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BEFORE THE ARKANSAS PUBLIC SERVICE COMMISSION

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

SUR-REPLY COMMENTS OF SUB-GROUP 2
OF THE NET-METERING WORKING GROUP

I. INTRODUCTION

In its opening sentence in Order No. 1, the Commission explicitly established this docket to "gather information to be used to determine appropriate rates, terms, and conditions under Act 827 of 2015 ("Act 827") for net metering contracts, including any changes necessary to the Commission's Net Metering Rules ("NMRs")." The Commission's action was mandated by the Arkansas General Assembly, which, through its revisions to Ark. Code Ann. § 23-18-604(b)(1), required that the Commission ensure that "the rates charged to each net-metering customer recover the electric utility's ***entire cost*** of providing service to each net-metering customer…." [emphasis added]. The issue before the Commission in Phase 2 of this proceeding is how to further modify the NMRs beyond what occurred in Phase 1 in order to comply with this specific legislative mandate.

Sub-Groups 1 and 2 have submitted separate recommendations based on fundamentally different views of ratemaking to assist the Commission with addressing the issue before it. Sub-Group 1 argues that the long-term, forecasted benefits of distributed solar generation exceed the current costs by citing the results of a study prepared by Crossborder Energy ("Crossborder Report"). Based on that report, Sub-Group 1 recommends that no changes be made to the existing billing framework for net-

metering, including the credit for excess energy delivered back to the grid. Sub-Group 1's approach will cause non-net-metering customers to absorb additional costs through the ratemaking process for uncertain future benefits that may never materialize. By contrast, Sub-Group 2 performed detailed analyses using long-standing, Commission-approved methodologies and Cost-of-Service ("COS") inputs. Sub-Group 2 recommends that the Commission adopt 2-Channel Billing for new[1] net-metering customers taking service under ***non-demand*** billed tariffs, which represents a fair, balanced, and equitable approach to addressing the relevant provisions of Act 827 of 2015.[2] As part of its 2-Channel Billing recommendation, Sub-Group 2 provided a specific methodology to calculate the credit for excess generation that is grounded in long-standing COS ratemaking principles, is data-driven, evidence-based, and can be applied to every APSC-jurisdictional utility in the state of Arkansas.[3] The end result of the Commission adopting 2-Channel Billing and applying a COS-based methodology to valuing excess energy delivered to the grid by future net-metering customers would fulfill the Commission's role in meeting the legislative mandate specified by the Arkansas General Assembly in Act 827.

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[1] *See* Order No. 10 at 142-150, including the Commission's finding at 146: "The Commission finds that to be grandfathered under the existing rate structure, a customer must have submitted a signed Standard Interconnection Agreement to the appropriate utility on or before the date of the order, if any, in Phase 2 adopting the new rate structure."

[2] *See* Joint Report and Recommendations of the Net-Metering Working Group at 15 (September 15, 2017), which provides: "2-Channel Billing does not require a more sophisticated meter beyond the normal bi-directional digital meter that is used today…Under 2-Channel Billing, the net-metering customer fully retains the benefit of its reduced energy consumption (in other words, the energy it self-produces that is used behind the meter)…2-Channel Billing collects the utility's cost to serve the net-metering customer for energy delivered by the utility through Channel 1 and applies an excess generation credit that appropriately recognizes the utility costs that the net-metering customer avoids as well as the benefits the net-metering customer provides to the system for all self-generated energy exported to the grid through Channel 2."

[3] In fact, in its original proposal filed on September 15, 2017, in this docket, Sub-Group 2 provided the results of such calculations for every APSC-jurisdictional utility. Supporting work papers were also made available to all members of the Net-Metering Working Group.

Sub-Group 1 has argued that the Crossborder Report provides a sufficient rationale to support Sub-Group 1's recommendation that the existing NMRs and net-metering billing framework should continue unchanged. However, Sub-Group 2 has pointed out two notable flaws in Sub-Group 1's recommendation and the supporting Crossborder Report. First, as discussed extensively in Sub-Group 2's Reply Comments, using a long-term, avoided-cost study that incorporates numerous assumptions regarding future benefits that may or may not occur many years into the future to establish the net-metering rate for ***today*** contravenes Arkansas law and established COS principles that the Commission uses for ratemaking.[4] Sub-Group 2 reiterates several key points from its Reply Comments:

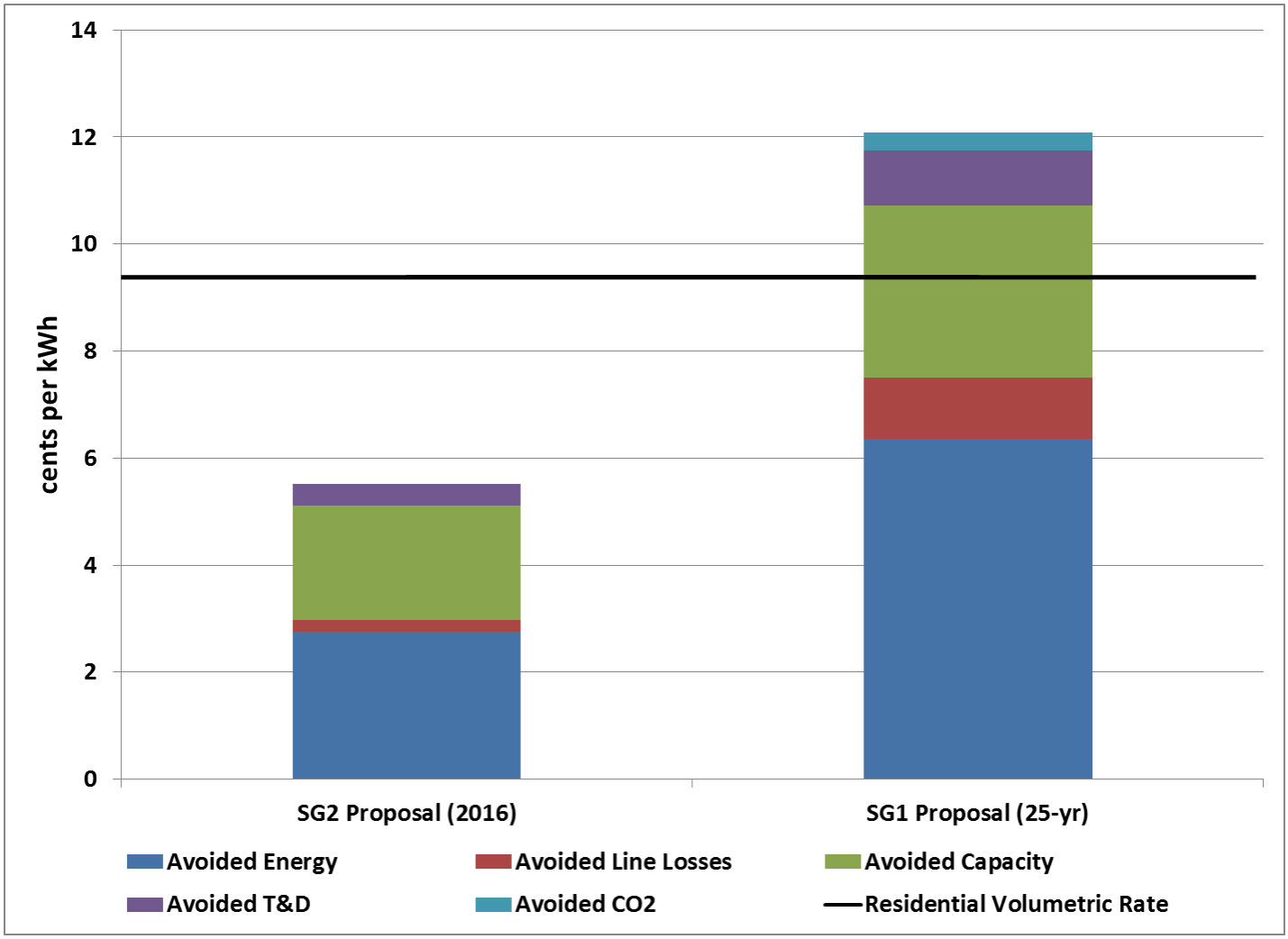
> -Long-term avoided costs such as the ones relied upon by Sub-Group 1 are replete with uncertain assumptions and predictions about future energy prices, key policy changes (e.g., carbon), and the rate of penetration of net-metering facilities in Arkansas.
>
> -Only currently incurred costs or embedded costs are included in rates, which are not set based upon the long-term "values" for any capital investment, expense, or service.
>
> -Rates are set based upon the actual COS for the ratemaking period in question relying upon the actual incurred or embedded costs in utilities' most recent COS Studies that reflect the actual, embedded cost of providing service to the net-metering customers.
>
> -Benefits, should they exist, also are (or will be) reflected in a utility's revenues and COS, but Arkansas ratemaking policy does not consider hypothetical future benefits in setting rates.
>
> -Sub-Group 1's reliance on a long-term analysis of costs and benefits to support retaining the current net-metering policy of crediting excess kWh at the full retail rate should be rejected.

This difference in approaches and how each Sub-Group views utility ratemaking is readily apparent when considering the quantitative build-up of value (and underlying

[4] Reply Comments of Sub-Group 2 of the Net-Metering Working Group at 8-10 (October 20, 2017).

inputs) included by each of the two Sub-Groups in the September 15th Joint Report and Recommendations, as illustrated in Figure 1:

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



Sub-Group 2's recommendation to adopt 2-Channel Billing and set a more appropriate cost-based credit rate for excess energy delivered to the grid is based on actual incurred and embedded costs from 2016, which, using Entergy Arkansas, Inc.'s ("EAI") figures, results in a credit value of approximately 5.5 cents per kWh. Sub-Group 1 relies upon Crossborder's calculations that use 25 years of forward, speculative,

unrealized, and currently unquantifiable benefits which result in a levelized, nominal value of solar of approximately 12.1 cents per kWh.

In fact, somewhat remarkably, Crossborder's calculation of the levelized, nominal value of Avoided Energy alone exceeds the total current value of 2016 embedded costs in Sub-Group 2's recommendation. Put another way, using EAI's data as reflected in Figure 1 above, the actual value of energy in 2016 provided by a net-metering customer in the Midcontinent Independent System Operator (MISO) market was approximately 2.76 cents per kWh. Sub-Group 1 would argue that the "value" of the same solar energy produced today is actually much higher (6.35 cents per kWh) because producing that kWh with a solar PV system that is net-metered somehow, someway helps "avoid" future energy costs that would otherwise be much higher. Based on that conclusion and incorporating future values for other categories of benefits, Sub-Group 1 argues that the Commission should retain the current NMRs and net-metering billing framework.

