STATE OF MARYLAND

PUBLIC SERVICE COMMISSION

March 31, 2017

Hon. Thomas M. Middleton
Chair, Finance Committee
3 East Miller Senate Office Building
11 Bladen Street
Annapolis, MD 21401

Hon. Sally Y. Jameson
Vice-Chair, Economic Matters Committee
231 House Office Building
6 Bladen Street
Annapolis, MD 21401

Re: ***Final Report of the PSC Regarding a Review of the Benefits and Costs of Distributed Solar and the Associated Potential Rate Design Options Applicable to the Service Territories of the Maryland Electric Cooperatives***

Dear Chairman Middleton and Vice-Chair Jameson:

Together with the enclosed Report of the Commission's independent consultant, Daymark Energy Advisors ("Daymark"), this letter constitutes the Commission's Final Report regarding its review of the benefits and costs of distributed solar in the Maryland electric cooperatives' service territories. The Final Report further details the results of an initial investigation into alternative rate design and compensation models that could facilitate solar deployment in the electric cooperatives' service territories with minimal impact to non-participating ratepayers.

In response to your request of April 14, 2016, the Commission agreed to study the implications of permitting an electric cooperative to increase its fixed charge for purposes of aligning the collection of fixed and usage charges with actual system costs, in accordance with the provisions of Senate Bill 1131 ("SB 1131") of 2016, and submitted a final report to you on February 1, 2017 in Public Conference 46. At the same time, the Commission decided to also investigate the valuation of distributed solar resources sited in the electric cooperatives' service territories, given the potential for discovering policy implications that might not emerge under a broader study that included Maryland's investor-owned utilities.[1] Such a study is now expected to be conducted in the context of Public Conference 44.

Therefore, the Commission engaged Daymark to conduct a study regarding these matters on behalf of the Commission. Specifically, Daymark was tasked with (1) quantifying the comprehensive value of distributed solar in the two Maryland electric cooperatives in 2016, and

[1] This approach was supported by the Maryland Energy Administration ("MEA") in its comments on the Daymark Report, in which MEA cautioned against applying the findings of the Daymark Report directly to the Maryland investor-owned utilities, given that certain assumptions in the Daymark Report may not be applicable to traditional utilities.

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(2) taking the value of solar into account, developing rate design options that facilitate solar development with minimum impact to non-participating ratepayers. In conducting its own analysis, Daymark held an in-person stakeholder meeting of interested parties at the Commission on January 12, 2017, and subsequently engaged in one-on-one telephone conferences with numerous stakeholders – including representatives of the electric cooperatives. Daymark submitted a report to the Commission detailing its evaluation on February 24, 2017.

The Daymark Report addresses comprehensively the valuation of costs and benefits associated with distributed solar deployed in the electric cooperatives' service territories, and further provides an overview of a multitude of alternative rate design options that could address concerns regarding cost-shifting between net metered and non-net metered customers. While the Daymark Report analyzes an array of potential components for inclusion in the valuation of distributed solar, the results are presented from the perspective of the electric cooperative; societal benefits that accrue to the populace at large, and other benefits realized by individual participating customers, are presented in the Report but are not part of the core analysis used to determine the value of distributed solar. The Daymark Report included the following findings:

- Technical Potential for Distributed Solar: For both cooperatives, the Daymark Report noted that the technical potential for distributed solar remains significant; although, residential solar installations currently account for less than 2% of residential annual energy requirements for SMECO with a total annual production of 40,000 MWh in 2016, and accounted for a residential net metered generation of only 6,000 MWh in 2016 in the Choptank service territory. Specifically, Daymark concluded that SMECO could potentially add an additional 1,315 MW and Choptank could potentially add an incremental 923 MW to their existing residential rooftop solar generation profiles based on currently available housing stock.
- Levelized Cost of Energy: The Daymark analysis found that the levelized cost of energy for a residential rooftop solar system is 16 cents/kWh with the inclusion of a 30% investment tax credit ("ITC"), and 22 cents/kWh without the ITC. The Report contrasted these costs with available compensation opportunities currently provided by the State, such as Solar Renewable Energy Credits ("SRECs"), and found that at average 2016 pricing, SRECs cover a much smaller portion of a solar installation's levelized costs than would otherwise occur in situations of higher SREC demand (33% of installation costs, compared to 58% of installation costs, respectively). The Report noted that increases in the solar RPS carve-out over time could counter this phenomenon.
- Current Maryland Net Metering Laws: The Report concluded that the current compensation approach in Maryland may overcompensate distributed generation customers in the electric cooperatives' service territories when the direct costs and benefits of the cooperatives alone are considered. A sensitivity cost/benefit analysis, which included some societal benefits associated with avoided emissions, concluded that the magnitude of overcompensation may improve so that it occurs only with respect to a

few rate classes when societal emissions benefits are incorporated.[2] The Report provided a valuation estimate for 2018 of approximately $0.06/kWh (and $0.11/kWh with societal emissions benefits), which is expected to increase every year. According to the Report, current net metering laws, however, provide compensation to SMECO residential net metering participants at a rate of $0.1301/kWh and to Choptank residential net metering participants at a rate of $0.1349/kWh.

- Alternative Rate Design Options: The Daymark Report provides a brief analysis of six rate design options that could assist the cooperatives in recovering lost revenues attributable to solar installations: (1) uniform volumetric rate increases; (2) fixed charge increases; (3) residential demand charges; (4) winter time-of-use rates; (5) net exports compensated at the value of solar rate; and (6) distributed energy resource facility charges. The analysis concluded that there is an inverse relationship between rate designs that address cross subsidies and revenue recovery, and those rate designs that best support solar development in the State. Specifically, the Daymark Report found that the net exports and DER facility charge options do not compensate solar customers enough to incentivize solar development when combined with current SREC prices.

After receiving the Daymark Report, the Commission convened Public Conference 48 for the limited purposes of receiving stakeholder comments and making them publicly available in the same location as Daymark's report. Stakeholders provided comments on and around March 15, 2017, which are appended to this Final Report. Commenting parties included: joint comments filed by Southern Maryland Electric Cooperative ("SMECO") and Choptank Electric Cooperative ("Choptank"); joint comments filed by Baltimore Gas and Electric Company ("BGE"), Potomac Electric Power Company ("Pepco"), and Delmarva Power & Light Company ("DPL"); the Maryland Office of People's Counsel ("OPC"); joint comments filed by Maryland Solar United Neighborhoods ("MD SUN"), Chesapeake Climate Action Network ("CCAN"), Institute for Energy and Environmental Research, and the Fuel Fund of Maryland; the Maryland Energy Administration ("MEA"); the Potomac Edison Company ("PE"); and the Commission's Technical Staff.

As was reflected in the initial stakeholder meeting, the written comments varied widely in their positions, with the only consensus being that the topic warrants extensive further consideration, likely in the context of the Commission's ongoing grid of the future proceeding. The written comments spanned both sides of the issue, with stakeholders opining that the methodology underlying the Report did not capture the full range of benefits, or costs, attributable to distributed solar.[3] Further, stakeholders such as OPC recognized the qualifying

[2] Because the externality values of societal benefits vary widely and are not currently incorporated into the cooperatives' cost of service structure, the subsequent rate design analysis presented in the Daymark Report considered only direct impacts to the cooperatives and their customers.

[3] For example, the joint comments filed by MD SUN, CCAN, Fuel Fund of Maryland, and the Institute for Energy and Environmental Research contend that Daymark should have reviewed and included values and methodologies used in other publicly-conducted value of solar studies as a source for value estimates that could not be calculated due to a lack of utility data, and thus the Daymark Report should be viewed only as a starting point to the conversation. Conversely, SMECO and Choptank argue in their joint comments that the Daymark Report reflects exaggerated avoided energy costs and further should have included only five of the 14 components considered in the

remarks contained in the Daymark Report, which stated that the analysis is intended to assist the Commission, policymakers, cooperatives, and stakeholders, in understanding the trade-offs involved in establishing net metering compensation mechanisms and reasonable rate designs.

Although the Commission takes no position at this time with respect to the valuation of distributed solar or alternative rate design options presented in the Daymark Report, the Commission notes that the Daymark Report was not intended to advocate for any specific net metering compensation model, but rather was structured as a first step toward understanding the various rate design options and how they may support State policy objectives while minimizing costs to non-participating ratepayers. The Commission notes that this topic is identified already as a central theme of the ongoing Public Conference 44 grid modernization proceeding, during which the Commission anticipates a multitude of additional opportunities for stakeholders to engage in the development of innovate rate design options.

The Commission looks forward to continuing to inform the General Assembly on these issues. Please feel free to contact the Commission with any questions or if the Commission may be of further assistance.

By Direction of the Commission,

/s/ David J. Collins

David J. Collins
Executive Secretary

DJC:tlj

cc: Sarah T. Albert, Department of Legislative Services (5 copies)

Report's methodological description. The Joint Comments submitted by BGE, Pepco, and DPL suggest that the Daymark Report did not appropriately consider the impact to system reliability, while PE asserts that further evaluation is necessary regarding the potential costs of future distribution and transmission investment in response to increase solar penetration.

Enclosures

1. Report: *Value of Solar for Maryland's Electric Cooperatives* (February 24, 2017), prepared by Daymark Energy Advisors for the Maryland Public Service Commission
2. Comments submitted in PC48 by:
    a. Southern Maryland Electric Cooperative and Choptank Electric Cooperative;
    b. Baltimore Gas and Electric Company, Potomac Electric Power Company, and Delmarva Power & Light Company;
    c. Maryland Office of People's Counsel;
    d. Maryland Solar United Neighborhoods, Chesapeake Climate Action Network, Institute for Energy and Environmental Research, and the Fuel Fund of Maryland;
    e. Maryland Energy Administration;
    f. The Potomac Edison Company; and
    g. The Commission's Technical Staff.

