BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

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

SURREPLY COMMENTS OF SUB-GROUP 1 TO JOINT REPORT AND RECOMMENDATIONS OF THE NET-METERING WORKING GROUP

I. Introduction

The Commission should conclude that existing net metering policies recover the full cost of serving net metering customers, net of quantifiable benefits, as required by Ark. Code Ann. § 23-18-604(b)(1)(A). As shown in the analysis of Entergy Arkansas, Inc.'s system by Crossborder Energy, all customers benefit from net-metering because current rules, rate design, and policies equitably balance the interests of net-metering customers, non-net-metering customers, and utilities, and serve the overall public interest.

In its reply comments, Sub-Group 2 acknowledges that it is "the goal of AREDA to encourage the use of renewable energy through net-metering," and asserts that the group "supports the development of renewable energy resources and renewable energy technologies in Arkansas."[1] While these statements confirm Sub-Group 2's understanding of the important policy reflected in AREDA, they stand in sharp contrast with the end results of the proposed rate

[1] Reply Comments of Sub-Group 2 of the Net-Metering Working Group, Docket No. 16-027-R (filed Oct. 20, 2017), at 1-2 (hereinafter Sub-Group 2 Reply Comments).

changes Sub-Group 2 would have this Commission adopt. Moreover, these assertions are contradicted by Sub-Group 2's effort to portray the current net metering rate design as not reflective of important Arkansas state policy.

Sub-Group 2 seeks to minimize the significance of the Crossborder Energy study filed by Sub-Group 1, by contending that long-term benefits and costs of distributed generation are irrelevant to the statutory analysis. However, the Crossborder study is in fact highly relevant to the Commission's inquiry here. It reveals that compensating residential net metering customers at retail rates for their exports to the grid provides net benefits to other ratepayers over the long term and provides significant environmental and economic benefits to Arkansas, just as the General Assembly recognized when enacting AREDA. If the Commission were to eliminate net metering in favor of a billing design that would further impede development of distributed generation in the state, none of these long-term benefits, either direct or societal, would be realized. The long-term benefits to Arkansans are well within the Commission's discretion to consider as it determines whether current net metering tariffs comply with AREDA.[2]

[2] *See, e.g.*, Carl Linvill, John Shenot & Jim Lazar, *Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition* (Nov. 2013), at 25 ("For states where the public policy driver is a clean energy policy aimed at supporting a wide range of non-energy benefits like promoting public health, protecting the environment, or promoting energy security by reducing dependence on imported energy, an [Societal Cost Test] that includes some valuation of these non-energy benefits is important to assessing the net value created by adding distributed generation."), available at http://www.raponline.org/wp-content/uploads/2016/05/rap-linvillshenotlazar-faircompensation-2013-nov-27.pdf.

II. AREDA's purpose is to "encourage the use of renewable energy resources" through net metering

The purpose section of AREDA is a critical guide for the Commission in this rulemaking proceeding.[3] As explained in Sub-Group 1's initial comments, 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."[4] Specifically, the General Assembly recognized a wide spectrum of 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."

The General Assembly's view that net metering is vital to Arkansas's long-term interests because it promotes renewable generation is beyond dispute. Sub-Group 2 does not deny this legislative purpose, though it does minimize its significance. Sub-Group 2 repeatedly boasts fealty to the statutory language, but it downplays the legislative purpose statement and its ramifications for the Commission's decision in this matter.

While Sub-Group 1 has emphasized the importance of this proceeding for the renewable energy industry in Arkansas, Sub-Group 1 does not believe, and has never asserted, that "this proceeding is the appropriate venue to address the need for renewable energy resources in

[3] Ark. Code Ann. § 23-18-602.
[4] *Id.* § 23-18-602(a).

Arkansas," as Sub-Group 2 inaccurately states.[5] However, it is absurd to pretend that the changes in net metering design and rates, especially changes as drastic as those advocated by Sub-Group 2, will not significantly impact distributed renewable energy adoption in Arkansas. Sub-Group 1's initial comments expressed a strong view that the stakes in this proceeding are high for the renewable energy industry in Arkansas because that is true, not because it is the only proceeding of consequence for that industry. There is much more that the Commission can do—such as facilitating community solar development, ensuring that avoided cost rates paid under PURPA are not discriminatory, implementing improved interconnection processes, requiring rigorous consideration of renewable energy in integrated resource plans—that would support and advance renewable energy resources in Arkansas.

It is true that AREDA does not require the Commission to promote renewable energy regardless of the cost to other ratepayers. However, the record here demonstrates that in this case the Commission faces no divergence of interests. As the Crossborder study shows, net metering provides net benefits to other ratepayers by encouraging private investment in generation resources that reduce the utility's costs. Thus, Sub-Group 1 does not assert that the purpose section of AREDA means the Commission need not consider the potential impact on non-participating customers, as Sub-Group 2 alleges.[6] Non-participating customers benefit from net

[5] Sub-Group 2 Reply Comments at 5.
[6] *Id.* at 17.

metering, as shown by the Crossborder study's findings that net metering of solar distributed generation receives a score greater than one on the Ratepayer Impact Measure test.[7]

Two-channel billing would not promote distributed generation in Arkansas. The problems with this construct are deeper than the methodology proposed to set the exported generation credit rate, the flaws of which are discussed below in Section V. Two-channel billing 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. The two-channel billing 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. The Commission should reject the two-channel billing construct as fundamentally inconsistent with AREDA for these policy reasons alone.

[7] Joint Report and Recommendations of the Net-Metering Working Group, at 95, Table 20. As this Commission has discussed in the context of energy efficiency programs, the RIM test should not be the deciding factor regarding any particular measure or portfolio. We note that other cost-effectiveness tests, such as the total resource cost test and the program administrator cost test (utility cost test), are also relevant to the question of whether non-participating customers benefit, and the Crossborder study also shows that benefits exceed costs under these tests as well, if at least some of the expanded direct costs are included. *Id.*

III. AREDA does not require the Commission to strictly adhere to embedded cost of service data and ignore long-term benefits associated with distributed generation.

Sub-Group 2 contends that AREDA requires the Commission to determine rates charged to net metering customers based solely on embedded cost of service principles, because that is how rates have always been set in Arkansas and the Commission has no authority to set rates any other way.[8] This argument is flawed for two reasons. First, the statute defines the "cost of providing service to each net-metering customer" using language that modifies the traditional meaning of "cost of service," creating an issue of first impression for this Commission as to the proper approach to set rates in this context. Second, this Commission does not, and is not required to, mechanically follow cost of service when allocating costs or designing rates, but can and does instead consider other policy objectives within its purview.

A. AREDA instructs the Commission to consider benefits of distributed generation, a matter on which a utility's cost of service study is silent.

Act 827 added language to AREDA requiring that "rates charged to each net-metering customer recover the electric utility's entire cost of providing service to each net-metering customer."[9] The statute then defines "cost of providing service to each net-metering customer" to be "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

[8] Sub-Group 2 Reply Comments at 14-21.

[9] Ark. Code Ann. §23-18-604(b)(1)(A)(i). AREDA also requires the cost of serving a net metering customer to "[i]nclude[] 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." *Id.* §23-18-604(b)(1)(A)(ii)(a). The Crossborder study evaluated additional costs as well, which may include (depending on the test at issue) integration costs, lost revenues, and administrative costs.

capacity, reliability, distribution system, or transmission system" (hereinafter, the "benefits provision")[10].

Sub-Group 2 contends that AREDA does not establish a new regulatory framework for the Commission to set rates.[11] Yet AREDA indisputably requires the Commission to consider—when setting rates for net metering customers—something that no cost of service study evaluates – the benefits (i.e., negative costs) associated with net metering. Thus, the Commission is considering a matter of first impression in Arkansas law – what does it mean to net out benefits of a customer-sited generation resource against that customer's cost of service? The Commission has discretion to depart from a strict cost of service structure if it finds that such a departure would not accurately and fully capture the benefits to the utility, as the General Assembly required. First and foremost, we note that Ark. Code Ann. §23-18-604(b)(1)(A)(i) only requires that rates <u>charged to</u> net metering customers recover the full cost of service. Thus, Sub-Group 2's contention that rates <u>paid</u> to net metering customers must also be based solely on a strict cost of service analysis is unsupported by the statutory text.

Furthermore, as discussed in our prior comments, a cost of service structure does not capture the avoided system costs associated with distributed generation, which is an inherently forward-looking inquiry. In its response to Sub-Group 2's proposal, Crossborder Energy explains:[12]

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[10] *Id.* §23-18-604(b)(1)(A)(ii)(b).
[11] Sub-Group 2 Reply Comments at 7.
[12] Attachment A to Reply Comments of Sub-Group 1.

> 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."[13] 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 new long-term resource such as DG.

