology, which applies a unique Commission-approved cost-of-service (COS)-based fixed charge to net-metering customers who receive service under a rate schedule that includes a demand component [for] customers by rate class (*e.g.*, SGS, LGS). The methodology and inputs for calculating the Grid Charge are described in the [Phase 3] Direct Testimony of D. Andrew Owens and supporting workpapers thereto. Upon issuance of an Order in this rulemaking, the Commission will allow each utility to make a compliance filing setting forth its Grid Charge for each rate class to which it will apply, for confirmation that the calculations are performed consistent with the parameters set forth in the Commission's Phase 3 Order and the utility's most recent Commission-approved COS as adjusted for subsequent COS changes if the utility operates under a Commission-approve formula rate plan (FRP) tariff.

EAL Surreply (Doc. No. 401) at 10.

Although EAL does not agree with the positions of Staff, Distributed Solar Advocates, and Scenic Hill Solar[213] which suggest that Act 464 prohibits the Commission from adopting a Net-Metering rate structure that differs from 1:1 full retail crediting, EAL asserts that its proposed approach avoids implicating any debate about the amount of the credit by applying a separate grid charge consistent with the positions advocated by OG&E, AEEC, and, to an extent, Staff. Despite assertions from the Distributed Solar Advocates to the contrary, EAL states that there is no provision in Act 464 that precludes the Commission from implementing a cost-based grid charge for Net-Metering Customers of any size who receive service under a rate schedule that includes a demand component. *Id.* at 11-12.

In its Initial and Reply Comments, EAL asks the Commission to consider two alternative Net-Metering rate structures – 2-channel billing and a grid charge – and asserts that the Commission has authority to implement both. EAL recommends that the Commission adopt 2-channel billing for Net-Metering Customers who receive service under a rate schedule that does not include a demand component. In response to Staff's contention that the Commission does not have legal authority to implement 2-channel billing for Net-Metering Customers who receive service under a rate schedule that includes a demand component (a position with which EAL does not agree), EAL suggests "in the interest of building consensus" that the Commission establish a grid charge for Net-Metering Customers who receive service under a rate schedule that includes a demand component. *Id.* at 23-24.

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[213] Staff Reply at 4; Distributed Solar Advocates at 3; Scenic Hill Solar Reply at 1.

Specifically, EAL recommends that the Commission order the following in this rulemaking:

(a) A rate structure that includes a grid charge for Net-Metering Customers who receive service under a rate schedule that includes a demand component;

(b) Direct utilities to calculate the grid charge in the step-by-step manner described in Section II.B ("Calculating a Grid Charge") of the Direct Testimony of D. Andrew Owens;

(c) Direct utilities to make a compliance filing incorporating such a grid charge into their Net-Metering tariffs;

(d) Clarify that the grid charge will be considered part of the rate structure in effect on the date that the Phase 3 order is issued, and

(e) State that the rate structure in effect on the date that a Net-Metering project is interconnected and becomes operational will be the rate structure applied to that project, for a period of no longer than 10 years.

EAL states that provisions (c) – (e) will provide certainty to all parties about the rate structure that will apply to each project and length of time that it will apply. Consistent with Act 464, EAL states, for customers whose Net-Metering Facilities are interconnected and operational prior to the issuance of the Phase 3 order, the applicable rate structure will not include the grid charge; for customers whose Net-Metering Facilities that are interconnected and operational after the issuance of the Phase 3 order, the applicable rate structure will include the grid charge. *Id*. at 23-25.

EAL states that it recognizes that the language of Act 464 applies the rate structure in effect when the Net-Metering contract was signed, rather than the rate structure in effect when the project enters service. However, EAL proposes that the Commission state, per its proposed provision (e), that utilities will use the date that the Net-Metering Facility becomes operational as a good proxy for the date that the Net-Metering contract was signed. EAL asserts that doing so will help avoid conflicts that might otherwise arise – in particular EAL expects that if the date that the Net-Metering contract [Standard Interconnection Agreement] is signed by the customer is used as the sole "cutoff date" for determining grandfathering eligibility, developers will prematurely submit a wave of contracts for signature and then accuse EAL of foot-dragging if it does not sign such contracts immediately upon receipt despite that such facilities are not yet constructed or ready to be interconnected. EAL argues that establishing the date that the Net-Metering Facility enters service as an objective cutoff date, as provision (d) does, is consistent with legislative intent and will help avoid controversy. EAL also asserts that provision (e) should resolve a concern expressed by some parties that it would be administratively inefficient for individual parties to apply to the Commission to be grandfathered under the existing rate structure on a case-by-case basis for up to 20 years, per Act 464. EAL states that it appreciates that concern and has sought to address it with provision (e), which would allow for grandfathering of all customers with qualifying Net-Metering Facilities for 10 years. *Id*. at 25-27.

<u>SWEPCO:</u> SWEPCO highlights the gap created by Act 464 for those demand-component Net-Metering Customers from which the utility is not fully recovering its costs to serve. SWEPCO cites the example of its General Service tariff that provides for a demand charge for kW of billing demand in excess of 6 kW, but notes that many customers taking service under this rate do not meet the 6 kW demand charge threshold. Moreover, SWEPCO

states, a significant portion of its costs under the General Service tariff are achieved through the energy charge. Therefore, SWEPCO states that it is not fully recovering its costs to provide service as designed by the tariff, in particular in the instances where the actual load is below the 6 kW minimum. SWEPCO Initial (Doc. No. 370) at 8-9.

SWEPCO states that if the Commission is in agreement with Distributed Solar Advocates that there is no rate design issue to be resolved in this proceeding related to demand-component customers, SWEPCO proposes that a fee or charge be applied to those demand-component Net-Metering Customers from which the utility is not recovering its cost to serve. In support of this type of charge, SWEPCO cites Ark. Code Ann. § 23-18-604(b)(4), which permits the Commission to "authorize an electric utility to assess a Net-Metering Customer a greater fee or charge of any type if the 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 utility's entire customer base." Accordingly, SWEPCO states, the gap created by Act 464 could be addressed by allowing the utility to charge an additional fee to demand-billed customers where current rate schedules do not recover the majority of fixed, functionalized costs through existing demand charges. SWEPCO states that this additional fee can be charged pursuant to the Net-Metering tariff and would not require additional tariff or rate changes – in other words, the utility would not need to file a general rate case to effectuate the change. SWEPCO Surreply (Doc. No. 399) at 11-13.

<u>OG&E:</u> OG&E maintains its Initial Comments support for Net-Metering solutions that are utility-specific due to unique operating and consumer circumstances. Absent a utility-specific solution, OG&E recommends adopting a Grid Access Charge as the most

reasonable path forward for all customers. OG&E points out that support for this proposal was laid out in OG&E's Initial Comments as well as those of EAL[214] and AEEC,[215] and it was acknowledged as a potential path forward by Staff,[216] the AG,[217] and AECC.[218] OG&E Reply (Doc. No. 379) at 3-4.

OG&E observes that the Initial Comments on Net-Metering rate structures were not limited to customers not served under a demand component, noting that multiple Parties brought up how the Net-Metering structure for customers served under a demand-component rate should be modified in light of Act 464. OG&E states that while the law certainly allows for maintaining the current 1:1 rate structure for Net-Metering customers served under a demand rate, there is a need to ensure that the demand rates being charged to these customers are set at an appropriate level to fully recover the demand portion of the cost to serve. Otherwise, OG&E argues, it will result in an unreasonable allocation of costs to non-Net-Metering Customers under the 1:1 Net-Metering structure. OG&E supports a process going forward that allows for the examination of the current price level of demand charges to ensure each utility is recovering the appropriate level of demand-related costs to mitigate unreasonable allocations of costs to non-Net-Metering Customers. *Id* at 5.

In addition to future Net-Metering rate structure discussions, OG&E supports the idea of combining retail Net-Metering with time-of-use (TOU) rates, but notes that placing all Net-Metering Customers on TOU rates does not, on its own, address the changes necessary to combat the unreasonable allocation of costs to non-participants. However, in

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[214] EAL Initial at 31.
[215] AEEC Initial at 5.
[216] Staff Initial at 7.
[217] AG Initial at 7.
[218] AECC Initial at 6.

conjunction with the changes outlined in Act 464 for Net-Metering, OG&E would be supportive of separating Net-Metering Customers into their own class in a cost-of-service study to analyze and design an appropriate rate structure specific to these customers, TOU or otherwise. OG&E states that taking service under a TOU rate structure would allow Net-Metering Customers to realize the time-specific value of the energy that they produce. If this process were undertaken, OG&E states, it should be intended "to ensure that the on-peak windows selected, and the rates imposed for usage (and exports) during different periods, accurately reflect the cost to the utility of providing service during peak times."[219] To aid in reducing the current unreasonable allocation of costs to non-Net-Metering Customers, OG&E suggests, a transition to Net-Metering-specific TOU rates could be addressed by all utilities in their next proceeding in which a new cost-of-service study can be presented and Net-Metering Customers can be analyzed in a standalone class of customers. *Id.* at 4.

Empire: Empire states that it supports a grid charge. T2 1473.

AECC: AECC takes no specific position on a grid charge, but states that Act 464 does not mandate a particular rate structure for any rate class or type of Net-Metering Customer, stating that it is the Commission's discretion to set a rate. AECC states that the Commission "may choose any option for each net-metering customer class." AECC Surreply (Doc. No. 398) at 3.

AEEC: AEEC supports the concept of a grid charge along the lines suggested by EAL. AEEC Surreply (Doc. No. 402) at 5-6.

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[219] Distributed Solar Advocates Initial at 17

Distributed Solar Advocates and Scenic Hill Solar: Distributed Solar Advocates state that although AREDA certainly permits the Commission to authorize a grid charge, the only costs that may be recovered through such a fee are the utility's demand-related distribution costs, and only if those costs are not actually avoided by generation from the Net-Metering Facility and also not offset by Quantifiable Benefits.[220] Distributed Solar Advocates assert that determining whether demand-related distribution costs are avoided by the Net-Metering Customer requires an understanding, among other things, of the net load profile of that customer, which could well reflect lower demand during the times that determine the residential class's share of those distribution system costs. Distributed Solar Advocates argue that a fee imposed on Net-Metering Customers for demand-related distribution costs, when they likely have lower peak demands than others in their class, does not reflect cost-based ratemaking, and is not consistent with cost-based ratemaking, or considerations of the public interest. Distributed Solar Advocates Surreply (Doc. No. 404) at 26-27.

Scenic Hill Solar: Scenic Hill Solar asserts that a requirement for a 1:1 full retail credit for customers with a demand component is clear in Act 464 and provides no basis for a grid charge. Scenic Hill Solar Surreply (Doc. No. 403) at 1.

AEEC: AEEC speaks favorably of the concept of a grid charge along the lines suggested by OG&E – a process going forward for customers with a demand component that allows for the examination of the current price level of demand charges to ensure each utility is recovering the appropriate level of demand-related costs to mitigate unreasonable allocations of costs to non-Net-Metering Customers.[221] AEEC states that it "heartily agrees

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[220] Ark. Code Ann. § 23-18-604(b)(2)(C)(2).
[221] OG&E Reply (Doc. No. 379) at 5.

with OG&E" that adjusting the rate designs for those rate classes that have a demand component that nonetheless fails to recover a significant portion of fixed costs presents the best way to address the cost shifting resulting from Net-Metering Customers in those classes. Indeed, AEEC asserts, that policy aligns with the legislative policy enshrined in Act 725 of 2017 (Ark. Code Ann. § 23-4-422(b)(1), which provides, in pertinent part:

> (b) Notwithstanding the commission's authority to otherwise determine and fix rates for all classes of customers, including allocating or assigning costs and designing rates, if the commission finds that it will be beneficial to economic development or the promotion of employment opportunities, and that it will result in just and reasonable rates for all classes of customers, the commission shall determine rates and charges for utility services that:
> (1) For the class of customers with the highest level of consumption per customer which has rates that include a demand component, and any successors to such class, as they existed on January 1, 2015, <u>ensure that all costs and expenses related to demand and capacity are identified and allocated on a demand basis and recovered from customers in those classes through a demand rate component and not through a volumetric rate component unless the commission determines that the rates should be adjusted under subsections (e) and (f) of this section</u>.

(emphasis added.) AEEC expresses its concern, however, that implementing a procedure such as that suggested by OG&E will require considerable time, insofar as it will require adjustments to rate designs in each utility's next general rate case, some of which may not happen for several years, or even decades and thus may not allow for the timely consideration of the need to address subsidies resulting from Net-Metering applications in these rate classes in the short term. AEEC states that if the Commission concludes that it has authority to address the subsidies through a change in the Net-Metering rates rather than a long-term change in various rate designs, it urges the Commission to act now before the subsidy becomes more impactful.[222] AEEC Surreply (Doc. No. 402) at 5-6.

William Ball: Mr. Ball states that if changes to Net-Metering are necessary, he believes a Grid Access Charge applied to all volumetric customers is a preferable option. He states that this approach would consider impacts to all volumetric rate customers and be less likely to target only Net-Metering Customers. He recommends that the grid access charge, if any, should be based on the size of a customer's electric service and, if the customer is a Net-Metering Customer, it should not be based on the size of their Net-Metering Facility. Ball Reply (Doc. No. 382) at (unnumbered) 3-4.

ii. Net-Metering Rate Structure Options for Demand-Component Customers with Generation Capacity in Excess of 1 MW

Staff Comments and Strawman: Staff's Strawman provides that the 1:1 full retail credit shall apply to Net-Metering Customers having a demand component and a generating capacity up to 5 MW. Staff Surreply (Doc. No. 400) at 2-3, footnotes 10 and 11.

AECC: AECC states that Act 464 does not mandate a particular rate structure for any rate class or type of Net-Metering Customer, stating that it is the Commission's discretion to set a rate and a rate structure for each class of Net-Metering Customers. AECC states that the Commission "may choose any option for each net-metering customer class." AECC disagrees with the accuracy of Staff's contention[223] that any utility-specific approach to Net-Metering must be preceded by a *Rules of Practice and Procedure* Section 8 general rate case and corresponding cost-of-service study, asserting that the value of generation is

[222] The Commission notes that subsection (h) of Ark. Code Ann. 23-4-422 provides that electric cooperatives are not subject to this section.
[223] Staff Reply at 7.

known today and already set by wholesale markets. Moreover, AECC asserts such a claim ignores the fact that Act 464 does not require a Section 8 rate case or a new cost-of-service to change Net-Metering rates. AECC notes that the closest Act 464 comes to relying on a cost-of-service study concerns "Quantifiable Benefits," referencing the utility's "most recent" cost-of-service study "filed" with the Commission. AECC argues that the two quoted adjectives demonstrate that Act 464 intended to rely on an existing, not new, cost-of-service study, and even then, only for a very limited purpose. AECC Surreply (Doc. No. 398) at 2-5.

Distributed Solar Advocates and Scenic Hill Solar: Distributed Solar Advocates and Scenic Hill Solar take the position that changes other than updating the Rules to reflect statutory language changes to Net-Metering for demand-component customers need not be resolved in this proceeding. They believe that Act 464 does not give the Commission authority to modify the rate structures for customers with demand-component rates and contend that the Commission has ample evidence to find that Net-Metering Customers with a demand component are not shifting costs to other customers. Distributed Solar Advocates Surreply (Doc. No. 404) at 2-6; Scenic Hill Surreply (Doc. No. 403) at 2-3.

Walmart: Walmart recommends adding language to Staff's Strawman at Sections 3.5 and 3.6 that directs the utility to reduce the Net-Metering Customers' billing demand to reflect any applicable reduction in demand resulting from the Net-Metering Facility, provided however, that the billed demand cannot be reduced below zero. Walmart recommends that Section 3.2 should be modified to clarify that a net excess generation credit is not the only bill reduction available to Net-Metering Customers with a rate that includes a demand component. Walmart Initial (Doc. No. 364) at 1-2.

William Ball: Mr. Ball notes that every large commercial solar facility that has been installed in Arkansas, or is currently being pursued, is now serving, or will serve customers that pay a demand charge. The result, he states, is that the customer is helping reduce demand for the utility at the solar facility while still paying demand charges at the location(s) at which they consume grid power. He contends that meter aggregation is not retail wheeling, as the customer's facility is offsetting part or all of their energy requirements, regardless of whether their meter is located behind the meter or at a location with no customer load. Ball Reply (Doc. No. 382) at (unnumbered) 2.