VALUE OF SOLAR REPORT

FEBRUARY 24,2017

PREPARED FOR

Maryland PSC

PREPARED BY

Daymark Energy Advisors

TABLE OF CONTENTS

ACRONYMS

Acronym or Abbreviation	Description
ACP	Alternative Compliance Payment
BLS	Bureau of Labor Statistics
BRA	Base Residual Auction
BTM	Behind the Meter
CONE	Cost of New Entry
CPP	Critical Peak Pricing
CSS	Customer Self-Supply
DER	Distributed Energy Resource
DG	Distributed Generation
DRIPE	Demand Reduction Induced Price Effects
EIA	Energy Information Administration
IAM	Integrated Assessment Model
ITC	Investment Tax Credit
LMP	Locational Market Price
LSE	Load Serving Entity
MMBTU	One Million British Thermal Units
NARUC	National Association of Regulatory Commissioners
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NITS	Network Integration Transmission Service
NREL	National Renewable Energy Laboratory
NSPL	Network Service Peak Load
ODEC	Old Dominion Energy Cooperative
PJM	PJM Interconnection
PLC	Peak Load Contribution
PPCA	Purchased Power Cost Adjustment
REC	Renewable Energy Credit
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Energy Portfolio Standard
RTEP	Regional Transmission Expansion Planning
RTO	Regional Transmission Organization
RTP	Real Time Pricing

Acronym or Abbreviation	Description
T&D	Transmission and Distribution
TOU	Time of Use
UCAP	Unforced Capacity
VOS	Value of Solar
VRR	Variable Resource Requirement

1. EXECUTIVE SUMMARY

Daymark Energy Advisors (Daymark) was engaged by the Maryland Public Service Commission (MD PSC or Commission or Staff) to provide an independent assessment with respect to solar for the two largest electric cooperatives in the State of Maryland, Southern Maryland Electric Cooperative (SMECO) and Choptank Electric Cooperative (Choptank). Two key objectives are addressed in this report: (1) quantifying the comprehensive value of distributed solar in the two largest Maryland electric cooperatives in 2016, and (2) taking the value of solar from the first objective into account, developing rate design options that facilitate solar development with minimum impact to non-participating ratepayers.

To address the first of these objectives, Daymark undertook the following tasks:

- Developed solar generation profiles of typical systems in SMECO and Choptank service territories;
- Quantified solar generation in SMECO and Choptank service territories since 2008;
- Estimated potential for additional rooftop generation in the SMECO and Choptank service territories;
- Assessed capacity and energy benefits of solar by looking at avoided energy and capacity value and calculated the levelized cost of energy (LCOE) of residential solar installation with and without tax credits;
- Compared solar project net metering revenues to avoided energy and capacity benefits calculated above;
- Defined categories of costs and benefits of solar; and
- Quantified costs and benefits of solar.

To address the second objective Daymark Energy Advisors' scope included:

- Defining the types of impacts to non-participating ratepayers from current rate approaches to solar deployment;

- Developing a list of rate design mechanisms that are being used in other jurisdictions to balance the costs and benefits of solar deployment to all cooperative customers/members; and
- Analyzing impacts of the most appropriate mechanisms for each rate class for the cooperatives.

As part of the independent analysis the Daymark team organized one stakeholder session which was managed by Commission Staff and attended by representatives of each of the cooperatives and a variety of interested parties, either in person or by teleconference. During this stakeholder meeting Daymark presented preliminary results of the investigation, fielded questions from the stakeholders, and gathered additional information for consideration as the report was developed.

1.1 Conclusions and Recommendations

The level of adoption of distributed solar generation is small in both cooperative service areas, while higher in SMECO than in Choptank. Total production for all residential installations online by September 16, 2016 in the SMECO service areas is estimated to be just under 40,000 MWh. Residential solar is estimated at approximately 2% of residential annual energy requirements for SMECO; all SMECO installations account for approximately 1.4% of all customer energy requirements based on current total solar installations.

Total net metered generation in the Choptank service territory was estimated to be 18,000 MWh for 2016. Just over 6,000 MWh of generation in the Choptank service area was from Residential facilities with most of the remaining generation coming from Small Commercial. This was over double the generation of the previous year, 2015.

For both cooperatives, the technical potential for solar distributed generation remains significant.

The components considered in the development of the Value of Solar for the cooperatives are depicted in the following table. Four of the benefits, avoided energy, avoided capacity, avoided REC purchases and avoided transmission charge accrue directly to the cooperatives. The societal benefits, which are the remainder of the benefits, accrue to cooperative customers, but do not directly impact the cooperatives' cost structure to serve their customers.

Table 1: Value of Solar Components

COMPONENT	DESCRIPTION
Avoided Energy	Market energy purchases avoided due to distributed solar
Avoided Capacity	Market capacity purchases avoided due to distributed solar
Avoided Transmission Costs	Avoids/defers/reduces transmission investment/charges due to reduction in peak load
Avoided Distribution Capacity	Avoids/defers distribution investment due to reduction in peak load
Ancillary Services Avoided	Impact of solar on Ancillary Services costs
Market Price Response	Indirect effects of solar on market prices for energy and capacity
Fuel Price Hedge Savings	Reduces exposure to volatile prices of fuels due to solar generation reducing energy needs
Avoided REC Purchases	Reduces entity requirement to comply with RPS policies
Carbon Impacts	Reduces compliance costs and social costs of carbon
Criteria Pollutant Impacts	Reduces compliance and social costs (includes NO_x and SO_2)
Job Impacts	Benefits to local communities for installation and maintenance jobs
Local Economic Development Impacts	Provides local economic development benefits (tax revenue from economic development)
Water Impact	Avoids water usage through avoided cooling for thermal generation
Land Use Impact	Avoids construction of conventional generation on land parcels

Figure 1 and Figure 2, below show the results of the value of solar analysis for south facing systems.

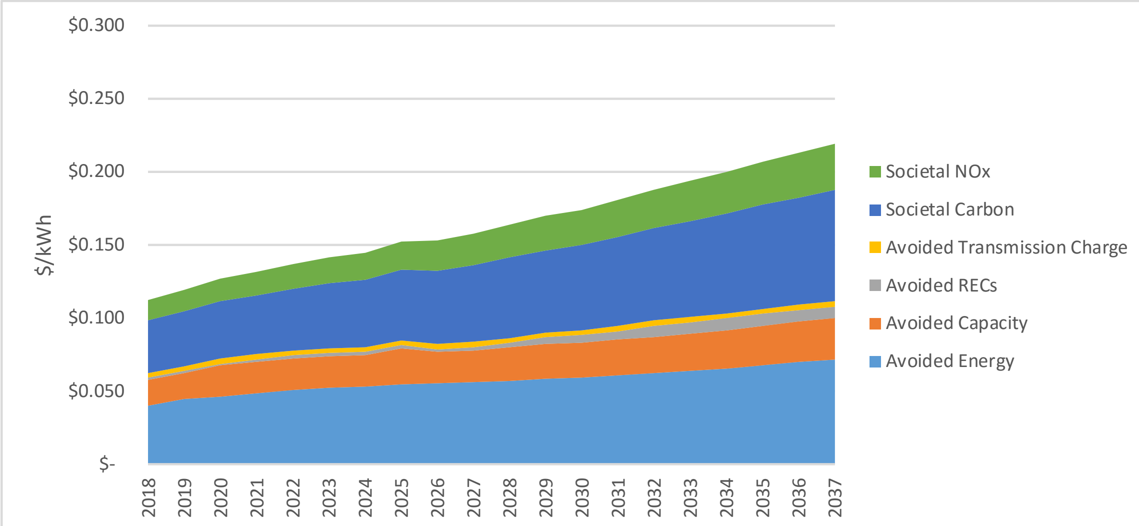

Figure 1:SMECO South Facing Solar System – Value of Solar

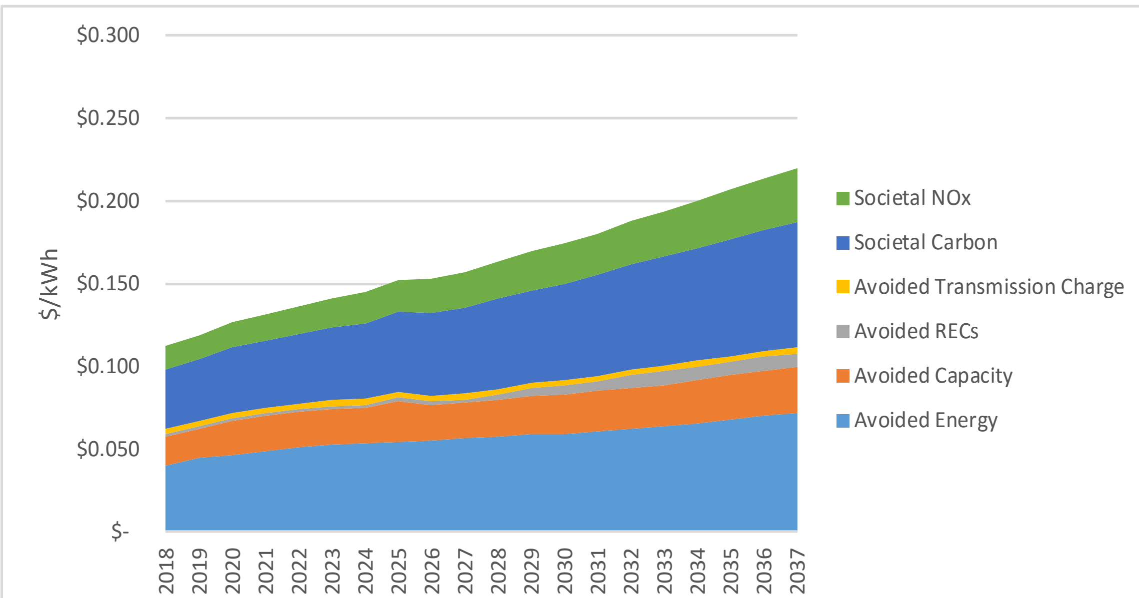

Figure 2: Choptank South Facing Solar System – Value of Solar

Daymark Energy Advisors' analysis is intended to help the Commission, policymakers, cooperatives and other stakeholders understand the trade-offs necessary to address policy intentions, customer equity and revenue recovery opportunities under the cooperatives' current rate design and NEM policy. To the extent that the Commission may be interested in pursuing changes that alter the existing balance of such trade-offs, we explore some of the more common rate design and DER compensation approaches to balancing the impacts of DER.