Experts at the Regulatory Assistance Project also describe the role of long-run marginal costs in this type of inquiry:

> The long run marginal cost is the appropriate metric to use to represent the utility system avoided cost, because a [distributed generation] investment by consumers should be considered to be a resource rather than merely a device to achieve short-term load reduction. As such the utility system benefit should include all avoided marginal costs, including avoided transmission, net avoided distribution and avoided generation cost, avoided line loss, avoided reserve requirements, and avoided RPS standard compliance costs.[14]

Cost-of-service studies simply do not inform the Commission about the level of benefits that distributed generation resources provide to the utility's system, "including without

[13] *See* 18 C.F.R. Part 292.101(b)(6) (emphasis added).

[14] Linvill et al., *Designing Distributed Generation Tariffs Well*, at 23; *see also id.* at 31 ("[T]hose DG customers who produce power are offering a long term product with a service life of 20 years or more to the utility and as such are helping the utility and its customers to avoid the long-run marginal cost of new resources. Thus it should not be surprising that the basis for the value of services offered by the utility to DG customers differs from the value of services offered by the DG customer to the utility.").

limitation" benefits to its capacity, reliability, distribution and transmission systems.[15] Nor has Sub-Group 2 pointed to any precedent for a cost-of-service-based calculation of the benefits of distributed generation that would require the Commission to limit its inquiry to benefits based on embedded cost-of-service concepts. As noted in Sub-Group 1's reply comments,[16] AREDA requires that "rates charged to net metering customers should recover the utility's entire cost of providing service," but is silent about credits *paid* to net metering customers. Thus, contrary to Sub-Group 2's suggestion that the Commission has no discretion and must proceed solely on cost of service grounds,[17] AREDA in fact delegates considerable discretion to the Commission to interpret the novel ratemaking concept embodied by the benefits provision. In short, 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. Should the Commission determine that Ark. Code Ann. § 23-18-604 is ambiguous as to how the benefits of net metered facilities are to be factored into the utility's cost to serve a net metering customer, it should refer to AREDA's overarching intent to determine how to best interpret the benefits provision.[18]

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[15] While Sub-Group 2 has formulated a way in which the net metering customer's avoided *responsibility* for those costs *could* be calculated based on cost-of-service concepts that does not mean that such an interpretation of AREDA's benefits provision is inevitable or required.
[16] Reply Comments of Sub-Group 1 to Joint Report and Recommendations of the Net-Metering Working Group (filed Oct. 20, 2017), at 14-15.
[17] Sub-Group 2 Reply Comments at 15 (asserting that language of AREDA is unambiguous).
[18] *See, e.g.*, Docket 16-027-R, Order No. 13, at 23-24 (referring to the General Assembly's intent to promote net metering in resolving unclear statutory language regarding net metering for systems larger than 300 kilowatts).

As described further below, cost-of-service ratemaking is not as cut and dried as Sub-Group 2 suggests, even in routine applications. Thus, there is certainly nothing "well-defined" and "time-tested" about establishing rates paid to net metering customers for their exported power based on those concepts. Contrary to Sub-Group 2's argument, AREDA does not say that net metering rates should be based on the exact form and results of the utility's most recent embedded cost of service study. Indeed, by requiring benefits provided by net metering to the utility's system to be netted against the customer's cost of service, the statute clearly indicates that the Commission should take a different approach to the issue—one which accommodates consideration of long-term avoided costs. Sub-Group 2 strains to ignore this simple reality, because, as the Crossborder study reveals, there is great value in distributed generation to which traditional cost of service studies are blind due to their backward-looking nature and essential concern with allocating responsibility for current costs.

Sub-Group 2 provides a sentence diagram of the benefits provision that is grammatically dubious and ultimately misleading.[19] First, that diagram and Sub-Group 2's related discussion omits the entire second half of the benefits provision, which reads: "including without limitation benefits to the electric utility's capacity, reliability, distribution system, or transmission system."[20] Those words, as well as the leading "any" which Sub-Group 2's diagram also omits, are revealing of the General Assembly's intent for the Commission to cast a wide net when determining what quantifiable, additional benefits are associated with net metering. Sub-Group

[19] Sub-Group 2 Reply Comments at 20-21.
[20] Ark. Code Ann. §23-18-604(b)(1)(A)(ii)(b).

2's interpretation of "associated with" is also inexplicably narrow.[21] For example, all of the benefits calculated in the Crossborder study are "associated with" the interconnection of the net metering system—were it not interconnected with the utility's system, none of those benefits would be realized.

Sub-Group 2 states: "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."[22] This sentence is revealing of why Sub-Group 2's conceptual approach is inconsistent with AREDA. By its very nature, no utility embedded cost can be avoided by today's exports from a customer's distributed generation system. The customer's self-generation can only change how much of those costs are allocated to the class to which a net metering customer belongs in a subsequent cost of service study. A net metering customer cannot "benefit" the utility's system by reducing his or her responsibility for existing system costs[23]—the customer benefits the system (i.e., other consumers) by reducing the need for the utility to incur future costs. Thus, to interpret AREDA's benefits provision to be solely concerned with how a customer reduces his or her responsibility for embedded costs misses the General Assembly's point entirely.[24]

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[21] Sub-Group 2 Reply Comments at 21.
[22] *Id.*
[23] That customer will, however, benefit the residential class by reducing the system peaks that will determine which costs are allocated to the residential class in the subsequent rate case. A net metering customer may also benefit Arkansas customers more broadly by reducing the share of a utility's costs allocated to this jurisdiction.
[24] The energy portion of Sub-Group 2's excess generation credit rate does use marginal costs, rather than embedded costs and in that respect, captures "avoided costs" in a conceptually sound manner. However, the other costs included in the excess generation credit rate are based on embedded costs, and Sub-Group 2's overarching approach to this valuation relies upon cost-of-service studies which, in Arkansas, are based primarily on embedded costs.

B. The Commission has authority to depart from cost of service when setting rates

AREDA does not change this Commission's practice and inherent authority to set rates that are fair, just and reasonable, using cost of service as a guidepost, but not a determinative factor. Sub-Group 2's approach to AREDA reduces this Commission's role in rate-setting to a mechanical application of a cost of service study.

This Commission recognizes policy interests other than strict adherence to cost of service when setting rates. For example, the Commission has approved deviations from the class cost allocations produced by a cost of service study in accepting rate mitigation strategies to ensure that no class receives a rate decrease when other classes are receiving rate increases.[25] As the Commission has explained in adjusting cost allocations, "[t]he Commission's policy concerning cost-based rates has been tempered with the desire to avoid unnecessary significant adverse customer impact."[26] The Commission has also invited utilities to file rate cases including customer charges set at a level low enough to encourage conservation,[27] a clear indication that it will depart from cost of service principles where justified by other important policy considerations.[28] Indeed, the Commission has already demonstrated in this docket that it will

[25] *See In the Matter of the Application of Entergy Arkansas, Inc., for Approval of Changes in Rates for Retail Electric Service*, Docket No. 13-028-U, Order No. 21 (Dec. 30, 2013), at p. 133.
[26] *In the Matter of the Application of CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Arkansas Gas for a General Change or Modification in its Rates, Changes and Tariffs*, Docket No. 15-098-U, Order No. 8 (Sept. 2, 2016), at p. 45.
[27] *In The Matter Of The Consideration Of Innovative Approaches To Ratebase Rate Of Return Ratemaking Including, But Not Limited To, Annual Earnings Reviews, Formula Rates, And Incentive Rates For Jurisdictional Electric And Natural Gas Utilities*, Docket No. 08-137-U, Order No. 19.
[28] *See also In the Matter of the Application of Entergy Arkansas, Inc., for Approval of Changes in Rates for Retail Electric Service*, Docket No. 13-028-U, Order No. 21, at p.137 ("The

depart from what Sub-Group 2 portrays as Act 827's strict cost of service approach where other policy concerns are implicated, when it determined that should net metering rates change, existing net metering customers would be allowed to continue taking service under the existing rates.[29]

In directing the Commission to ensure that rates charged to net metering customers recover the full cost of serving them, the General Assembly is presumed to be aware of the Commission's practice of departing from strictly cost-based rates to avoid certain unacceptable impacts on customers and to achieve public policy objectives within the Commission's purview.[30]

Sub-Group 1 has not, as Sub-Group 2 suggests, advocated for a value of solar approach to setting rates for exports from distributed generation systems.[31] We have not advocated, for example, that exported generation for EAI residential customers be set at 12.9 or 17.2 cents, which are the two values for solar distributed generation based on the Crossborder Study. To be clear, Sub-Group 1 presents the Crossborder Study not as the basis for establishing new rates, but

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Commission finds the AG's recommendations in this case appropriately assign costs to those components of the rates which will provide incentives for conservation.").