Findings:

Based on the evidence presented by the Parties, and in consideration of the provisions of Act 464, the Commission finds that the institution of a grid charge mechanism for Net-Metering Customers over 1 MW is the preferred alternative at this time to address utility allegations of unreasonable cost shifting or cost allocations having a negative impact on non-Net-Metering Customers. As previously noted, in the absence of utility-specific data and evidence, the Commission cannot establish a utility-specific rate for the grid charge; therefore, the initial grid charge rate will be set at zero. Under this approach, a utility, at its discretion, may propose a revised grid charge rate.[224] The Commission will not require that the application be made in a general rate case, but if the utility has opted to utilize a formula rate plan, the utility shall ensure that its relief sought in the application is consistent with the formula rate plan.

[224] The Commission notes and agrees with AECC's Initial Comments observation that net metering is a utility-specific matter and thus the Commission should ensure that rates can be tailored to each utility's approved cost-of-service and system characteristics. AECC Initial at 6-7. The Commission also believes that the grid charge approach outlined in this Order will allow the Commission to consider, individually, on a utility-by-utility, case-by-case basis or, at a minimum, on a class-of-service basis, alternate rate methodology in situations where Net-Metering Customers have unique characteristics, such as taking service under seasonal accounts, including irrigation, poultry houses, and other agricultural accounts where normal rate mechanisms do not fit neatly within the parameters of Act 464. AECC Initial at 10.

The revised grid charge rate should recover the avoided or unrecovered distribution-related demand costs specific to each tariff schedule and will apply to the Generation Meter. To avoid double recovery, the utility is also directed to identify and credit customers with such demand-related costs as are already being recovered in rates. The utility shall apply the grid charge to the Generation Meter, and then apply the demand credit to each aggregated meter.

A utility desiring to implement a revised grid charge rate should file a separate application to establish the revised grid charge rate. In its filing, the utility should quantify, on a dollar-per-kWh basis, the distinct functionalized[225] as well as classified[226] cost components that are currently recovered via the volumetric rates applicable to its rate schedules. In spreadsheet format with formulas linked to supporting sources, the utility shall present, by month, each rate schedule's volumetric rate[227] decomposed into constituent costs.

In its application for its revised grid charge rate, the utility shall identify all energy and capacity benefits that offset any avoided or unrecovered distribution-related demand costs. To evaluate energy benefits, the utility shall quantify the benefit associated with avoided incremental fuel costs, as represented by the hourly locational marginal prices from MISO, SPP, or both, as applicable.[228] Additionally, any benefit associated with avoided incremental fuel costs shall include avoided distribution line losses consistent with

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[225] Primarily production (generation) , transmission, distribution, and customer service.
[226] Primarily demand, energy, and customer.
[227] Levelized (or blended) for rate schedules with block rates.
[228] The calculation shall be presented in the same manner as identified in the Phase 2 discussion of the Excess Generation Credit Methodology in the Net-Metering Working Group Sub-Group 2 Recommendations, Attachment B to the Joint Report and Recommendations of the Net=Metering Working Group (Doc. 228) at pages 168-176.

the cost allocation methodology underlying the utility's current rates.[229] To evaluate capacity benefits, the utility should calculate on a dollar-per-kWh basis for each applicable rate schedule, consistent with the cost allocation methodology, an embedded capacity credit based upon a Net-Metering Facility's maximum production capability during system peak hours.[230]

The revised grid charge rate established by the Commission in such proceeding shall apply going forward to the usage of all Net-Metering Customers with facilities which are approved to exceed the 1 MW statutory limit after the date of this Order (except for those Net-Metering Facilities which are grandfathered).[231]

To the extent that a utility believes that its existing demand charge is not properly covering its demand costs and needs to be adjusted, the utility may propose re-determined demand charges in a general rate case. Likewise, proposals for TOU rates or separating Net-Metering Customers into their own class should be addressed in a general rate case.

d. Grandfathering of Net-Metering Rate Structure

Staff Comments and Strawman: Staff's Strawman Rule 2.07 adheres to the strict provisions of Act 464 in providing for grandfathering for the two categories of Net-Metering Customers with generating capacity up to 1 MW (customers with and without a demand component). For customers with a demand component that request a waiver to exceed the statutory limits pursuant to Ark. Code Ann. § 23-18-604(b)(9), Staff recommends that the Commission consider and approve grandfathering rate structures on

[229] Id.
[230] Id.
[231] And with the exception of customers who are grandfathered under the exception to Rule 2.07 in the following section III.B.1.d.

a case-by-case basis. Staff Surreply (Doc. No. 400) and revised Strawman Rule 2.07.C., Exhibit A at 41.

AG: The AG states that Act 464 establishes three levels of grandfathering: Level 1 — Net-Metering Facilities approved before July 24, 2019, which are automatically grandfathered (although Act 464 does not say for how long). Level 2 – Net-Metering Facilities submitted after Act 464 became effective and before December 31, 2022, which facilities must obtain Commission approval that would be for no more than twenty years. Level 3 – facilities that are submitted after December 31, 2022, and do not qualify for grandfathering. AG Surreply (Doc. No. 396) at 6-7.

EAL: EAL asserted in Initial and Reply Comments that the phrase "subject to approval by a [C]omission" in Act 464 means that the Commission must approve all Net-Metering projects on a case-by-case basis. As noted in the summary of EAL's position on the grid charge issue above, EAL recommends in Surreply Comments that the Commission adopt 2-channel billing and grandfather all facilities approved, interconnected, and operational before an order in Phase 3 for a period of no longer than ten years at the 1:1 full retail credit. EAL Surreply (Doc. No. 401) at 23-27.

SWEPCO: SWEPCO believes the Commission is required to approve every project seeking to be grandfathered. SWEPCO Reply (Doc. No. 399) at 10.

OG&E: OG&E recommends that grandfathering decision should remain subject to Commission approval on a case-by-case basis, with the choice and length of time for any grandfathering decision based on a public interest finding. OG&E supports the Level 2 and 3 explanation of grandfathering provided by the AG. OG&E believes that grandfathering should apply only to the Net-Metering Customer and not the facility. OG&E finds

Distributed Solar Advocates' and Scenic Hill Solar's recommendation to strike "subject to approval of the Commission" to be in direct contradiction to Act 464 and inherently flawed. OG&E Reply (Doc. No. 363) at 7-8.

Empire: Empire takes no specific position on grandfathering.

AECC: AECC states that grandfathering should not be approved by the Commission for any Net-Metering Facility, absent the case-by-case, Act 464-required individual facility/customer showing that a guaranteed, long-term, higher energy payment will serve the public interest. AECC Reply (Doc. No. 365) at 10.

Distributed Solar Advocates: Distributed Solar Advocates recommends striking the phrase "subject to approval by the [C]omission" to make it clear the Commission is not required to engage in case-by-case grandfathering. They agree with Staff's explanation in its Reply Comments that "[t]o promote administrative efficiency and effectuate the policy goals of Act 464, the Commission should make some grandfathering automatic, as it did in Order No. 10...." They urge the Commission to exercise its discretion regarding the term of years for customers beginning in 2023 for the same fairness reasons cited by the Commission in Order No. 10 of this Docket. Distributed Solar Advocates Surreply (Doc. No. 404) at 13-15.

Scenic Hill Solar: Scenic Hill Solar supports the positions presented in the Reply Comments of the Distributed Solar Advocates. Scenic Hill Solar Surreply (Doc. No. 403) at 1.

AEEC: AEEC recommends that the Commission replace Staff's Strawman language in Rule 2.07 with language that actually resolves the controversy surrounding the meaning of the phrase "subject to the approval of the [C]omission." AEEC believes Act 464 requires the Commission to decide on a case-by-case basis whether a Net-Metering Facility is grandfathered and recommends that the Commission not grandfather any more facilities. AEEC Initial Comments (Doc. No. 402) at 4, Reply (Doc. No. 378) at 5, Surreply (Doc. No. 402) at 7.

William Ball: Mr. Ball supports the existing plan of Act 464 to extend grandfathering of Net-Metering under the 1:1 full retail credit until December 31, 2022, is prudent and consistent with the scheduled decline in the federal tax credit. Ball Reply (Doc. No. 382) at (unnumbered) 6.

Findings:

The Parties place disparate and wide-ranging interpretations on the meaning and applicability of grandfathering under Act 464.

As the Commission previously observed in this Order in its interpretation of the impacts of Act 464 on grandfathering, Ark. Code Ann. § 23-18-604(b)(10)(A) codifies the ability of the Commission to grandfather Net-Metering Facilities under an existing Net-Metering rate structure. The Commission finds that Act 464 codified and expanded the grandfathering provision in Order No. 10. Proposed Rule 2.07 on grandfathering has therefore been revised to reflect Act 464 and the holdings of Order No. 10. The Commission affirms that the eligibility for grandfathering is based on the date the customer submits a signed Standard Interconnection Agreement to the utility.

Net-Metering Facilities Below Statutory Limits[232]

On the subject of the provision at the end of subdivision Ark. Code Ann. § 23-18-604(b)(10)(A) that provides for grandfathering "subject to approval by a commission," the Commission interprets this language as requiring Commission approval of the specific

[232] Reference Ark. Code Ann. § 23-18-603(8) (B)(i) and (ii).

terms of grandfathering, including the appropriate period of years, and that by Order No. 10 the Commission has already approved a grandfathering period of twenty years (from the date of the order adopting a different Net-Metering rate structure – *i.e.*, the date of this Order) for all Net-Metering Facilities that have generating capacity under the pre-Act 464 statutory limit of 25 kW for residential facilities and 300 kW for non-residential Net-Metering Facilities served under a rate with a demand component. Under Order No. 10, the Commission required case-by-case decisions on grandfathering for Net-Metering Facilities exceeding the 300 kW limit. As before, the Commission has the option under Act 464 to grandfather individually or as a group, as it did in Order No. 10. Now that Act 464 has raised the statutory limit to 1,000 kW for non-residential customers, and because customers pursuing projects within these size limits are legislatively exempted by Act 464 from even applying to the Commission for approval to install such facilities, the Commission does not require such customers to seek grandfathered status by filing with the Commission – the grandfathering is automatic. The Commission finds for purposes of administrative efficiency and certainty that the grandfathering period shall be twenty years from the date of this Order for the following categories of facilities: (1) all existing Net-Metering Facilities with generating capacity below the pre-Act 464 or Act 464 (as applicable) statutory limits approved or installed prior to the effective date of this Order; and (2) all Net-Metering Facilities with generating capacity below the Act 464 statutory limits where the Net-Metering Customer has submitted to the Electric Utility a signed Standard Interconnection Agreement between the date of this Order and December 31, 2022.[233]

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[233] The Net-Metering Facilities of these customers remain subject to any other change or modification in rates, terms, and conditions. Ark. Code Ann. § 23-18-604(b)(10)(B).

Net-Metering Facilities Exceeding Statutory Limits

For Net-Metering Customers seeking approval on a case-by-case basis to exceed the statutory limits and to be grandfathered under the Net-Metering rate structure as of the date of the customer's submission to the Electric Utility of a signed Standard Interconnection Agreement, the Commission reaffirms its authority and discretion to approve grandfathering periods up to twenty years for these large-customer facilities, if the Net-Metering Facilities are determined to be in the public interest, including a finding that they will not result in an unreasonable allocation of costs to other customers, pursuant to Ark Code Ann. § 23-18-604(b)(9)(A) and (b)(9)(B). This eligibility shall apply where the Net-Metering Customer has submitted to the Electric Utility a signed Standard Interconnection Agreement before December 31, 2022. Where the Standard Interconnection Agreement is submitted before the date of this Order, the Net-Metering Facility is eligible to be grandfathered under the 1:1 Net-Metering retail rate credit. Where the Standard Interconnection Agreement is submitted on or after the date of this Order but before December 31, 2022, the Net-Metering Facility is eligible to be grandfathered under the 1:1 Net-Metering retail rate credit plus a grid charge as set forth in Section III.B.1.a.

Rule 2.07 is further revised to clarify the eligibility for grandfathering of proposed upgrades to these large Net-Metering Facilities.[234] The Rule allows the original generating capacity to retain its grandfathered status, if any, but provides that additional generating capacity approved is subject to the new Net-Metering rate structure, *i.e.*, a grid charge. With this provision, there is no disincentive to upgrade because the facility will not lose any grandfathered status for the original capacity, but the Commission retains the ability

[234] Order No. 10 had allowed upgrades to facilities below the statutory limits so long as the facilities continued to meet the statutory definition of a Net-Metering Facility, but did not address large facilities exceeding the statutory limits.

to review and approve the upgrade based on the statutory factors. The Rule also specifies that the cost of any additional metering equipment necessitated by grandfathering the original capacity but not the additional capacity must be borne by the Net-Metering Customer as the cost-causer.

The Commission finds that it is in the public interest to waive the application of this holding and the adopted rule in one instance. The Commission finds that it is reasonable to allow a customer who has submitted a PISRR to the utility before the date of this Order, but has not yet submitted a signed Standard Interconnection Agreement, to be eligible to be grandfathered on the existing 1:1 retail rate credit when that customer petitions the Commission for approval to exceed the statutory limit. This interpretation is consistent with the Commission's determination in Order No. 10 that this approach ensures that the utility will not unduly delay its own approvals in order to defeat the Net-Metering Customer's eligibility for grandfathering. Order No. 10 (Doc. No. 212) at 146. The PISRR whose submission to the Electric Utility establishes the grandfathering date under the statute should be associated with the specific site which is ultimately selected for the Net-Metering Facility. However, if circumstances arise which prevent a customer from siting the Net-Metering Facility at the location proposed by the PISRR (for reasons such as economic or technical concerns) and the customer submits another PISRR within a reasonable time after the date of this Order, the customer may apply to the Commission for permission to grandfather the substitute Net-Metering Facility into the Net-Metering rate structure in effect when the original PISRR was submitted. The substitute Net-Metering Facility cannot exceed the generating capacity identified in a PISRR submitted before the date of this Order. Consistent with the current NMRs and Order No. 10, each customer applying to exceed the statutory limits and who desires to be grandfathered should submit with its application a request and proof of eligibility of grandfathering. Appropriate terms and conditions for grandfathering, including the term of years, shall be established for each customer based on the evidence in the case under Ark. Code Ann. § 604(b)(10)(A).

Customers after December 31, 2022

For Net-Metering Customers who execute a Standard Interconnection Agreement after December 31, 2022, the Commission finds that it is premature to address grandfathering for those Net-Metering Facilities at this time. If the rate structure for Net-Metering changes after December 31, 2022, the Commission will address at that time whether those facilities should be grandfathered at their then-current Net-Metering rate structure.

e. Ownership of Renewable Energy Credits (RECs)

Staff Comments and Strawman: Staff proposes retention of the existing NMR Rule 2.04.E. that recites the existing AREDA provision that 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 REC. Staff states that development of clean and renewable solar energy provides broad benefits to society regardless of who retains the RECs that are produced by solar development. According to Staff, although Arkansas does not currently have renewable energy standards or goals that are tied to the accounting of RECs, any ability for the customer, utility, or the state to count these Net-Metering Facilities as "renewable energy" lies with the holding or retiring of the REC. Therefore, Staff recommends that the Net-Metering Consumer Guide should inform Net-Metering

Customers that they are not required to simply hand over any RECs that they own to the utility, or third-party solar developer. Staff Reply (Doc. No. 388) at 12-13.

AG: The AG takes no specific position regarding the ownership of RECs and retains the existing statutory provision (unchanged by Act 464) in its draft NMR strawman. AG Initial (Doc. No. 362) Appendix A, AG Strawman Rule 4(4).

EAL: EAL recommends that all RECs be retained by the customer whose energy the Net-Metering Facility is offsetting and not be assigned to the third-party solar developer, noting that this is what it requires for EAL's grid-scale solar facilities. EAL asserts that without retention of the REC, the energy produced by a Net-Metering Facility is effectively not renewable energy for the utility or its customers (including non-Net-Metering Customers). EAL Initial Comments (Doc. No. 383) at 21-26.

Distributed Solar Advocates: Distributed Solar Advocates take the position that the contested issue regarding retention of RECs need not be resolved in this proceeding in order to implement Act 464. Distributed Solar Advocates Surreply (Doc. No. 404) at 2.

William Ball: Mr. Ball states that RECs belong to the customer, not the developer or utility. He asserts that trying to cast doubt on who owns the RECs is a distraction, given that Arkansas does not have a renewable portfolio standard and RECs have little economic value. He notes that RECs can only be sold by the owner, whether with the help of the developer or not. If they are sold, he states, only the purchaser of the RECs can claim their environmental attributes. He asks whether if the customer decided to give the RECs to the utility, would the utility claim the customer is not actually using (or purchasing) renewable energy, and that the customer is thus simply ineligible for Net-Metering? Mr. Ball has no objection with the customer transferring REC ownership to the utility at the customer's discretion. Ball Reply (Doc. No. 382) at (unnumbered) 4.