However, Arkansas electric utilities represent more than electrons flowing through distribution and transmission wires, or the energy that net-metering customers and their neighbors are receiving, whether the utility generates that energy or purchases it. Not only does a utility have an obligation to serve and stands ready to serve 24 hours a day, seven days a week, the utility provides, among many other things, administrative services, customer services, storm restoration services, optional programs, efficiency programs, and investments in and maintenance of substations, poles, and wires essential to electric service for all customers, including net-metering customers. All of these costs along with infrastructure costs, debt service, etc., are

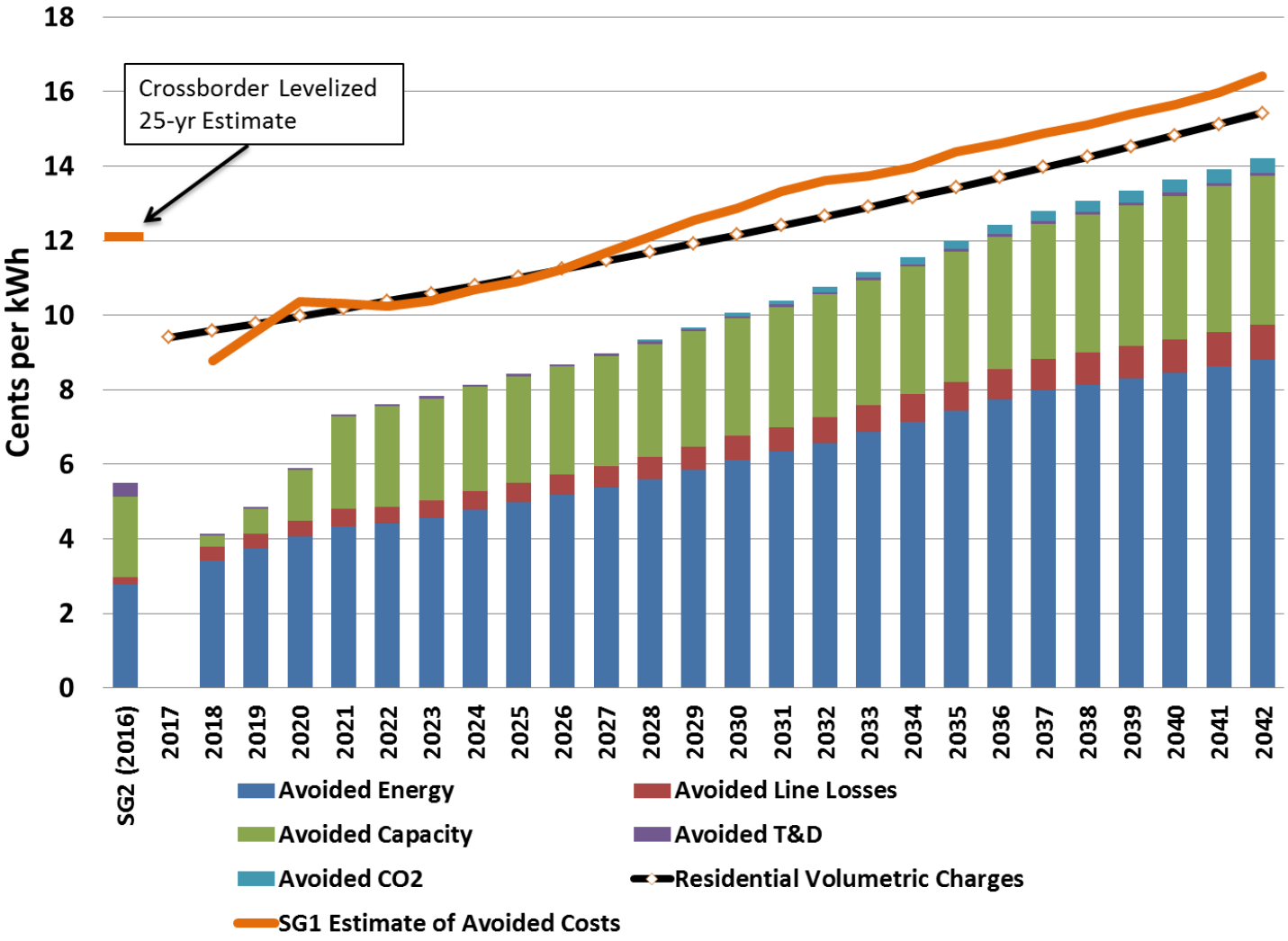
embedded in the rates that utilities charge their customers and that the Commission has approved through regulatory proceedings.

As previously explained, longstanding ratemaking principles and the Commission's policies require that rates be set on actual, incurred, and embedded costs rather than speculative forward projections. Act 827 makes clear that such costs include the utility's "entire cost of providing service." Sub-Group 2's proposal to adopt 2-Channel Billing in Arkansas is flexible and provides a framework for calculating appropriate excess energy credit values that can be updated periodically to reflect current, actual costs. As a result, should the value of avoided energy increase over time, that higher value will no doubt be captured in future updates to the utility-specific, excess energy credit rates being proposed by Sub-Group 2.

The second flaw in Sub-Group 1's recommendation and the supporting Crossborder Report is that Crossborder makes numerous flawed and incorrect assumptions in its analysis.[5] Figure 2 below, corrects certain errors and inputs included in Crossborder's "base case" scenario over each of the 25 years of the forecasted analysis (2018-2042).[6] In addition, Figure 2 shows a projection of EAI's total volumetric rate[7] over 25 years assuming an increase of two percent annually as well as Crossborder's underlying annual estimates used to develop its 25-year levelized values.[8]

[5] See, Attachments 1 and 2 to Sub-Group 2's Reply Comments.
[6] See, Attachment 1 to these Surreply Comments for additional detail and explanation of the underlying calculations in Figure 2.
[7] The total volumetric rate of ~9.4 cents per kWh includes the current Energy Charge, FRP, riders, etc., but excludes franchise fees, Rider SRC and local and state taxes.
[8] The shorter orange line on the far left of the chart is the 25-year "levelized" value calculated by Crossborder for its "base case" scenario.

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



The items corrected and revised for 2018-2042 include real-time (instead of day-ahead) MISO energy price data within the avoided energy calculations; correcting the marginal line loss rates in the avoided line loss calculations; using current, more accurate estimates of capacity value and accounting for solar degradation in the avoided capacity calculations; using the metric currently approved for EAI's energy efficiency programs to calculate avoided Transmission and Distribution ("T&D"); and calculating avoided CO_2 costs by using both EAI's current internal forecast for CO_2

prices as well as EAI's 2016 actual resource portfolio CO_2 emission rate. Correcting the errors in Crossborder's methodology and inputs makes a very significant difference in the outcome of the analysis underlying Sub-Group's 1 recommendation to maintain the status quo. Not only do the purported benefits fail to exceed costs in the first year, the benefits do not exceed costs as reflected by the line labeled Residential Volumetric Charges at any point within the 25-year study horizon.

As stated earlier, Sub-Group 2's approach and resulting recommendation is consistent with longstanding ratemaking principles and relies upon actual, realized costs that are reflected in the rates that customers actually pay. Should the utility's avoided costs (i.e., the benefits) increase over time as a result of the net-metering customers' distributed solar generation, the value will be captured and reflected in future updates to the utility-specific excess energy credit rates Sub-Group 2 recommends. For example, should carbon emissions be regulated at some future date, the excess energy credit rate methodology Sub-Group 2 recommends would reflect the actual value of avoided compliance costs triggered by those future regulations.

II. ARGUMENTS

A. Burdens of Production and Persuasion

Sub-Group1 uses statements of the Commission in an attempt to infer the issue before the Commission.[9] However, there is no inference required. In the first sentence in Order No. 1, the Commission clearly established the docket to "gather information to be used to determine appropriate rates, terms, and conditions under Act 827 of 2015 (Act 827) for net metering contracts, including any changes necessary to the

Commission's Net Metering Rules (NMRs)." This determination is mandated by the General Assembly in Ark. Code Ann. § 23-18-604(b)(1). The statutory language provides that the Commission "[s]hall establish appropriate rates, terms, and conditions for net-metering contracts . . ." Thus, Sub-Group 1's and Pulaski County's separate assertions regarding prerequisites and burdens for ratemaking are misplaced and inapplicable.

B. Cost of Service under the Arkansas Renewable Energy Development Act (AREDA)

Sub-Group1 asserts that Sub-Group 2's 2-Channel Billing proposal is unjustly discriminatory because the costs that Sub-Group 2 alleges are created are not matched to alleged revenue deficiencies caused by any "additional costs" of net-metering.[10] However, Sub-Group 1 misstates the basis upon which Sub-Group 2 determined the appropriate credit rate for excess energy for net-metering. Sub-Group 2's illustrative Excess Generation Credit Rate ("EGCR") for EAI is based on the utility's entire embedded cost of providing service to the residential class as reflected in the utility's Cost of Service (COS) Study. Sub-Group 2 did not identify or quantify any additional embedded costs associated with providing service to net-metering customers through the utility's base rates[11] and consequently there is no *new* revenue deficiency calculated or purported "matching" required. In fact, the underlying premise of Sub-Group 2's approach to determining the net-metering rate is that the current embedded COS

[9] Sub-Group 1, Reply Comments, p. 2.
[10] Sub-Group 1's Reply Comments, p. 4.
[11] As the number of net-metering customers continues to increase in Arkansas, utilities may incur added administrative, operational, and related costs associated with providing service to net-metering customers that are not included in embedded costs today. Should those additional costs materialize, they will be captured in updates to the EGCR in accordance with Sub-group 2's proposed methodology.

(infrastructure and other services) to serve all customers including net-metering customers does not change and is the appropriate basis for determining the costs that should be recovered from net-metering. Differences between customers within a class are generally addressed through rate design, as is the case in Sub-Group 2's determination of the EGCR.[12]

As described in Sub-Group 2's Reply Comments, the COS Study and the RTO Market data encompass the full, quantifiable costs and benefits of the utility's capacity, reliability, distribution system, and transmission system and form the basis for defining the EGCR.[13] Sub-Group 2's proposed 2-Channel Billing approach is not discriminatory as it is based on actual COS data and evidence underlying rates in Arkansas in contrast to Sub-Group 1's maintain the status-quo approach which is based on assumed and speculative information regarding the hypothetical future value of solar generation. Furthermore, Sub-Group 1's proposed approach to establishing a value for net-metering rates does not align with the requirements of AREDA or the statutory framework that underlies ratemaking in Arkansas.