[29] *See* Docket 16-027-R, Order No. 10, at 143 ("The Commission finds that adoption of a grandfathering period to provide such notice and to promote certainty in the market for NMFs need not conflict with Act 827's requirement that "each" NMC pay its entire cost of service."); *see also id.* at 144 ("This approach comports with the Commission's general duty to fix just and reasonable rates, and it comports with common ratemaking principles, which include gradualism in the introduction of new policies that affect specific ratepayers or classes of ratepayers.").

[30] *Davis v. Old Dominion Freight Line, Inc.*, 341 Ark. 751, 756, 20 S.W.3d 326, 329 (2000) ("[W]hen the construction of a statute is at issue, we will presume that the General Assembly, in enacting it, possessed the full knowledge of the constitutional scope of its powers, full knowledge of prior legislation on the same subject, and full knowledge of judicial decisions under preexisting law.").

[31] Sub-Group 2 Reply Comments at 15.

to demonstrate that existing net metering rates recover the full cost of serving net metering customers when the additional benefits and costs of distributed generation are considered. However, we note that such an approach would be within the Commission's discretion, given the breadth of AREDA's benefits provision.

Another matter for the Commission to consider when determining whether it is strictly bound by cost of service principles when implementing AREDA is the *de minimis* nature of Sub-Group 2's alleged shortfall. A parsing of Sub-Group 2's proposed approach seems to indicate they believe there is a shortfall in revenue recovery from residential net metering customers amounting to approximately $10 per customer per month, or $120 per year.[32] If one assumes there are 500 net metering customers in Arkansas to whom this rate would apply,[33] the alleged shortfall amounts to roughly $60,000 of additional revenue annually to be recovered from these 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. As a result, if the number of residential net metering customers were to grow by a factor of 10—an exceedingly optimistic assumption—the average residential customer in Arkansas by Sub-Group 2's estimation may incur about 50 cents per year in additional costs.

[32] This illustrative calculation employs the cost recovery shortfall based on data for Entergy Arkansas, as presented the Sub-Group 2 initial comments. A more detailed analysis, which is unnecessary for the rhetorical point made here, would obviously employ data specific to each utility.

[33] The utilities' reported data on net metering customers do not indicate the class to which those customers belong. The total number of net metering customers based on 2016 reports is approximately 630, of which we assume 500 are on non-demand tariffs for the purpose of this analysis. Per the Commission's ruling Order No. 10, none of these customers would be actually subject to two-channel billing; this analysis is merely meant to illustrate what the cost recovery shortfall would be according to Sub-Group 2's apparent view of the matter.

Cost of service is an approximate term as it applies to any individual customer. Customers are segregated into classes based on broad usage characteristics, with no consideration given to many types of intra-class subsidies. Since some level of quantifiable cross-subsidization is inherent in all rate design, particularly for large diverse classes, an independent finding of a material cost shift should be required before regulators authorize substantial changes to rates or rate design. Sub-Group 2's entire discussion of historical, embedded-cost studies ignores the fact that a cost of service study averages huge amounts of customer diversity, fails to account for benefits in real time, and is full of subjective assumptions and subjective methodology decisions. Cost of service studies do not write on a clean slate—they are designed to address historical costs associated with the traditional way of providing electricity service—a top-down monopoly-driven model that socializes all costs in very large groups of customers.

In sum, the General Assembly's direction that the Commission to ensure that rates charged to net metering customers reflect their cost of service, net of benefits, does not require the Commission 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.

IV. Crossborder Energy's evaluation is highly relevant to the Commission's decision

Crossborder Energy's *Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc.*,[34] is critical to this Commission's decision because it is the only evidence in the record of the direct system costs that distributed generation helps the utility to avoid.[35] It also provides detailed analysis of quantifiable societal benefits as contemplated by AREDA, and presents its findings in a manner that both allows comparison to Entergy's residential retail rates, and evaluation of the cost-effectiveness of net metering within the familiar framework employed for energy efficiency programs. The basic findings of that report are as follows:[36]

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

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

3. **Modifications to net metering are not needed** to recover the utility's full cost of service over time from net metering customers. Major rate design

[34] Joint Report and Recommendations of the Net Metering Working Group, Attachment A-1. When Staff compiled the Joint Report, it replaced the page numbering in Crossborder's report in order to continuously paginate the Joint Report per the Commission's rules. As a result, the page number references provided in the Table of Contents of the Crossborder Study provide little help to the Commission. Sub-Group 1 would be happy to provide an unmodified version of the Crossborder study to the Commission, if requested.

[35] As explained above, whether some fraction of the distributed generation output reduces a customer's responsibility for embedded utility costs is not an avoided cost analysis.

[36] Joint Report and Recommendations of the Net Metering Working Group, at 46-47 (emphasis in original).

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

4. **The economics of solar DG are marginal** for EAI's residential customers, as shown by the Participant test results below 0.9 and the modest amount of solar adoption to date. This means that any reduction in the compensation provided to solar DG customers is likely to be detrimental to the growth of this resource, although these economics may improve as solar costs continue to fall.

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

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

Although Sub-Group 2 raises several concerns about assumptions or methods employed in the Crossborder Study,[37] none of these critiques call into question the basic conclusion of that report.[38] Crossborder Energy has produced a detailed response to each of Sub-Group 2's

[37] Sub-Group 2 Reply Comments at 8, n.11, Attachments 1 and 2.
[38] On page 8 of its reply comments, Sub-Group 2 suggests that one of the predictions in the Crossborder study is the "rate of penetration of net-metering facilities in Arkansas." Rate of

critiques, provided as Attachment A to these comments.[39] The methodologies that Crossborder employed to develop its estimates are well-established and supported. The fact that future costs are not completely certain, as Sub-Group 2 states, is no basis to ignore reasonable estimates of those costs—the Commission regularly does so in resource planning decisions.

The cost-effectiveness tests presented in the Crossborder study are relevant to the Commission's consideration even though net metering is not a utility incentive program exactly like energy efficiency or demand response.[40] As Crossborder explains:[41]

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

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penetration is not a factor in the Crossborder study, which is an analysis of the long-term benefits and costs of a new net metering facility installed in 2018. The Crossborder study does not make assumptions about the number of net metering systems that will be installed in 2018 or future years but instead uses marginal costs to capture the change in costs associated with the addition of a kW or kWh of new renewable distributed generation output, in the same way that benefit-cost evaluations of other demand-side resources measure the avoided costs from thousands of energy efficiency measures or demand response customers.

[39] While Crossborder's response to Sub-Group 2's critiques demonstrates that they are baseless or immaterial, we also note that many of them could have been provided much earlier, since Crossborder provided workpapers associated with a draft version of its analysis in late July. The purpose of presenting this draft to the Net Metering Working Group was, ostensibly, for members of the NMWG to provide feedback to Crossborder about its data sources or assumptions. None of the critiques now offered by Sub-Group 2 were previously presented to Crossborder.

[40] Sub-Group 2 Reply Comments at 8-9.

[41] Joint Report and Recommendations of the Net Metering Working Group, at 51.

effectiveness framework will help to ensure that all of these resource options are evaluated in a fair and consistent manner.

Sub-Group 1 does not advocate use of these tests to set rates, as Sub-Group 2 asserts, but rather 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. In this application, retail rate compensation for exports is viewed as the incentive provided by the utility, and paid for by other consumers.[42] Crossborder's analysis shows that the benefits of distributed generation are such that other consumers come out ahead even after paying this "incentive." Net metering is a good deal for all consumers; a factor clearly within the Commission's discretion to consider as it determines whether the existing rules are fair, just and reasonable.