Findings:

The Commission accepts Staff's recommendation to retain existing NMR Rule 2.04.E that recites the AREDA provision that any REC created as a result of electricity supplied by a Net-Metering Customer is the property of the Net-Metering Customer that generated the REC. The Commission agrees with Staff that in the absence of any state renewable portfolio standard or goals that are tied to the accounting for RECs, any ability for the customer, utility, or the state to count these Net-Metering Facilities lies with the holding or retiring of the REC. The Commission further agrees with Staff that the Net-Metering Consumer Guide to be developed as a customer protection tool should inform Net-Metering Customers that they are not required to transfer any RECs that they own to the utility or third party solar developer. The Commission defers any decision regarding whether the energy produced by a Net-Metering Facility that does not retain the REC is renewable energy for the utility or its customers (including non-Net-Metering Customers).

2. Leases, Service Contracts (PPAs), and Safe Harbor

Staff Comments and Strawman: Staff agrees with Distributed Solar Advocates that there should be a streamlined process to determine eligibility of leased facilities or those managed under service contracts. Staff proposes that the Commission approve a standard form and affidavit for customers to certify that they meet the specific requirements to qualify for safe harbor,[235] similar in format to the Act 253 Notice and Affidavits[236] used in the energy efficiency (EE) dockets. In contrast to the requirements in the EE dockets,

[235] Ark. Code Ann. § 23-18-603(7)(C).
[236] The Act 253 Notice and Affidavit may be found at: http://www.apscservices.info/pdffiles/Act253of2013-Affidavit2019.pdf

however, Staff does not believe the NMRs should require such Notice and Affidavits to be filed with the Commission. Staff recommends that the Notice and Affidavit should certify that the Net-Metering Customer meets the safe harbor requirements of the Internal Revenue Service and Office of Management and Budget. For convenience, Staff proposes that the Notice and Affidavit for Safe Harbor should be added to the standard form Staff proposes to designate common ownership for meter aggregation, so as to allow the Net-Metering Customer to check all that apply (*e.g.*, common ownership, safe harbor, etc.). Staff agrees with EAL and Distributed Solar Advocates that the Commission should designate Staff to review the agreements and attempt to resolve disputes regarding eligibility, including by confirming whether the agreements meets the eligibility requirements of safe harbor, as an administratively efficient process. Staff notes that the Notice and Affidavit for facilities over 1 MW will already be subject to review as part of the application for Net-Metering. However, Staff states, Commission review should occur for those facilities under the statutory maximum of 1 MW only after the utility submits a formal complaint or otherwise presents evidence under the RPPs that the Net-Metering Customers Notice and Affidavit asserting safe harbor lacks merit. Staff Surreply (Doc. No. 400) at 17-18.

EAL: EAL argues that the Commission is required to review each lease and service contract (which it characterizes as a Power Purchase Agreement (PPA)) to see if they meet the requirements of Act 464. EAL recognizes that this is a daunting task given the flood of interconnection requests that has been occurring with EAL and other utilities. EAL suggests several alternative options for leases, including (1) establishing a review process for lease agreements to be submitted to Staff and the utility to ensure compliance; or (2) establishing a form agreement that either must be used or that, if used, would allow the Net-Metering Customer to forgo Commission review. EAL raises several more complicated issues regarding contracts, noting the need under Act 464 for the Commission to interpret and apply federal law provisions governing qualification for safe harbor protection. EAL notes that standard form contracts may be another option to facilitate the required Commission review, but notes that that option will not be available to review the numerous contracts that developers have already rushed to get executed in advance of any changes to Net-Metering, with the hope that customers can get the current Net-Metering framework grandfathered. EAL Initial (Doc. No. 367) at 54-57.

SWEPCO: SWEPCO recommends that the Commission adopt additional rules or guidelines regarding eligibility and criteria for leases. SWEPCO Initial (Doc. No. 370) at 14.

Findings:

The Commission finds reasonable Staff's comments agreeing with Distributed Solar Advocates that there should be a streamlined process for the determination of eligibility of leased facilities or those managed under service contracts. The Commission also agrees with Staff's proposal that the Commission approve a standard form and affidavit for Net-Metering Customers to certify that they meet all federal and state requirements to qualify for safe harbor eligibility under Act 464. The Commission further agrees with Staff that, for convenience, the Notice and Affidavit for Safe Harbor should be added to the standard form Staff proposes to designate common ownership for meter aggregation, so as to allow the Net-Metering Customer to check all that apply (*e.g.*, common ownership, safe harbor, etc.).

The Commission also agrees with EAL and Distributed Solar Advocates that the Commission should designate Staff to review the agreements and attempt to resolve disputes regarding eligibility, including by confirming whether the agreements meet the eligibility requirements of safe harbor, as an administratively efficient process. The Commission further agrees with EAL's suggestion that the following alternatives may facilitate the process of verifying that leases and service contracts meet Act 464 requirements and that federal law provisions governing qualification for safe harbor protection are met: (1) establishing a review process for lease and contract agreements to be submitted to Staff and the utility to ensure compliance; (2) establishing a form agreement that, if used, would allow the Net-Metering Customer to forgo Commission review of leases and contracts; and (3) standard form contracts to facilitate Staff and Commission review. In addition, the Commission finds that, to facilitate Staff's review, Net-Metering Customers claiming safe harbor status should be required to present evidence that all federal and state requirements have been met if a dispute arises.

The Commission agrees with Staff's observation that the Notice, Application, and Affidavit for Net-Metering Facilities exceeding the 1 MW statutory limit will already be subject to review as part of the application for Net-Metering. For facilities under the 1 MW statutory maximum, the Commission finds reasonable Staff's recommendation that Commission review for those facilities should occur only after the utility submits a formal complaint or otherwise presents evidence under the RPPs that the Net-Metering Customer's Notice and Affidavit asserting safe harbor lacks merit. The Commission directs Staff and the interested parties to confer and refine their proposals for standard forms to provide the flexibility to make changes as the number of Net-Metering interconnection requests grows. Given the need to explore and refine the options and to maintain administrative efficiency, the Commission declines at this point to adopt as part of the NMRs a specific Notice, Application Form, and Affidavit addressing leasing and service agreements, safe harbor, and meter aggregation, but suggests as a starting point for the Parties' discussions on these issues Staff's Strawman Rule 2.08 (Safe Harbor), as well as EAL's Strawman Rule 2.10 (Leasing and Service Agreements). The Commission directs that Staff, after consultation with other Parties, submit proposals for such standard form documents within 90 days from the date of this Order.

Accordingly, the Commission approves Staff's Strawman Rules 2.08 (Safe Harbor) as modified to consolidate subsections A and B and incorporate the informal resolution process and modified to incorporate similar provisions on leases.

3. Common Ownership and Meter Aggregation

Staff Comments and Strawman: Staff agrees with the position of Distributed Solar Advocates that customers seeking to aggregate meters should be allowed to indicate common ownership. Staff proposes Strawman Rule 2.05 to address Meter Aggregation. Staff takes the position that utilities should be prohibited from requiring common tax ID numbers, since more than one tax ID number can be under common ownership. However, Staff does not believe that customer's signature is enough proof. Staff recommends adopting a standard ownership form and sworn affidavit, the veracity of which the utility would be allowed to question under the RPPs through the filing of a request for declaratory order or formal complaint. Staff recommends that the Commission approve the ownership form and sworn affidavit that Staff proposed in its Reply Comments. Based on comments regarding delays in the interconnection process, Staff strongly supports that a clear, streamlined, auditable, and therefore readily enforceable approach is essential. Staff Reply at 11-12, Staff Surreply (Doc. No. 400) at 13-14, and revised Strawman Rule 2.05.D.

EAL: EAL defines "common ownership" as accounts which have the same tax ID number (a residential customer's Social Security Account Number or a non-residential customer's federal EIN). EAL Initial at 38-44. EAL recommends continuation of its current practice of requiring a customer to demonstrate the same tax ID for any aggregated accounts. With respect to customers with a demand component, EAL recommends that the Commission adopt Staff's recommendation requiring an affidavit, supported by appropriate documentation, to demonstrate common ownership, and that is subject to reasonable and justifiable challenges. EAL Surreply (Doc. No. 401) at 14-16.

AECC: AECC asserts that under Ark. Code Ann. § 23-18-604(c)(2)(A)(ii), meter aggregation does not apply if more than two government or tax-exempt customers co-locate. AECC argues that this subdivision of Act 464 prohibits rather than promotes meter aggregation, but does not address whether meter aggregation is applicable if one or two such entities seek to aggregate meters. AECC Initial (Doc. No. 365) at 4-5.

Distributed Solar Advocates: Distributed Solar Advocates do not support requiring tax IDs to confirm common ownership, stating that a customer's name, number, and signature are sufficient to verify common ownership. Distributed Solar Associates agrees with Staff's modification to their proposal regarding how common ownership should be determined. Distributed Solar Advocates Initial Comments (Doc. No. 374) at 5-6 and Surreply (Doc. No. 404) at 18.

William Ball: Mr. Ball argues that EAL's request that all meters aggregated for the purpose of Net-Metering should be under a common tax ID is a red herring and an attempt to suppress Net-Metering. Ball Reply (Doc. No. 382) at (unnumbered) 4.

Findings:

The Commission agrees with the position of Staff and Distributed Solar Advocates that customers seeking to aggregate meters should be allowed to indicate common ownership and that utilities should be prohibited from requiring common tax ID numbers, since more than one tax ID number can be under common ownership. However, the Commission also agrees with Staff that the customer's signature is not sufficient proof of common ownership. The Commission finds reasonable Staff's recommendation in its Strawman Rule 2.05 that the Commission develop and adopt standard Application and Sworn Affidavit forms, whose veracity the utility would be allowed to question under the RPPs through the filing of a request for declaratory order or formal complaint. The Commission approves Staff Strawman Rule 2.05, as modified, to address Meter Aggregation and, as with the Notice and Affidavit for leases, service contracts, and safe harbor discussed above, directs Staff, after consultation with other Parties, to propose for Commission approval a standard form Application and Sworn Affidavit as proof of Meter Aggregation and Common Ownership within 90 days from the date of this Order. The Commission further finds that Staff's Strawman Rule 2.05(C) properly implements the provisions of Ark. Code Ann. § 23-18-604(c)(2)(A)(ii).

4. Remote Facilities

Staff Comments and Strawman: Staff asserts that the plain text of Act 464 grants the Commission discretion to allow remote generators to qualify for Net-Metering.

Responding to EAL's observation that the current NMRs define "Generation Meter" as "the meter associated with the Net-Metering Customer's account to which the Net-Metering facility is physically attached,"[237] Staff states that this definition does not answer the remote facility question. Staff states that the relevant issue is not whether the Generation Meter has to be attached to the Net-Metering Facility, but whether the Net-Metering Facility must also be physically attached to the facility using electricity. According to Staff, Act 464 only requires this type of physical attachment between the Net-Metering Facility and the facility using electricity for governmental entities claiming safe harbor protections.[238] Staff Surreply (Doc. No. 400) at 14.

Staff takes the position that the General Assembly's decision to expand AREDA and allow Net-Metering Customers to lease a Net-Metering Facility demonstrates the legislative intent to allow Net-Metering for remote facilities, which is consistent with the policy goals of AREDA. Staff notes that behind-the-meter facilities provide more benefits to the grid than remote facilities, which export all their generation to the grid and therefore would need the grid to provide more transmission and distribution capacity. Staff states that utilities could recommend adding a grid charge to the interconnection of remote Net-Metering Facilities to account for this use of the grid. Staff asserts that questions of qualification as a Net-Metering Facility, including a remote facility, are within the primary jurisdiction of the Commission and should not be unilaterally determined by a utility. Staff states that utilities have the obligation to timely accept and process Net-Metering applications and *should* begin "blindly" accepting and processing purported "net metering" applications regardless of whether they are properly considered Net-Metering

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[237] EAL Reply (Doc. No. 383) at 27.
[238] Ark. Code Ann. § 23-18-603(7)(C).

arrangements.[239] Staff states that a utility that questions the qualifications of a Net-Metering customer or facility should present the question to the Commission for consideration rather than engage in dilatory tactics. Staff points to Strawman Rule 2.05(B)(4) as providing that applications for a Net-Metering Facility above statutory limits require a copy of the "Preliminary Interconnection Site Review Request submitted to the Electric Utility and the results of the utility's interconnection site review…." According to Staff, a utility's unilateral determination of Net-Metering qualifications in its processing of Preliminary Interconnection Site Review Requests necessarily delays a customer's application and the Commission's review of their qualifications. *Id.* at 14-17.

EAL: EAL asserts that from a Net-Metering standpoint, the sole purpose of a two-direction, or bi-directional, meter is to allow the measurement of electricity flowing in both directions, adding that this provision only applies in a circumstance where the load and the generator are behind the same meter; otherwise, EAL asserts, there is simply no "flow of electricity in two (2) directions." Therefore, EAL contends, there can be no reasonable dispute that the General Assembly contemplated and that AREDA requires Net-Metering Facilities to be located behind a customer's meter where there is actual usage to record and where the flow of the net-metered generation can offset the customer's load at that location. EAL argues that permitting physical separation of the generator and the load against which it is Net-Metered would open the door for retail wheeling in potential violation of applicable FERC rules and federal law. EAL Initial (Doc. No. 367) at 45-46. For these reasons, EAL asserts that the Commission should retain the definition of Generation Meter currently included in the NMRs and clarify that a Net-Metering Facility

[239] Staff is responding to EAL Reply Comments at 11, fn 18.

must be physically attached to the customer's load in order to qualify for Net-Metering. EAL Reply (Doc. No. 383) at 28.

William Ball: Mr. Ball contends that meter aggregation is not retail wheeling, as the customer's facility is offsetting part or all of their energy requirements, regardless of whether their meter is located behind the meter or at a location with no customer load. Ball Reply (Doc. No. 382) at (unnumbered) 2.

Findings:

EAL asserts that AREDA, as amended by Act 464, requires Net-Metering Facilities to be located behind a customer's meter where there is actual usage to record and where the flow of the net-metered generation can offset the customer's load at that location, citing the current NMR definition of "Generation Meter."[240] OG&E supports EAL's argument that any net-metered facility must be behind the customer's meter and must displace some amount of electricity that the customer consumes. Staff responds that the definition of "Generation Meter" in the existing NMRs (and unchanged in Staff's Strawman NMRs) does not answer the remote facility question. The Commission finds that the relevant issue is not whether the generation meter has to be attached to the Net-Metering Facility (because by definition, it does), but whether the Net-Metering Facility and generation meter must also be physically attached to the customer's facility using electricity. The Commission finds that the generation meter does not have to be physically attached to the facility using electricity but agrees with Staff that behind-the-meter facilities provide more benefits to the grid than remote facilities that export all their generation to the grid and therefore need the grid to provide more transmission and

[240] EAL Reply at 27. The Commission notes that Act 464 did not change this definition, which is in the current NMRs and has not been proposed for change by any Party.

distribution capacity. The Commission also agrees with Staff that utilities could recommend adding a charge to the interconnection of remote Net-Metering Facilities to account for this use of the grid and notes that this option will be available to utilities either under the grid charge mechanism that the Commission adopts as an option for utilities in Section 1.C. of these findings or under Ark. Code Ann. § 23-18-604(b)(4).

The Commission further finds, as Staff recommends, that questions of qualification as a Net-Metering Facility, including a remote facility, are within the primary jurisdiction of the Commission and should not be unilaterally determined by a utility. A utility that questions the qualifications of a Net-Metering Customer or Facility should present the question to the Commission for consideration.

The Commission accepts Staff's Strawman Rule 2.06(B)(4), which provides that applications for a Net-Metering Facility above statutory limits require a copy of the "Preliminary Interconnection Site Review Request submitted to the Electric Utility and the results of the utility's interconnection site review…" and agrees that a utility's unilateral determination of Net-Metering qualifications in its processing of such Requests necessarily delays a customer's application and the Commission's review and decision regarding their qualifications.[241] Based upon this finding, which is consistent with comments and recommendations of Scenic Hill Solar,[242] the Commission directs the Electric Utilities to conduct their review of PISRRs purely on the basis of the proposed Net-Metering Facility's technical feasibility. To implement these findings, the Commission approves Staff Strawman Rule 2.06.A.2., which provides:

[241] Staff Surreply at 14-17.
[242] Scenic Hill Solar Reply at 20-21.

2. For purposes of Rule 2.06(A)(1), "generation capacity" includes the aggregate ability to produce electricity from all Net-Metering Facilities under common ownership that are located within a single utility's service territory.