Our findings indicate that the current compensation approach in Maryland may overcompensate distributed generation customers when the direct costs and benefits of the cooperatives alone are considered. Incorporating societal emission costs in the analysis improves the situation but overcompensation may still be the case. Based on the information reviewed as part of this analysis, the societal costs that could be valued were limited to emissions. See Figure 3 and Figure 4 below.

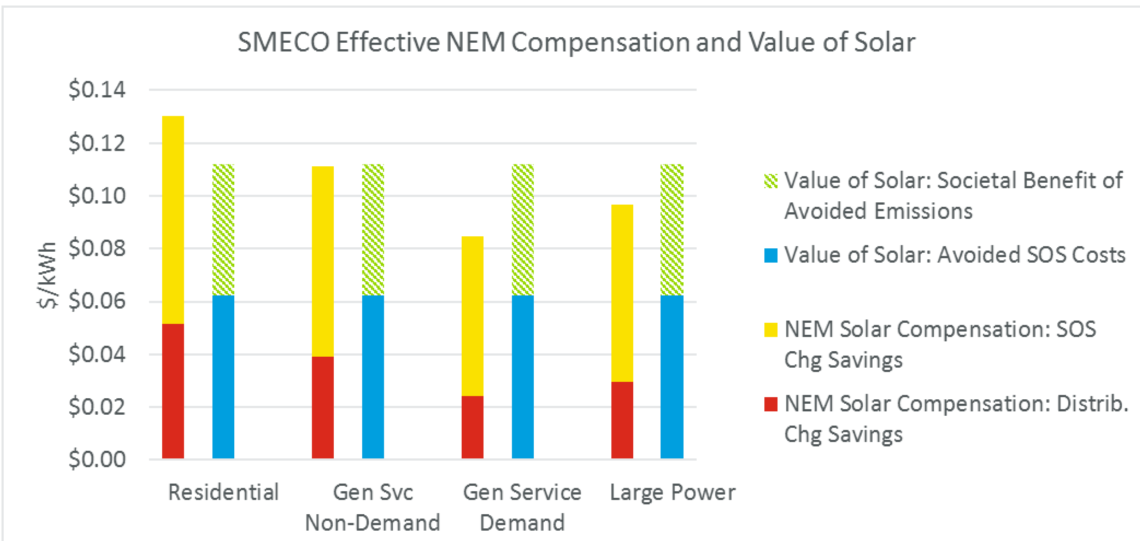

Figure 3: Comparison of Effective NEM Compensation and Value of Solar for SMECO Rate Classes

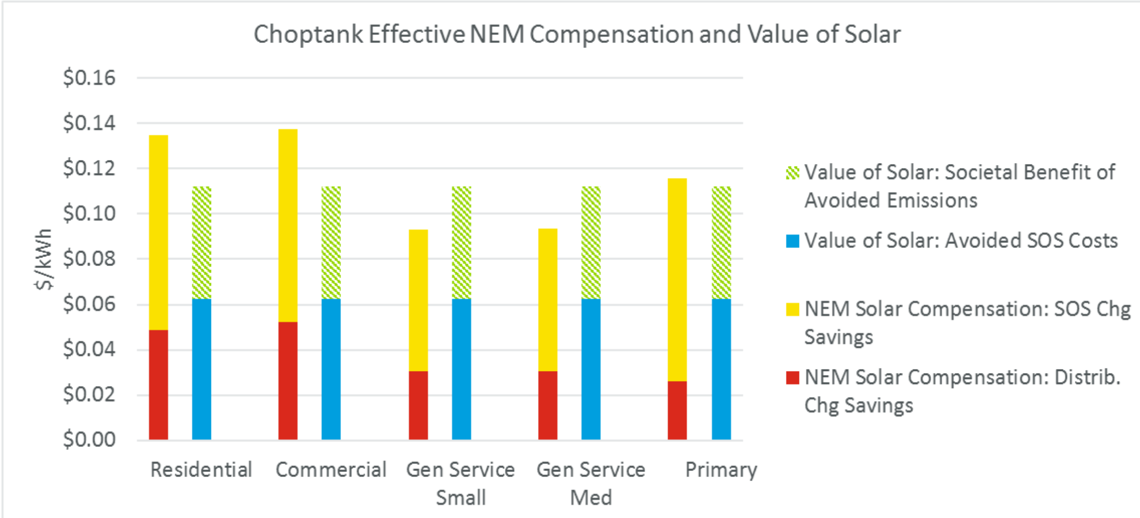

Figure 4: Comparison of Effective NEM Compensation and Value of Solar for Choptank Rate Classes

Policy considerations such as encouraging the adoption of distributed generation in an effort to reduce investment in new generation and distribution facilities and to address emissions locally are all valuable goals and such policy efforts must be balanced with the framework adopted for distributed generation and solar.

2. INTRODUCTION

Daymark Energy Advisors has provided consulting services in energy planning, market analysis, utility ratemaking, and regulatory policy in the electricity, natural gas, and water industries for more than 35 years. Our wide experience in energy regulation and the energy markets enables us to provide strategic planning advice to senior managers and policymakers, which we support with expert, technical analysis. Since our founding in 1980, we have earned a reputation for practical and objective advice and timely, accurate, and innovative analyses.

This report on the Maryland cooperative's value of solar is organized as follows.

Section A Results:

- Generation Scenarios
- Summation of Current Solar in Cooperative Territories
- Potential for Future Rooftop Solar
- Value of Solar Development
- Recommendations for Value of Solar

Section B Results:

- Rate Design and DER
- Measuring Current NEM Impacts
- Alternative Rate Design Approaches
- Compensation Arrangements for Distributed Energy Resources
- Summary of Residential Class Impacts

3. Solar Development Status and Potential Value of Solar

Daymark Energy Advisors first investigated the current status of solar development and the potential for future development for SMECO and Choptank. We address each of the following in Sections 3.1 through 3.3 of this report:

- Develop solar generation profile of a typical system in SMECO and Choptank service territories;
- Quantify solar generation in SMECO and Choptank service territories since 2008; and
- Estimate potential for additional rooftop generation in the SMECO and Choptank service territories.

Sections 3.3 to 3.5 address the cost of solar, the energy and capacity costs avoided by solar, and the categories and value that may be associated with solar for SMECO and Choptank.

3.1 Generation Scenarios

We present three scenarios (low, reference, and high) of generation from an individual solar project located in the Maryland service territories of Choptank and SMECO, independently. The data is presented as three scenarios of hourly generation for each of the 12 months in an average weather year. This representation allowed us to analyze the differences between expected solar generation for years of sunnier days and years of cloudier days to assess the range of solar output that may occur from year to year. These scenarios therefore provide estimates of high, low, and reference generation over the Maryland service territories of Choptank and SMECO and estimate the total generation of installed PV capacity in each respective cooperative service territory.

3.1.1 Methodology

We used the National Renewable Energy Laboratory (NREL) tool PVWatts[1] to develop the solar generation scenarios. The PVWatts tool estimates electricity production of customer sited solar systems based on system characteristics such as location, DC size, module type, array type, inverter efficiency, array tilt angle, and array azimuth angle. Characteristics of each individual system in a region will differ based on housing factors

1 http://pvwatts.nrel.gov/

such as roof angle and orientation. There will also likely be changes to inverter and panel efficiency through time, making some systems more efficient than others. By assuming general characteristics of expected installation it allows the tool to give a best estimate of yearly output from customer sited solar for the region based on normal weather. PVWatts weather data is derived from the nearest reporting weather station and incorporates metrics that impact efficiency of nameplate solar generation such as wind speed, temperature, and cloud cover.

The system orientation which produces the largest amount of energy in the territories of Choptank and SMECO consists of a southern facing angle (180 degree) installation with a panel tilt of about 32 degrees[2]. For the generation scenarios developed to estimate potential rooftop solar contribution in both Choptank and SMECO service areas, 180 degree facing panels with a 30-degree tilt was assumed. This assumption was based on housing characteristics and assumptions that primary installers of solar PV will likely be those with near optimal roof tops as solar installations on these houses would be most economic.

The compass orientation of solar panels determines their output shape throughout the day, with east facing panels peaking earlier and west facing panels peaking later in the day. We have assumed a south facing system as it likely represents the average panel orientation in the SMECO and Choptank service territories. Degree tilt can also impact system performance, but it has a small impact and therefore a 30-degree assumption was deemed appropriate for this study.