V. Sub-Group 2's proposal is technically flawed and demonstrates selective application of cost of service principles

Sub-Group 2 asserts that its approach is "data-driven" and "evidence-based," but its cramped interpretation of AREDA has caused it to rely upon the wrong data and to overlook evidence inconsistent with its approach. As explained in our reply comments, Sub-Group 2 considers only half the picture of the cost of serving net metering customers, because it assumes that the "Channel 1" load of net metering customers costs the same to serve as that of other residential customers, thereby ignoring how the customer's distributed generation system reduces the customer's contribution to peak loads that determine cost responsibility. Crossborder Energy provided a detailed analysis of how much less the net metering customer's

[42] Joint Report at 51, Table 1 (showing utility lost revenues as a cost under the RIM test).

grid-supplied load would cost to serve, and concluded that those reduced costs, combined with Sub-Group 2's proposed "excess generation credit rate," would actually provide higher bill savings than current net metering tariffs.[43] Thus, although Sub-Group 2 asserts that it is adhering to cost of service principles, it ignores the actual load profile of net metering customers, which is essential to understanding their cost to serve.[44]

Despite its conviction that rates for net metering customers must change, Sub-Group 2 never says what the cost to serve a net metering customer, as defined by AREDA, actually is. Sub-Group 2 elides this basic question, first, by assuming incorrectly that the cost to serve those customers is the same as any other customer in the class, and, second, by claiming that any benefits associated with the net metering customer's system are captured by its "excess generation credit rate." Sub-Group 2 asserts that it has shown that current rates do not reflect the full cost of serving net metering customers because its calculated excess generation credit rate is less than the retail rate.[45] However, Sub-Group 2's narrow cost-of-service approach *guarantees* that outcome. By taking the retail rate and then subtracting costs for which the net metering customer does not avoid responsibility, while refusing to allow for any benefits associated with

[43] Attachment A to Reply Comments of Sub-Group 1.
[44] Sub-Group 2 member Oklahoma Gas & Electric Company disputes Sub-Group 1's description of its Oklahoma cost of service study. Sub-Group 2 Reply Comments at 11 n.14. Specifically, OG&E takes issue with Sub-Group 1's assertion that those Oklahoma net metering customers cost less to serve *because* of their distributed generation systems, rather than just as a matter of coincidence. OG&E does not dispute that its study showed that net metering customers were less costly to serve. Sub-Group 1 raises this Oklahoma issue not to re-litigate that matter in footnotes here, but simply to highlight for the Commission that the cost of serving net metering customers deserves fuller exploration should the Commission believe changes to rates are necessary.
[45] Sub-Group 2 Reply Comments at 12.

actual, forward-looking avoided costs, the final number will necessarily be less than the retail rate.

Furthermore, as noted in Sub-Group 1's reply comments,[46] even if one accepted Sub-Group 2's cost-of-service focused methodology for calculating the excess generation credit rate, that rate is under-inclusive because it ignores avoided cost responsibility for distribution system costs, despite the General Assembly's specific requirement that such avoided costs be included if quantifiable. Sub-Group 2 provided no explanation for why it could not quantify avoided distribution costs.

The evidence underlying Sub-Group 2's excess generation credit rate is flawed in another respect as well. That calculation is based on the output from a 5 kW solar system—if Sub-Group 2 had used a larger system, it would have calculated a higher contribution to system peaks and therefore higher avoided cost values. Our review of 2014 annual reports shows that the average solar system size for net metering customers of investor-owned utilities is 8 kW, suggesting that a larger system size may have been appropriate.

Finally, Sub-Group 2 contends that net metering customers will realize the benefits that they create by reducing system costs only at some unknown future date when those savings finally percolate through the entire system cost of service. Sub-Group 2's proposal is therefore asymmetrical—privatizing quantified costs to net metering customers while socializing the benefits that they create. The only rational response will be not to invest in net metering systems, which is plainly contrary to the purpose of AREDA.

[46] Reply Comments of Sub-Group 1 at 11.

The members of Sub-Group 1 object to Sub-Group 2's two-channel billing proposal on a number of grounds in addition to improper valuation. Such a billing construct:

- Needlessly undermines meter aggregation, a policy critical to expanding access to distributed generation.
- Creates perverse incentives that financially encourage distributed generation customers to increase energy usage during peaks.
- Applies a uniform billing "fix" to utilities with a wide range of bill structures across utilities, including monthly customer charges that range from $6 to $22 per month, and volumetric rate structures ranging from declining to inclining, without any utility-specific demonstration that this structure is tailored to recover the full cost of serving that customer (if any shortcoming in cost recovery has been demonstrated).
- Does not provide long-term rate stability as the excess generation credit rate will fluctuate with each rate case, potentially unpredictably.
- Monetizes the netting transaction which may have a number of unintended taxation and jurisdictional consequences. Despite the monetization of credits, the Sub-Group 2 proposal does not allow customers to credit that value against any and all bill charges.

VI. Conclusion

Net metering, as it currently exists in Arkansas, is a billing policy supported by over three-quarters of Americans according to a recent poll from the University of Michigan.[47] Sub-Group 2's contention that its group represents diverse perspectives, including those of Arkansas electric consumers, does not square with this broad support for net metering.[48] Public opinion does not determine Commission policy, but this poll reflects the common sense understanding that distributed renewable generation is an asset to the grid worthy of fair compensation. We urge the Commission to carefully examine the record regarding the full spectrum of benefits and reject a two-channel billing approach that would not fully compensate for those benefits and would stifle the development of distributed renewable energy in the state. The record does not show that changes to net metering are needed to comply with Act 827. The parties advocating change—the members of Sub-Group 2—have not explained or fully analyzed what the cost of serving net metering customers is, nor proposed a rate design proportionate in its response. The

[47] *See* Nicholas Simon & Sarah B. Mills, A Majority of Americans Support Net Energy Metering: a report from the National Surveys on Energy and Environment (Sept. 2017), available at http://closup.umich.edu/files/ieep-nsee-2017-net-metering.pdf. 76% of respondents indicated support (49% of them strong support), in response to the following question: "There is a policy that allows homes and businesses with solar panels to sell any extra power they generate back to the electric grid for the same price that the utility charges consumers to buy the electricity. This policy is called net metering, since these customers' electric meters run both forward and backward. Would you say you strongly support, somewhat support, somewhat oppose, or strongly oppose this type of policy."

[48] Nor is it clear why Arkansas Electric Energy Consumers, whose members include large industrial and agricultural consumers that take service exclusively on demand-metered tariffs (so far as we are aware), is concerned about a proceeding to modify net metering policies for residential customers. As noted by Wal-Mart in its surreply comments filed on November 8, 2017, the interests of consumers on demand-billed tariffs are not directly implicated by the changes proposed by Sub-Group 2.

Sub-Group 2 analysis is fatally flawed because it failed completely to consider that the Channel 1 loads of net metering customers are actually significantly less expensive to serve than those of other, non-DG customers. Considering the unambiguous declaration of legislative intent, the Commission should not replace net metering with an untested and confusing alternative that will undermine the market for distributed generation, when long-term cost benefit analysis shows the positive return that net metering offers the state's electric consumers.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing Surreply Comments of Sub-Group 1 to Joint Report and Recommendations of the Net-Metering Working Group was electronically filed via the Arkansas PSC's electronic filing system. Notice of this filing will be served upon all parties of record who have registered through this electronic filing system.

/s/ Casey A. Roberts

Casey A. Roberts

Date: November 9, 2017

Crossborder Energy's Response to Subgroup 2's Comments on the Benefit / Cost Study of Net Metering on the Entergy Arkansas, Inc. System

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Sub-Group 2's reply comments presents several criticisms of Crossborder Energy's study, *The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc*. (hereafter, "Crossborder report" or "Crossborder study"). None of these critiques is meritorious or would substantially change the conclusions in that study. Furthermore, the efforts of the Sub-Group 2 critique to recalculate the results of the Crossborder report do not use the most reasonable metrics for the value of new renewable capacity on the EAI system, and fail to consider important benefits of these new clean energy resources that the utility itself has touted when it has contracted for new solar generation. Below we provide summaries of the Sub-Group 2 comments and our response to each.

(1) **Day-ahead vs. real-time LMPs.** Sub-Group 2's first claim is that real-time MISO locational marginal prices (LMPs) are more appropriate than day-ahead MISO LMPs to value excess energy production from distributed generation. (Sub-Group 2 Reply Comments at 32.) Sub-Group 2 offers several reasons that real-time market prices should be used instead of day-ahead market prices. They assert that because of generation intermittency and load uncertainty, it is difficult for Entergy Arkansas (EAI) to incorporate estimated excess energy into day-ahead load forecasting. If the utility forecasts zero excess energy in the MISO day-ahead market, all excess energy would be settled as imbalance energy at real-time prices (assuming the utility does not use it to serve its load).

Crossborder Response. This critique is misplaced for several reasons. First, the Sub-Group 2 comments incorrectly imply that real-time prices are generally significantly lower than day-ahead prices. For example, the Sub-Group 2 comments state that the Crossborder study would likely have resulted in significantly lower benefits if it had used real-time prices. This is not the case: as noted in the MISO's *2016 State of the Market*

Report, the day-ahead vs. real-time price difference in 2016 averaged a negative 0.4%.[49] In other words, real-time prices were slightly higher than day-ahead prices. Figure 9 in that report includes a figure showing that monthly average day-ahead and real-time prices have tracked very closely over time.

Second, this difference will remain small over time, as MISO expects the day-ahead and real-time prices naturally to converge. MISO judges day-ahead market performance by the extent of convergence with real-time prices.[50] There is a market for virtual transactions (i.e., purchases or sales between the day-ahead and real-time markets), which the MISO report describes as "essential facilitators of price convergence because they arbitrage price differences between the day-ahead and real-time markets."[51] In hours when the prices do not converge, real-time prices can be either higher or lower than day-ahead prices. The MISO report notes that although factors, such as forecast errors, "may limit convergence in a well-performing market on an hourly basis, prices should converge well over longer timeframes (monthly or annual)."