The Commission rejects EAL's interpretation that the definition of "Generation Meter" means that a Net-Metering Facility must be physically attached to the customer's load in order to qualify for Net-Metering and thus need not address EAL's assertions that permitting physical separation of the generator and the load against which it is Net-Metered would open the door for retail wheeling in potential violation of applicable FERC rules and federal law. The Commission does not adopt EAL's Strawman amendment to Rule 2.01 that would provide that "an electric utility is not required to interconnect a customer installing a renewable facility that is not connected to load."

5. Oversizing of Net-Metering Facilities

EAL: EAL argues that the sizing of Net-Metering Facilities should be limited to what is necessary to meet no more than the customer's usage for the 12 months prior to interconnection, noting that its experience has been that solar developers will exhort the customer to install the largest facility possible, often asking EAL to consider a customer's usage based on future hypotheticals that EAL has no way to verify. EAL Initial (Doc. No. 367) at 46-47. In Surreply, EAL argues that for demand-component customers the Commission should set the maximum size equal to the capacity to generate no more than 25 percent net exports based on the customer's annual solar production compared to annual usage. EAL Surreply at 17-18. For non-demand customers, EAL proposes use of the customer's prior 12 months of energy usage to calculate the maximum size. *Id.* at 18-19. EAL asserts that sizing of the Net-Metering Facility is a matter where gaming can occur absent clear direction from the Commission, noting that Act 464 provides that the

Net-Metering Facility is "intended primarily to offset part or all of the net-metering customer requirements for electricity."[243] EAL cites the Commission Chairman's statement in support of the legislature's maintenance of the limitation on quantity, stating that a customer is not supposed to build more than it needs and finance that by selling to others.[244] EAL agrees with SWEPCO's observation in Initial Comments that "there is no dis-incentive at this time to oversizing a system. Rather, conditions have changed in a way that makes one-for-one netting and cost payment an inducement to oversizing."[245] EAL Reply (Doc. No. 383) at 28-29.

SWEPCO: SWEPCO supports adopting rules to prevent oversizing a project, suggesting penalties or termination of the interconnection agreement as a remedy. SWEPCO Reply (Doc. No. 381) at 12-13.

Findings:

EAL and SWEPCO raise concerns about the oversizing of Net-Metering Facilities. EAL contends that the sizing of Net-Metering Facilities should be limited to what is necessary to meet no more than the customer's usage for the 12 months prior to interconnection, noting that its experience has been that solar developers will exhort the customer to install the largest facility possible, often asking EAL to consider a customer's usage based on future hypotheticals that EAL has no way to verify. EAL proposes that for demand-component customers the Commission should set the maximum size equal to the capacity to generate no more than 25 percent net exports based on the customer's annual solar production compared to annual usage. For non-demand customers, EAL proposes

[243] Ark. Code Ann. § 23-18-604(a).
[244] Testimony of Chairman Ted Thomas in support of Senate Bill 145 on February 14, 2019, before the House Insurance and Commerce Committee (quote from audio transcript at 10:39:38).
[245] SWEPCO Initial at 9.

use of the customer's prior 12 months of energy usage to calculate the maximum size of the Net-Metering Facility.

Ark. Code Ann. § 23-18-603(8)(E) requires that the Net-Metering Facility must be "intended primarily to offset part or all of the net-metering customer requirements for electricity," which is unchanged by Act 464. Just as before Act 464, unresolved conflicts about the proper sizing of a facility may be brought before the Commission. The Commission finds no support in AREDA or Act 464's amendments to institute EAL's additional constraints on the size of Net-Metering Facilities and thus does not adopt EAL's proposed new language on this point in its Strawman Rule.

6. Gaming

Staff Comments and Strawman: Staff agrees with other Parties that rules should be developed to prevent large projects from being broken up into smaller ones to avoid Commission review, and proposes a new NMR Section 5 – Rules to Guard Against Gaming. Staff's Strawman proposed Rule 5.01 adopts a modified version of a gaming proposal by AECC and broadly defines the term "Facility" for the purpose of determining generation capacity limits; Rule 5.02 prohibits gaming of the NMRs; and Rule 5.03 provides penalties for gaming: suspension or termination of qualification as a Net-Metering Customer, following notice and hearing. Staff Surreply (Doc. No. 400) and revised Strawman at Section 5. Staff recommends that the Commission clarify that, absent evidence to the contrary proffered by the Net-Metering Customer, multiple Net-Metering Facilities under common ownership within a single utility's service area will be treated as a single facility for the purpose determining whether the facility exceeds the 1 MW capacity limit provided by Ark. Code Ann. § 23-18-603(8)(B)(ii) and is thus subject to Commission approval pursuant to Ark. Code Ann. § 23-18-604(b)(9). *Id.* at 7-8.

Staff further recommends that Rule 2.06(A) of the NMRs regarding an Application to Exceed Generating Capacity Limit be amended to incorporate a new protection against gaming, providing that "For purposes of Rule 2.06(A)(1), "generation capacity" includes the aggregate ability to produce electricity from all Net-Metering Facilities under common ownership that are located within a single utility's service territory." Staff asserts that this modified version of AECC's proposal of an account- and service-territory-wide bubble concept for the definition of generation facility is consistent with the statutory text, which allows facilities to be aggregated for the purposes of billing (*i.e.*, "meter aggregation") if they are "under common ownership within a single electric utilitiy's service area."[246] *Id*. at 8-10.

Staff agrees with Distributed Solar Advocates that, for the sake of consistency, "if a collection of entities are not deemed commonly owned such that they can aggregate across meters, then they should not be deemed commonly owned for the purpose of gaming rules around co-located facilities."[247] However, Staff states, a customer's decision whether or not to aggregate meters should not exclude them from Commission review if the aggregate capacity of their facilities exceeds 1 MW within a particular utility's service area. Staff states that tying capacity limits to a customer's decision to aggregate would be inefficient from an administrative standpoint, since a customer could change his or her decision to aggregate at any point, but the Commission's review of facilities that exceed the 1 MW generation capacity limit must necessarily take place before any Net-Metering occurs.

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[246] Ark. Code Ann. § 23-18-604(c)(2)(A)(i).
[247] Distributed Solar Advocates Reply at 30.

Therefore, Staff asserts, its proposed rule additions address gaming in a manner that provides consistency and administrative efficiency for the purpose of Commission review. *Id*. at 10-11.

EAL: EAL believes that gaming is currently occuring – breaking up a large project into multiple less-than-1 MW projects to stay below the threshold for Commission review. EAL Initial (Doc. No. 363) at 58. EAL recommends that the Commission clarify that multiple Net-Metering Faciltiies owned by a single customer (tax ID) are considered a single project for Commission review and approval. EAL Surreply (Doc. No. 383) at 15.

SWEPCO: SWEPCO supports adopting rules to prevent gaming. SWEPCO Reply (Doc. No. 381) at 12.

OG&E: OG&E supports developing rules against gaming of the new 1 MW threshold and supports EAL's argument that any net-metered facility must be behind the customer's meter and must displace some amount of electricity that the customer consumes. OG&E Reply (Doc. No. 370) at 12.

AECC: AECC states that the statutory limits imposed by Act 464 should be respected and should not be circumvented to avoid Commission review, and the utilities should have the right – just as they do for meter tampering – to disconnect Net-Metering Facilities that violate the NMRs or engage in gaming. To provide better protection, AECC recommends and provides its own proposed Strawman Gaming Section 5 be included in the NMRs. In particular, AECC's proposed Rule 5.03(E)(1) states:

> Any facilities used for Net-Metering being credited to a customer's account regardless of the location of the facility and its aggregation, will be treated as a single facility and must comply with the imposed capacity and/or sizing limits under these Rules.

AECC Initial (Doc. No. 365) at 10-11 and Appendix B.

William Ball: Mr. Ball asserts that it is disingenuous of the utilities to accuse renewable developers of gaming a system in which the utilities hold all the cards. He supports consumer protection language in the NMRs protecting renewable energy developers from utilities that are contacting customers to offer lower costs if the utilities do the project instead of the private solar company. Ball Reply at (unnumbered) 5.

Findings:

The Commission adopts Staff's recommendation to amend Rule 2.06(A) of the NMRs regarding an Application to Exceed Generating Capacity limit to incorporate a new protection against gaming, providing that:

> For purposes of Rule 2.06(A)(1), "generation capacity" includes the aggregate ability to produce electricity from all Net-Metering Facilities under common ownership that are located within a single utility's service territory.

The Commission agrees with Staff that this modified version of AECC's proposal of an account- and service-territory-wide bubble concept for the definition of generation facility is consistent with the statutory text of Act 464, which allows facilities to be aggregated for the purposes of billing (*i.e.*, "meter aggregation") if they are "under common ownership within a single electric utility's service area."[248]

The Commission agrees with Staff and Distributed Solar Advocates that, for the sake of consistency, "if a collection of entities are not deemed commonly owned such that they can aggregate across meters, then they should not be deemed commonly owned for the purpose of gaming rules around co-located facilities."[249] However, the Commission also agrees with Staff that a customer's decision whether or not to aggregate meters should not exclude them from Commission review if the aggregate capacity of their facilities

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[248] Ark. Code Ann. § 23-18-604(c)(2)(A)(i).
[249] Distributed Solar Advocates Reply (Doc. No. 385) at 30.

exceeds 1 MW within a particular utility's service area. The Commission finds that tying capacity limits to a customer's decision to aggregate would be inefficient from an administrative standpoint, since a customer could change his or her decision to aggregate at any point, but the Commission's review of facilities that exceed the 1 MW generation capacity limit must necessarily take place before any Net-Metering occurs. Therefore, the Commission finds Staff's proposed rule additions which address gaming in a manner that provides consistency and administrative efficiency for the purpose of Commission review and are reasonable.

The Commission clarifies that, absent evidence to the contrary proffered by the Net-Metering Customer, multiple Net-Metering Facilities under common ownership within a single utility's service area will be treated as a single facility for the purpose of determining whether the facility exceeds the 1 MW capacity limit provided by Ark. Code Ann. § 23-18-603(8)(B)(ii) and is thus subject to Commission approval pursuant to Ark. Code Ann. § 23-18-604(b)(9), whether or not the meters are aggregated. The Commission emphasizes that gaming must be considered on a case-by-case basis under the specific facts of the case. The timing of the multiple facilities may be a factor to be considered.[250]

The Commission recognizes that the utilities are, by virtue of their positions, in the best position to recognize if gaming is or might be occurring as Net-Metering Facilities are proposed. Therefore, the Commission expects the utilities to be vigilent and report suspected gaming to the Commission by filing a complaint or to deny interconnection if gaming is occurring. Likewise, the Commission welcomes inquiries from Net-Metering Customers or developers if they desire a ruling on the permissibility of a proposed facility.

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[250] See *infra* in which the Commission directs the NMWG to consider whether additional provisions addressing gaming are appropriate.

7. Interconnection Rules

a. Changes to Interconnection Rules

Staff: Staff recommends that the Commission use the Interstate Renewable Energy Council's (IREC) *Model Interconnection Procedures, 2019 Edition* to consider amendments to the existing Interconnection Rules (Section 3 of the NMRs) and to address related technical, safety, and other issues. Staff Initial (Doc. No. 376) at 9.

EAL: EAL proposes that the Phase 3 Order direct Staff to include the IREC uniform interconnection procedures for discussion along with other interconnection-related and consumer protection matters, by the NMWG in a separate, docketed rulemaking proceeding allowing for comment and proper notice and hearing consistent with the Commission's RPPs. EAL asserts that Staff's proposed adoption of IREC uniform rules (or other changes that may be proposed to the technical aspects of the interconnection review process) will not address policy issues associated with Net-Metering. Thus, EAL states, the IREC rules will not address the bases upon which EAL and other utilities "legitimately have been unable to process" certain PISRRs and or interconnection application requests. Thus, EAL states, while prompt Commission action is needed to provide the utilities with direction on those policy issues (e.g., ownership requirements, Community-Solar-related issues, proper signatories to the SIA) regarding facilities that qualify for Net-Metering, future policy issues not addressed in the Phase 3 Order would be vetted through the NMWG for resolution before being presented to the Commission. EAL Surrebuttal (Doc. No. 401) at 19-20.

AECC: AECC proposes to revise Rule 3.01(G) to require the Electric Utility to review and process all completed PISRRs in the order they are received. AECC also proposes that the

Electric Utility and Net-Metering Customer mutually agree on addressing the risks of interconnecting a facility where sustems capacity is likely to be exceeded. AECC Initial Comments (Doc. No. 365) at 15.

b. Preliminary Interconnection Site Review Request Charge

EAL: EAL recommends requiring a PISRR for all facilities and allowing for recovery of a fee for such such review, noting that, to date, it has charged customers for certain feasibility studies, but has not charged customers for PISRRs. EAL Initial (Doc. No. 367) at 51. EAL states that the influx of new interconnection requests has placed significant administrative and other demands on EAL to review and process these requests, with an employee now assigned specifically on a near full-time basis to handle and coordinate its response to PISRRs. EAL adds that its engineering team spends significant time evaluating PISRRs and interconnection request and conducting physical inspections of facilities, adding that field services must install a bi-directional meter for each Net-Metering Customer that has not yet been converted to an advanced meter. Further, EAL asserts, developers' actions have increased that administrative and cost burden, in some cases submitting multiple requests for a PISRR on a speculative basis, with no specific customer or intention to pursue those requests, noting that developers have acknowledged as much in oral communications with EAL. In later comments, EAL cites as example of Gaming (1) a customers' simultaneous submission of multiple PISRRs with the intention of only installing one system; and (2) submission of PISRRs without an actual customer associated with them and that are only intended to "scout out" the potential for a site for a new solar facility. *Id.* at 132. EAL Initial (Doc. No. 367) at 58.

As currently written, Rule 3.03.A. states that the Net-Metering Customer shall submit a separate completed PISRR for each point of interconnection if information about multiple points of interconnection is requested. EAL proposes adding a sentence to this Rule that provides that "Each Preliminary Interconnection site Review Request will be considered separately and in the order in which received." EAL Initial Comment Exhibit-2 Redline Version of NMRs (Doc. No. 367) and EAL Surreply (Doc. No. 401) at 48.

AECC: AECC comments regarding the Interconnection queue and recommends that the utility prioritize Net-Metering projects based on the order in which PISRRs are is completed and submitted for review to the utility. AECC Initial (Doc. No. 365) at 15.

c. Additional Billing Charges for Net-Metering Customers

EAL: EAL argues that any costs needed to upgrade EAL's current manual billing system solely to accommodate meter aggregation should be borne by Net-Metering Customers that use meter aggregation and not by all customers, who derive no benefit and are, in fact, harmed by these Net-Metering arrangements under the current Net-Metering rate structure. EAL Initial (Doc. No. 367) at 52-53.

d. Penalties for Unapproved Interconnections

EAL: EAL recommends that the Commission adopt a policy that disqualifies unauthorized interconnections from Net-Metering. *Id.* at 53-54.

e. Signatures on the Standard Interconnection Agreement

EAL: For third-party arrangements such as leases and service contracts, EAL recommends requiring both the third-party owner of the facility and the Net-Metering Customer to sign the SIA. EAL provides language in Section 3 of its own strawman that would include the owner as a signatory of the SIA. *Id.* at 42-44.

Findings:

With respect to issues associated with changes to the Commission's Rules on Interconnection (Section 3 of the NMRs), the Commission finds reasonable EAL's recommendation that Staff include proposed Interstate Renewable Energy Council's (IREC) *Model Interconnection Procedures, 2019 Edition*, for discussion, along with other interconnection-related and consumer protection matters,[251] allowing for comment and proper notice and hearing consistent with the Commission's RPPs. However, the Commission also notes Staff's observation that there are concurrent discussions about the interconnection procedures in relation to DERs in Docket No 16-028-U, and thus finds the interconnection issues should be addressed by the DER Working Group on Interconnection Issues in Docket No. 16-028-U.

The Commission observes that the IREC Procedures address questions on the following topics:

- Interconnection of Energy Storage Systems
- Requirements for Publishing a Public Queue and Reporting
- Updated Dispute Resolution Process
- Clarification to the Material Modifications Provisions

The Commission further notes that IREC's Procedures also provide guidance and best practices on the following issues:

- Applicability of Interconnection Standards and Eligibility
- System Size and Review Process, including expedited approval of small, inverter-based systems and Fast Track processes for larger systems

[251] The Commission finds below that consumer protection issues should be addressed by the NMWG.

- Timelines
- Dispute Resolution
- Information Sharing and Transparency

The Commission favors a single solution for both DER and Net-Metering Facilities that recognizes new ownership structures and new technologies associated with Act 464 and thus will direct that a DER Working Group on Interconnection Issues consider and make recommendations on the IREC Procedures and other interconnection issues, including recommendations to the Commission regarding a future rulemaking on those topics.