Three output scenarios were developed using these assumed installation attributes consisting of a reference case, a high case, and a low case. The reference case assumed average weather over the past 10 years based on NREL PVWatts inputs. The low case assumed less than a 1 out of 10-year occurrence of below average solar output (90% of average) and the high case assumed a less than 1 out of 10-year occurrence above average solar output of (110%). These cases refer to yearly output, the variability between certain months and seasons throughout multiple years would have the potential to be greater.

[2] Solar tilt calculation (38 degrees (latitude) * 0.76 + 3.1 degrees = optimal tilt for fixed rooftop (www.solarpaneltilt.com)

Figure 5 and Figure 6show the three scenarios for each cooperative plotted over the course of a year. The production values are based on output for a 1 kW installation of solar for an average day during the month.

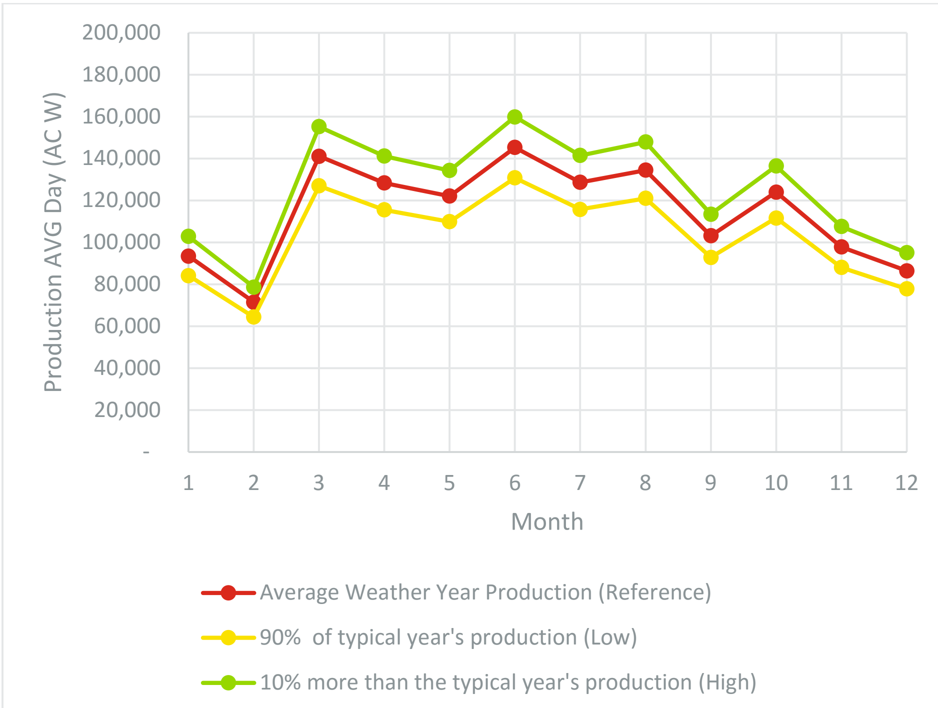

Figure 5: SMECO Solar Production Shapes per 1 kW AC

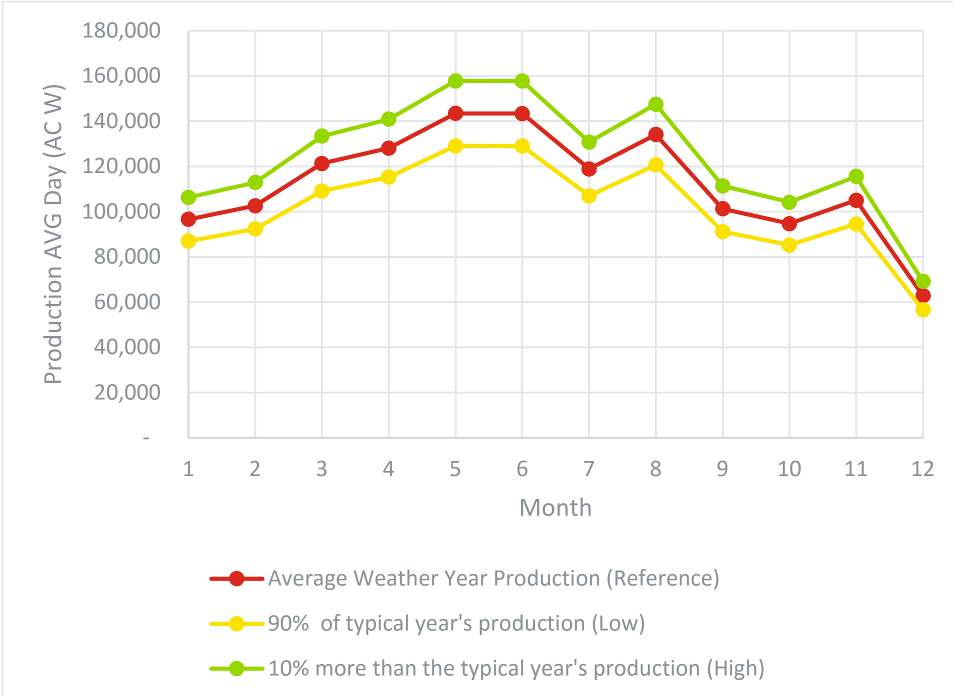

Figure 6: Choptank Solar Production Shapes per 1 kW AC

3.1.2 Results/Conclusions

Annual production of solar systems in the SMECO and Choptank regions is not likely to vary significantly from year to year. The highest production month for solar in both co-ops occurs during June. The lowest production month for SMECO is February while for Choptank it is December. Any differences between annual solar production between the coops is due to regional climatic differences that drive temperature and cloud cover. Choptank territory is on the eastern side of the Chesapeake Bay and closer to the ocean, hence, cloud variability and temperature changes will be more regulated through ocean-air interactions and prevailing wind intensity and direction. SMECO is on the western side of the Chesapeake Bay and is less regulated by ocean-air interaction but more so by Chesapeake Bay – air interaction and associated prevailing wind intensity and direction that can drive cloud formation

3.2 Current Solar Installations - Choptank and SMECO

3.2.3 Introduction

The amount of solar present in both Choptank and SMECO territories is quantified here from 2008 through present. The result of this analysis presents installed capacity for each year as new systems interconnected and the amount of generation from rooftop PV that occurred each year based on the generation reference scenario developed.

3.2.4 Methodology

Customer sited solar panel systems can become interconnected upon approval at any time during the calendar year and have an expected life of 20-25 years where their capacity will be between 80 – 85% of original nameplate.[3] For each year a solar panel is operational the panels degrade on average 0.5%.[4] To more accurately model how much solar was online during each year, each connection and its respective capacity was modeled from the month and year of interconnection forward. For example, if a panel was interconnected in April of 2008, the total amount of generation for 2008 contributed by that panel is calculated from April 2008 forward to year end. For 2009 that panel was given a degradation percentage of 0.5%, and the same degradation factor is applied to that panel for each successive generation year. The result is an estimation of the contribution from rooftop solar to the energy needs of each cooperative for a given year.

3.2.5 SMECO

Solar Capacity Additions

Residential solar installations for SMECO began to ramp up in 2013 and 2014 peaking with installation of nearly 12,000 kW in nameplate capacity in 2015. The proportion of medium general service and large power customer solar installations has dropped in the last few years compared to the increase seen in residential. Figure 7below breaks out the buildout for each year since 2008. Data for 2016 does not cover the entire year since it was only available through September. Given the continued

3 At an age of 25 years, solar panels will be between 80 to 85% of original capacity, but panels have the potential to last longer at a reduced capacity. (http://energyinformative.org/lifespan-solar-panels/)

4 0.5% degradation rate estimate for modern solar panels. Photovoltaic Degradation Rates — An Analytical Review. NREL, June 2012.

trend in 2016, it is likely this year would have superseded 2015 in residential solar installations.

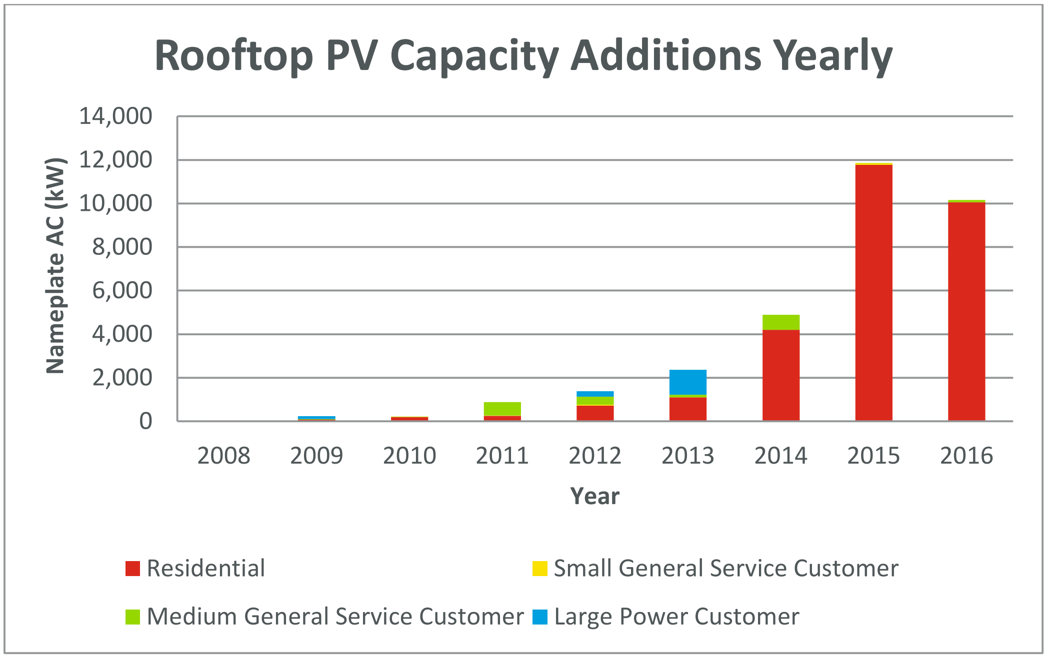

Figure 7: SMECO Customer Sited PV Additions (2008-2016)

Total Energy Generated

Residential installations became the largest generator of customer sited solar energy in 2013 and continue to be the largest contributor today. Total production for all residential installations online by September 16, 2016 is estimated to be just under 40,000 MWh. (See Figure 8). Residential solar is estimated at approximately 2% of residential annual energy requirements for SMECO; all installations account for approximately 1.4% of all customer energy requirements based on current total solar installations.