The Sub-Group 2 comments state that historical real-time prices, rather than historical day-ahead prices, are what should have been used to develop a long-term LMP forecast. Given that the MISO finds real-time and day-ahead prices were essentially the same, we do not expect there to be a large impact if historical real-time prices were used. To test this expectation, we substituted real-time prices for the day-ahead prices in our analysis. The historical (June 2016 to May 2017) solar-weighted LMP for the Arkansas Hub, was $31.74 per MWh in the day-ahead market and $31.40 per MWh in the real time market – just a 1% difference of $0.34 per MWh.

Given that day-ahead market prices can be expected to converge with real-time market prices, especially when looking at longer timeframes, we disagree that the use of real-time market prices is a useful improvement to the Crossborder study methodology. If real-time prices were consistently and significantly lower than day-ahead market prices and expected to remain so for the next 25 years, then the comment on this point would be appropriate. But, given past convergence, expectations for improved future convergence,

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[49] *See* Potomac Economics, 2016 State of the Markets Report for the MISO Electricity Markets (June 2017), at page 21, available at www.misoenergy.org/Library/Repository/Report/IMM/2016%20State%20of%20the%20Market%20Report.pdf.
[50] Id., at 20.
[51] *Id.*, at 13.

and no good reason to expect that 100% of sales would take place in the real-time energy imbalance market in the first place, the Sub-Group 2 comment on this point should be disregarded.

Moreover, even if there were a material difference between real-time and day-ahead prices (which there is not), there is no reason that the utility would be unable to forecast distributed generation exports on a day-ahead basis. We note that the utility has many elements of load and generation that are uncertain and which must be forecasted if loads and resources are to be scheduled into the MISO day-ahead market. Forecasts of each individual solar customer's exports are not needed, to the extent that EAI can forecast the aggregate level of exports from all solar customers and the aggregate effect of solar DG output on net load. The aggregate forecast is the amount that would be scheduled in the day-ahead market, if the energy were to be valued in the market. Given that EAI would schedule day-ahead energy every day, day after day, one would expect EAI would gain experience and greater accuracy in forecasting aggregate exports over time. The key is the ability to forecast average exports accurately over the long term, even if individual days may be high or low.

The only reason that all exports would have to be priced at real-time prices would be if EAI consistently forecasted zero exports every day, which is not reasonable given non-zero daily average exports. Uncertainty does not justify forecasting zero exports. As a simple example if EAI receives an uncertain 0 to 5 kW in an hour, it would be far more reasonable to forecast the expected amount of exports (2.5 kW assuming a uniform distribution). If it is "extremely difficult" to forecast the daily amount with precision, that does not imply the most reasonable alternative is to forecast zero, and hence that the "more appropriate" value of the excess energy is at possibly low real time prices. Were the utility attempting to maximize the value of solar exports, and were it true that real-time prices are always lower than day-ahead prices (which they are not), EAI would want to forecast the full expected amount of solar DG output in the day-ahead market (thus reducing the utility's net purchases from the "expensive" day-ahead market), and only pay the difference between the real-time and day-ahead prices for the error (e.g., the imbalance) in its forecast. The value of the power is then a weighted average of sales at the day-ahead price and sales at the real-time price:

Average Price = (% Scheduled Energy) x $\text{Price}_{\text{Day-ahead}}$ + (% Imbalance Energy) x $\text{Price}_{\text{Real-time}}$

In addition, utilities have tools for load forecasting, and for estimating weather impacts on load and on solar generation, so it is unlikely that utilities cannot predict variations in exports at all. For example, on a very sunny day, it might be reasonable to forecast more exports than on a very cloudy day. Weather forecasting is increasingly accurate, especially in the day-ahead timeframe. Similarly, loads and exports are not so unpredictable that the best the utility can do is forecast zero. We note that system operators such as the California Independent System Operator (CAISO) routinely deal with schedules that include high penetrations of behind-the-meter solar (now over 5 GW on the CAISO system whose peak demand is about 50 GW). This has required the development of new tools for forecasting DG solar output, but the CAISO's market performance reports do not indicate that the new challenge of forecasting solar DG output at this high penetration has caused substantially increased costs for market participants.

As a result, it is not correct to assert that the relevant market for the pricing of DG exports is necessarily the real-time market, or that real-time prices will differ significantly from day-ahead prices.

(2) **Natural Gas Price Forecast.** Next, Sub-Group 2 observes that the Crossborder Study relies on the Energy Information Administration's (EIA) *2017 Annual Energy Outlook* (*2017 AEO*) forecast of natural gas prices at the Henry Hub, in order to escalate historical avoided energy costs. (Sub-Group 2 Reply Comments at 32.) Because EAI uses multiple natural gas price forecasts for energy efficiency, integrated resource plans, and resource certifications, the Sub-Group 2 critique argues that use of a single forecast is inferior.

Response: The Crossborder study forecasted energy prices by escalating a historical day-ahead solar-weighted LMP price according to a natural gas price forecast. Given that natural gas-fired generation is typically the marginal generation resource on the MISO system (particularly during daytime hours), escalation of an historical energy price using a gas price forecast reasonably assumes that historical prices will change along with the change in the cost of the fuel supply for marginal generation resources.

Significantly, the Crossborder Study did not review only a <u>single</u> forecast in deciding to make use of the *2017 AEO* numbers. As high and low sensitivities, and to validate the reasonableness of the EIA AEO forecast, the Crossborder Study also looked at recent (June 2017) Henry Hub forward market prices, plus AEO forecast escalation after the first two years, and at the reference case forecasts in EAI's most recent *Integrated Resource Plan (2015 IRP)*, which itself included a base case and high and low scenarios.

Second, the *2017 AEO* report, which was released on January 5, 2017, is a recent, industry standard, and publicly available forecast of natural gas prices. The EAI *2015 IRP* forecast is older, and not as readily available (e.g., its prices are simply shown on a chart, which we had to estimate visually). The Sub-Group 2 critique states in several places that its forecasts are "external" to EAI, but we would note that a publicly available forecast meets a higher hurdle – private forecasts by EAI's consultants may be "external" but that does not mean they are transparent, publicly available, and widely used.

Finally, we note that it is unclear why multiple forecasts would necessarily be superior. For example, the *Key Assumptions* document for the 2015 EE cost effectiveness evaluation indicates that: "The avoided cost for natural gas is based on Energy Information Administration of the Department of Energy." If there is an issue with use of EIA forecasts alone, EAI did not identify it when using just the EIA forecast in its *Key Assumptions* for EE. Even if EAI creates a consensus forecast out of several forecasts, it is not clear why a stale "consensus" forecast would be superior to a more recent and robust single forecast, such as the *2017 AEO*.

(3) **Marginal Line Losses.** Sub-Group 2 argues that the Crossborder Report should have used EIA's filed marginal line loss factors, instead of previously reported average line losses multiplied by 150%. (Sub-Group 2 Reply Comments at 32.) Sub-Group 2 cites to a marginal line loss analysis completed by Kenneth Collison of ICF in support of EAI's 2017-2019 energy efficiency program plan.

Response: Mr. Collison's June 1, 2016 testimony estimated that EAI's marginal distribution line loss rate is 8.3%, or 1.5 x 5.4% average distribution line losses.[52] Thus, Mr. Collison does not appear to disagree with the Regulatory Assistance Project (RAP) paper's assertion that marginal losses are 50% higher than average losses, or that marginal losses are more appropriate than average losses for analysis of incremental changes such as EE or solar DG.

Mr. Collison says that average and marginal losses were computed for EAI's 13.8 kV and 34.5 kV primary distribution systems. This suggests that Mr. Collison did not include all distribution system losses incurred between the primary distribution system and the point of consumption (e.g., on the secondary 0.24 kV distribution system circuits, or in the final line transformers).

[52] *See* Collison Testimony, at 21, Fig. 1.

The key EE assumptions which Crossborder used were taken from the May 1, 2017 "accompanying Program Portfolio Annual Report Excel Workbook" to the EE Program Portfolio Annual Report for the 2016 Program Year for EAI.[53] Mr. Collison's numbers, on the other hand, were filed in June 2016, almost one year earlier. Thus, the average losses presented in the *EE Key Assumptions* is not "previously filed" data relative to the date when Mr. Collison's data were presented. The EE assumptions appear to be the most recent, up-to-date, publicly available data on line losses. Because those reported line losses are average, not marginal, line losses, Crossborder included the 1.5 adjustment to determine marginal losses, as did ICF.

(4) **Transmission Line Losses Excluded.** Sub-Group 2 correctly observes that the Crossborder report excludes marginal transmission line losses. (Sub-Group 2 Reply Comments at 33.) Sub-Group 2 also notes that EAI's EE program evaluations gross up energy savings for both T&D losses, whereas the Crossborder Study only includes distribution losses, although they assert the impact would be modest. The comments also express uncertainty about whether there would be double counting of losses, if real-time LMPs were used instead of day-ahead LMPs.