The Commission agrees with Staff that until such time as a single set of interconnection procedures can be developed to be applied to Distributed Energy Resources and Net-Metering Facilities and can be incorporated into the NMRs, the current NMR forms should be amended to recognize new ownership structures such as leasing and new technologies such as storage allowed by Act 464.[252] The Commission approves Staff's Strawman amendments making these changes to the Standard Interconnection Agreement (Appendix A) and the PISRR (Appendix A-1).

The Commission adopts EAL's proposal to include "or owner of a Net-Metering Facility" following "Net-Metering Customer" and "or owner" following "customer" in all appropriate places in Section 3 of the NMRs.

The Commission declines to adopt EAL's suggested change to Rule 3.01.D[253] that would insert the phrase "Net Metering from a billing perspective," finding that such considerations are not germane to the engineering, technical, and safety-related issues that are the subject of that Rule.

[252] Staff Surreply (Doc. No. 400) at 14.
[253] EAL Initial (Doc. No. 367) at 130.

The Commission declines to adopt AECC's proposed amendments to Rule 3.01.G. finding that the existing Rule as proposed for retention by Staff's Strawman adequately addresses the obligation of the Net-Metering Customer or owner of the Net-Metering Facility to pay the cost of additional or reconfigured facilities if the utility's existing facilities are not adequate to interconnect with the Net-Metering Facility.

The Commission adopts EAL's proposal to amend Rule 3.03.A., which provides: "Each Preliminary Interconnection Site Review Request will be considered separately and in the order in which received."[254] However, the Commission finds that the existing Rule countenances the situation in which a Net-Metering Customer or owner may submit multiple PISRRs relating to a proposed Net-Metering Facility, which under the provisions of current Rule 3.03.B., the Electric Utility would be required to review and provide the customer or owner with the results of the review of each of the multiple PISRRs within 30 calendar days. Given the increased workload and costs that parallel processing of PISRRs for such customers or owners may present to the Electric Utility, the Commission finds that the customer or owner may request parallel processing but must agree to pay the actual costs of conducting the reviews and any subsequent costs associated with site screening that may be required, as provided by Rule 3.03.C. The Commission also finds that in such an event, the Electric Utility shall respond to the request and process and present the results of the review of the multiple PISRRs within a reasonable time that may not exceed 90 calendar days.

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[254] *Id.* at 132. The Commission notes that AECC also proposed similar language regarding the order of processing of completed PISRRs. See AECC Initial Exhibit-1 (Doc. 365) at 3-2.

As with the case with Rule 3.01.D. discussed above, the Commission declines to adopt EAL's suggested change to Rule 3.03.B,[255] regarding requirements for PISRRs that would allow the Electric Utility to raise issues "with respect to the customer's eligibility for Net Metering from a billing perspective or pursuant to APSC Net-Metering Rule," noting again that the existing Rule subsection (which in Staff's Strawman remains unchanged from the current NMRs) focuses primarily on the safety and engineering limits issues of interconnection, and thus EAL's proposed amendatory language is not germane to the provisions of that subsection of the Rule. The Commission retains the language of the existing Rule. 3.03.B. as proposed by Staff.

The Commission declines to adopt EAL's recommendation to require in Section 3 of the NMRs that a PISRR be required for all Net-Metering Facilities and, as discussed above, directs that this issue be addressed by the DER Working Group on Interconnection Issues and notes the observation by the Distributed Solar Advocates that the IREC Procedures recommend requiring PISRRs only for larger projecdts.[256]

Concerning additional billing charges for processing PISRRs and other Interconnection costs such as billing, the Commission finds that these issues are deserving of future consideration, but in the absence of specific proposals for such fees declines to take action on EAL's and other similar utility requests at this time. Any utility is welcome to make a utility-specific proposal for any such fee or cost recovery. The DER Working Group on Interconnection Issues is encouraged to consider and make recommendations regarding a possible generic solution to this issue.

[255] EAL Initial (Doc. No. 367) at 132.
[256] Distributed Solar Advocates Reply (Doc. No. 385) at 25.

Concerning penalties for unapproved interconnections, the Commission believes EAL's recommendation has merit, and Section 5 on Gaming amends the NMRs to include EAL's proposed language.

8. Consumer Protection Issues

Staff Comments and Strawman: Staff supports development of a Consumer Guide, including a Customer Bill of Rights and a Code of Conduct. Staff agrees with the AG that the Commission does not have statutory authority over non-utility providers. Staff Surreply (Doc. No. 400) at 18-19.

AG: The AG is concerned about unregulated third party developers of Net-Metering Facilities misleading customers. The AG recommends that the Commission establish a working group consisting of Staff, the AG, and Net-Metering providers to develop a code of conduct and a process to certify Net-Metering providers. AG Initial (Doc. No. 362) at 15. The AG states that the Commission does not currently have statutory authority over non-utility participants and recommends examining existing authority to see how the AG and the Commission could enforce a code of conduct, noting that this may require legislative amendments. AG Surreply (Doc. No. 396) at 7-8.

EAL: EAL recommends that the Commission require an explanation and timeline of the Net-Metering process so customers are not misled. EAL Initial (Doc. No. 367) at 65. EAL recommends that the Commission in a separate rulemaking docket require the NMWG to develop Interconnection Rules and Consumer Protection Rules using Staff's proposed IREC uniform rules as a template. EAL states that the NMWG could also develop a Consumer Guide, mandatory standards for developers, and standard templates for leases and service agreements (PPAs). EAL Surreply (Doc. No. 401) at 20-22.

AECC: AECC cites the "Solar Consumer Protection Guide" recently issued by the California PUC for guidance on protections against gaming. AECC recommends developing a Customer Bill of Rights and Code of Ethics, to limit the consumer's exposure for the purchase of a system during the utility's review of the Preliminary Interconnection Site Review Request. AECC Surreply (Doc. No. 398) at 11-13.

William Ball: Mr. Ball supports consumer protection language in the NMRs protecting renewable energy developers from utilities that are contacting customers to offer lower costs if the utilities do the project instead of the private solar company. Ball Reply (Doc. No. 382) at (unnumbered) 5.

Findings:

The Commission finds reasonable the recommendations of the AG, Staff, and other Parties that the Commission utilize the NMWG consisting of Staff, the AG, Net-Metering Facility providers, the utilities, and other interested stakeholders, to develop a Customer Bill of Rights, a Consumer Protection Guide, and Codes of Conduct for review and approval by the Commission.[257] The Codes of Conduct are to address issues for third-party developers, customers, and utilities. The Codes of Conduct are to include possible mandatory standards for developers, and templates for leases and service agreements (PPAs). The Commission directs the NMWG to propose within 90 days from the date of this Order a workplan for creating such a working group and a timeframe for its report and recommendations to the Commission. The NMWG should consider Consumer Protections and how codes of conduct could address potential abuses of the interests of all stakeholders in the Net-Metering process, including possible anticompetitive activities by

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[257] The Commission also directs the NMWG to consider whether additional provisions addressing gaming are appropriate.

utilities. The Commission directs the NMWG's attention to the report prepared for the Commission by the Regulatory Assistance Project in 2018, *Enabling Third-Party Aggregation of Distributed Energy Resources*. This Report is Commission Attachment 1 to Order No. 10 in Docket No. 16-028-U[258]: http://www.apscservices.info/pdf/16/16-028-U_118_1.pdf

The Commission agrees with the AG that the Commission does not currently have statutory authority over non-utility participants. The Commission directs the NMWG to make recommendations regarding: whether the AG and the Commission could enforce a code of conduct; how to enforce a code of conduct; and whether this may require new legislation. The Commission declines to adopt any process to certify third-party developers of Net-Metering Facilities, both because it currently has no jurisdiction under AREDA and because third party developers of Net-Metering Facilities are not monopolies but operate in a competitive marketplace.

9. Other Issues

a. Unreasonable Allocation of Costs

AECC: AECC recommends that the term "unreasonable allocation of costs" should be defined in the NMRs. AECC Initial (Doc. No. 365) at 13.

Distributed Solar Advocates: Distributed Solar Advocates state that Act 464 does not define "unreasonable allocation of costs" and therefore argues that the Commission has the discretion to design rates that allow *de minimis* shifting of costs as it traditionally has done in ratemaking. Distributed Solar Advocates Initial (Doc. No. 374) at 7-9.

Findings:

[258] In the Matter of the Investigation of Policies Related to Distributed Energy Resources.

The Commission will consider AECC's recommendation on this issue in the case-by-case applications by Net-Metering Customers to exceed the statutory size limitations for Net-Metering Facilities. For purposes of such consideration, the Commission finds that a "cost shift" may be defined as the cumulative amount of fixed costs avoided by Net-Metering Customers because of Net-Metering, as expressed by monthly bill impacts. The cost shift should be offset by direct benefits which impact customer bills. "Direct benefits" should consider benefits to all customers of market-driven innovation, including forward-looking projections of avoidable generation, transmission, and distribution costs associated with customer-owned and financed Net-Metering Facilities and other distributed energy resources. The Commission may determine that a cost shift is unreasonable if the monthly bill impact to non-Net-Metering Customers exceeds the direct benefits.

The Commission intends for the utility to demonstrate that cost shifting has occurred or is occurring on a cumulative basis, rather than on the basis of an individual Net-Metering Customer's proposed facility.

b. Data Sharing

SWEPCO: SWEPCO recommends that the issue of data sharing mentioned by the Commission in Order No. 10 be addressed in Docket No. 16-028-U. SWEPCO states that a production meter is required to directly measure production from a Net-Metering Facility and argues that a utility should not have to pay for access to a Net-Metering Customer's production data. SWEPCO Initial (Doc. No. 370) at 10-12.

Distributed Solar Advocates: Distributed Solar Advocates believes that there should be an incentive such as an adder to compensate Net-Metering Customers that allow their data to be used to provide ancillary services to the grid. They note that this and other tools for optimizing the siting of distributed generation investment and advanced inverter capabilities can be evaluated in Docket No. 16-028-U. Distributed Solar Advocates Initial (Doc. No. 374) at 18-19.

Findings:

The Commission agrees with SWEPCO's recommendation that the issue of data sharing mentioned in Order No. 10 should be addressed in Docket No. 16-028-U.

c. Separate Rate Class

OG&E: OG&E recommends adopting a three-part rate structure with an appropriate level of demand charge, and treating Net-Metering Customers as a separate rate class. OG&E Initial (Doc. No. 363) at 6-7.

Findings:

The Commission finds it premature to address this issue, as the data necessary to address it will not be available unless and until the utilities provide updated information regarding the amounts of distribution-related demand costs that the utilities are not recovering in their rates. This topic can be addressed when and if any makes such a request in a general rate case.

d. Common Ownership by Tax-exempt Entities

Staff: Staff's proposes in its model Net-Metering Tariff (Staff Strawman (Doc. No. 346), Appendix B), Section X.3.10, in which Staff proposes to add the following language:

> However, the common ownership requirement shall not apply if more than two customers that are governmental entities or other entities that are exempt from state and federal income tax defined under 23-18-603(7)(c) co-locate at a site hosting the Net-Metering Facility.

Findings:

The Commission agrees that this addition is reasonable and thus this provision will be added to the NMRs.

e. Community Solar

EAL: EAL asserts that grouping together individual meters, including but not limited to residential meters, that exceed in total allotted thresholds (*e.g.*, 1 MW) and are not tied to any actual load (*i.e.*, so-called "community solar" projects seeking to utilize meter aggregation), are examples of Gaming that may be happening under the Commission's existing NMRs. EAL Initial (Doc. No. 367) at 59. EAL notes that some purported Net-Metering Facilities are more properly characterized as Community Solar Garden facilities and notes that in Order No. 10, the Commission indicated that "community solar" type arrangements would be handled in Docket No. 16-028-U and specifically stated that the Commission was not making any findings in that Order with respect to "community solar" or "virtual net metering." *Id.* at 2-3.

Findings:

The Commission agrees that the issue of Community Solar mentioned in Order No. 10 should be addressed in a separate docket. Any issues of Gaming can be addressed on a case-by-case basis.

f. Annual Reports

Staff: Staff states that the Commission should require reporting of the following metrics: adoption of Net-Metering Facilities as a percentage of the utility's total production capacity in kW and kWh by rate class; and Net-Metering as a percentage of the utility's monthly peak demand by rate class. Staff says that this increased reporting will allow the

Commission to be more informed regarding the level of Net-Metering penetration in Arkansas. Staff Reply (Doc. 388) at 37.

Findings:

Because the Commission has declined to use a level of penetration to help decide when to impose alternative rate structures, the Commission declines to adopt Staff's suggested changes to Rule 4.02. The Commission notes that much of this information is being filed annually by the utilities in Docket No. 06-105-U.

g. Non-bypassable Riders

EAL: EAL witness Owens explains that there are some riders, such as fuel or energy efficiency riders, and franchise fees that are bypassable and cites a securitized storm rider as an example of a non-bypassable rider. He further explains that an applicable minimum bill is a catch-all piece of language that says if a customer has no consumption there is still going to be a minimum bill comprising a fixed customer charge and taxes. T2. 20-30.

SWEPCO: SWEPCO notes that in the first seven months of 2019, it issued 263 "net kWh zero bills" in Arkansas, which reflects that the customer does not pay for fuel, energy efficiency programs, or any factor that is based on kWh usage. SWEPCO Initial Comments (Doc. No. 368) at 6-7.

AECC: AECC witness Shields testifies that distribution cooperatives generally have only one non-bypassable charges, the service availability charge, that can vary between co-ops. He states that this charge does not include all of the fixed-cost components that supply distribution service, some of which end up in the volumetric energy charge. He asserts that this creates a market distortion, which can be changed by setting the proper price signal. He urges determining this signal today instead of when saturation is reached. T2. 96-97.

Findings:

The Commission finds that the issue of whether certain riders should be bypassable or non-bypassable by utility customers should be addressed separately from the NMRs. Although some riders are common to multiple utilities and treatment might be addressed in a generic docket, some riders are utility-specific. The Commission therefore intends to open a docket in the future to address this issue.

IV. ADDITIONAL COMMISSION FINDINGS

In addition to the changes to Staff's NMR Strawman made as described herein, the Commission has made minor changes to formatting to make the NMRs internally consistent and consistent with other Commission rules, as shown on the blacklined copy in Attachment 2.

The Commission finds that newspaper notice of this Rulemaking has been published pursuant to Rule 2.03 of the Commission's RPPs. The Commission further finds that the Arkansas Legislative Council and the Joint Interim Committee on Insurance and Commerce of the Arkansas General Assembly have been notified of this rulemaking proceeding in the manner prescribed by law. The Commission also finds that the Governor of Arkansas has been notified of and approved the NMRs as proposed, in accordance with Executive Order 15-02.

Having reviewed and considered the Parties' written comments and testimony and the oral testimony provided by the parties during the public evidentiary hearings, the

Commission finds that the NMRs as set out in Attachment 1 to this Order incorporate the changes required by Act 464 of 2019 and make the necessary changes to the Net-Metering process in Arkansas. The Commission finds that the NMRs are just and reasonable and will serve to ensure the orderly administration of matters and proceedings before the Commission, and thus are in the public interest. Therefore, the Commission adopts the NMRs as set in Attachment 1 to this Order. Attachment 1 is the "clean" copy of the final NMRs adopted herein. Attachment 2 is a blacklined[259] copy of the NMRs which shows the changes adopted by this Order to Staff's Strawman filed September 17, 2019.

V. COMMISSION RULING AND ORDER

Accordingly, the Commission orders and directs as follows:

1. The revised NMRs as set out in Attachment 1 to this Order are reasonable, appropriate, and in the public interest and are hereby adopted to be effective upon review and approval by the Governor and the Arkansas Legislative Council.

2. The Commission directs Staff, after consultation with the Parties, to submit proposals for standard form documents for Notice, Application Form, and Affidavit addressing leasing and service agreements, safe harbor, and meter aggregation and common ownership within 90 days from the date of this Order.

3. The Commission directs the NMWG to propose within 90 days from the date of this Order a workplan for creating such a working group and a timeframe for its report and recommendations to the Commission on consumer protection issues, including development of a Customer Bill of Rights, a Consumer Protection Guide, and Codes of

[259] Staff revisions are marked in red and Commission revisions in blue.

Conduct, for review and approval by the Commission.

4. The Commission directs that interconnection-related matters, including Staff's proposed IREC's *Model Interconnection Procedures, 2019 Edition*, be addressed by the DER Working Group on Interconnection Issues in Docket No. 16-028-U. The DER Working Group on Interconnection Issues should consider and make recommendations on the IREC Procedures and other interconnection issues, including recommendations to the Commission regarding a future rulemaking on those topics.