Contrary to Sub-Group 1's allegation that Sub-Group 2 did not explain the cost to serve net-metering customers, Sub-Group 2 has provided a clear explanation of these costs.[14] Currently, net-metering customers are credited at the full retail rate for excess kWhs that are exported to the grid. A credit equivalent to the full retail rate for excess generation results in a credit for utility-provided services and programs that are not avoided by net-metering customers. Crediting net-metering customers for costs that are not avoided means that the electric utility does not recover its entire cost of providing

[12] See, Joint Report and Recommendations of the Net-Metering Working Group, p. 166.
[13] Sub-Group 2's Reply Comments, p.10.

service to each net-metering customer, net of quantifiable benefits as required by Act 827 of 2015. Therefore, the current net-metering policy that credits excess generation at the full retail rate must be changed for new net-metering customers." To elaborate further, Sub-Group 2 explained that, for EAI, when a net-metering customer receives a capacity credit at the full embedded COS amount; the customer receives a credit of 4.5 cents per kWh in excess of the benefits the net-metering customer provides when it self-generates. Further, the utility does not avoid and continues to incur 4.5 cents per kWh in infrastructure and operating costs to provide service to the net-metering customer during hours of the day when the utility is responsible for serving the net-metering customer's load and to allow the net-metering customer to export self-generated excess energy to the grid.[15]

C. Net-Metering Rate Change

Sub-Group1 contends that Sub-Group 2's proposal is based on the unfounded premise that the current rate structure does not fully recover the cost of serving net-metering customers.[16] Contrary to Sub-Group 1's assertion, Sub-Group 2's recommendation is fully supported by its COS analysis, is consistent with Ark. Code Ann. § 23-18-604(b)(1)(A)(i), and is therefore not unfounded.

A kWh credit equivalent to the full retail rate for excess generation effectively credits the net-metering customer for costs of providing utility services and programs which the utility does not avoid due to the net-metering customer's excess generation

[14] See, Joint Report and Recommendations of the Net-Metering Working Group, p. 4.
[15] Sub-Group 2 Reply Comments, October 20, 2017, p. 12 -13. It is important to reiterate that the 4.5 cents per kWh value for EAI noted above does not include non-fuel riders that the net-metering customer also avoids where the associated cost incurred by the utility does not simply disappear.

exported to the grid. Therefore, under the present net-metering policy, utilities do not recover the entire cost of their investments in generation, transmission, and distribution to serve net-metering customers, including costs for metering systems, billing systems, customer care systems, storm restoration costs, and energy efficiency program costs that apply to all customers.

Typically, a utility's costs (e.g., generation capacity, fuel, poles, wires, metering, billing, call center, certain taxes and fees) are recovered from customers through retail rates that vary primarily by usage, in conjunction with some level of fixed customer charge that is independent of usage. However, significant portions of a utility's embedded costs are typically recovered through the volumetric portion of a customer's bill. Current net-metering policy credits net-metering customers at the full retail rate (which includes the embedded costs). This allows net-metering customers to avoid the amount of embedded costs which are recovered through volumetric charges of maintaining and operating the energy grid which they rely upon 24-hours a day, every day of the year. The current net-metering billing mechanism does not "recover the electric utility's entire cost of providing service to each net-metering customer" as required by Ark. Code Ann. § 23-18-604(b)(1)(A)(i). Therefore, the current net-metering rate must change.

D. Sub-Group 2 Does Not Seek Repeal of Net Metering

Sub-Group 1 asserts that Sub-Group 2's position to repeal net-metering and replace it with 2-Channel Billing.[17] This assertion, however, is false. Sub-Group 2 is not seeking to repeal net-metering in the State of Arkansas. Rather, in response to the

[16] Sub-Group 1 Reply Comments, p. 3.

General Assembly's mandate in Act 827, the Commission must ensure that the state's net-metering policy allows electric utilities to recover their entire cost to serve net-metering customers. The 2-Channel Billing approach is the appropriate rate methodology to ensure compliance with AREDA.

2-Channel Billing credits net-metering customers for net excess generation (kWh) at a rate consistent with AREDA, ensuring that net-metering customers' rates reflect the utility's entire cost of providing service. Like net-metering currently, net-metering customers are able to offset retail electricity purchases under the 2-Channel Billing approach. Any accumulated net excess generation credits, measured in kWh, will be carried forward and applied in the next applicable billing period, just as the net excess generation, measured in kWh, is treated currently. The primary difference between 2-Channel Billing and current net-metering is that there are different rates associated with the excess energy exported to the grid measured by Channel 2 and energy received from the grid measured by Channel 1.

E. Analysis Supporting Change

The claim of Sub-Group 1 that Sub-Group 2 did not conduct a study measuring the impact of net-metering is without merit.[18] In the September 15 Joint Report and Recommendations, Sub-Group 2's recommendation to adopt 2-Channel Billing quantified the COS impacts of net-metering generation for all Arkansas utilities. As detailed in Figure 1 above, the analysis included in the Joint Report determined an appropriate cost-based credit rate for excess energy delivered to the grid that is based on actual incurred and embedded costs from 2016, which results in a credit value of

[17] Sub-Group 1 Reply Comments, p. 4.

approximately 5.5 cents per kWh using EAI figures. Sub-Group 2's analysis demonstrates that the COS impacts of net-metering excess generation are materially less than current volumetric rates, which, in the case of EAI, are approximately 9.4 cents per kilowatt-hour. This relationship shows that, under the status quo, the utility is not recovering its entire cost of service for excess generation, and that a change from the status quo is warranted.

In addition, Act 827 contains no requirement that a rate change be premised on the existence or determination of cross-subsidies, or quantifying the magnitude of such cross-subsidies, as the result of net-metering. AREDA does require, however, that the Commission establish rates that recover the entire cost of serving net metering customers, net of any quantifiable benefits those customers provide. Sub-Group 2's COS analysis of the actual cost of providing service to net-metering customers demonstrates that when a net-metering customer receives an Excess Generation Credit Rate (EGCR) equal to the full retail rate-- which is in excess of the cost of service benefits that the net-metering generation provides, the net-metering customer does not pay rates that reflect the entire cost of serving the customer, net of quantifiable benefits. Consequently, these "costs to serve" are not collected from the net-metering customers and must be paid by other customers through the ratemaking process.

F. Behind the Meter and Exported Generation

Sub-Group 1 alleges that 2-Channel Billing treats self-generated kilowatt-hours used behind the meter differently from self-generated kilowatt-hours which are exported in that the former are effectively compensated at the retail rate, while the latter receive

[18] Sub-Group 1 Reply Comments, p. 4.

only the exported generation credit, creating "winners and losers" based on individual load distribution.[19] Sub-Group 2's recommendation does not pick winners and losers based on load, but instead provides cost-based justification based on COS and traditional ratemaking principles for the effective behind-the-meter retail rate and the EGCR.

The reduction in purchased energy from the utility associated with behind the meter generation is similar to conservation and efficiency activities such as turning off lights, adjusting the thermostat, adding insulation, sealing leaks, replacing windows, installing LED lights, and/or purchasing more efficient appliances. Because Sub-Group 2's proposed 2-Channel Billing approach does not change the underlying residential rate structure, for purposes of COS ratemaking Sub-Group 2 did not seek to treat the lost revenues associated with behind the meter energy conservation resulting from self-generation any differently from the way lost revenues are treated for any other type of customer-directed energy conservation effort. Therefore, under 2-Channel Billing, net-metering customers continue to effectively receive the full retail rate for their conservation behind the meter and are treated like all other customers when they are taking service from the utility under Channel 1.[20]

Net metering customers are different, however, from all other customers when they are exporting excess generation to the grid. Consistent with traditional ratemaking methodology, this difference among customers within a class is addressed through rate

[19] Sub-Group 1 Reply Comments, p. 5.
[20] While Sub-Group 2 investigated alternative rate design scenarios including rates that recovered fixed charges through a demand rate or a grid charge to recover behind-the-meter lost revenues, and believes that these alternative rate designs may have merit in the absence of 2-Channel Billing, Sub-Group 2 proposed 2-Channel Billing at this time in order to avoid a significant change in the existing residential rate structure.

design -- in this case the establishment of the EGCR for net-metering customers. Sub-Group 2 used a COS approach to determining the EGCR which includes providing the net-metering customer with the quantifiable benefits of avoided capacity costs associated with the net-metering customer's entire self-generation, both behind the meter generation and excess generation exported to the grid.

The EGCR also appropriately recognizes costs that are essential to provide utility service that are not avoided by net-metering customers and should not be credited to net-metering customers. Excess generation exported to the grid is simply electrons and does not include all of the attributes of utility service such as billing, metering, reliability, energy efficiency programs, and other approved investments and ongoing costs essential to maintaining utility infrastructure. The net-metering customer does not offset these essential utility costs when it exports kWh's to the grid and should not be credited for these services as is the case when the net-metering customer is credited at the full retail rate.

The EGCR ensures that the utility recovers its entire cost of providing service, net of quantifiable benefits, from net-metering customers. Thus, the difference between the effective rate for behind the meter conservation and the EGCR is fully consistent with COS principles and recognizes the ratemaking differences between conservation and excess generation exported to the grid.

Sub-Group1 also alleges that Sub-Group 2's treatment of the behind-the-meter usage creates "…a perverse incentive for distributed generation customers to use more electricity while their systems are producing, which is detrimental in many respects."[21] Net-metering is by definition "intended primarily to offset part or all of the net-metering

customer requirements for electricity." Ark. Code Ann. § 23-18-603(6)(E). The intent of net-metering is to allow for the self-generation of a customer's energy needs. The most efficient way for a customer with self-generation to serve its own energy needs is to directly consume its self-generated energy behind the meter. Therefore, Sub-Group 2's treatment is consistent with AREDA and appropriate, not perverse or detrimental in some manner.

G. Long-Term Avoided Costs

Sub-Group 1 asserts that a longer-term view of avoided marginal costs such as that taken in resource planning is the more appropriate approach to developing net-metering rates.[22] Sub-Group 1's assertion is incorrect.

Resource Planning is a planning process that screens various utility supply-side and demand-side resources to ascertain the optimal, lowest cost way to serve future load. It is not, and should not be, the basis for establishing electric rates. The Commission's regulatory authority to establish rates is derived from existing ratemaking statutes that require rates based on costs.

Historically, the Commission has developed rates using COS Studies. These Studies provide the regulatory framework for establishing rates based on costs that include not only costs-of-service but also benefits associated with the costs avoided by net-metering customers.[23] The General Assembly is presumed to know how the

[21] Reply Comments of Sub-Group 1, p. 5.
[22] *Id.* at p. 6.
[23] *Id.*

Commission defines and determines cost of service.[24] Therefore, the treatment of avoided costs is historically consistent both with the Commission's ratemaking process and AREDA.

Any benefits related to the utilities' embedded costs including investments in generation, transmission, and distribution plant that may occur over the longer term as the result of providing service to net-metering customers will be captured in future, updated utility COS Studies and approved revenue requirement and rates. Any investments to comply with environmental regulations associated with the existing generation are likewise reflected in COS Studies and any future investments to comply with environmental regulations will be reflected in future COS Studies and future rates.

Net-metering customers will receive the benefits of embedded costs, including any expenditure to comply with environmental regulations, when they are actually avoided. Over time, to the extent that the net-metering facilities provide benefits to the utilities' generation, transmission, and distribution costs, and avoided expenditures to comply with environmental regulations, such benefits will be reflected within the revenue requirement and rates as approved by the Commission and reflected in the underlying COS Study.