Response. The comment seems to suggest that, to be consistent with the EE evaluation, transmission losses also should have been included. Crossborder did not include these losses out of a concern that transmission losses may already be accounted for in the Arkansas Hub LMPs. For example, if EAI were to take energy off the transmission system directly at the virtual "Arkansas Hub," the only downstream losses would occur on the lower voltage EAI-operated transmission and distribution systems (and perhaps also on transformers between the high-voltage MISO grid and the EAI-operated system). The Sub-Group 2 comment on this point conveys that group's view that day-ahead market prices do not already reflect transmission line losses and congestion, and therefore supports using a higher loss factor which also includes transmission losses. Obviously, such a change would increase the avoided cost benefits cited in the Crossborder report.

(5) **Line Loss Adjustment to Avoided Capacity.** Sub-Group 2 argues that line losses do not exist for avoided capacity, and should not have been included. (Sub-Group 2 Reply Comments at 33.)

Response: This position is unexplained and incorrect. To be sure, capacity is not sent along transmission and distribution lines in the same way as is electrical energy;

[53] *See* the "Key Assumptions" tab of EAI's Standard Annualized Reporting Notebook, Docket No. 07-085-TF, available at http://www.apscservices.info/pdf/07/07-085-TF_626_2.xlsx.

nonetheless, it is standard practice to adjust capacity values for losses to reflect, in part, the different values for capacity depending on its location on the grid. Generating capacity is simply the maximum capability to produce energy. For example, a central-station generator with a 100 MW capacity can produce at most 100 MW in any instant, at the generator's busbar. Nevertheless, if that 100 MW is produced over some period of time (e.g., one hour), the energy produced (e.g., 100 MWh) will suffer losses as it is transmitted to a customer. Thus, in order to value solar capacity that is sited at a different location, i.e. at the point of end use, avoided capacity costs measured at the busbar of a large-scale generator (such as the marginal combustion turbine) must be translated to a cost at the location where the solar capacity is sited (i.e. at the point of end use). Just like photovoltaic generation at a customer site avoids energy losses from an alternative (avoided) utility generation supply, local capacity (e.g., 1 kW on a customer's roof) avoids a larger amount (e.g., 1.1 kW) of central station capacity, assuming 10% losses and all other things equal.[54] Thus, the point is that the central station generator's capacity to provide energy <u>at a customer's location</u> must include losses. The cost per MW of capacity at the busbar is not the same as the cost per MW of capacity at the solar customer's location.

If such an adjustment were not made, the result would be that EAI would put no value on where generation capacity is located, even though energy provided from the generation capacity resource at the remote central station suffers losses to serve load that are not experienced by the local generation sited at load. Given that capacity measures the maximum amount of energy that can be produced, capacity gets "lost" when it is moved to a downstream location, just as does energy.

We also note that it is standard practice in utility ratemaking to adjust combustion turbine capacity costs by losses in order to determine per unit costs of capacity at different voltage levels.

(6) **Year of Need for Generation Capacity.** Sub-Group 2 argues that the Crossborder study incorrectly relied on a 2017 capacity deficit year, based on EAI's *2015 IRP* from October 2015. (Sub-Group 2 Reply Comments at 33.) Sub-Group 2 asserts that the IRP

[54] For example, if a hypothetical 10 kW plant provides free energy for all its output, but charges $10 per kW-year of plant capacity, and losses to reach the customer equal 10%, then that plant would cost the customer $100 per year for 9 kW received capacity at the customer's location, and from the perspective of what is delivered, the average cost of the capacity would be $1.11 per kW delivered.

information is no longer current, even though a new IRP has not yet been issued, and argues that it is inconsistent with the assumptions used for EAI's Three-Year 2017-2019 Program Plan for EE, which assumed a new combustion turbine in 2022. Sub-Group 2 therefore asserts that the Crossborder Study should have used the avoided capacity cost forecast from EAI's Three-Year 2017 Program Plan for EE, "to the extent that it was publicly available." Finally, Sub-Group 2 argues that the Crossborder Report should not have relied on the avoided capacity cost that "was referenced in the 2016 EE Program Year evaluation report filed in May 2017" and should clarify that that report was only to be used for evaluation of 2016 EE programs.

Response. The IRP is the major EAI planning document guiding long-term procurement that specifically includes issues such as when new capacity will be needed. Use of the most recent (2015) IRP, as referenced in the most recent EE evaluation report, is reasonable. From the language of the Sub-Group 2 comment, it is not clear that the avoided capacity cost forecast from EAI's Three-Year 2017 Program Plan is publicly available, nor does Sub-Group 2 offer any indication of where that document might be located.

In addition, capacity does not have zero avoided cost value in the years before 2022. If EAI's need has been postponed to 2022 at least in part as a result of lower loads due to demand-side resources such as EE and solar DG, then these demand-side resources should be credited with avoiding capacity costs in the years prior to 2022. A significant benefit of demand-side resources is that they can be deployed more quickly and in smaller increments than central station resources.[55] This argues for ascribing significant capacity benefits to solar DG in the years prior to 2022.

(7) **Degradation in Avoided Capacity Calculation.** Sub-Group 2 states that Crossborder Energy failed to account for the degradation of solar system output over time when calculating avoided capacity value, and asserts, without explanation or detailed revised formulas, that Crossborder should have applied the same 0.5% annual degradation rate used elsewhere, such as for the avoided cost of energy. (Sub-Group 2 Reply Comments at 33.)

Response. It is mathematically incorrect to assert degradation would have made a difference for the avoided capacity calculations. The combustion turbine cost in $/kW-year is not affected by degradation. In converting the combustion turbine cost to a volumetric price per kWh of solar output, there are identical factors for degradation in

[55] This benefit of smaller-scale renewable resources is recognized explicitly in the FERC's PURPA rules for avoided cost pricing. *See* 18 C.F.R. §292.304(e)(2)(vii).

both the numerator and denominator of the conversion factor that cancel out: (1) the 54% solar capacity value would become a lower levelized 51.6% value with degradation over time, as 54% is a first-year value that assumes no degradation; and (2) the first-year 1,530 kWh output per kW installed also degrades over time to a levelized kWh per kW of 1,463 kWh per kW over time. These calculations assume a 6.1% discount rate. To see that degradation does not change the result, we note that the first year and levelized calculations produce the same result: $81.13 x 54% / 1,530 kWh = 3.21 cents per kWh and $81.13 x 51.6% / 1,463 kWh = 3.21 cents per kWh.

(8) **Solar Capacity Credit for Avoided Generation Capacity.** Sub-Group 2 notes that Crossborder assumed that peak hours for EAI will be between 3-5 p.m. EST (or 2-4 p.m. CST) in June-August, which results in a 54% solar capacity value. (Sub-Group 2 Reply Comments at 37.) Sub-Group 2 asserts that EAI's peak hours reported on FERC Form 1 for June-August generally occur between 3 and 5 p.m. CST.

Response: The MISO solar capacity valuation method calls for the periods we used. *See* Crossborder report, at p. 12, footnote 13, citing the MISO Business Practice Manual BPM-011-r16, Section 4.2.3.4.1. This is the value that EAI should place on solar generation capacity given that it could sell (or buy) that capacity in the MISO capacity market. We assumed the solar capacity credit should be based on the methodology for such a credit in the MISO footprint in which EAI operates.

(9) **Avoided T&D Capacity.** Sub-Group 2 argues that Mr. Collison's June 2016 testimony supported just $1.30 per kW-year in avoided distribution costs for EAI. (Sub-Group 2 Reply Comments at 34.) Thus, Mr. Collison's calculation of avoided T&D costs for EAI's Three-Year 2017-2019 Program Plan assumed no avoided transmission capacity value, and a very small avoided distribution value. The Crossborder Report looked at two approaches to calculating avoided T&D capacity, based on either EAI's 2017 *Key Assumptions* value of $23.86 per kW-year or based on a linear regression analysis of EAI's historical T&D investments as a function of historical peak load growth. Sub-Group 2 argues that, even though the $1.30 per kW-year in avoided distribution costs was calculated for EAI's Three-Year 2017-2019 Program Plan for energy efficiency, it would not be correct to use that cost in Crossborder's analysis because it is focused on a limited number of distribution projects targeting specific circuits, whereas net metering customers are located across EAI's system. Sub-Group 2 also argues that Crossborder should not have included avoided T&D costs to begin with, and should not have used $23.86 per kW-year because it has been superseded by a new and lower value.