5. The Commission will also initiate a separate docket to consider the topic of Community Solar projects, including issues of utility and third-party developer participation in such projects.

6. The Commission will also initiate a separate docket to consider the topic of non-bypassable riders.

7. Having addressed the net-metering rate structure issues in this Docket, the Commission finds that the *Motion for Interim Net-Metering Rate Structure and to Establish Accelerated Procedural Schedule to Address Same, and Incorporated Memorandum in Support* (Motion) filed by EAL on September 23, 2019, is now moot. The Commission therefore denies EAL's Motion.

BY ORDER OF THE COMMISSION.

This 1st day of June, 2020.

Ted J. Thomas, Chairman

Kimberly A. O'Guinn, Commissioner

Justin Tate, Commissioner

Mary Loos

Mary Loos, Secretary of the Commission

I hereby certify that this order, issued by the Arkansas Public Service Commission, has been served on all parties of record on this date by the following method:

____U.S. mail with postage prepaid using the mailing address of each party as indicated in the official docket file, or

✓ Electronic mail using the email address of each party as indicated in the official docket file.

Attachment 1

Clean Copy of Net Metering Rules

ARKANSAS
PUBLIC SERVICE COMMISSION

NET-METERING RULES

Last Revised: June 1, 2020
Order No. 28
Docket No. 16-027-R
Effective: x x - x x - x x x x

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	03/08/17	10	Revised Rules to comply with Act 827 of 2015.
	08/16/17	14	Errata Order.
	06/01/20	28	Revised Rules to comply with Act 464 of 2019.

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) Additional Meter

A meter associated with the Net-Metering Customer's account that the Net-Metering Customer may credit with Net Excess Generation 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.

(b) Annual Billing Cycle

The normal annual fiscal accounting period used by the utility.

(c) Avoided Cost

As defined in Ark. Code Ann. § 23-18-603(1).

(d) 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) Commission

The Arkansas Public Service Commission.

(g) Electric Utility

As defined in Ark. Code Ann, § 23-18-603(3). A person who acts as a lessor or service provider as described in Ark. Code Ann. § 23-18-603(7)(B) or (C) shall not be considered an Electric Utility .

(h) Energy Storage Device

A device that captures energy produced at one time, stores that energy for a period of time, and delivers that energy as electricity for use at a future time.

(i) Fuel Cell Resource

A resource that converts the chemical energy of a fuel directly to direct current electricity without intermediate combustion or thermal cycles.

(j) Generation Meter

The meter associated with the Net-Metering Customer's account to which the Net- Metering Facility is physically attached.

(k) 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.

(l) Hydroelectric Resource

A resource in which the prime mover is a water wheel. The water wheel is driven by falling water.

(m) Micro Turbine Resource

A resource that uses a small combustion turbine to produce electricity.

(n) Net Excess Generation

As defined in Ark. Code Ann, § 23-18-603(5).

(0) Net-Metering

As defined in Ark. Code Ann, § 23-18-603(6).

(p) Net-Metering Customer

As defined in Ark. Code Ann, § 23-18-603(7).

(q) Net-Metering Facility

As defined in Ark. Code Ann, § 23-18-603(8).

(r) 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).

(t) Quantifiable Benefits

As defined in Ark. Code Ann, § 23-18-603(9).

(u) Renewable Energy Credit

As defined in Ark. Code Ann, § 23-18-603(10).

(v) Residential Use

Service provided under an Electric Utility’s standard rate schedules applicable to residential service.

(w) Solar Resource

A resource in which electricity is generated through the collection, transfer and/or storage of the sun's heat or light.

(x) 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)(4).

Rule 2.04 Billing for Net Metering

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, except as provided herein.

1. For Net-Metering Customers who receive service under a rate that does not include a demand component::

    a. Except as provided in Rule 2.04 A.1.b, an Electric Utility shall credit a Net-Metering Customer with the amount of any accumulated Net Excess Generation as measured in kilowatt hours or kilowatt hours multiplied by the applicable retail rate in the next applicable billing period and base the bill of the Net-Metering Customer on the net amount of electricity as measured in kilowatt hours or kilowatt hours multiplied by the applicable retail rate that the Net-Metering Customer has received from or fed back to the electric utility during the billing period.

b. After December 31, 2022, an Electric Utility may file an application to establish an alternative net-metering class and rate structure pursuant to Ark. Code Ann. § 23-18-604(b)(2)(B)-(D). The application shall include a cost of service study and substantial evidence that the Electric Utility's proposed rate structure is in the public interest and will not result in an unreasonable allocation of or increase in costs to the Electric Utility's other customers.

2. For Net-Metering Customers who receive service under a rate that includes a demand component with a generating capacity of 1,000 kW or less:

An Electric Utility shall credit a Net-Metering Customer with the amount of any accumulated Net Excess Generation as measured in kilowatt hours or kilowatt hours multiplied by the applicable retail rate in the next applicable billing period and base the bill of the Net-Metering Customer on the net amount of electricity as measured in kilowatt hours or kilowatt hours multiplied by the applicable retail rate that the Net-Metering Customer has received from or fed back to the electric utility during the billing period.

3. For Net-Metering Customers who receive service under a rate that includes a demand component with a generating capacity over 1,000 kW and up to 20 MW and who receive approval to exceed the statutory limits under Ark. Code Ann. § 23-18-604(b)(9):

a. An Electric Utility shall credit a Net-Metering Customer with the amount of any accumulated Net Excess Generation as measured in kilowatt hours or kilowatt hours multiplied by the applicable retail rate in the next applicable billing period and base the bill of the Net-Metering Customer on the net amount of electricity as measured in kilowatt hours or kilowatt hours multiplied by the applicable retail rate that the Net-Metering Customer has received from or fed back to the electric utility during the billing period.

b. An Electric Utility shall also bill the Net-Metering Customer a grid charge.

c. The grid charge rate shall initially be set at zero effective May XX, 2020.

d. After the effective date of these NMRs, an Electric Utility may file an application to revise the grid charge rate. The application shall include a cost-of-service study and evidence demonstrating that an unreasonable cost shift to non-Net-Metering Customers is occurring or has already occurred on a cumulative basis rather than on the basis of an individual Net-Metering Customer's proposed facility(ies) and that the Electric Utility's proposed grid charge rate is in the public interest. Once approved, the Electric Utility shall bill these Net-Metering Customers in accordance with the Electric Utility's approved grid charge.

B. If the kWh supplied by the Electric Utility exceeds the kWh 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 kWh supplied by the Electric Utility in accordance with the rates and charges under the customer's standard rate schedule.

C. If the kWh generated by the Net-Metering Facility and fed back to the Electric Utility exceed the kWh supplied by the Electric Utility to the Net-Metering Customer during the applicable Billing Period, the Electric Utility shall credit the Net-Metering Customer with any accumulated Net Excess Generation as measured in kilowatt hours pursuant to Rule 2.04(A)(1)(a) or kilowatt hours multiplied by the applicable rate established by the Commission pursuant to Rule 2.04(A)(1)(b) in the next applicable Billing Period.

1. Net Excess Generation shall first be credited to the Net-Metering Customer's Generation Meter.

2. After application of subsection C.1. and upon request of the Net-Metering Customer pursuant to subsection D., 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.

3. Net Excess Generation shall be credited as described in subsections C.1. and C.2. during subsequent Billing Periods. The amount of 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 Avoided Cost plus any additional sum determined by the Commission 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 Avoided Cost, plus any additional sum determined by the Commission, 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. 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.

4. At the time an Electric Utility processes a request for applying any remaining Net Excess Generation as a credit to one (1) or more of a Net-metering Customer's meters in the rank order provided by the Net-metering Customer pursuant to Ark. Code Ann. § 23-18-604(c), the Electric Utility shall synchronize the billing cycles of each additional customer meter with the customer's primary net-metering meter.

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 Meter Aggregation

A. Except as provided in subsections (B) and (C) of this Rule 2.05, an 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.

B. At the Net-Metering Customer's discretion, an electric utility may apply net-metering credits from a net-metering facility to any separate meter locations if the net-metering facility and the separate meter locations are under common ownership within a single electric utility's service area.

C. Subsection (B) of this Rule 2.05 does not apply if more than two (2) customers that are governmental entities or other entities that are exempt from state and federal income tax defined under § 23-18-607(7)(C) co-locate at a site hosting the net-metering facility.

D. A Net-Metering Customer seeking to aggregate multiple accounts under common ownership shall submit a request to the Electric Utility identifying the accounts that are under common ownership. The request shall include the following documents:

1. Standard Application Form and Affidavit as approved by the Commission.
2. Sworn Affidavit: The Net-Metering Customer shall submit a sworn affidavit by a person with personal knowledge affirming that the Net-Metering Customer is in fact the legal owner or authorized representative responsible for paying the bill for all accounts listed in the application form.

Rule 2.06 Application to Exceed Generating Capacity Limit

A. 1. 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 1,000 kW for non-residential use under Ark. Code Ann. §§ 23-18- 604(b)(9) as appropriate.

2. For purposes of Rule 2.06(A)(1), "generation capacity" includes the aggregate ability to produce electricity from all Net-Metering Facilities under common ownership that are located within a single utility's service territory.

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 1,000 kW satisfies the requirements of Ark. Code Ann. §§ 23-18-604(b)(9);

2. A description of the proposed Net-Metering Facility for each discrete location including:

a. Project proposal;

b. Project location (street address, town, utility service area);

c. Generator type (wind, solar, hydro, energy storage device, 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 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.

Rule 2.07 Grandfathering Net-Metering Rate Structures

A. Net-Metering Facilities for residential use or for other than residential use that does not exceed one thousand (1,000) kW:

1. The Net-Metering Facility of a Net-Metering Customer who submits a Standard Interconnection Agreement to the Electric Utility before December 31, 2022, shall remain under the Net-Metering rate structure in effect when the Standard Interconnection Agreement was signed by the Net-Metering Customer, for a period of twenty (20) years beginning May XX, 2020.

2. A Net-Metering Facility may be upgraded and retain grandfathered status so long as the Net-Metering Facility still meets the statutory definition under Ark. Code Ann. § 23-18-603(8).

B. Net-Metering Facilities for which approval is required to exceed one thousand (1,000) kW:

1. If a Net-Metering Customer (a) requests approval to exceed the statutory limit for a Net-Metering Facility pursuant to Ark. Code Ann. § 23-18-604(b)(9), and (b) has submitted a Standard Interconnection Agreement to the Electric Utility before December 31, 2022, the Net-Metering Customer may request that the Net-Metering Facility remain under the Net-Metering rate structure in effect when the Standard Interconnection Agreement was signed by the Net-Metering Customer. The request will be considered on a case-by-case basis for a grandfathering period up to twenty (20) years. The request to be

grandfathered shall be made when the request to exceed the statutory limit is made.

2. If a Net-Metering Customer proposes to upgrade a Net-Metering Facility under 1,000 kW and add additional generating capacity by either (a) an upgrade to the existing Net-Metering Facility, or (b) an additional Net-Metering Facility, and such upgrade would cause the total generating capacity to exceed 1,000 kW, then the original capacity of the Net-Metering Facility shall retain any grandfathered status and the additional capacity shall be subject to the Net-Metering rate structure in effect when the Standard Interconnection Agreement for the additional capacity is signed by the Net-Metering Customer.

3. If a Net-Metering Customer proposes to upgrade a Net-Metering Facility for which approval was previously granted by the Commission pursuant to Ark. Code Ann. § 23-18-604(b)(9) and add additional generating by either (a) an upgrade to the existing Net-Metering Facility, or (b) an additional Net-Metering Facility, then the original capacity of the Net-Metering Facility shall retain any grandfathered status and the additional capacity shall be subject to the Net-Metering rate structure in effect when the Standard Interconnection Agreement for the additional capacity is signed by the Net-Metering Customer.

4. The cost of any additional metering equipment required under subsections B.2. or B.3. above shall be borne by the Net-Metering Customer.

C. The Electric Utility need not have approved and signed the Standard Interconnection Agreement for the date of eligibility for grandfathering to be established.

D. The grandfather period shall attach to the Net-Metering Facility on the premises rather than the Net-Metering Customer.

E. If the Net-Metering Customer sells a premises with a Net-Metering Facility, the Standard Interconnection Agreement may be transferred to the new Net-Metering Customer and the grandfather period shall continue for the remainder of the twenty (20) year term, assuming no other triggering event occurs.

F. A Net-Metering Customer may not transfer a Net-Metering Facility to a new premises or location and continue to operate under the grandfather period.

G. Maintenance and repair of existing Net-Metering Facilities shall not be a triggering event which ends the grandfather period.

H. A Net-Metering Facility grandfathered under this Rule remains subject to any other change or modification in rates, terms, or conditions.

Rule 2.08 Leases and Safe Harbor for Service Agreements

A. A Net-Metering Customer entering into a lease for a Net-Metering Facility shall provide to the Electric Utility a standard Notice and Affidavit approved by the Commission to the Electric Utility certifying that the lease is in compliance with all Commission Rules and Ark. Code Ann. § 23-18-603(7)(B).

B. A Net-Metering Customer entering into a service agreement for a Net-Metering Facility who is relying on Ark. Code Ann. § 23-18-603(7)(C) to qualify for net metering shall submit a standard Notice and Affidavit approved by the Commission to the Electric Utility certifying that the customer qualifies for safe-harbor protection as provided by Ark. Code Ann. § 23-18-603(7)(C) and 26 U.S.C. § 7701(e)(3)(A)) and that the service agreement is in compliance with all Commission Rules.

C. Disputes over compliance with Subsection (A) or (B) above shall be submitted to Staff for review and attempted resolution. Thereafter, a Net-Metering Customer or Electric Utility who disagrees with Staff's resolution may petition the Commission to resolve the dispute. Electric Utilities shall presume that any person who submits a completed Notice and Affidavit form is in compliance with the Commission's Rules and the provisions under Ark. Code Ann. § 23-18-603(7)(B) or (C) until the Commission makes a finding otherwise.

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 and owner of the Net-Metering Facility, if different, 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 Facility 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 tested by utility personnel.

C. The customer and owner of the Net-Metering Facility, if different, 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 or owner 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 or owner of the Net-Metering Facility 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 or owner of the Net-Metering Facility 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 or owner of the Net-Metering Facility 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 2.06.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. Each Preliminary Interconnection Site Review Request will be considered separately and in the order in which received. 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. The customer may request parallel processing of multiple reviews but must pay actual costs of conducting the review and any subsequent costs associated with site screening that may be required under Rule 3,03.C. In such event, the Electric Utility shall respond to the request and shall process and present the results of the multiple reviews within a reasonable time, not to exceed ninety (90) 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.

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), Preliminary Interconnection Site Review Request (Appendix A-1) and a Net-Metering Tariff in standard tariff format (Appendix B).

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, Storage, etc.), its use (by specific rate class(es), 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

SECTION 5. RULES TO GUARD AGAINST GAMING

Rule 5.01 Gaming Defined

Gaming is defined as manipulating, misrepresenting, or otherwise configuring a Net-Metering Facility or Facilities in a manner that is intended to result in, or that actually results in, the avoidance of statutory or Commission limits or rules.

Gaming of the Net-Metering Rules includes, but is not limited to, the following actions:

A. Adding additional capacity to an existing Net-metering Facility without notifying the Electric Utility to which the Net-Metering Facility is interconnected;
B. Changing the ownership, lease, or service contact of a Net-Metering Facility for the purpose of avoiding the 1,000 kW generation capacity threshold;

C. Failing to include any and all facilities used for Net-Metering under common ownership in a single utility's service area as a single facility for generation capacity purposes pursuant to Rule 2.06, regardless of the location of the facility and the customer's decision to aggregate for meter, bill, and crediting purposes;

D. Unauthorized interconnections.

Rule 5.02 Gaming Prohibited

Gaming of the Net-Metering Rules is prohibited.

Rule 5.03 Penalties for Gaming

Any Net-Metering Customer found to be engaged in activity considered to be gaming under the Net-metering Rules may have its qualification as a Net-Metering Customer suspended or terminated by the Commission following notice and opportunity for hearing.

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 Energy Storage Device (circle all that apply)

Generator Rating (kW):_________________________DC

Inverter Rating (kW):_________________________AC

Describe Location of Accessible and Lockable Disconnect: ___

____

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 (Net Metering Customer):_________________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(8) 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 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.

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 customer's 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 customer's 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:
______________________________________	______________________________________

Third-Party Owner (if applicable):

____

By:___________________________________

Title:_________________________________

Mailing Address:

____

____

E-mail Address:

____

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 A-1

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 Energy Storage Device (circle all that apply)
Generator Rating (kW):________________________DC
Inverter Rating (kW):________________________ AC 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 1,000 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 1,000 kW facility size limit pursuant to Net Metering Rule 2.06.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.