H. Channel 1 Cost of Service

Sub-Group 1 identifies and argues that there a number of "conceptual problems" with Sub-Group 2's COS approach and details those "problems" in Attachment A to its

[24] *Arkansas Public Service Commission v. Allied Telephone Company, et al,* 274 Ark. 478, 625 S.W.2d 515 (1981). "[W]hen the Legislature adopts certain language, or expressions, or terminology in an enactment, it adopts prior construction or constructions thereof." Citing *American Workmen Insurance Co. v. Irvin*, 194 Ark. 1149, 110 S.W.2d 487 (1937).

Reply Comments.[25] Sub-Group 1 then presents what it characterizes as a complete COS analysis for all net-metering output, including the portion that is used on-site and that produces a lower COS for Channel 1 loads which Sub-Group 2 allegedly fails to consider.

Sub-Group 1's critique of Sub-Group 2's EGCR methodology errs in that Sub-Group 2 only focuses on the net-metering customer's excess energy exported to the grid. Sub-Group 2's recommendation is a 2-Channel Billing framework which recognizes the kWhs measured on Channel 1 and Channel 2 as separate and unique billing determinants.

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

Sub-Group 2's recommended 2-Channel Billing approach also uses traditional cost-of-service and rate design methods in developing the EGCR. The recommended 2-Channel Billing approach uses the known billing determinants, namely energy measured on Channel 1 and Channel 2, which represent the net-metering customer's usage of the grid and export to the grid, respectively, and provides clear and accurate price signals. The 2-Channel Billing framework and EGCR methodology are simple to understand and can be applied universally to all utilities in Arkansas. As shown on

[25] See, Reply Comments of Sub-Group 1, pp. 30-31.

Attachment B-4 to Sub-Group 2's Recommendations, the estimated customer impact is consistent across all utilities.

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

Sub-Group 1 asserts "that many of the cost savings associated with net-metering come from behind-the-meter usage."[26] Sub-Group 2 agrees and emphasizes that under the recommended 2-Channel Billing framework, the same behind-the-meter savings that current net-metering customers receive today will still be available to new net-metering customers in the future. Sub-Group 2's recommended approach will allow the net-metering customer to retain the significant benefit of lower overall consumption and a lower bill compared to non-net metering customers.

In addition, the 2-Channel Billing framework provides the correct economic price signals that promote and encourage net-metering customers to maximize the savings associated with the behind-the-meter usage. Sub-Group 2 would also note that the current 1:1 full retail rate credit has the practical effect of valuing all net-metering generation as if it were consumed directly behind-the-meter. Consequently, ***all*** of the

[26] Reply Comments of Sub-Group 1, p. 8.

cost savings associated with net-metering under the current 1:1 full retail rate credit comes from the level of net-metering generation and not with behind-the-meter usage.

Sub-Group 1 suggests that to properly evaluate the behind-the-meter usage with a COS approach requires adjusting the Channel 1 rate as well as the Channel 2 rate. Sub-Group 2 disagrees with the flawed assumption that the current base rates contained in a utility's tariff are not capable of recovering a fair and reasonable level of costs from each customer based on their use of the utility system.

Net-metering customers' infrastructure requirements for electric service are not different from other customers. Net-metering customers will still take energy generated by the electric utility via transmission and distribution facilities. Some customers will require more electricity, and some less depending on their needs. Net-metering customers like non-net-metering customers, expect safe and reliable service. The utility uses the same metering and billing systems, customer care and customer service functions and programs, and other utility systems to serve both its net-metering customers and non-net-metering customers. When receiving electric service from the utility, a net-metering customer does not differ from any other customer. The electric service received by net-metering customers will be measured on Channel 1.

The rates for energy charges are designed for the residential class to include all functional costs (generation, transmission, and distribution). The energy charge for Channel 1 is based on the per kWh rate for electric service based on the class under which the customer takes service each month. The energy charge will vary between customers based on the usage needed and requested by each customer in the class, however, the approved rate per kWh (based on the cost to serve the class) will not change based on a net-metering customer's usage in the month. In other words, the

net-metering customer's bill may be less due to lower usage recorded on Channel 1, but the cost per kWh will not be less.

The current rate designs used by utilities in Arkansas for usage on Channel 1 appropriately recognize that customers have varying usage and demand profiles. The only difference between a net-metering customer and a non-net-metering customer is that the net-metering customer owns generation, consumes a portion of its own generation behind the meter, and, at times, exports excess energy to the grid. The exported energy will be measured on Channel 2 and netted against the "imported" energy measured on Channel 1 "during the applicable billing period" as required by statute.[27] It is important to note that even when a net-metering customer's self-supplied energy is greater than energy received from the utility, the utility's obligation to serve the net metering customer has not changed and the investment incurred to fulfill the obligation to serve the customer likewise has not changed. Sub-Group 1's flawed COS approach would lead to a new base-rate for the energy measured on Channel 1. In fact, as demonstrated in Attachment A, Sub-Group 1's COS approach cannot be applied to all customers given that it would require a customized Channel 1 rate for each individual customer. Sub-Group 2 does not recommend an approach that changes the base rate structure that is applied to all other customers in the class as part of this rulemaking proceeding. Such an approach would likely entail separate rate proceedings to determine the cost-of-service for net-metering customers for each jurisdictional electric utility and the potential for implementing a rate structure with higher fixed or demand charges, which, ironically, is a result that solar proponents in other states have strongly opposed."

I. "Net Excess Generation"

Sub-Group 1 alleges that Sub-Group 2 misuses the term "Net-Excess Generation."[28] However, Sub-Group 2 does not use the term "Net-Excess Generation" when referring to the excess generation credit rate applicable to excess kWh's exported to the grid as measured by Channel 2. Therefore, there is no misapplication of this term.

J. Distribution System Benefits

Sub-Group 1 asserts that Sub-Group 2's analysis ignores distribution system benefits, which the AREDA specifically requires be assessed.[29] Sub-Group 1 both misinterprets the statute and misstates Sub-Group 2's analysis. Ark Code Ann. § 23-18-604(b)(1)(A)(ii)(a) states that in determining the "entire cost of providing service" the Commission must include "any quantifiable *additional* costs associated with the net-metering customer's use of the electric utility's…distribution system…" [emphasis added]. Furthermore, Ark. Code Ann. § 23-18-604(b)(1)(A)(ii)(b) provides that in netting quantifiable benefits, the Commission must consider "…benefits associated with the interconnection with and providing service to the net-metering customer including…benefits to the electric utility's …distribution system."

Contrary to Sub-Group I's assertion that Sub-Group 2's analysis ignores distribution system benefits; the EGCR includes the benefits of distribution system line losses associated with the avoided cost of delivering energy. Sub-Group 2's

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[27] Ark. Code Ann. § 23-18-603(4).
[28] Sub-Group 1 Reply Comments, p. 10.
[29] Sub-Group 1 Reply Comments, p. 11.

recommendation that no capacity-related distribution system benefits be included in the calculation of the rate credited to excess generation kWh measured on Channel 2 is based upon the COS studies underlying current rates. Currently, there are no quantifiable distribution benefits provided by the net-metering customers, whether receiving kWh from the utility as measured on Channel 1 or exporting excess kWh to the grid as measured on Channel 2, the net-metering customer is using the poles, wires, transformers, and other distribution facilities of the utility. Currently, the presence of net-metering customers has not produced quantifiable distribution system benefits. In the future, if net-metering customers provide any distribution system benefits, those benefits will be reflected in future COS Studies for each utility and reflected in the rates the net-metering customers and other customers pay.

K. Export Generation Credit Rate

Sub-Group 1 asserts that Sub-Group 2's approach to calculation of the exported generation credit fails to consider differences in types of solar systems.[30] However, Sub-Group 1 does not provide any specifics regarding such "differences" in solar systems. And to the extent that a customer installs a more or less efficient solar system, that fact will be reflected in how much energy the system produces. Sub-Group 2's approach to rate making is also a commonly accepted practice by the Commission. As is done with rates in general, rates are designed to bill the average customer. Rates are not tailored to fit each possible difference that a group of customers may have. Therefore, Sub-Group 1's recommendation that exported generation rates be developed

[30] Sub-Group 1 Reply Comments, p. 12.

particular to solar installation types with higher capacity factors is not consistent with traditional ratemaking.

L. Netting kWhs

Sub-Group1 argues that the 2-Channel Billing rate structure is inconsistent with AREDA's definition of net metering because it "does not 'net' or measure the difference between consumption and production electricity amounts (in kilowatt-hours), but rather the monetized difference between the two."[31] Net-metering is defined as "measuring the difference between electricity supplied by an electric utility and the electricity generated by a net-metering customer and fed back to the electric utility over the applicable billing period."[32] Therefore, Sub-Group1's argument is inaccurate because electricity consumed and produced is only measured in kWh. AREDA has mandated that the Commission establish a rate for net-metering.[33] 2-Channel Billing complies with all aspects of AREDA as the approach measures the "electricity supplied" on Channel 1 and the "electricity "fed back" on Channel 2 in kWhs during the applicable billing period and establishes a cost-based credit for the electricity supplied to the grid by the net-metering customer.

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

[31] Reply Comments of Sub-Group 1, p. 13.
[32] Ark. Code Ann. § 23-18-603(4).
[33] Ark. Code Ann. § 23-18-604(b)(1).

M. Docket No. 02-046-R

Sub-Group 1 alleges that a proposal similar to the 2-Channel Billing approach was rejected by the Commission in Docket No. 02-046-R.[34] However, Sub-Group 1 not only confuses the approach currently recommended by Sub-Group 2, but also the current law. Docket No. 02-046-R was established to implement the provisions of Act 1781 of 2001 which established AREDA. In that docket, several of the investor-owned utilities proposed to treat net-metering customers as Qualifying Facilities subject to the *Cogeneration Rules,* and in turn establish the rate for all generation at the avoided cost rate. The Commission found that due to Act 1781, net-metering customers were eligible for net metering benefits that were greater than the avoided cost payments for this size of generators.[35] Nonetheless, that was 15 years ago and a different law. The 2015 amendments to AREDA show a significant change in the legislative mandate as the passing of those provisions by the Legislature represents that the State is now concerned with ensuring that electric utilities are able to recover their entire cost of serving net-metering customers. Given that the Commission's determination in this matter relates to the implementation of the statutory provisions included in AREDA via Act 827, its interpretation regarding a prior version of the law is misplaced. As repeatedly stated throughout its comments, Sub-Group 2's 2-Channel Billing approach is consistent with all the requirements contained in the current version of AREDA and ratemaking practices of the Commission.

[34] Sub-Group 1 Reply Comments, p. 14.
[35] APSC Docket No. 16-027-R, Order No. 3, p. 5.