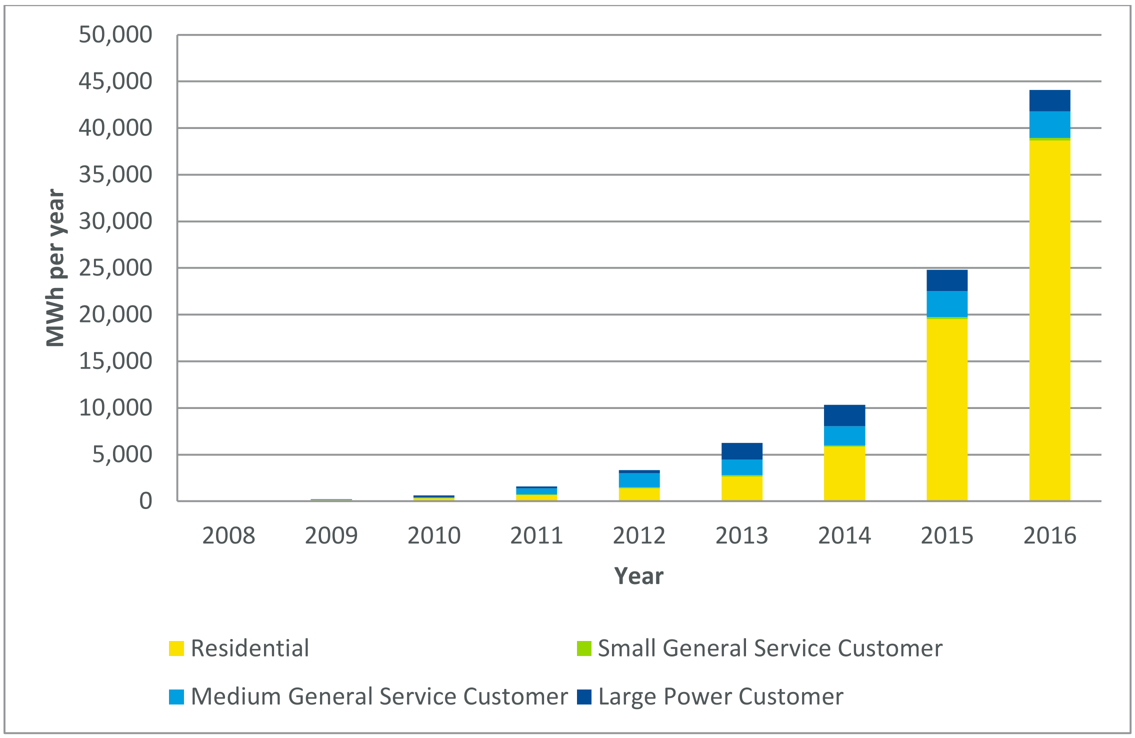

Figure 8: SMECO Annual Customer Sited PV Generation (2008-2016)

Capacity by Customer Type

The majority of customer sited solar capacity is residential. Residential systems make up about 28 MW of the 32 MW currently installed on the SMECO system. Figure 9 shows capacity installed by customer type.

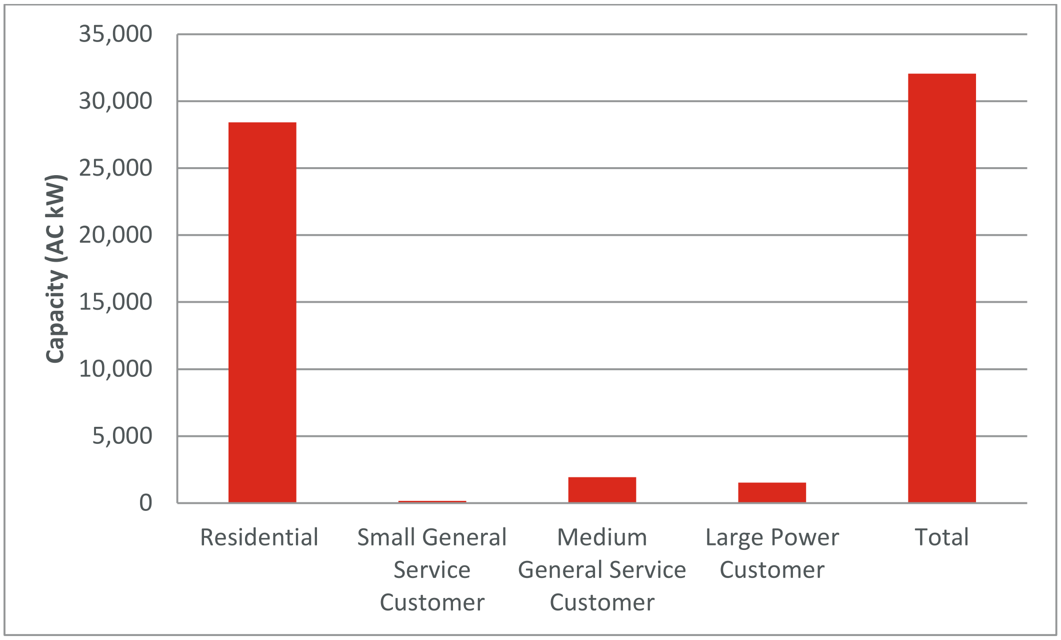

Figure 9: SMECO Customer Sited PV Installations by Customer Type

Average Facility Size

The average customer sited solar system in the SMECO service territory grew steadily from 2008 to 2013 and decreased slightly between 2013 and 2016. In 2016, the average system size was just over 8 kW. (See Figure 10). This recent downward trend may be due to solar becoming increasingly economical for smaller homes to install solar and be on a net metering tariff, when previously only larger homes acted on an economic incentive to invest in solar to reduce electric bills.

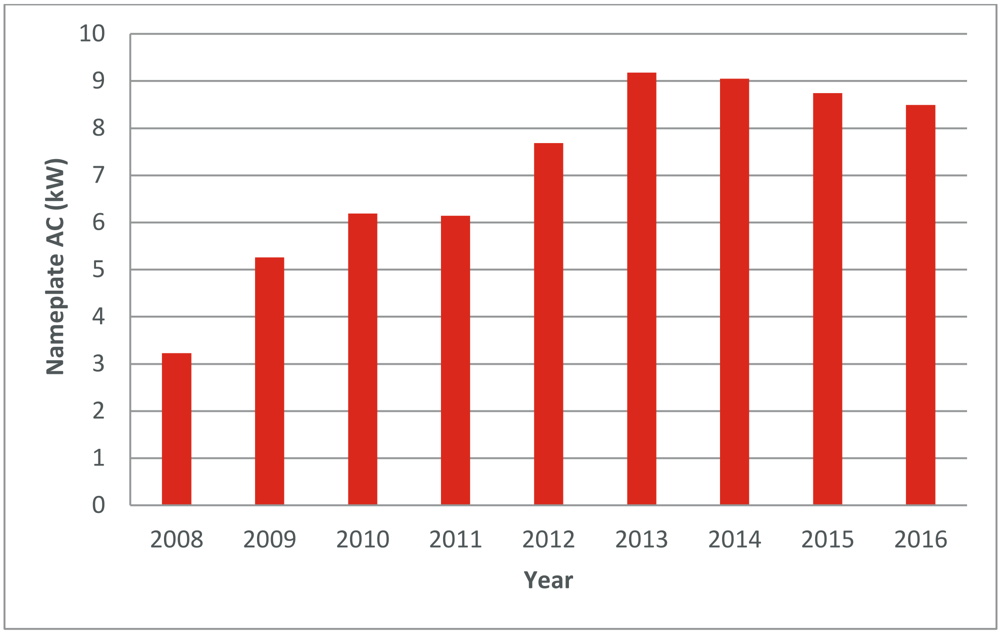

Figure 10: SMECO Average Residential Rooftop Size by Year

Number of Customers with Solar

Currently, there are around 3,300 net metered residential accounts in the SMECO territory. There are a small number of general service and large power class solar accounts, and these installations are generally much larger per account than residential. (See Figure 11). There were 159,142 meters in place at year end 2015, for comparative purposes, approximately 2 percent of meters were net metered in 2016.[5]