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Name of Company		
Kind of Service: Electric	Class of Service: All	
Part III. Rate Schedule No. X		
Title: NET-METERING		PSC File Mark Only

X. NET-METERING

X.1. DEFINITIONS

X.1.1. Avoided Cost
As defined in A.C.A. 23-18-603(1)

X.1.2. Net Metering
As defined in A.C.A. 23-18-603(6)

X.1.3. Net Metering Customer
As defined in A.C.A. 23-18-603(7)

X.1.4. Net Metering Facility
As defined in A.C.A. 23-18-603(8)

X.1.5. Electric Utility
As defined in A.C.A. 23-18-603(3)

X.1.6. Net Excess Generation
As defined in A.C.A. 23-18-603(5)

X.1.7. Renewable Energy Credit
As defined in A.C.A. 23-18-603(10)

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X.1.8. Quantifiable Benefits
As defined in A.C.A. 23-18-603(9)

X.2. AVAILABILITY

X.2.1. Service under the provisions of this tariff is available to any residential or any other customer who takes service under standard rate schedule(s) ________________ (list schedules) who is a Net-Metering Customer and who has obtained a signed Standard Interconnection Agreement for Net-Metering Facilities with an Electric Utility. 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 one thousand kilowatts (1,000 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.

The provisions of the customer's standard rate schedule are modified as specified herein.

X.2.2. 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.3. MONTHLY BILLING

X.3.1. 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.

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X.3.2. 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 Net–Metering Customer's bill are netted.

X.3.3. 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 billable kWhs supplied by the Electric Utility in accordance with the rates and charges under the Net-Metering Customer's standard rate schedule.

X.3.4. For Net-Metering Customers who receive service under a rate that does not include a demand component, the Electric Utility shall credit a Net-Metering Customer with the amount of any accumulated Net Excess Generation as measured in kWh or kWh multiplied by the applicable rate in the next applicable billing period and base the bill of the Net-Metering Customer on the net amount of electricity as measured in kWh or kWh multiplied by the applicable retail rate that the Net-Metering Customer has received from or fed back to the Electric Utility during the billing period.

X.3.5. For Net-Metering Customers who receive service under a rate that includes a demand component with a generating capacity of 1,000 kW or less, the Electric Utility shall credit the Net-Metering Customer with any accumulated Net Excess Generation in the next applicable billing period and base the bill of the Net-Metering Customer on the net amount of electricity that the Net-Metering Customer has received from or fed back to the Electric Utility during the billing period.

X.3.6 For Net-Metering Customers who receive service under a rate that includes a demand component with a generating capacity over 1,000 kW and up to 20 MW and who receive approval to exceed the statutory limits under Ark. Code Ann. § 23-18-604(b)(9), the Electric Utility shall credit a Net-Metering Customer with the amount of any accumulated Net Excess Generation as measured in kWh or kWh multiplied by the applicable retail rate in the next applicable billing period and base the bill of the Net-Metering Customer on the net amount of electricity as measured in kWh or kWh multiplied by the applicable retail rate that the Net-Metering Customer has received from or fed back to the electric

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utility during the billing period.

The Electric Utility shall also bill the Net-Metering Customer a grid charge.

Grid charge rate: $0.00.

X.3.7. 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 shall credit the Net-Metering Customer with any accumulated Net Excess Generation in the next applicable Billing Period.

X.3.8. 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).

X.3.9. After application of X.3.8. and upon request of the Net-Metering Customer pursuant to X.3.11., any remaining Net Excess Generation 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.

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X.3.10. Net Excess Generation shall be credited as described in X.3.8. and X.3.9. during subsequent Billing Periods; the Net Excess Generation credits remaining in a Net- Metering Customer's account at the close of a billing cycle shall not expire and shall be carried forward to subsequent billing cycles indefinitely. 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 Avoided Cost plus any additional sum determined under the Net Metering Rules, if the sum to be paid to the Net-Metering Customer is at least one hundred dollars ($100). An Electric Utility shall purchase at the Electric Utility's Avoided Cost, plus any additional sum determined under the Net Metering Rules 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.

When purchasing Net Excess Generation credits from a Net-Metering Customer, the Electric Utility shall calculate the payment based on its Avoided Costs plus any additional sum determined under the Net Metering Rules for the current year.

X.3.11. 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:

(a) The Net-Metering Customer must give at least 30 days' notice to the Electric Utility.

(b) The Additional Meter(s) must 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.

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However, the common ownership requirement shall not apply if more than two customers that are governmental entities or other entities that are exempt from state and federal income tax defined under 23-18-603(7)(c) co-locate at a site hosting the Net Metering Facility.

(c) In the event that more than one of the Net-Metering Customer's meters is identified, the Net-Metering Customer must designate the rank order for the Additional Meters to which excess kWh are to be applied. The Net-Metering Customer cannot designate the rank order more than once during the Annual Billing Cycle.

X.3.12. 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.

X.3.12. Grandfathering shall be governed by Ark. Code Ann. 23-18-604(b)(10).

Attachment 2

Blacklined Copy of Net Metering Rules

ARKANSAS
PUBLIC SERVICE COMMISSION

NET-METERING RULES

Last Revised: June 1, 2020
Order No. 28
Docket No. 16-027-R
Effective: xx-xx-xxxx

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	03/08/17	10	Revised Rules to comply with Act 827 of 2015.
	08/16/17	14	Errata Order.
	06/01/20	28	Revised Rules to comply with Act 464 of 2019.

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) Additional Meter

A meter associated with the Net-Metering Customer's account that the Net-Metering Customer may credit with Net Excess Generation 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.

(b) Annual Billing Cycle

The normal annual fiscal accounting period used by the utility.

(c) Avoided Cost~~s~~

As defined in Ark. Code Ann. § ~~23-3-702(1)~~23-18-603(1).

(d) 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) Commission

The Arkansas Public Service Commission.

(g) Electric Utility

~~(h)~~

~~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.~~As defined in Ark. Code Ann, § 23-18-603(3). A person who acts as a lessor or service provider as described in Ark. Code Ann. § 23-18-603(7)(B) or (C) shall not be considered an Electric Utility .

(h) Energy Storage Device

A device that captures energy produced at one time, stores that energy for a period of time, and delivers that energy as electricity for use at a future time.

(i) Fuel Cell Resource

A resource that converts the chemical energy of a fuel directly to direct current electricity without intermediate combustion or thermal cycles.

(j) Generation Meter

The meter associated with the Net-Metering Customer's account to which the Net- Metering Facility is physically attached.

(k) 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.

(l) Hydroelectric Resource

A resource in which the prime mover is a water wheel. The water wheel is driven by falling water.

(m) Micro Turbine Resource

A resource that uses a small combustion turbine to produce electricity.

(n) Net Excess Generation

As defined in Ark. Code Ann, § 23-18-603(5~~3~~).

~~(n)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 2.04, purchased by the utility in a future billing period.~~

(0) Net-Metering

As defined in Ark. Code Ann, § 23-18-603(6~~4~~).

(p) Net-Metering Customer

As defined in Ark. Code Ann, § 23-18-603(7~~5~~).

(q) Net-Metering Facility

As defined in Ark. Code Ann, § 23-18-603(8~~6~~).

(r) 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).

(t) Quantifiable Benefits

As defined in Ark. Code Ann, § 23-18-603(9).

~~(t)~~(u) Renewable Energy Credit

As defined in Ark. Code Ann, § 23-18-603(10~~7~~).

~~(u)~~(v) Residential Use

Service provided under an Electric Utility's standard rate schedules applicable to residential service.

~~(v)~~(w) Solar Resource

A resource in which electricity is generated through the collection, transfer and/or storage of the sun's heat or light.

~~(w)~~(x) 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)(4~~2~~).

Rule 2.04 Billing for Net Metering

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, except as provided herein~~in Rule 2.04 A.1.b~~.

   1. For Net-Metering Customers who receive service under a rate that does not include a demand component~~:, the Commission has decided, pursuant to Ark. Code § 23-18-604(b), to implement the following rate structure and procedure for requesting an alternative rate structures~~~~Under Net-Metering:~~

a. ~~;~~ Except as provided in Rule 2.04 A.1.b, a~~A~~n ~~the~~ Electric Utility shall~~shall~~ credit a Net-Metering Customer with the amount of any accumulated Net Excess Generation as measured in kilowatt hours or kilowatt hours multiplied by the applicabl~~te~~ retail rate in the next applicable billing period and base the bill of the Net-Metering Customer on the net amount of electricity as measured in kilowatt hours or kilowatt hours multiplied by the applicable retail rate –that the Net-Metering Customer has received from or fed back to the electric utility during the billing period.

b. –After December 31, 2022, An Electric Utility may file an application ~~for a general change in rates~~ to ~~request that the Commission~~ establish ~~and approve a new~~an alternative net- metering class and rate structure pursuant to Ark. Code Ann. § 23-18-604(b)(2)(B)-(D). ~~for its Net-Metering Customers who receive service under a rate that does not include a demand component.~~ The application shall include a cost of service study and substantial evidence that the Electric Utility's proposed rate structure is in the public interest and will not result in an unreasonable allocation of or increase in costs to the Electric Utility's other customers.

~~After reviewing the Electric Utility's application filed pursuant to this section, the Commission may establish one of the alternative rate structure options outlined in § 23-18-604(b)(2)(B)-(D) for the Electric Utility if the Commission determines the rate structure is in the public interest and doing so will not result in an unreasonable allocation of or increase in costs to the Electric Utility's other customers.~~

2. For Net-Metering Customers who receive service under a rate that includes a demand component with a generating capacity of 1,000 kW or less:~~, the Commission has decided, pursuant to Ark. Code § 23-18-604(b)(6), to implement the following rate structures:~~

An Electric Utility shall credit a Net-Metering Customer with the amount of any accumulated Net Excess Generation as measured in kilowatt hours or kilowatt hours multiplied by the applicable retail rate in the next applicable billing period and base the bill of the Net-Metering Customer on the net amount of electricity as measured in kilowatt hours or kilowatt hours multiplied by the applicable retail rate that the Net-Metering Customer has received from or fed back to the electric utility during the billing period.

~~For a Net Metering Facility with a generating capacity of up to 5 MW:, Tthe Electric Utility shall credit the net-metering customer with any accumulated Nnet Eexcess Ggeneration in the next applicable billing period and base the bill of the net-metering customer on the net amount of electricity that the net-metering customer has received from or fed back to the electric utility during the billing period.~~

~~a. For a Net Metering Facility with a generating capacity that exceeds 5 MW but does not exceed 20 MW: Pursuant to Ark. Code § 23-18-~~

~~604(b)(6), when considering whether to approve the facility, the Commission must determine that the Net-Metering Facility, and thus the approved rate structure, does not result in an unreasonable cost shift to other utility customers. Therefore, the Electric Utility shall credit the Net-Metering Customer with any accumulated Net Excess Generation in the next applicable billing period and base the bill of the Net-Metering Customer on the rate structure determined by the Commission at the time it approves the Net-Metering Facility.~~

3. For Net-Metering Customers who receive service under a rate that includes a demand component with a generating capacity over 1,000 kW and up to 20 MW and who receive approval to exceed the statutory limits under Ark. Code Ann. § 23-18-604(b)(9):

a. An Electric Utility shall credit a Net-Metering Customer with the amount of any accumulated Net Excess Generation as measured in kilowatt hours or kilowatt hours multiplied by the applicable retail rate in the next applicable billing period and base the bill of the Net-Metering Customer on the net amount of electricity as measured in kilowatt hours or kilowatt hours multiplied by the applicable retail rate that the Net-Metering Customer has received from or fed back to the electric utility during the billing period.

b. An Electric Utility shall also bill the Net-Metering Customer a grid charge.

c. The grid charge rate shall initially be set at zero effective May XX, 2020.

d. After the effective date of these NMRs, an Electric Utility may file an application to revise the grid charge rate. The application shall include a cost-of-service study and evidence demonstrating that an unreasonable cost shift to non-Net-Metering Customers is occurring or has already occurred on a cumulative basis rather than on the basis of an individual Net-Metering Customer's proposed facility(ies) and that the Electric Utility's proposed grid charge rate is in the public interest. Once approved, the Electric Utility shall bill these Net-Metering Customers in accordance with the Electric Utility's approved grid charge.

~~A.~~ If the kWh~~s~~ supplied by the Electric Utility exceeds the kWh~~s~~ 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 kWh~~s~~ supplied by the Electric Utility in accordance with the rates and charges

B. under the customer's standard rate schedule.

C. If the kWh~~s~~ generated by the Net-Metering Facility and fed back to the Electric Utility exceed the kWh~~s~~ supplied by the Electric Utility to the Net-Metering Customer during the applicable Billing Period, the Electric Utility shall credit the Net-Metering Customer with any accumulated Net Excess Generation as measured in kilowatt hours pursuant to Rule 2.04(A)(1)(a) or kilowatt hours multiplied by the applicable rate established by the Commission pursuant to Rule 2.04(A)(1)(b) in the next applicable Billing Period.

1. Net Excess Generation shall first be credited to the Net-Metering Customer's Generation Meter.

2. After application of subsection C.1. and upon request of the Net-Metering Customer pursuant to subsection D., 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.

3. Net Excess Generation shall be credited as described in subsections C.1. and C.2. during subsequent Billing Periods. The amount of –Net –Excess Generation c~~C~~redits ~~as measured in kilowatt hours or kilowatt hours multiplied by the applicable rate~~ 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 c~~C~~redits 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~~ plus any additional sum determined by the Commission 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~~ plus any additional sum determined– by the Commission, any Net Excess Generation c~~C~~redits 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.

~~When purchasing Net Excess Generation cCredits from a Net-Metering Customer, the Electric Utility shall calculate the payment based on its annual average aAvoided energy cCosts plus any additional sum determined under the Net Metering Rules 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.

~~3.~~4. At the time an Electric Utility processes a request for applying any remaining Net Excess Generation as a credit to one (1) or more of a Net-metering Customer's meters in the rank order provided by the Net-metering Customer pursuant to Ark. Code Ann. § 23-18-604(c), the Electric Utility shall synchronize the billing cycles of each additional customer meter with the customer's primary net-metering meter.

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.

~~E. A person who acts as a lessor or service provider as described in § 23-18-603(7)(B) or (C) shall not be considered a public utility as defined in § 23-1-101(9).~~

Rule 2.05 Meter Aggregation

A. ~~A.~~ Except as provided in subsections (B) and (C) of this Rule 2.05, an 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.

B. ~~B.~~ At the Net-Metering Customer's discretion, an electric utility may apply net-metering credits from a net-metering facility to any separate meter locations if the net-metering facility and the separate meter locations are under common ownership within a single electric utility's service area.

C. ~~C.~~ Subsection (B) of this Rule 2.05 does not apply if more than two (2) customers that are governmental entities or other entities that are exempt from state and federal income tax defined under § 23-18-607(7)(C) co-locate at a site hosting the net-metering facility.

~~A.~~D. A Net-Metering Customer seeking to aggregate multiple accounts under common ownership shall submit a request to the~~ir~~ Electric Utility identifying the accounts that are under common ownership. The request shall include the following documents:

1. Standard Application Form and Affidavit as approved by the Commission.~~: The Commission shall develop and provide an application form and form Affidavit for this purpose.~~
2. Sworn Affidavit: The Net-Metering Customer shall submit a sworn affidavit by a person with personal knowledge affirming that the Net-Metering Customer is in fact the legal owner or authorized representative responsible for paying the bill for all accounts listed in the application form.

Rule 2.06~~5~~ Application to Exceed Generating Capacity Limit

A. 1. 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 1,000~~300~~ kW for non-residential use under Ark. Code Ann. §§ 23-18- 604(b)~~-~~(9~~5) or (7~~) as appropriate.

2. For purposes of Rule 2.06(A)(1), "generation capacity" includes the aggregate ability to produce electricity from all Net-Metering Facilities under common ownership that are located within a single utility's service territory.