N. Rate Setting Authority

Sub-Group 1 states that Sub-Group 2 has improperly construed the Commission's rate setting authority provided in Ark. Code Ann. § 23-18-604(b)(1)(A)(i).[36] This section provides that "appropriate rates, terms, and conditions for net-metering contracts" must include "[a] requirement that the rates charged…recover the electric utility's entire cost of providing service…"[37] Sub-Group1 alleges that under 2-Channel Billing, the utility would *pay* for exported energy. This assertion is blatantly fallacious. Under 2-Channel Billing, as with the current net-metering approach, net-metering customers are not *paid* for energy - they are credited with kWh. This approach is consistent with the statutory requirement that electric utilities must "credit a net-metering customer with any accumulated net excess generation in the next applicable billing period."[38] It is also consistent with the requirements that the "net excess generation credit" remaining in a customer's account is carried forward indefinitely[39] and that a net-metering customer may elect to have the utility purchase net excess generation credits older than 24 months at the utility's estimated annual average avoided cost rate for wholesale energy.[40]

Because the 2-Channel Billing approach does not propose any cash payment by the utility for exported energy, Sub-Group 1's argument relating the fictional payment to a "greater fee or charge" authorized in Ark. Code Ann. § 23-18-604(b)(2) is misplaced and need not be addressed.

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[36] Sub-Group 1's Reply Comments, pp. 14 - 15.
[37] Ark. Code Ann. § 23-18-604(b)(1)(A)(i).
[38] Ark. Code Ann. § 23-18-604(b)(3).
[39] Ark. Code Ann. § 23-18-604(b)(6)(A)(i).

O. Encouraging the use of Renewables through Net-Metering

In its Reply Comments, Sub-Group 1 states that the 2-Channel Billing approach proposed by Sub-Group 2 is inconsistent with the intent of the General Assembly to promote net-metering and will diminish the growth of distributed generation.[41] As stated in Sub-Group 2's Reply Comments, AREDA and this docket only address net-metering, which is a specific type of billing mechanism used to credit customers for renewable energy they supply to the grid.[42] AREDA does not establish Arkansas' renewable energy policy but only addresses the promotion of renewable energy resources through net-metering. Sub-Group 1, therefore, inaccurately portrays the purpose of this proceeding.[43] In addition, Sub-Group 2's approach to net-metering is fully consistent with intent of the AREDA to encourage the use of renewables through net-metering while ensuring that net-metering customers pay their entire cost of service, net of benefits.

Sub-Group 1 further asserts that 2-Channel Billing is confusing.[44] However Sub-Group 1's characterization is not valid. Sub-Group 1's states that, "The notion that a customer could have a bill today for energy usage, and also a kilowatt-hour credit that they cannot apply to the bill, is counter-intuitive and frankly, confusing."[45] However, the billing scenario that Sub-Group 1 describes regarding unused excess kWh's rolling over to the next month is the same way billing is done today, is something net-metering customers understand, and is not confusing.

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[40] Ark. Code Ann. § 23-18-604(b)(6)(A)(ii).
[41] Sub-Group 1 Reply Comments pp. 15 – 16,
[42] Sub-Group 2 Reply Comments, pp. 5 – 7.
[43] Reply Comments of Sub-Group 2 of the Net-Metering Working Group, p. 5
[44] Sub-Group 1 Reply Comments, p. 16.
[45] Sub-Group 1 Reply Comments, p. 17.

Sub-Group 1 alleges that unlike the current net-metering policy in which a customer "can look at past bills, compare to the system's output and calculate the monthly bill savings,"[46] the 2-Channel approach contains "significant uncertainty" that makes it "very difficult" to determine the payback period of the net-metering facility.[47]

AREDA does not require the Commission to ensure a particular payback period or return on investment for net-metering customers. Neither does AREDA include a requirement that non-net metering absorb the utility's costs of serving net-metering customers. AREDA requires the Commission to establish rates for net-metering service that recover the utility's entire cost of serving net-metering customers from those customers.

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

[46] Reply Comments of Sub-Group 1, p. 17.
[47] Reply Comments of Sub-Group 1, p. 19.

the assistance of their installers) would be able to do the same. Any attempt to imply that a precise payback period can be calculated *only* with a full retail net-metering rate offset and/or with a precise customer-specific load profile is misleading; since there are so many other factors that can skew the numbers (including the weather, solar patterns, future rate changes, equipment performance, etc.). The expectation of a risk free calculation is unrealistic, even with the best information.

It is important to note, however, that under 2-Channel Billing the net-metering customer will continue to receive the full retail rate value for energy they self-generate and use behind-the-meter, which constitutes the majority of a customer's return on investment ("ROI"). The change in billing mechanisms only affects the energy exported to the grid. For example as illustrated in Figure 3 below, the average EAI residential customer installing a 5 kW_{DC} solar net-metering system would still be able to save over $50 per month under 2-Channel Billing in comparison to that same customer without net-metering. In addition, the difference between the current rules and 2-Channel Billing is estimated to have less than a $10 impact on a customer's total average monthly bill.

Figure 3: Comparison of Net-Metering Savings

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

Sub-Group 1 also raised a concern about the uncertainty that arises from the fact that the exported generation rate will presumably change with every COS update. As such, the net-metering customer would need to forecast how their exported generation credit would change over the years, and such a complex, essentially unpredictable rate design would frustrate the emerging self-generation market.[48] However, all ratemaking contains, and will continue to contain, an element of uncertainty in forecasting long-term utility rates. This uncertainty is explicit in the nature of ratemaking. As such, all utility customers bear that uncertainty. No one, including current, grandfathered, net-metering customers, is guaranteed that rates will remain unchanged. It should be no different for net-metering customers subject to the Commission's decision in this docket.

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

P. Meter Aggregation

Contrary to Sub-Group 1's assertion, Sub-Group 2's recommended 2-Channel Billing approach does not undermine net-metering aggregation. Rather, the 2-Channel Billing approach amends the credit rate applicable to the excess generation measured in kWh from the net-metering customer's generation meter, that are then applied to the net-metering customer's additional meters.

Meter aggregation is a clear use of the electric utility's distribution system. 2-Channel Billing does not discourage meter aggregation, but rather more properly aligns

[48] Reply Comments of Sub-Group 1, pp. 18-19.

such a system to its realized costs and benefits to the utility, the electric system, and all customers. Net-metering customers who aggregate their loads should be subject to the same rates, terms and conditions as customers who do not aggregate their loads.

Q. FERC-Jurisdictional Sales

Sub-Group1 asserts that the 2-Channel Billing approach treats exported generation as "a sale to the utility." As it states "Generation that is operated to offset consumption under traditional net metering, as defined in federal law (16 U.S.C. § 2621) and Arkansas statute (Ark. Code Ann. § 23-18-603(6)(E)) is not considered a jurisdictional sale even when generation exceeds the instantaneous level of consumption."[49] As stated numerous times in the filed comments, Sub-Group 2 proposes a billing mechanism to recover the electric utility's entire cost of providing service to the net-metering customer in accordance with the statute. Sub-Group 2's recommendations do not alter net-metering. Sub-Group 1's labeling of the exported energy measured by Channel 2 as a "sale" is inconsistent with federal law, state law, and even with its own comments. Since the energy measured on Channel 2 does not involve a sale in any manner, the remainder of Sub-Group1's concerns regarding treatment of the sale is moot.

This type of billing structure for net-metering has been adopted in numerous states without sparking any jurisdictional issues at the state or federal level concerning net sales or QFs under The Public Utility Regulatory Policies Act ("PURPA"), Pub.L. 95–617, 92 Stat. 3117, enacted November 9, 1978) or the Federal Power Act, ("FPA"), 16 U.S. Code Chapter 12. FERC has ruled previously that sales of energy from net

metering would only constitute a jurisdictional sale if it is a net sale, meaning that the exported generation is greater than the consumed generation over the course of the applicable monthly billing period: With net-metering, there is no sale; instead, there is a netting of kWh through the use of monthly bill credits. The net-metering customer is credited for excess kWh exported to the grid, and the credits serve to offset future kWh consumed by the net-metering customer. "No sale occurs when an individual homeowner or business installs generation and accounts for its dealings with the utility through the practice of netting."[50] 2-Channel Billing does not result in any sale to the utility.

R. Optimizing ROI

Sub-Group 1's allegation that the 2-Channel Billing Approach creates a "perverse incentive" for DG customers is without merit. Net metering customers should seek to optimize their return on investment by offsetting part or all of their requirements for electricity consistent with the intent of the statutory definition of net-metering facility. The purpose of net-metering is not to export kWhs to the utility. It is a rational plan for the net-metering customer to use its system and reduce his or her requirements for electricity. As illustrated in Sub-Group 2's Attachment B to the Joint Report, on average net-metering customers provide little to no excess generation to the utility during the utility's summer peak load hours of 4 p.m. to 7 p.m. Therefore, the net-metering customer is not denying the benefits of excess generation to other customers during the utility's peak as alleged by Sub-Group 1.

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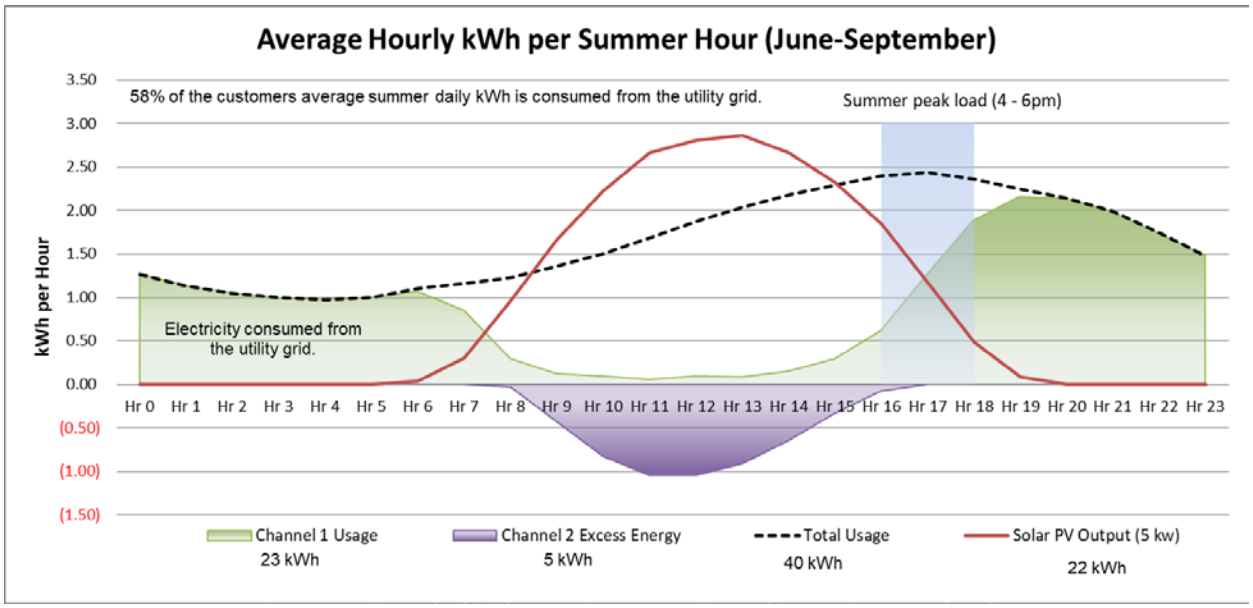
[49] Reply Comments of Sub-Group1, p. 22.
[50] *MidAmerican Energy Co*., 94 FERC ¶ 61,340, at 61,345 (2001).