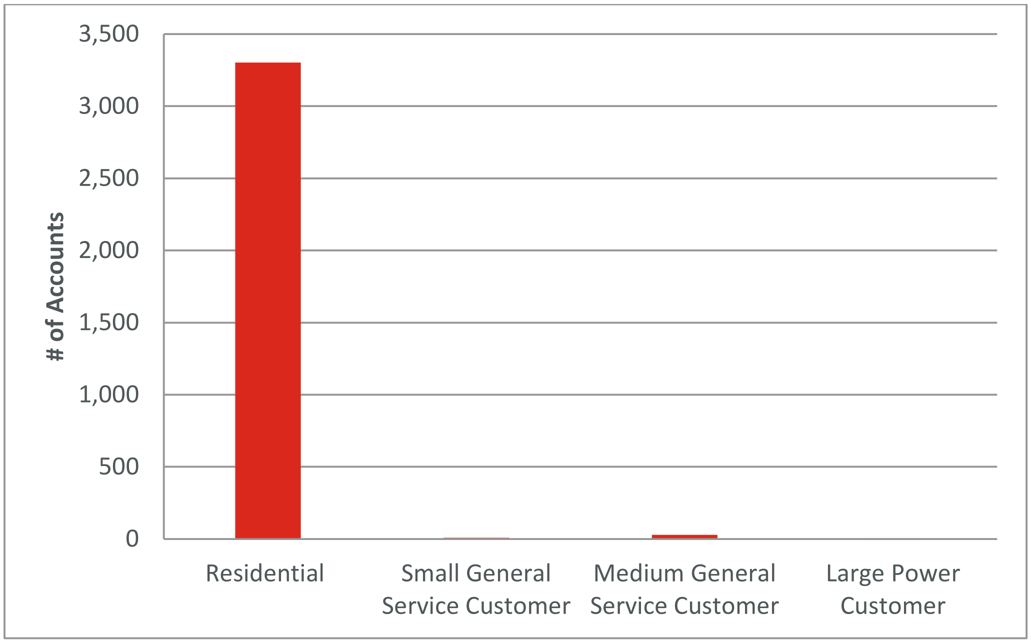

Figure 11: SMECO Customer Sited PV Accounts as of September 2016

[5] Meters or customer data for 2016 were unavailable.

3.2.6 Choptank

Solar Capacity Additions

Choptank saw its biggest additions in solar net metering in 2016 with over 5,000 kW AC nameplate capacity added. Half of this capacity was residential, with a large amount of the remaining capacity comprised of small general service, and then about 500 kW made up of Medium, Commercial, and Primary customers. Figure 12 graphically presents this information.

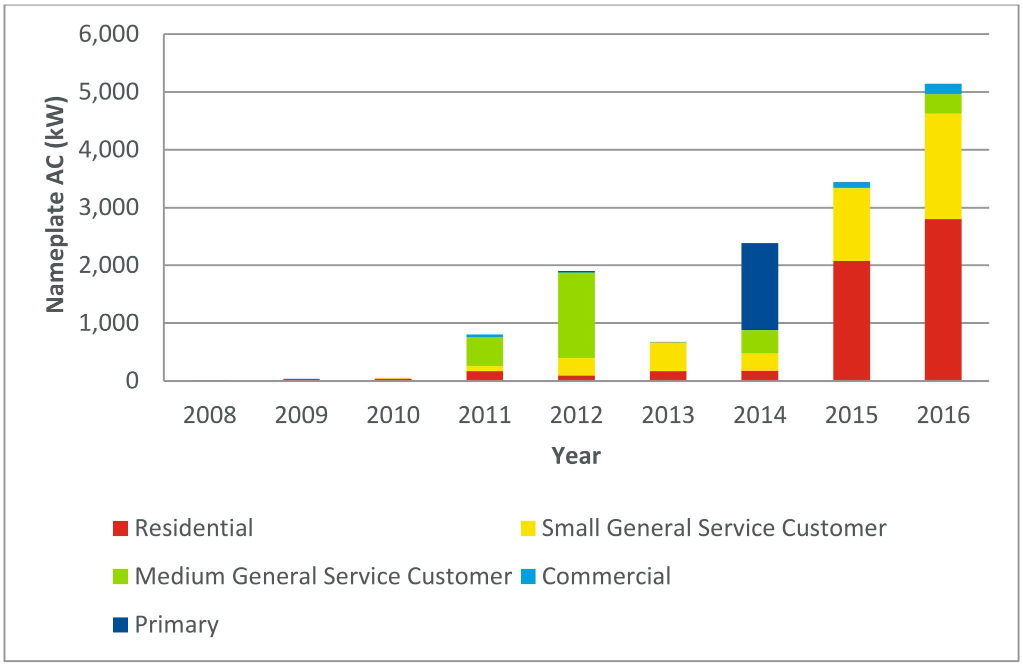

Figure 12: Choptank Solar Capacity Additions by Type of Customer

Total Energy Generated by Solar

Total net metered generation in the Choptank service territory was estimated to be 18,000 MWh for 2016. Just over 6,000 MWh of generation was from Residential facilities with most of the remaining generation coming from Small Commercial. This was over double the generation of the previous year, 2015. Figure 13 provides the historical net metered generation estimate per year since 2008 through 2016.

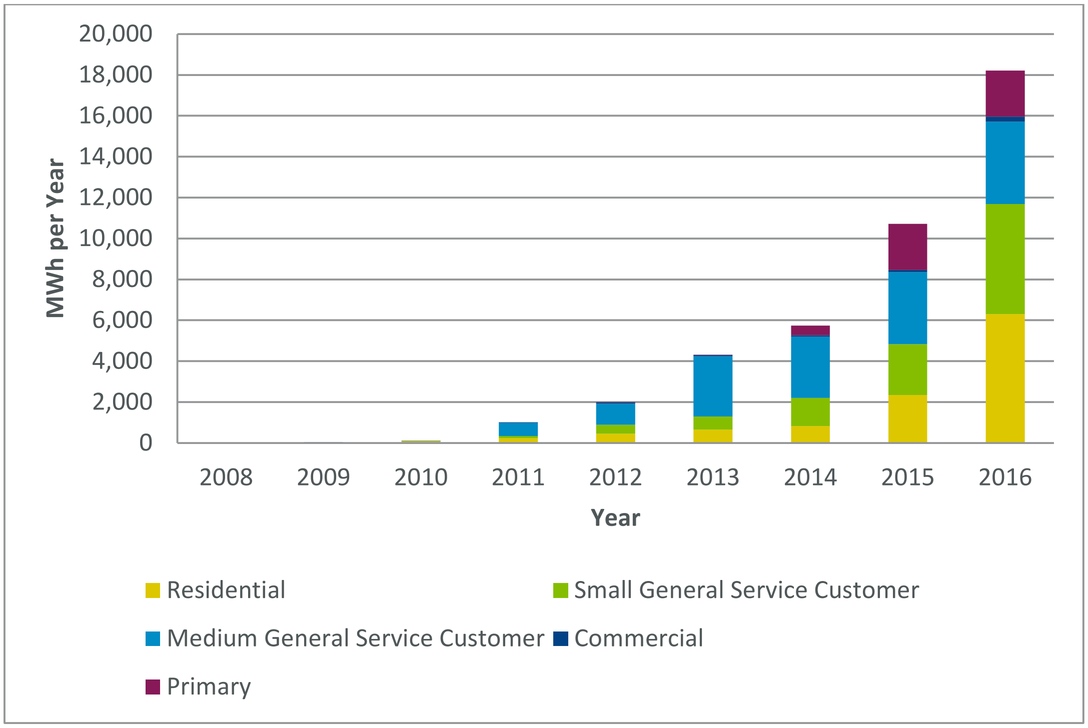

Figure 13: Choptank Annual Customer Sited PV Generation

Current Solar Capacity

Residential customer sited solar has a current installed nameplate capacity of around 5,500 kW. Small General Service makes up the next largest portion with around 4,200 kW of nameplate capacity. Medium General Service, Commercial, and Primary make up the remaining portion. (See Figure 14) In the Choptank service territory about half the customer sited solar is comprised of residential systems. This is significantly less than in SMECO's service territory, where almost all of the customer sited solar capacity is residential systems. These differences generally relate to each cooperative's customer demographics, economics, and other locational differences that drive customer decisions for solar installation.

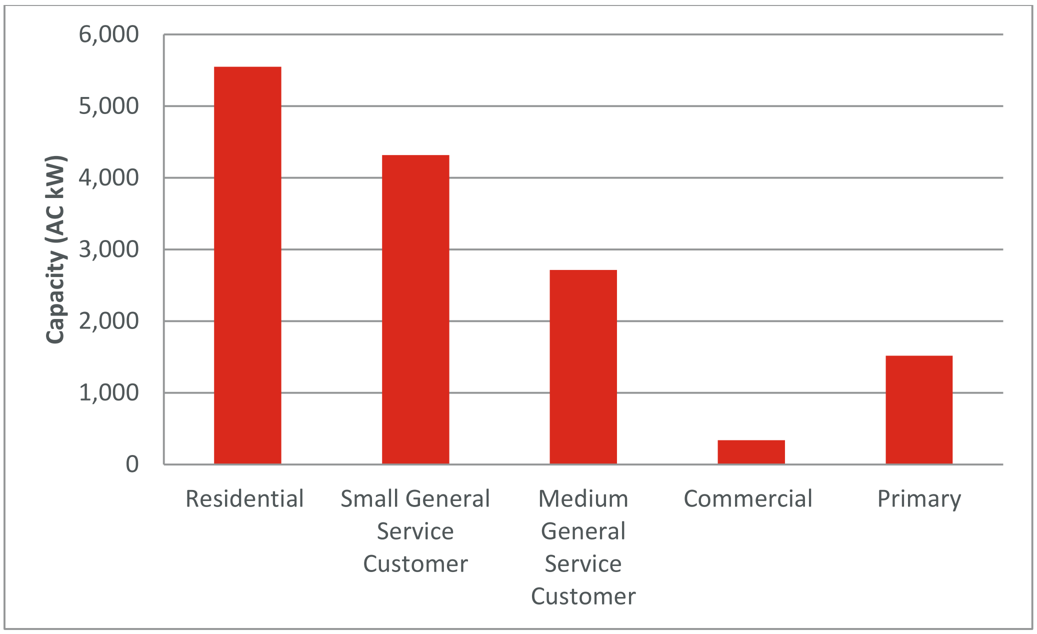

Figure 14: Current Capacity Customer Sited PV – Choptank

Average Facility Size

The size of the average residential rooftop solar installation in the Choptank service area has increased since 2008, when system sizes averaged 6 kW. Current average installation size hovers around 11 kW of nameplate capacity. (See Figure 15)