Response: The $23.86 per kW-year assumption used in Crossborder's base case does not appear to be an earlier assumption. It came from EAI's May 1, 2017 *Key Assumptions* report for evaluating EE programs. Moreover, this avoided cost estimate is used for EAI's EE program evaluations, which concern measures that are distributed across the EAI system in just the same manner as net metering customers.

(10) **Amount of Avoided T&D Capacity.** Sub-Group 2 states that it has no opinion about the 52% Peak Capacity Allocation Factor used in the Crossborder report. However, Sub-Group 2 does note that 36% is the EAI 12 CP value that was included in its September 15 report. (Sub-Group 2 Reply Comments at 34.)

Response. It is true that Sub-Group 2 took a different conceptual approach to avoided transmission capacity than did the Crossborder study. However, a 12 CP value is not appropriate for determining the T&D capacity costs avoided by distributed generation. Transmission system loads do not reach or approach the maximum system capacity in every month of the year. Thus, a PCAF approach that looks at the distribution of hours when loads are above a threshold, such as 90% of annual peak demand, better captures the times – and average solar capacity factor – during the key hours when the transmission system is operating near capacity. We note that the MISO method for solar capacity credits produces a similar result (54%) as the PCAF calculation, and is based on solar capacity factors during certain hours (HE 15-17) of the summer months of June to August. This is similar to the PCAF calculation in the sense that all months of the year are not given equal weight. Sub-Group 2 offers no reason why a 12 CP method, based on a single hour in each month, is a better measure of the T&D capacity avoided by solar than the PCAF calculation which focuses on the hours of highest demand that drive the need for transmission capacity. We disagree that the solar capacity credit should be revised to 36% as Sub-Group 2 recommends.

(11) **Linear Regression Analysis of Avoided T&D Capacity.** Sub-Group 2 asserts that historical spending cannot be used as a good indicator of future transmission investments. Upgrades are specific to site, timing, circumstance, age of existing infrastructure and other factors. (Sub-Group 2 Reply Comments at 34.)

Sub-Group 2 also identifies low (0.25 to 0.29) R-squared values for the linear regressions in the Crossborder study, and concludes that there is essentially no direct relationship between annual historical spend in transmission and distribution relative to peak load. *Id.* at 35.

Response: It is true that only a portion of transmission spending is related directly to load growth. For example, transmission can be built to access non-marginal generation that is needed for policy reasons (e.g., renewables to meet a state portfolio standard requirement).[56] In addition, transmission investments occur in lumps (e.g., every few years or longer) whereas load changes more gradually. The function of a linear regression is to pick out (and to associate with the slope parameter of the regression) only those transmission investments that were a function of load growth. Other costs that are constant or unrelated to load growth are captured in the constant parameter of the regression, and are thus excluded from the marginal transmission costs that are defined by the slope of the regression. The linear regression analysis of historical costs is a good indicator of marginal transmission additions per unit of load growth, particularly because these investments occur over a long time frame, and are intended to deal with load growth over the same long time frame. Looking at a subset of transmission investments expected over just a few years may cause one to believe marginal transmission costs are zero (as Mr. Collison finds) or are very low, if there is not significant load growth within those years or if there is enough slack transmission capacity that few investments are needed. Once capacity becomes tight, however, and capacity additions are needed, such a three-year study could have a large, non-zero cost. Thus, for a forecast analysis to improve on a historical forecast, it should include a larger number of forecast years (e.g., at least ten years).

Regarding the low R-squared values in the Crossborder regression analysis, we note that a very high R-squared value should not be expected when transmission investments are, by necessity, lumpy in comparison to load growth. The regression still finds there is a significant and non-zero correlation, and the regression slope isolates the costs that are correlated with peak load. The R-squared statistic is the square of the correlation coefficient. Thus, R^2 values of 0.24 for transmission and 0.29 for distribution correspond, respectively, to correlations of 49% and 53% (e.g., 0.49 x 0.49 = 0.24). Again, with transmission investments required both in "lumpy" amounts and ahead of when peak loads materialize, it is not surprising that correlations are not much better than about 50%.

(12) **Avoided CO_2 Emissions.** The Sub-Group 2 comments argue that statewide emissions estimates for CO_2 do not reflect the much lower recent emission profile of EAI's

[56] It is important to recognize that transmission investments to replace aging infrastructure or to maintain reliability are related to load, as they are necessary to maintain the existing capacity of the transmission system to serve load.

portfolio. Sub-Group 2 also notes that, while Crossborder is using the most recent public forecast available for CO_2 prices, it does not reflect EAI's "current assumptions" regarding the timing and pricing for CO_2 regulation. Sub-Group 2 claims the *2015 IRP* forecast of CO_2 prices is outdated. (Sub-Group 2 Reply Comments at 35.)

Response: The Environmental Protection Agency (EPA) AVERT model is a publicly available source for estimating statewide emissions. As noted in the Crossborder study, AVERT's 1.44 lbs/kWh avoided carbon emissions rate in Arkansas is similar to (and lower than) the 1.49 lbs/kWh estimate used to evaluate EAI's EE programs. It is not clear why a solar program evaluation should use different assumptions than EAI uses for EE program evaluation.

Moreover, the average emissions from EAI's portfolio are not necessarily relevant to the determination of marginal emissions. For example, marginal emissions might reflect the resource mix of dirtier market purchases that are avoided due to an EE measure or PV production.

Regarding carbon prices, it is not clear what EAI's current assumptions are, particularly if they have not been presented in a long-term planning document such as an IRP. Carbon prices from EAI's EE *Key Assumptions* were used as a low case. The base case price forecast in the Crossborder study was from the *2015 IRP*, which is not outdated – it is EAI's most recent IRP forecast.

Also, whether or not CO_2 is eventually directly regulated in Arkansas, such that carbon emissions costs are internalized and included in production costs, there is no reason not to evaluate solar generation benefits similar to how EE measures are evaluated, in terms of emissions benefits. For example, if EAI now believes that a cap and trade program or a carbon tax is likely never to be implemented in Arkansas, and thus the expected cost of direct regulation is zero, the utility will need to convince the Commission that there are zero direct future avoided costs related to the avoided emissions from all programs and technologies that reduce carbon emissions, including EE as well as net metering. Regulatory policies can change with the political winds, while the impacts of carbon dioxide emissions on the future climate is a matter of physics and chemistry.

(13) **Reducing Fuel Price Uncertainty.** Sub-Group 2 argues this benefit is speculative, and not based on embedded costs in rates. (Sub-Group 2 Reply Comments at 35.)

Response: The benefits of reduced fuel price uncertainty are directly related to the costs of natural gas fuel that are embedded in rates today and that clearly will be included in future rates. The periodic costs to ratepayers from natural gas price volatility are not speculative; ratepayers have suffered from such volatility in the past and will do so in the future. If EAI were to fix the cost of fuel supply for gas-fired generation – in order to mimic the fixed-price benefit of solar generation – the fuel price uncertainty benefit measures the cost that would be incurred to do that. This cost is based on comparing (1) EAI's weighted average cost of capital that it would normally earn on an investment to (2) the lower return it would earn on the "risk-free" investments in U.S. Treasury bills that it would have to make in order to save the money needed to pay for the locked-in fuel supply. This benefit recognizes the real cost to ratepayers of the fact that ratepayers are exposed to the volatility of fossil fuel prices over time.

In addition, it is clear that EAI itself values the elimination of fuel price uncertainty. A major selling point in the utility's Stuttgart application to recover the costs for a utility-scale solar project was that the solar PPA would mitigate the risk of fuel cost fluctuations and availability.[57]

(14) **Market Price Mitigation.** Sub-Group 2 contends that the calculation presented in the Crossborder Study is speculative, based on the New England market, and is several years old (2013 and 2015). (Sub-Group 2 Reply Comments at 35.)

Response. It is correct that the Crossborder Study did not attempt to calculate a market price mitigation benefit based on the MISO market, as doing so is highly resource intensive. However, we note that the economic theory is very clear: with the lower demand resulting from solar distributed generation (e.g., shifting the demand curve to the left), and no change in the supply curve, the market clearing price will decrease. The estimated market mitigation benefit is 4% of the avoided energy cost plus losses, or $2.80 per MWh. Thus, we emphasize the issue presented by this comment is whether the value of market price mitigation is small or zero. Sub-Group 2 argues that a small non-zero value is unreasonable because it might be a different (but presumably still nonzero) value if an analysis for the Arkansas market were conducted today. However, we note that discarding this benefit altogether is even more speculative, given that it has been shown to exist in many other markets and it is highly unlikely to actually equal zero. Inclusion

[57] *See Direct Testimony of Kurtis W. Castleberry, Director, Resource Planning and Market Operations on Behalf of EAI*, Docket No. 15-014-U (Apr. 15, 2015), at p. 15.

of a small placeholder value for the market price mitigation benefit is far more reasonable than ignoring it entirely.