Figure 4: Illustrative Electricity Flows for the Average Summer Day



As illustrated above, during the utility's summer peak load hours the solar PV system is supplying energy, but not in excess of the net-metering customer's requirements. The majority of the excess energy, depicted by the purple shaded area, is provided to the grid between 9 a.m. and 3 p.m. It is a rational plan for the net-metering customer to use its system and reduce his or her requirements for electricity by shifting part of his or her energy needs between 4 p.m. and 7 p.m. (the utility's peak hours) to the hours of 9 a.m. to 3 p.m. (solar peak hours) when the customer's self-generation is available.

S. Bill Impacts

Sub-Group 1 alleges that the 2-Channel billing approach has an "arbitrary and perverse" impact on net-metering customers' bills due to the variability of the solar

customer's energy usage patterns.[51] In support of this allegation, Sub-Group 1 presented Attachment B to its Reply Comments. This attachment compares the usage profile of five "actual" customers to the "hypothetical" customer Sub-Group 2 used in the development of the Excess Generation Credit Rate. By this analysis, Sub-Group 1 hoped to show the wide variety of bill impacts to net-metering customers based on their usage patterns and other factors resulting in difficulty in forecasting billing savings which undermines AREDA.[52] However, once the data for the five customers provided by Sub-Group 1 was adjusted to place it on an apples-to-apples basis with Sub-Group 2's analysis, the data provided support that Sub-Group 2's customer is representative of the average net-metering customer.

Sub-Group 1's Attachment B provides Channel 1 and Channel 2 data for five net-metering customers for the year 2016. This data and the data for Sub-Group 2's three modeled kW systems is then placed into figures to compare the energy consumed and energy exported for the five customers. Sub-Group 1 stated that "As expected, seasonal changes in grid energy use are readily apparent for SG2's model systems and somewhat less discernible among the five customers. Likewise, seasonal patterns are obvious for SG2's model and apparent but more muted among the customers."[53]

[51] See, Reply Comments of Sub-Group 1, pp. 20-21.
[52] See, Reply Comments of Sub-Group 1, p. 21.
[53] Reply Comments of Sub-Group 1, Attachment B, p. 43.

Fig. 1. 3-kW Systems Model - Consumption

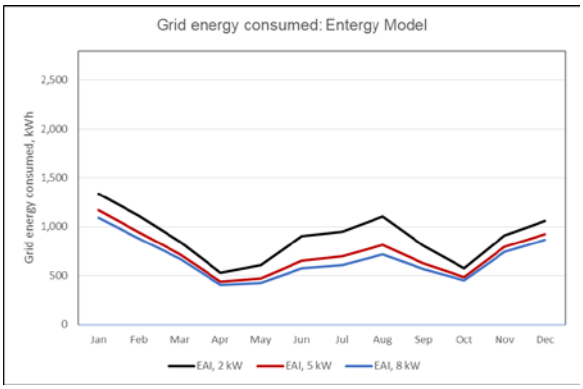


Fig. 2. 5-Customer Model -Consumption

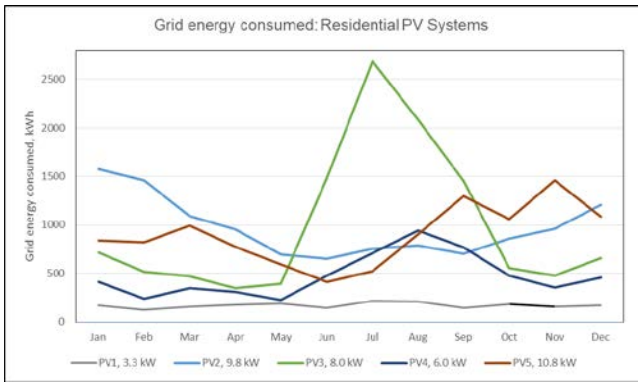


Fig. 3. 3-kW Systems Model - Consumption

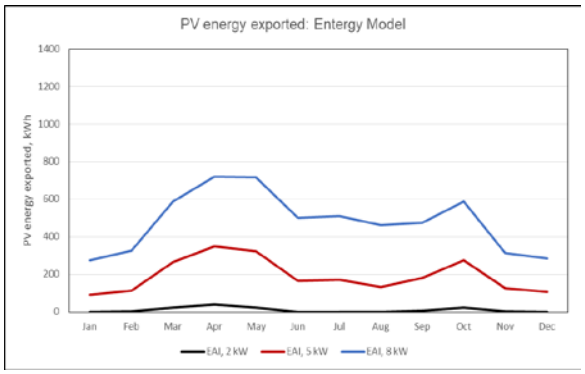
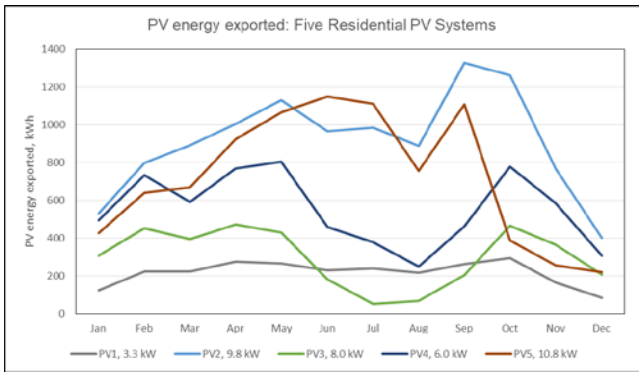


Fig. 4. 5-Customer Model -Consumption



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

Usage patterns will vary widely among individual consumers within a rate class. This is why traditional rate making methodologies base rates on the average customer. As stated through its comments, SG2's model is intended to represent the average customer not each individual customer. It is inappropriate, therefore, to draw conclusions based on the usage of individual customers as suggested by Sub-Group 1.

However, if the five customers provided by Sub-Group 1 were averaged to place the data on an apples-to-apples basis with Sub-Group 2's data and then compared with Sub-Group 2's average customer under the 2-Channel Billing approach, one would see that the average of Sub-Group 1's customers look more like Sub Group 2's average customers as shown below.

Fig. 5. SG1 & SG2 consumption models

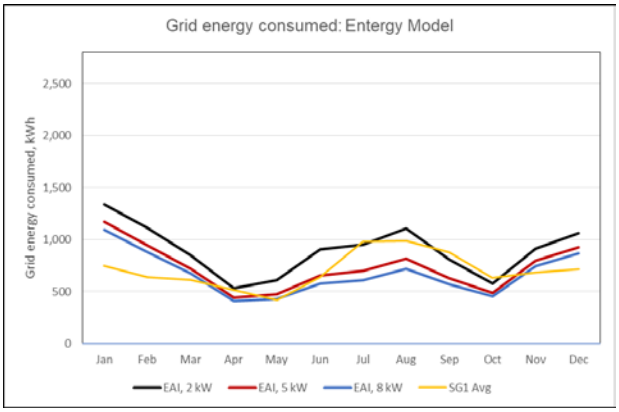
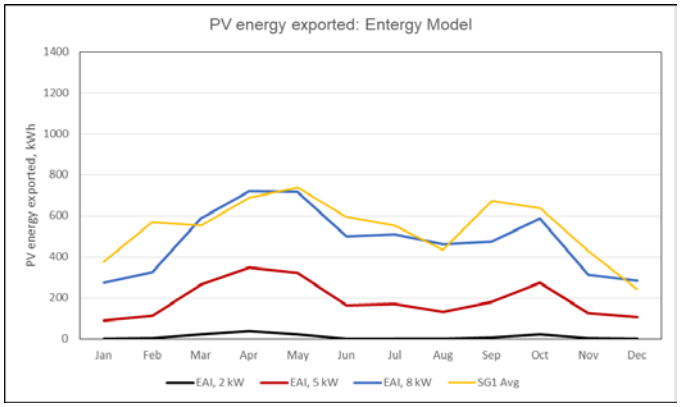


Fig. 6. SG1 & SG2 export models



These figures demonstrate that despite the small sample size, the average energy consumed and energy exported by Sub-Group 1's five customers is comparable to the "average" customers modeled by Sub-Group 2. Thus, rather than refuting Sub-Group 2's methodology, the individual customer data provides support that Sub-Group 2's customer is representative of the average net-metering customer.[54]

T. Further Study of Net-Metering

Sub-Group 1 requests that the Commission order a more thorough investigation of the costs and benefits of net-metering through a third-party and pending the results of that study, leave the current net-metering mechanism in place. However, as set forth in

[55] Pulaski County, Arkansas' Reply Comments, p. 3.

Sub-Group 2's prior comments, further third-party study is not necessary. A data-driven, evidence-based review of the existing COS studies reveals that the current practice of crediting excess generation kWh exported from net-metering customers to the grid fails to comply with the requirements of AREDA and must change. Sub-Group 2 has presented analyses, data, and evidence which demonstrate that its recommended 2-Channel Billing approach complies with the goals and requirements of AREDA. Sub-Group 2's recommendation establishes rates for net-metering that recover the costs of serving the net-metering customers with both the costs and benefits measured through COS studies. This approach is consistent with AREDA and with established ratemaking procedures and policies. Sub-Group 1's proposed Value of Solar approach is not consistent with either AREDA or established ratemaking procedures and policies and should not be used for any purpose in this proceeding.

U. Pulaski County Recommendations

Pulaski County recommends that "the Commission should do nothing."[55] Only if the Commission felt compelled to do something, does Pulaski County recommend setting a threshold of net-metering penetration to gather enough data at which point the docket could be reopened and a neutral facilitator retained to study the matter. However, Pulaski County's suggestion ignores the statutory mandate to the Commission.

AREDA requires that the Commission establish rates for net-metering that recover the costs of serving net-metering customers net of any quantifiable benefits

[55] Pulaski County, Arkansas' Reply Comments, p. 3.

from those customers. The current practice fails to meet that requirement and must change to reflect the current statute. AREDA does not include any provision for the Commission to establish some sort of threshold and delay action until that threshold is met. AREDA requires the Commission to set rates that conform to its mandates. Further study is not required for the Commission to act now as Sub-Group 2 recommends.

V. William Ball's Recommendations

Mr. Ball argues that the "costs to a utility from a net metering customer not incurred by the utility serving non-net metering customers within a given customer class are minimal."[56] As such, Mr. Ball believes that only three areas of cost to a utility are worth weighing against benefits: a one-time cost to process a NEM application; a one-time cost to verify the operation of the NEM facility; and "possibly" administrative costs associated with billing. As stated in the opening paragraph of these comments, this docket was established to "gather information to be used to determine appropriate rates, terms, and conditions under Act 827 of 2015 ("Act 827") for net metering contracts, including any changes necessary to the Commission's Net Metering Rules ("NMRs")." Mr. Ball's proposal fails to encompass the electric utility's costs to serve the net-metering as described above. Additional costs, such as those described by Mr. Ball are contemplated by the statute and may become relevant in the future in some other docket, but they are not relevant in this docket.