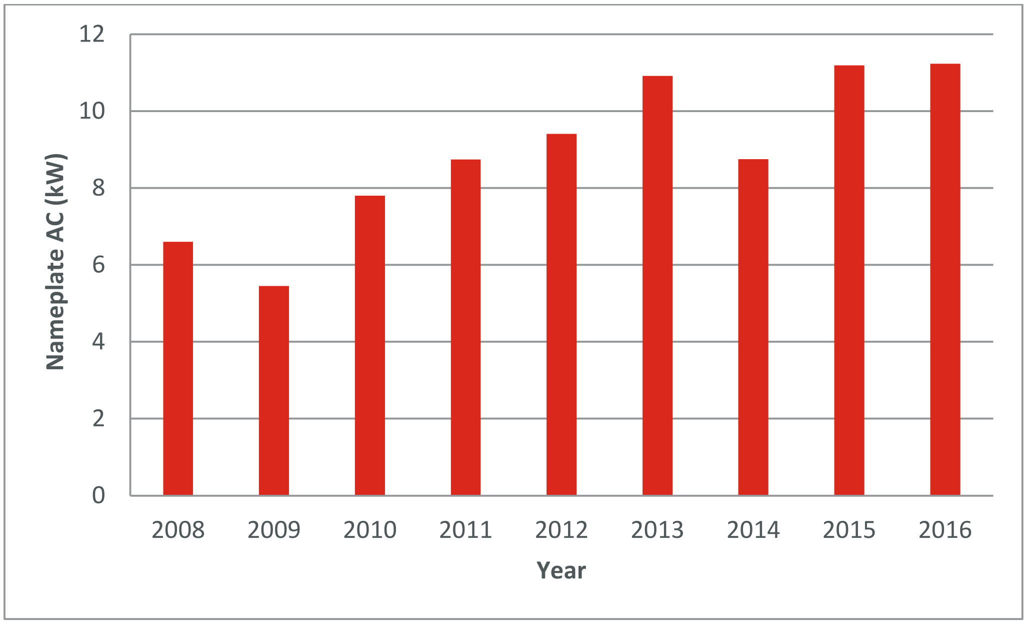

Figure 15: Residential Average Solar System Size - Choptank

Number of Customers with PV

A breakout of accounts shows, in Figure 16, just over 500 Residential customers have sited solar in the Choptank service territory. Small General Service in contrast have around 20 solar customers, but as discussed previously, small general service accounts contribute almost as much generation over the year as Residential systems in total, due to their larger average installation size. Medium General Service, Commercial, and Primary only have a few accounts each, but these facilities still contribute a large portion of the net metered generation to Choptank's system over the course of the year.

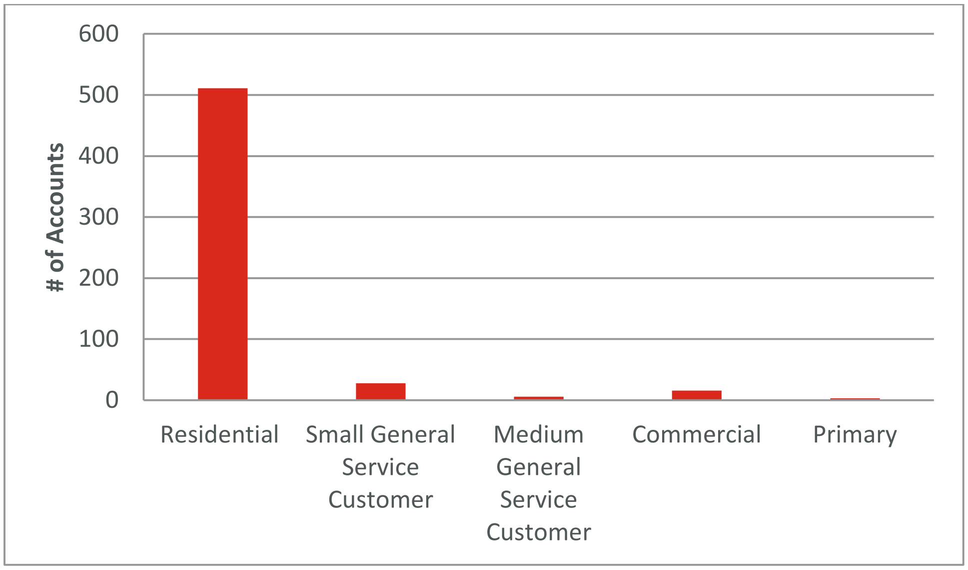

Figure 16: Customer Sited Solar Accounts – Choptank December 2016

3.3 Potential for Future Rooftop Solar

The potential for future solar buildout is important to understand for each cooperative in this report. Specific criteria for solar installations eliminate rooftops with certain attributes from being suitable for solar installations. While it is not likely every suitable house would install solar in a region, it is important to understand the potential of rooftop solar installation in the evaluation of solar for a region.

NREL provides percent suitability estimates by zip code for most regions in the United States. These percentages were applied to zip codes that fell within each cooperative's territory to estimate the housing percentages that could potentially install rooftop solar. To estimate housing stock, a combination of data from Zillow and the United States Postal Service was used to estimate the number of dwellings. Since these datasets include condos and apartment complexes, which would not be able to install solar, a reduction factor of 10% was added.

Using data provided for current net metered solar interconnection for each cooperative, the number of current net metered homes was determined along with the already installed capacity. Housing stock capability for each cooperative was estimated from the total number of suitable homes possible assuming an average installation of 8 kW. The current installed capacity was subtracted from that number to find the potential future capacity of rooftop solar for each cooperative. Table 2 summarizes the rooftop solar potential for each cooperative.

Table 2: Potential for Residential Rooftop Solar

	SMECO	Choptank
Current Net Metered Residential Accounts	3,303	511
Current Installed Capacity (MW)	28.42	5.55
Total Housing Stock Capability (MW)	1,343	929
Potential Future Additions based on currently available housing stock (MW)	1,315	923

3.4 Cost of Residential Solar

The costs of all sizes of solar installations have declined significantly in recent years. Residential solar has also experienced cost declines.

We have calculated the levelized cost of energy for a residential rooftop solar project. The key assumptions for this calculation are included in Table 3 below.

Table 3: Solar Levelized Cost of Energy Assumptions[6]

Assumption	Value (2017$)
Installed Cost	$3,300/kW
Operations and Maintenance	$40/kW-AC
% Equity Investment	100%
Target ROE	5%
Project Life	20 years
Year Installed	2018
Project Size	8 kW

6 We consulted several sources in developing these assumptions including the Lawrence Berkeley National Laboratory's *Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States* (https://emp.lbl.gov/publications/tracking-sun-ix-

The Federal Investment Tax Credit (ITC) currently provides a 30% tax credit on the installation cost of solar projects for projects online in 2019. Projects which come online in 2020 will receive a 26% tax credit, those online in 2021 will receive a 22% tax credit and those installed after 2021 will not receive a tax credit. Because of the future ITC phase-out, we have calculated the levelized cost of energy both with and without the ITC.

In addition to the ITC, Maryland residents are eligible for a $1,000 grant for installing a solar project between 1 and 20 kW. This grant is included in our cost analysis.

The results of the levelized cost analysis are included in Table 4.

Table 4: Levelized Cost of Energy 2018 Residential Solar Installation

With Full 30% ITC	Without ITC
16 cents/kWh	22 cents/kWh

3.4.1 Comparison of Levelized Cost of Energy to Solar Renewable Energy Certificates

Residential solar projects are eligible for Solar Renewable Energy Certificates (SRECs) in Maryland. The average SREC price in 2016 was about $53/MWh with prices significantly higher in the beginning of the year than the end of the year. By January 2017, the 2017 SRECs were trading around $23/MWh. Load serving entities required to comply with the renewable portfolio standard have the option of purchasing SRECs or paying the alternative compliance payment (ACP). If the SREC market were to go into shortage in the future, the SREC price could approach ACP. As of January 1, 2017, the 2017 ACP is $200/MWh or 20 cents/kWh and the ACP decreases on a pre-established schedule to $50/MWh in 2023.[7] If a residential solar project installed in 2018 were to receive SREC revenue equivalent to ACP for its 20-year life, this would yield a levelized value of $83/MWh.

installed-price) and Lazard's Levelized Cost of Energy Analysis (https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf) as well as our own experience evaluating solar policies and programs in other states.

[7] On February 3, 2017, the MD Senate overrode a veto of a bill that will increase the RPS targets from 20% by 2020 to 25% by 2020. The bill also increases the solar carve-out and delays the reduction in solar ACP.

SRECs represent one form of compensation that residential solar projects receive. These projects also allow their owners to receive net metering credits. The percentage of the project costs covered by SRECs in a shortage situation or at 2016 average price is shown in the table below for both projects with the ITC and without.