~~A.~~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:

Evidence that ~~:~~

1. ~~a.~~ ~~t~~~~T~~the Net-Metering Facility in excess of 1,000~~300~~ kW satisfies the requirements of Ark. Code Ann. §§ 23-18-604(b)(9~~)(5) or (7~~)~~:~~;

~~ab. The Net-Metering Facility has a generating capacity that does not exceed twenty thousand kilowatts (20,000 kW); and~~

~~bc(i). For any net-metering facility with a generating capacity of less than five thousand kilowatts (5,000 kW):~~

~~iA. The net-metering facility is not for residential use;~~

~~iiB. Increasing the generating capacity limits for individual net-metering facilities results in distribution system, environmental, or public policy benefits, or allowing an increased generating capacity for the net-metering facility would increase the state's ability to attract businesses to Arkansas; and~~

~~iiiC. Allowing an increased generating capacity for the net-metering facility is in the public interest; or~~

~~c(ii). For any net-metering facility with a generating capacity of greater than five thousand kilowatts (5,000 kW):~~

~~iA. The net-metering facility is not for residential use;~~

~~iiB. Increasing the generating capacity limits for individual net-metering facilities results in distribution system, environmental, or public policy benefits, or allowing an increased generating capacity for the net-metering facility would increase the ability of the state to attract business to Arkansas;~~

~~iiiC. Allowing an increased generating capacity for the net-metering facility does not result in an unreasonable allocation of costs to other utility customers; and~~

~~ivD. Allowing an increased generating capacity for the net-metering facility is in the public interest;~~

~~1.~~2. A description of the proposed Net-Metering Facility for each discrete location including:

a. Project proposal;

b. Project location (street address, town, utility service area);

c. Generator type (wind, solar, hydro, energy storage device, 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.);

~~2.~~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 Net Excess Generation or

b. In the absence of historical data reasonable estimates for the class and character of service may be made; and

~~3.~~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.

Rule 2.07 Grandfathering Net-Metering Rate Structures

A. Net-Metering Facilities for residential use or for other than residential use that does not exceed one thousand (1,000) kW:

1. The Net-Metering Facility of a Net-Metering Customer who submits a Standard Interconnection Agreement to the Electric Utility before December 31, 2022, shall remain under the Net-Metering rate structure in effect when the Standard Interconnection Agreement was signed by the Net-Metering Customer, for a period of twenty (20) years beginning May XX, 2020.

2. A Net-Metering Facility may be upgraded and retain grandfathered status so long as the Net-Metering Facility still meets the statutory definition under Ark. Code Ann. § 23-18-603(8).

B. Net-Metering Facilities for which approval is required to exceed one thousand (1,000) kW:

1. If a Net-Metering Customer (a) requests approval to exceed the statutory limit for a Net-Metering Facility pursuant to Ark. Code Ann. § 23-18-604(b)(9), and (b) has submitted a Standard Interconnection Agreement to the Electric Utility before December 31, 2022, the Net-Metering Customer may request that the Net-Metering Facility remain under the Net-Metering rate structure in effect when the Standard Interconnection Agreement was signed by the Net-Metering Customer. The request will be considered on a case-by-case basis for a grandfathering period up to twenty (20) years. The request to be grandfathered shall be made when the request to exceed the statutory limit is made.

2. If a Net-Metering Customer proposes to upgrade a Net-Metering Facility under 1,000 kW and add additional generating capacity by either (a) an upgrade to the existing Net-Metering Facility, or (b) an additional Net-Metering Facility, and such upgrade would cause the total generating capacity to exceed 1,000 kW, then the original capacity of the Net-Metering Facility shall retain any grandfathered status and the additional capacity shall be subject to the Net-Metering rate structure in effect when the Standard

Interconnection Agreement for the additional capacity is signed by the Net-Metering Customer.

3. If a Net-Metering Customer proposes to upgrade a Net-Metering Facility for which approval was previously granted by the Commission pursuant to Ark. Code Ann. § 23-18-604(b)(9) and add additional generating by either (a) an upgrade to the existing Net-Metering Facility, or (b) an additional Net-Metering Facility, then the original capacity of the Net-Metering Facility shall retain any grandfathered status and the additional capacity shall be subject to the Net-Metering rate structure in effect when the Standard Interconnection Agreement for the additional capacity is signed by the Net-Metering Customer.

4. The cost of any additional metering equipment required under subsections B.2. or B.3. above shall be borne by the Net-Metering Customer.

C. The Electric Utility need not have approved and signed the Standard Interconnection Agreement for the date of eligibility for grandfathering to be established.

D. The grandfather period shall attach to the Net-Metering Facility on the premises rather than the Net-Metering Customer.

E. If the Net-Metering Customer sells a premises with a Net-Metering Facility, the Standard Interconnection Agreement may be transferred to the new Net-Metering Customer and the grandfather period shall continue for the remainder of the twenty (20) year term, assuming no other triggering event occurs.

F. A Net-Metering Customer may not transfer a Net-Metering Facility to a new premises or location and continue to operate under the grandfather period.

G. Maintenance and repair of existing Net-Metering Facilities shall not be a triggering event which ends the grandfather period.

H. A Net-Metering Facility grandfathered under this Rule remains subject to any other change or modification in rates, terms, or conditions.

~~Pursuant to Ark Code § 23-18-604(b)(10), the net-metering facility of a net-metering customer who submits a standard interconnection agreement, as referred to in these Net Metering Rules, to the electric utility after July 24, 2019, but before December 31, 2022, is allowed to remain under the rate structure in effect when the agreement was signed, for a period not to exceed twenty (20) years, subject to approval by the Commission.~~

~~The Commission approves grandfathered rate structures for the following net-metering facilities described in of a net-metering customer who submits a standard interconnection agreement as referred to in these Net Metering Rules before December 31, 2022, for a period of 20 years:~~

~~Net-Metering Facilities for Residential use that meet the requirements of Ark. Code § 23-18-603(8) (B)(i);~~

~~Net-Metering Facilities for other than Residential use with a generating capacity that does not exceed 1,000 kW pursuant to Ark. Code § 23-18-603(8) (B)(ii).~~

~~The Commission will consider and approve grandfathering rate structures on a case-by-case basis for Net Metering Facilities whose customers request a waiver to exceed the statutory limits for Net-Metering Facilities pursuant to Ark. Code § 23-18-604(b)(9).~~

~~A net-metering facility grandfathered under this Rule remains subject to any other change or modification in rates, terms, or conditions.~~

Rule 2.08 Leases and Safe Harbor for Service Agreements

A. A Net-Metering Customer entering into a lease for a Net-Metering Facility shall provide to the Electric Utility a standard Notice and Affidavit approved by the Commission to the Electric Utility certifying that the lease is in compliance with all Commission Rules and Ark. Code Ann. § 23-18-603(7)(B).

~~A.~~B. A Net-Metering Customer entering into a service agreement for a Net-Metering Facility who~~that~~ is relying on Ark. Code Ann. § 23-18-603(7)(C) to qualify for net metering shall submit a standard Notice and Affidavit approved by the Commission to the ~~Public~~Electric Utility certifying that the customer qualifies for safe-harbor protection as provided by Ark. Code Ann. § 23-18-603(7)(C) and 26 U.S.C. § 7701(e)(3)(A)) and that the service agreement is in compliance with all Commission Rules.

C. ~~The Notice and Affidavit shall certify that the Net-Metering Customer meets the safe harbor requirements as provided by the Internal Revenue Service in Revenue Procedure 2017-19 and the Office of Management and Budget Memorandum M-12-21.~~

~~The Commission will provide a standard Act 464 Notice and Affidavit form and make the form available on its website.~~

Disputes over compliance with Subsection (A) or (B) above shall be submitted to Staff for review and attempted resolution. Thereafter, a Net-Metering Customer or Electric Utility who disagrees with Staff's resolution may petition the Commission to resolve the dispute. Electric~~Public~~ Utilities shall presume that any person who submits a completed Notice and Affidavit form is in compliance with the Commission's Rules and the ~~Act 464's Safe Harbor~~ provisions under Ark. Code Ann. § 23-18-603(7)(B) or (C) until the Commission makes a finding otherwise.

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 and owner of the Net-Metering Facility, if different, 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 Facility~~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 and owner of the Net-Metering Facility, if different, 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 or owner 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 or owner of the Net-Metering Facility 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 or owner of the Net-Metering Facility 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 or owner of the Net-Metering Facility 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 2.06~~5~~.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. Each Preliminary Interconnection Site Review Request will be considered separately and in the order in which received. 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. The customer may request parallel processing of multiple reviews but must pay actual costs of conducting the review and any subsequent costs associated with site screening that may be required under Rule 3,03.C. In such event, the Electric Utility shall respond to the request and shall process and present the results of the multiple reviews within a reasonable time, not to exceed ninety (90) 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.

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), Preliminary Interconnection Site Review Request (Appendix A-1) and a Net-Metering Tariff in standard tariff format (Appendix B).

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, Storage, etc.), its use (by specific rate class(es)~~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 ~~and shall also include:~~

~~A. Adoption of Net Metering facilities as a percentage of the utility's total production capacity in kW and kWh by rate class;~~

~~Net-Metering as a percentage of the utility's peak demand;~~

~~The solar PV installation information by rate class;~~

~~B. The total number of Net-Metering Customers by rate class;~~

~~C. The kW and kWh of each installation by rate class; and~~

~~D. The monthly peak demand by rate class.~~

SECTION 5. RULES TO GUARD AGAINST GAMING

Rule 5.01 Gaming Defined

Gaming is defined as ~~M~~manipulating, misrepresenting, or otherwise configuring a Net-Metering Facility or Facilities in a manner that is intended to result in, or that actually results in, the avoidance of statutory or Commission limits or rules.

Gaming of the Net-Metering Rules includes, but is not limited to, the following actions:

A. Adding additional capacity to an existing Net-metering Facility without notifying the Electric Utility to which the Net-Metering Facility is interconnected;

~~A.~~B. Changing the ownership, lease, or service contact of a Net-Metering Facility for the purpose of avoiding the 1,000kW generation capacity threshold;

C. Failing to include any and all facilities used for Net-Metering under common ownership in a single utility's service area as a single facility for generation capacity purposes pursuant to Rule 2.06, regardless of the location of the facility and the customer's decision to aggregate for meter, bill, and crediting purposes;~~.~~

D. Unauthorized interconnections.

Rule 5.02 Gaming Prohibited

Gaming of the Net-Metering Rules is prohibited.

Rule 5.03 Penalties for Gaming

Any Net-Metering Customer found to be engaged in activity considered to be gaming under the Net-metering Rules may have its~~their~~ qualification as a Net-Metering Customer suspended or terminated by the Commission following notice and opportunity for hearing.

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 Energy Storage Device (circle all that apply~~one~~)
Generator Rating (kW):____________________________ DC
Inverter 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 (Net Metering Customer~~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(8~~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 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.

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~~customer's 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 customer's~~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:
__________________________________	__________________________________

Third-Party Owner (if applicable): ____________

____

By: ______________________________________

Title: ____________________________________

Mailing Address: __________________________

____

____

E-mail Address: ___________________________

____

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 A-1

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 Energy Storage Device (circle all that apply~~one~~)
Generator Rating (kW):____________________________________DC
Inverter 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~~5~~.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 1,000~~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 1,000~~300~~ kW facility size limit pursuant to Net Metering Rule 2.06~~5~~.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.

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Kind of Service: Electric	Class of Service: All	
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Title: NET-METERING		PSC File Mark Only

X. NET-METERING

X.1. DEFINITIONS

X.1.1. Avoided Cost
As defined in A.C.A. 23-18-603(1)

X.1.2. Net Metering
As defined in A.C.A. 23-18-603(6)

X.1.3. Net Metering Customer
As defined in A.C.A. 23-18-603(7)

X.1.4. Net Metering Facility
As defined in A.C.A. 23-18-603(8)

X.1.5. Electric Utility
As defined in A.C.A. 23-18-603(3)

X.1.6. Net Excess Generation
As defined in A.C.A. 23-18-603(5)

X.1.7. Renewable Energy Credit
As defined in A.C.A. 23-18-603(10)

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X.1.8. Quantifiable Benefits
As defined in A.C.A. 23-18-603(9)

X.~~1~~2. AVAILABILITY

X.~~1.1~~2.1. Service under the provisions of this tariff is available to~~To~~ any residential or any other customer who takes service under standard rate schedule(s) ________________ (list schedules) who is a Net-Metering Customer~~ as defined,~~ and ~~who is an owner of a Net-Metering Facility and~~ who has obtained a signed Standard Interconnection Agreement for Net-Metering Facilities with an Electric Utility. 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~~one thousand kilowatts (~~300~~1,000 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.

The provisions of the customer's standard rate schedule are modified as specified herein.

X.~~1.2~~2.2. 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~~3. MONTHLY BILLING

X.~~2.1~~3.1. 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.

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X.~~2.2~~3.2. 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 Net–Metering Customer's bill are netted.

X.~~2.3~~3.3. 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 billable kWhs supplied by the Electric Utility in accordance with the rates and charges under the Net-Metering Customer's standard rate schedule.

X.3.4. For Net-Metering Customers who receive service under a rate that does not include a demand component, the Electric Utility shall credit a Net-Metering Customer with the amount of any accumulated Net Excess Generation as measured in kWh~~kilowatt hours~~ or kWh~~kilowatt hours~~ multiplied by the applicable- ~~retail~~ rate -in the next applicable billing period and base the bill of the Net-Metering Customer on the net amount of electricity as measured in kWh or kWh multiplied by the applicable retail rate that the Net-Metering Customer has received from or fed back to the Electric Utility during the billing period..

X.3.5. ~~Except as provided in Ark. Code Ann. §23-18-604(b)(9), f~~For Net-Metering Customers who receive service under a rate that includes a demand component with a generating capacity of 1,000 kW or less, the Electric Utility shall credit the Net-Metering Customer with any accumulated Net Excess Generation in the next applicable billing period and base the bill of the Net-Metering Customer on the net amount of electricity that the Net-Metering Customer has received from or fed back to the Electric Utility during the billing period.

X.3.6 For Net-Metering Customers who receive service under a rate that includes a demand component with a generating capacity over 1,000 kW and up to 20 MW and who receive approval to exceed the statutory limits under Ark. Code Ann. § 23-18-604(b)(9), the Electric Utility shall credit a Net-Metering Customer with the amount of any accumulated Net Excess Generation as measured in kWh or kWh multiplied by the applicable retail rate in the next applicable billing period and base the bill of the Net-Metering Customer on the net amount of electricity as measured in kWh or kWh multiplied by the applicable retail rate that the Net-Metering Customer has received from or fed back to the electric

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utility during the billing period.

The Electric Utility shall also bill the Net-Metering Customer a grid charge.

Grid charge rate: $0.00.

X.~~2.4~~3.7~~6~~. 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 shall credit the Net-Metering Customer with any accumulated Net Excess Generation in the next applicable Billing Period.

X.~~2.5~~3.8~~7~~. 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).

X.~~2.6~~3.9~~8~~. After application of X.~~2.5~~3.8~~7~~. and upon request of the Net-Metering Customer pursuant to X.~~2.8~~3.11~~10~~., any remaining Net Excess Generation 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.

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X.~~2.7~~3.10~~9~~. Net Excess Generation shall be credited as described in X.~~2.5~~3.8~~7.~~ and X.~~2.6~~3.9~~8~~. during subsequent Billing Periods; the Net Excess Generation c~~C~~redits remaining in a Net- Metering Customer's account at the close of a billing cycle shall not expire and shall be carried forward to subsequent billing cycles indefinitely. For Net Excess Generation c~~C~~redits older than twenty-four (24) months, a Net-Metering Customer may elect to have the Electric Utility purchase the Net Excess Generation c~~C~~redits in the Net-Metering Customer's account at the Electric Utility's ~~estimated annual average~~ A~~a~~voided C~~c~~ost plus any additional sum determined under the Net Metering Rules ~~rate for wholesale energy~~, if the sum to be paid to the Net-Metering Customer is at least one hundred dollars ($100). An Electric Utility shall purchase at the Electric Utility's ~~estimated annual average~~ Avoided Cost, plus any additional sum determined under the Net Metering Rules ~~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.

When purchasing Net Excess Generation c~~C~~redits from a Net-Metering Customer, the Electric Utility shall calculate the payment based on its ~~annual average~~ ~~a~~Avoided ~~energy~~ ~~c~~Costs plus any additional sum determined under the Net Metering Rules ~~in the applicable Regional Transmission Organization~~ for the current year.

X.~~2.8~~3.11~~10~~. 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:

(a) The Net-Metering Customer must give at least 30 days' notice to the Electric Utility.

(b) The Additional Meter(s) must 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.

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However, the common ownership requirement shall not apply if more than two customers that are governmental entities or other entities that are exempt from state and federal income tax defined under 23-18-603(7)(c) co-locate at a site hosting the Net Metering Facility.

(c) In the event that more than one of the Net-Metering Customer's meters is identified, the Net-Metering Customer must designate the rank order for the Additional Meters to which excess kWh~~s~~ are to be applied. The Net-Metering Customer cannot designate the rank order more than once during the Annual Billing Cycle.

X.~~2.9~~3.12~~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.

X.3.12~~12~~. Grandfathering shall be governed by Ark. Code~~.~~ Ann. 23-18-604(b)(10).