[56] Reply Comments William Ball, pro se, p. 1(unnumbered).

WHEREFORE, Sub-Group 2 submits its Sur-Reply Comments to the Commission.

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First Electric Cooperative Corporation
Mississippi County Electric Cooperative, Inc.
North Arkansas Electric Cooperative, Inc.
Ouachita Electric Cooperative Corporation
Ozarks Electric Cooperative Corporation
Petit Jean Electric Cooperative Corporation
Rich Mountain Electric Cooperative, Inc.
South Central Arkansas Electric Cooperative, Inc.
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CERTIFICATE OF SERVICE

I certify that a copy of the foregoing has been delivered to all Parties of Record by electronic mail via the Electronic Filing System, this 9th day of November, 2017.

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Sub-Group 1's flawed cost-of-service (COS) approach cannot be applied to all customers, given that it would require a customized Channel 1 rate for each individual customer. For example, in Table 1 in its Reply Comments,[57] Sub-Group 1's adjustment shows a 35% reduction in the base rate for a net-metering customer who adds a 5 kW_{DC} system. If that same net-metering customer added an 8 kW_{DC} system, Sub-Group 1's flawed analysis shows a 57% reduction to the base rate, and for a 2 kW_{DC} system a 4% reduction to the base rate. Given that adjustments to Channel 1 rates cannot be individualized for every possible net-metering system, and setting aside the question of whether this would result in discriminatory rates, it is impractical from a ratemaking perspective to engage in such an analysis. Rates are designed for classes of customers, not individual customers.

Sub-Group 1 states that: "Table 2 [replicated below] shows clearly that fully cost-based rates for both Channel 1 usage and Channel 2 exports – including retail rates for the Channel 1 usage of DG customers that are lower than standard retail rates – would result in greater savings for DG customers than now available under current net metering."[58]

Table 1: Sub-Group 1's Monthly Bill Savings ($) for Residential DG Customers

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

Sub-Group 2's COS approach is simple to understand and can be applied universally to all utilities in Arkansas with bill impacts consistent from utility to utility. By contrast, Sub-Group's 1's flawed COS analysis is significantly more complicated, makes assumptions that are not in accordance with longstanding COS principles, and has bill impacts that do not remain consistent from utility to utility.

In order to adjust the Channel 1 rate for the 5 kW_{DC} net-metering system, Sub-Group 1 argues that the production capacity costs allocated to the average residential net-metering customer should be reduced by the hourly value that a 5 kW_{DC} net-metering system would reduce this net-metering customer's 4CP load. Using the maximum hour, Sub-Group 1 concludes the appropriate allocation of production capacity costs is 21% of the net-metering customer's value before installing the net-metering facility. Under that approach, this value will be different for every incremental change in the net-metering system's capacity. Sub-Group 1 makes a similar calculation for reducing allocated transmission capacity costs using the customer's 12CP load, which results in allocation that is 41% of net-metering customer's value before installing solar.

Sub-Group 1 then makes an adjustment for the allocation of distribution capacity costs. Their adjustment actually raises the distribution costs because it determines that there is only a

[57] Reply Comments of Sub-Group 1, p. 38.
[58] Reply Comments of Sub-Group 1, p. 40.

30% reduction in the net-metering customer's non-coincident peak (NCP), or 70% of the value before the installation of the net-metering system. Sub-Group 1 arrived at the 30% reduction by calculating the NCP for each month of the year and averaging the months of January, February, July, and August. The commonly accepted COS practice would result in a customer's NCP being that of the highest peak in the year, not the average of four months. For this particular net-metering customer, the highest peak occurred in January. In January the net-metering customer has the same monthly NCP as the customer did before installing the net-metering system. In fact, the net-metering customer has the same monthly NCP as the customer did before installing the net-metering system in the months of January, April, November, and December. Had Sub-Group 1 used the single January NCP, it would have resulted in a 0% reduction in NCP. Correcting this one assumption input alone would change this customer's Channel 1 rate from a 35% reduction in base rates to a 29% reduction in base rates.

Furthermore, Sub-Group 1's flawed COS approach, when applied to other utilities, has substantially different results. Sub-Group 1's COS approach for Entergy Arkansas, Inc. (EAI). EAI has the lowest summer peaking hour in the state, and also, due to the efficiency of its generation units, has embedded fuel costs that are lower than the LMP. All utility systems do not share these characteristics. For example, the following table updates Sub-Group 1's Table 2 with OG&E data and applies Sub-Group 1's COS analysis.

Table 2: OG&E – Monthly Bill Savings ($) for Residential DG Customers

System Size (kW-DC)	**Current Net-Metering**	**Two Channel: Sub-Group 2 Recommendation**	**Two Channel: Sub-Group 1 Complete Channel 1 COS Proposal**
2 kW	22	21	16
4 kW	44	38	33
5 kW	55	44	41
8 kW	90	61	66
9.6 kW	98	66	74

As shown above, Sub-Group 1's COS analysis reveals that the savings from Sub-Group 2's 2-Channel Billing proposal actually would be greater for those with systems of 5 kW and below. Only at 8 kW does Sub-Group 1's COS analyses show savings greater than the 2-Channel Billing approach. However, if you were to adjust the NCP to the single NCP of the customer as discussed above and reflected in Table 3 below, the 2-Channel Billing approach would result in greater savings in every example except where the customer installs the maximum amount of solar. Even then, the savings are comparable.

Table 3: OG&E – Monthly Bill Savings ($) for Residential DG Customers NCP Adjustment

System Size (kW-DC)	Current Net-Metering	Two Channel: Sub-Group 2 Recommendation	Two Channel: Sub-Group 1 Complete Channel 1 COS Proposal
2 kW	22	21	15
4 kW	44	38	31
5 kW	55	44	38
8 kW	90	61	61
9.6 kW	98	66	69

The following tables show the impact on SWEPCO.

Table 4: SWEPCO – Monthly Bill Savings ($) for Residential DG Customers

System Size (kW-DC)	Current Net-Metering	Two Channel: Sub-Group 2 Recommendation	Two Channel: Sub-Group 1 Complete Channel 1 COS Proposal
2 kW	22	22	17
4 kW	45	38	33
5 kW	56	45	41
8 kW	89	61	63
9.6 kW	98	65	71

Table 4: SWEPCO – Monthly Bill Savings ($) for Residential DG Customers NCP Adjustment

System Size (kW-DC)	Current Net-Metering	Two Channel: Sub-Group 2 Recommendation	Two Channel: Sub-Group 1 Complete Channel 1 COS Proposal
2 kW	22	22	16
4 kW	45	38	31
5 kW	56	45	38
8 kW	89	61	59
9.6 kW	98	65	66

Finally, it is worth noting that this approach would be overly burdensome and complicated to implement from a billing perspective. In addition, this methodology is both inconsistent with longstanding COS and ratemaking principles and would require every single net-metering customer to receive a customized Channel 1 rate. Sub-Group's 1's flawed COS analysis is therefore significantly more complicated – and arguably infeasible – as compared to Sub-Group 2's ECGR proposal under 2-Channel Billing.

Examples of approved net-metering crediting mechanisms where either 100% of the energy generated by a net-metering system is credited at a different value than the full retail rate (i.e., buy-all/sell-all arrangements) or only excess energy that is exported to the grid net of behind-the-meter usage is credited at a different value than the full retail rate (i.e., "2-channel billing" or net billing).

	State	Utility	2-Channel Billing	"Buy-All/Sell-All"
1	Alabama	Alabama Power	✓ [A]	
2	Arizona	Arizona Public Service	✓	
3	Arizona	Tucson Electric Power	✓ [B]	
4	Arizona	UNS Electric	✓ [B]	
5	California	Imperial Irrigation District	✓	
6	California	Modesto Irrigation District	✓	
7	Georgia	Georgia Power	✓	
8	Hawaii	Hawaiian Electric Co (HECO)	✓	
9	Hawaii	Hawaii Electric Light Co (HECO)	✓	
10	Hawaii	Kauai Island Utility Cooperative	✓	
11	Hawaii	Maui Electric Co. (HECO)	✓	
12	Indiana	All utilities regulated by Indiana Utilities Regulatory Commission	✓ [B]	
13	Mississippi	Entergy Mississippi, Inc.	✓	
14	Mississippi	Mississippi Power Co.	✓	
15	Minnesota	All utilities regulated by Minnesota Public Utilities Commission		✓ (Optional)
16	South Dakota	Black Hills Power	✓ [A]	
17	South Dakota	Mid-American Energy	✓ [A]	
18	South Dakota	Montana-Dakota Utilities	✓ [A]	
19	South Dakota	Northern States Power Co. (Xcel)	✓ [A]	
20	South Dakota	Northwestern Energy	✓ [A]	
21	South Dakota	Otter Tail Power Company	✓ [A]	
22	Multiple States	Utilities served by TVA through the Green Power Provider (GPP) or Dispersed Power Production (DPP) programs	✓ (DPP)	✓ (GPP)
23	Texas	Austin Energy		✓
24	Texas	Entergy Texas, Inc.	✓	
25	Texas	SWEPCO	✓	
26	Utah	Rocky Mountain Power (PacifiCorp)	✓ [B]	

Notes:

[A] These utilities handle billing for net-metering customers through their QF (or small QF) tariffs such that all excess/exported energy is credited at an avoided cost-based rate.

[B] A new billing framework for net-metering customers has been approved either by a final regulatory commission order or state law. However, the transition to the new billing framework (and away from full retail NEM) for new net-metering customers has not yet occurred. In the case of Arizona, the ACC approved a net billing framework in their Value of Solar decision, but export rates for excess energy have not been approved yet for Tucson Electric Power or UNS Electric. In Indiana, a state law was passed,

but the transition away from full retail NEM will not occur until January 2018. A transition for utilities in Maine will occur in January 2018, and for Rocky Mountain Power (UT) – a transition to the new billing framework is expected to occur for new DG applications starting November 15, 2017.

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Annual Net Energy Charge

Percent Increase in Bills

In its Reply Comments, Sub-Group 1 develops an Annual Net Energy Charge (ANEC) amount that is paid by each of the five actual customers provided by Sub-Group 1 using both the current 1:1 full retail rate credit and Sub-Group 2's proposed 2 Channel Billing.[59] Sub-Group 1 stated that "all the customers would have paid a higher ANEC under Sub-Group 2's proposed 2-Channel Billing and, and four of the five, their ANEC would have been markedly higher."[60] Sub-Group 1 used the following table to illustrate the ANEC (to calculate the ANEC Sub-Group 1 used an average flat retail rate of $0.08 per kWh and an EGCR of $0.037 per kWh).