(15) **Societal Benefits.** Sub-Group 2 argues that the benefit calculations supporting the Societal Cost Test (SCT) should have been excluded. The societal benefits are speculative and not based on embedded costs reflected in current rates. (Sub-Group 2 Reply Comments at 35.)

Response. When making a decision whether or not to build a resource with a 25-year life, or to provide incentives for long-lived energy efficiency measures, all avoided costs during that period should be considered. The Commission also has a responsibility to examine the impacts of its decisions on the broad health and well-being of the citizens of Arkansas, and not just on the costs that are included in rates.

Economics tells us that efficient resource allocation occurs when the cost of the last unit produced, i.e., the marginal cost, equals the value that society places on that unit. The marginal cost should include all of the costs which the production and consumption of that unit places on society, even those "external" costs which do not directly impact the participants in the market transaction.[58] In this case, it is the role of the regulator to best approximate the outcome of a market in which both direct and external costs are considered.

Further, it is not necessary for a cost to be in current rates for it to be avoided in the future. For example, if central station fossil generation is built instead of adding more renewable resources, the cost of that central station plant will go into future rates, but it is not included in current rates as it does not exist yet. The converse is also true. Comparing options for future resource plans, and estimating benefits based on the differences between them, involve considerations that are entirely unrelated to the embedded costs in current rates. This is a basic point that goes beyond whether a cost effectiveness test is intended to look at direct costs or the broader societal costs to our environment.

Turning to the societal cost test, it is clear that this test is intended to capture broader costs and benefits to the citizens of Arkansas. Would Sub-Group 2 have EAI ignore the potential impacts of its future resource deployment choices just because the societal costs

[58] See, for example, Alfred E. Kahn, *The Economics of Regulation* (MIT Press, 1988), at pp. 179-80.

of these choices are not 100% certain? As noted in the report, many elements of the societal costs are not uncertain and can be quantified: if natural gas fired generation is used instead of distributed solar generation, all other things equal, there will be more cooling water requirements, more land use impacts to site new generation projects, and non-zero air emissions of all sorts including local criteria pollutants and methane leakage from pipelines. Health benefits from reduced criteria pollutants are not so uncertain that they should be discounted to zero – if there were no health benefits from reducing these air emissions, they would not be regulated today.

The EPA's AVERT model allowed us to determine emission rates specific to Arkansas. Thus, the main piece of the analysis to which Sub-Group 2 appears to object is putting a monetary value on these known impacts. Uncertainty in the valuation of societal cost impacts does not mean that these values are zero. In particular, we note that the SCT is its own test precisely so that these types of costs can be estimated and considered by decisionmakers. With regard to whether a non-zero price should be assigned to criteria pollutants or CO_2, we consider briefly the issue of global warming. Assume, for the sake of argument, no global warming has occurred yet, but that half the people in the state believe it will become a serious issue in future years and half do not. Either group might be right. Should government take sides, for example, ignoring one half and deciding that no value should be ascribed to CO_2 given an uncertain future, or would the most prudent approach be to assign an expected value (e.g., 50% zero / 50% SCC forecast). Some scientists have argued that uncertainty is like driving a car in the fog toward what may or may not be the top of a cliff, and that it might make sense to put on the brakes given that you are not entirely certain where the cliff begins. In the same sense, a valid comment on the societal cost forecasts might be that they were too high and some other non-zero values should be used, but not that no values (e.g., no brakes) should be applied.

The entire point of the SCT is to include all TRC costs and benefits, plus environmental benefits, other externalities, and a lower social discount rate.[59]

(16) **Lost Utility Revenues.** Sub-Group 2 notes that a larger rooftop PV system was modeled for bill savings than for other parts of the analysis, and also asserts that the bill savings included an arbitrary assumption (80%) for how much annual usage was being offset.

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[59] *See California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* (October 2001), at p. 18, available at http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF.

Sub-Group 2 also notes that a 9.5 cents per kWh bill savings is similar to what they calculated, but does not include franchise fees and local taxes. (Sub-Group 2 Reply Comments at 35.)

Response. It does not matter significantly if modeled system sizes are different. The assumed PV profile, and average 1,530 kWh per kW do not change. A system size of 80% of annual usage was used based on typical distributed generation solar system sizes from our extensive work in other markets. It is a reasonable assumption, and Sub-Group 2 does not challenge it on that basis. Because lost revenues are determined on a per unit basis, small changes in assumed system size do not affect the test results significantly.

We do not include taxes or franchise fees for estimating lost utility revenues, as these taxes and fees do not provide incremental revenues to the utility. Sales of solar systems also provide sales and property tax revenues to state and local governments.

(17) **Utility Rate Escalation.** Sub-Group 2 suggests that if one used a 3% annual rate escalation assumption, rather than the 2% annual rate escalation that Crossborder did, that the revised RIM and PCT Tests result in a benefit/cost ratio of less than 1.00. (Sub-Group 2 Reply Comments at 39-40.)

Response: 3% annual rate escalation is far above the historical 1.3% growth in Arkansas's electric rates from 1990 to 2015, according to EIA,[60] and contradicts EAI's marketing message that its rates are below the national average. Using this historical escalation in utility rates would improve our RIM results. EAI does not attempt to justify that 3% per year is a reasonable figure for its future rate escalation; such a justification would be difficult given today's low rate of inflation and the utility's desire to grow its loads. Sub-Group 2's point seems to be merely that an arbitrary, unjustified, and significant shift in a major assumption would, unsurprisingly, lead to a different result.

Increasing annual utility rate escalation by 1% increases the customer's 25-year levelized bill savings from 11.4 to 12.5 cents/kWh. This change results in a RIM Test below 1.00, but only if the expanded avoided cost benefits from the Crossborder study are ignored. The expanded benefits, as shown on Table 14 of the Crossborder study, are fuel price uncertainty, market price mitigation, carbon costs over and above the *EE Key Assumptions* low case, and T&D capacity costs using a linear regression method instead

[60] *See* U.S. Energy Information Administration, Electricity sales data available at www.eia.gov/electricity/data.php#sales.

of basing such costs on EAI's EE assumptions. The expanded benefits case includes only direct benefits -- not the societal benefits of solar distributed generation.

Sub-Group 2 acknowledges it "used the "Crossborder Report's Base Case without the highly-speculative expanded direct avoided costs."[61] If the expanded avoided costs identified in the Crossborder Study are excluded, then the RIM test decreases from 1.04 to 0.95. **The RIM test remains well above 1.00 if the expanded direct avoided costs are used, decreasing from 1.48 to 1.35.** Further, even if one accepts that the 5% deficit in the RIM is reasonable, this represents a negligible cost shift – about $28,000 per year for the 3 MW of residential solar now installed in Arkansas – that does not justify a substantial change to net metering in Arkansas. Moreover, Sub-Group 2 has not shown that the expanded benefits are "highly speculative." EAI itself has cited the fuel price uncertainty benefit to justify its own utility-scale solar power plant, and the impact of new renewable generation, with zero variable costs, on reducing market prices has been frequently observed and well documented in other markets. Other values used in Crossborder's expanded set of avoided costs are simply the result of different calculation methods (such as for avoided T&D costs) or different metrics that EAI has used in other contexts (such as the IRP carbon prices).

Below, we have reproduced Table ES-1 from the Crossborder study, and then provide a modified version of that table assuming 3% escalation of retail rates (Table 1) in which we highlighted the values that change with this assumption. As can be seen from these tables, the Participant Cost Test was already appreciably below 1.00. The increase from a 0.89 to a 0.98 benefit/cost ratio means that, with 3% annual rate escalation, customers can still expect the PV system costs to exceed the bill savings, but only slightly. The TRC did not change at all, because rate escalation is not a factor in this test.

[61] Sub-Group 2 Reply Comments, at p. 37.

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**	

Table 1: *Benefit/Cost Ratios Assuming **3%** Annual Rate Escalation*

Benefit-Cost Test	**Participant**		**RIM**		**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)		12.5	12.5					
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	12.5	12.7	12.1 – 17.2	13.0	12.1 – 17.2	13.0	28.5–33.6
Benefit-Cost Ratios	**0.98**		**0.95 -1.35 (RIM)**		**0.93 – 1.32**		**2.19 – 2.58**	

(18) **Changes to the Generation and T&D Capacity Values.** Sub-Group 2 argues in favor of lower generation and T&D capacity values. (Sub-Group 2 Reply Comments at 37-38). In combination, Sub-Group 2 represents that these lower values reduce the RIM test results to below 1.0 using the more limited set of avoided costs, and further reduce the TRC results.

Response. As discussed above in points 8 and 10, these criticisms are misplaced, and the values we used are fully supportable and best reflect distributed solar's contribution to the peak loads that drive EAI's capacity-related costs. Further, even with these changes, the test results are above 1.0 with the broader set of avoided direct costs.