Table 1: Sub-Group 1's Annual Net Energy Charge

Customer	**PV1**	**PV2**	**PV3**	**PV4**	**PV5**
PV System Capacity (kW)	3.3	9.8	8.0	6.0	10.8
1:1 Net-Metering	$0.00	$147.68	$661.20	$0.00	$111.27
2-Channel Billing	$48.54	$528.93	$815.70	$200.66	$511.29
% Change		258%	23%		359%

Sub-Group 1's analyzes the annual percent increase in bills in support of its argument. If a net-metering customer has a zero bill (as in the case of PV1 and PV 4) it is mathematically impossible to calculate a percent increase. It should also be noted that Sub-Group 1's billing analysis included varying level of carry-over kWh from the previous year for each net-metering customer, which distorts the bill impacts experienced by each net-metering customer used in its small sample.

Sub-Group 2's customer impact analysis does not look at percent increase in bills, but the average dollar increase in monthly bills compared to the current net-metering rates. Using Sub-Group 2's model,[61] for Carrol Electric the typical customer with a 5 kW system would have a dollar increase of $11 per month ($9 on an energy charge only basis). A customer with an 8 kW system would have a dollar increase of $27 per month ($24 on an energy charge only basis). Using Sub-Group 2's analysis above, the following table illustrates the five customer's respective increases when examined using the average dollar increase in monthly bills. As shown in Table 2, the average increase of $20 per month is below the estimated $24 increase from Sub-Group 2's model.

Table 2: Average Monthly Net Energy Charge

Customer	**PV1**	**PV2**	**PV3**	**PV4**	**PV5**	**Average**
PV System Capacity (kW)	3.3	9.8	8.0	6.0	10.8	7.6
1:1 Net-Metering	$0	$12	$55	$0	$9	$15
2-Channel Billing	$4	$44	$68	$17	$43	$35
$ Change	**$4**	**$32**	**$13**	**$17**	**$33**	**$20**

[59] Reply Comments of Sub-Group 1, p. 47.
[60] *Id.*
[61] For purposes of this analysis, the five customers were all assumed to take service from Carroll Electric Cooperative. This assumption was based on Footnote 14, on page 47 of the Reply Comments of Sub-Group 1.

Consumption versus Price increase

In reference to Table 1 above, Sub-Group 1 states that "It is noteworthy that the customer who had the smallest ANEC increase under two-channel billing, Customer PV3, had the highest annual consumption of utility energy."[62] Using Sub-Group 1's table (Table 1 above), Customer PV3 does have the smallest percent increase in its annual bill (23%). However, simply looking at the percent increase in the customer's bill is not the correct way to view this information. The following, Tables 3 and 4, is the monthly billing data for each of the five customers as provided by Sub-Group 1. As shown in the Channel 1 Table 3, Customer PV3 does have the highest utility delivered annual energy requirements at 11,858 kWh.

Table 3: Channel 1

Grid energy used (Channel 1)					
Month	PV1	PV2	PV3	PV4	PV5
	3.3 kW	9.8 kW	8.0 kW	6.0 kW	10.8 kW
Jan	172	1,575	718	411	840
Feb	127	1,462	519	241	817
Mar	158	1,089	469	348	992
Apr	180	956	351	310	773
May	189	695	395	224	595
Jun	147	654	1,483	477	413
Jul	219	753	2,686	713	520
Aug	212	786	2,087	945	905
Sep	148	706	1,451	768	1,295
Oct	185	856	557	476	1,060
Nov	158	964	480	357	1,461
Dec	168	1,207	662	458	1,088
Total	**2,063**	**11,703**	**11,858**	**5,728**	**10,759**

Table 4: Channel 2

PV energy exported (Channel 2)					
Month	PV1	PV2	PV3	PV4	PV5
	3.3 kW	9.8 kW	8.0 kW	6.0 kW	10.8 kW
Jan	122	531	307	493	426
Feb	222	797	451	732	640
Mar	224	890	394	592	669
Apr	276	1,005	470	769	922
May	265	1,130	430	804	1,064
Jun	229	964	182	460	1,148
Jul	240	985	51	379	1,112
Aug	215	889	68	250	754
Sep	263	1,326	203	461	1,109
Oct	293	1,262	465	779	386
Nov	166	768	365	583	255
Dec	85	399	207	308	221
Total	**2,600**	**10,946**	**3,593**	**6,610**	**8,706**

However, simply looking at the percent increase in the customer's bill is not the correct way to view this information. As shown in the Average Monthly Net Energy Charge table above (Table 2), Customer PV1 has the lowest dollar increase of $4 per month (which also has the lowest annual consumption of utility energy), while Customer PV3 has the second lowest dollar increase of $13 per month. However, the information provided by Sub-Group 1 does not provide the full picture for each net-metering customer, insofar as it does not include the net-metering customer's bill without net-metering (which indicates how much the customer saves). To calculate the bill without net-metering one must know the annual consumption of each customer, which was not provided by Sub-Group 1. If the level of self-generation from the customer's net-metering facility is known, than the level of consumption can be calculated. Sub-Group 1 provided the net-metering PV System Capacity in kW for each customer,[63] with this additional information one can estimate the annual generation for each customer based on capacity values obtained from PVWatts.

Based on Sub-Group 2's analysis, Customer PV3's small percent increase is not determined simply by the level of energy (in kWh) it receives from its utility, but by the percentage of its consumption that is served by the utility and most importantly the percentage of net-metering self-generation that is consumed directly behind the meter. Sub-Group 2's analysis shows that Customer PV3 directly consumed more of its self-generation than the other four customers - directly consuming approximately 68% of its self-generation behind the meter. The other four customers all consumed less

[62] Reply Comments of Sub-Group 1, pp. 47-48.
[63] *Id.,* pg. 42.

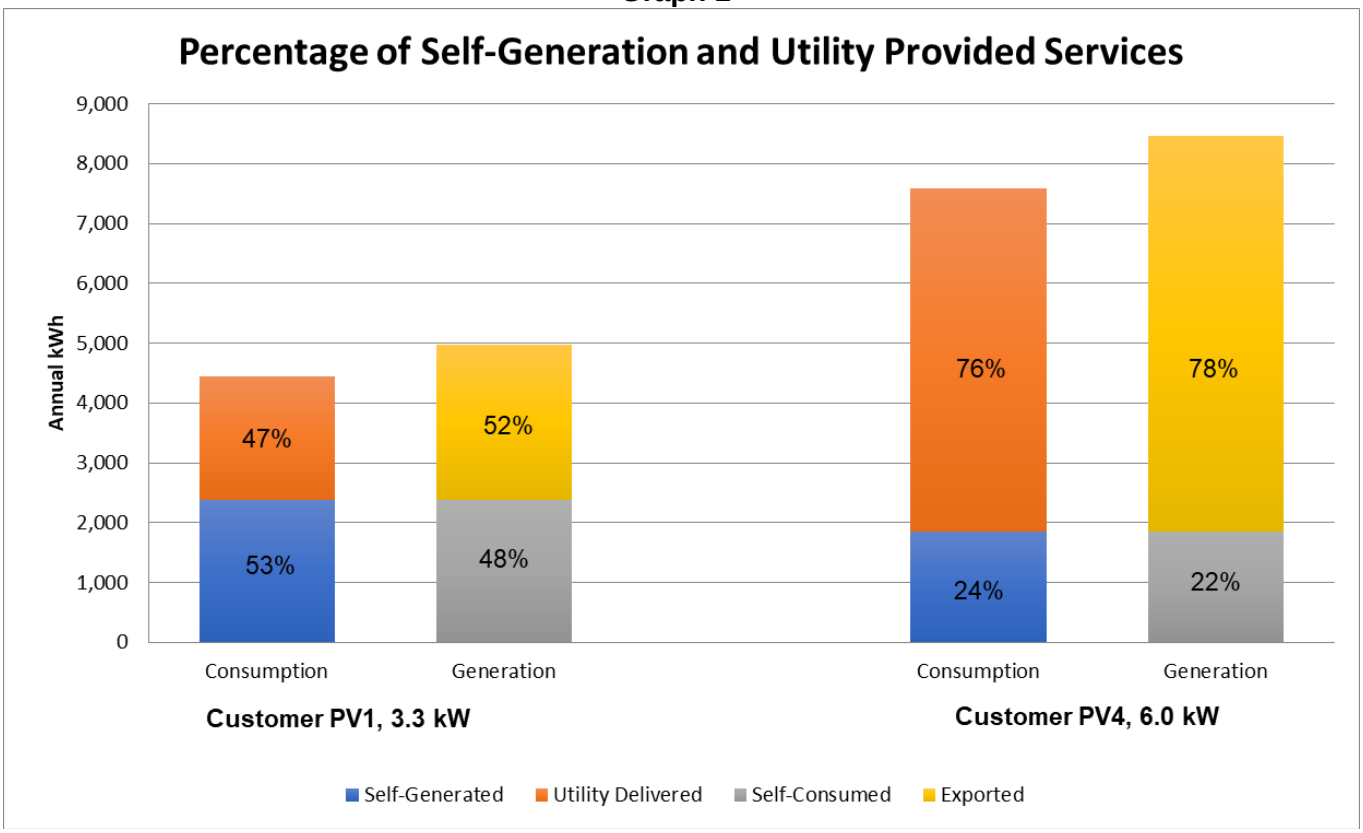
than 50% of their self-generation behind the meter, with two customers below 30% (Customer PV2 and Customer PV4).

Two customers exported more electricity than they purchased from the utility.

Sub-Group 1 stated that "Two net metering customers, Customer PV1 and Customer PV4, exported more electricity to their utility than they purchased from the utility."[64] Sub-Group 1 did not provide any additional comments or draw any conclusion from this statement.

Based on Sub-Group 1's bill calculation both of these customers have zero energy bills under the current 1:1 full retail rate credit. However, when you evaluate both net-metering customers using a cost to serve criteria, these two customers require markedly different requirements from the utility system. Based on Sub-Group 2's analysis Customer PV4's annual consumption is more than 70% greater than Customer PV1 and Customer PV1 receives only 47% of its energy requirements directly from the utility, while Customer PV4 receives 76% of its energy requirements directly from the utility. An illustration of the Consumption and Generation profile of each of the two customers is below.

Graph 1



As shown in Graph 1, the amounts of utility delivered and self-generated kWh for these two customers are not the same, insofar as Customer PV4 relies on the utility for a larger percentage of its energy needs than does Customer PV1. Customer PV1 also consumes a greater percentage of its self-generation than does Customer PV4 as Customer PV1 consumes 48% of its generation directly

[64] *Id.*, pg. 48.

behind the meter, while Customer PV 4 only consumes 22% of its self-generation directly behind the meter.

It is therefore clear that Customer PV4 relies more on utility-delivered generation than does Customer PV1. Sub-Group 2's 2-Channel Billing framework better comprehends the differences in the consumption of self-generated kWh and utility delivered kWh. As a result, Sub-Group 2's recommended 2-Channel Billing framework better sets rates that recover the cost of serving the net-metering customers from those customers.