Table 5: Percentage of Residential Solar Levelized Costs Covered by SREC Program

	WITH ITC	WITHOUT ITC
At Average 2016 SREC Prices	33%	24%
At Shortage SREC Prices	52%	38%

Table 5 shows that at shortage pricing, SRECs cover a significant portion of a residential solar installation's levelized costs. At average 2016 pricing, SRECs cover a much smaller portion of an installation's levelized costs. As more solar projects come online, the SREC prices are likely to drop, a phenomenon observed in other markets. This could be countered by the increases in the solar RPS carve out over time, which increase the demand for solar. Future reductions in SREC prices could result in solar becoming less economic for customers over time, unless there is a comparative reduction in the price of solar technology and project development costs.

3.5 Value of Solar Development

Value of Solar is a hot topic across the country. Multiple jurisdictions have conducted studies to understand what value adding solar brings to a utility service territory or state. Understanding what value solar brings to the cooperatives' electric systems can inform the decision with regard to fair compensation for customers who install solar.

A value of solar analysis is made up of components of potential benefits (or costs) that solar brings to the electric system in question. At the highest level these components can be categorized into direct cooperative benefits and societal benefits, with some components providing benefits in both categories. We identified the components for this value of solar analysis based on review of other value of solar analyses and our knowledge of the SMECO and Choptank systems. The components considered are provided in Table 6.

Table 6: Value of Solar Components

COMPONENT	DESCRIPTION
Avoided Energy	Market energy purchases avoided due to distributed solar
Avoided Capacity	Market capacity purchases avoided due to distributed solar
Avoided Transmission Costs	Avoids/defers/reduces transmission investment/charges due to reduction in peak load
Avoided Distribution Capacity	Avoids/defers distribution investment due to reduction in peak load
Ancillary Services Avoided	Impact of solar on Ancillary Services costs
Market Price Response	Indirect effects of solar on market prices for energy and capacity
Fuel Price Hedge Savings	Reduces exposure to volatile prices of fuels due to solar generation reducing energy needs
Avoided REC Purchases	Reduces entity requirement to comply with RPS policies
Carbon Impacts	Reduces compliance costs and social costs of carbon
Criteria Pollutant Impacts	Reduces compliance and social costs (includes NO_x and SO_2)
Job Impacts	Benefits to local communities for installation and maintenance jobs
Local Economic Development Impacts	Provides local economic development benefits (tax revenue from economic development)
Water Impact	Avoids water usage through avoided cooling for thermal generation
Land Use Impact	Avoids construction of conventional generation on land parcels

The remainder of this section discusses each component in detail, methodologies for calculating the impact of distributed solar on the component, and the results of our analysis.

3.5.1 Avoided Energy and Capacity Cost

Avoided energy and avoided capacity make up the traditional components of avoided cost. To establish the contribution that these components make to the value of solar, it is important to understand the interaction of the PJM energy and capacity markets and the cooperative utilities' avoided costs. The minute by minute demand for electric power by SMECO and Choptank customers are part of the PJM Interconnection (PJM) set up by the Regional Transmission Organization (RTO). PJM operates several markets to facilitate the best use of generation units to provide the needed capacity and energy to customers in real time. These markets ultimately are the exchanges where less energy needs to be purchased and less capacity required of PJM market participants when solar photovoltaic generation is added. It is this basic cost savings driver that results in Daymark taking the positions described in the avoided energy and avoided capacity sections below.

Choptank Contract with Old Dominion

The Daymark team evaluated whether the generation that supplies Choptank, which is owned by Old Dominion Energy Cooperative (ODEC) and its output supplied to Choptank under contract provisions, affects the avoided costs estimated here. The simplest solution for calculating avoided energy and capacity costs for Choptank is the use of their contract prices. However, there are two features of the relationship of Choptank and ODEC that are important to examine before accepting the contract prices as Choptank's avoided energy and capacity costs. The first is that ODEC will sell Choptank the electric power necessary to serve the full requirements for energy, capacity and other services required by Choptank's customers. The contract price paid by Choptank will cover the full embedded costs of ODEC for the fuel and facilities needed to provide that full requirements service. This is referred to as a contract priced at 'cost of service.'

The second feature is that Choptank is a member/owner of ODEC. Costs avoided by ODEC actually flow back to Choptank. ODEC's costs to serve Choptank will change by ODEC purchasing less from the PJM markets or by selling its now (as a result of solar installations) surplus capacity and energy into the marketplace. Either of these transactions would result in ODEC's cost of service being reduced to PJM market rates for capacity and energy. The Daymark team concludes, therefore, that PJM market based avoided costs, as described below, are appropriate for both SMECO and Choptank in this analysis.

Avoided Energy

In determining the value of avoided energy, the first step is to establish the price that would be paid by PJM for energy in each individual hour of the year. The hourly distribution of prices over the year is obtained from an analysis of historic data. Then a forecast of annual average energy prices through the study period is established. An hourly profile of solar generation output must also be estimated. The final step is to combine the historic energy pricing hourly distribution, the forecast of future energy price trends, and the hour by hour solar electric output profile to estimate the value of energy displaced by solar generation.

Typically, avoided cost of energy for solar is based on the generation or purchased power displaced when solar power is supplied to the grid. Since generators are dispatched in order of prices bid (from lowest to highest) in the wholesale markets to meet the instantaneous load at the lowest cost the net effect of solar is to displace the highest bid generation price. The highest bid price or marginal generator is represented by the Locational Market Price (LMP) in a specific area. LMP prices are composed of this energy cost component as well as a transmission congestion component, and a marginal line loss component. Thus, the LMP is a preferable measure of the value of solar generation in a specific location, because it captures not only the energy component, but also the marginal value of reduced congestion and line losses. The LMPs provide important economic signals that fully reflect both system and market operations at a specified time. At each node of the power grid, the LMP - by meeting the power balance equation- embodies the price of the energy from the generators, the impacts of the transmission losses, and the effects of the transmission constraints that result in network congestion.

Daymark utilized the results of PJM's EPA's Final Clean Power Plan Compliance Pathways Economic and Reliability Analysis report to estimate the avoided cost of energy. The report provided LMP forecasts for PJM under different scenarios. The PJM report produced the price impact under different Clean Power Plan implementation scenarios[8].

Reference scenario: The reference scenario represents a future without the Clean Power Plan. This means the Clean Power Plan does not influence any resource's entry and exit, dispatch or operating status decisions under this pathway. The Regional

[8] Page 4 of PJM's EPA's Final Clean Power Plan Compliance Pathways Economic and Reliability Analysis

Greenhouse Gas Initiative, which affects new and existing resources in Maryland and Delaware, is the only CO_2 emissions limitation modeled within the PJM footprint.

Low Gas Price scenario: A continuous low gas price forecast was utilized for this scenario (gas prices remaining in the $3-$4/MMbtu range, in constant 2018 dollars over the 20-year study period). The prolonged low gas price environment prompted accelerated retirements in the region and resulted in lower wholesale energy prices but higher capacity prices than the reference case.

Reference RPS scenario: This scenario denoted an outcome independent of the Clean Power Plan, ensuring that all currently established state renewable portfolio standards are satisfied.

Figure 17 below shows forecast PJM LMPs under these three scenarios, which are also used in our avoided capacity analysis.

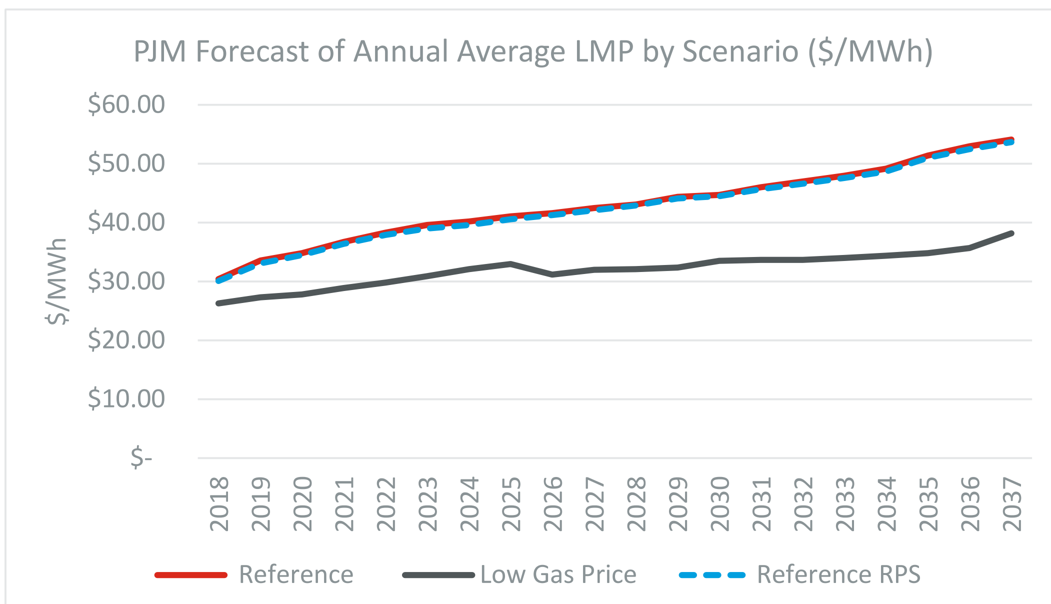

Figure 17: PJM Forecast of Annual Average LMPs

Due to the variable nature of solar output, the average value of solar energy differs from the annual average price. Figure 18 and Figure 19 below compares our south- and west-facing solar production shapes to historical annual average LMPs by hour for

Choptank and SMECO respectively. Note that LMPs generally tend to be higher during the solar irradiance period, when solar energy is generated, when compared to overnight periods, but are lower than on-peak LMPs.

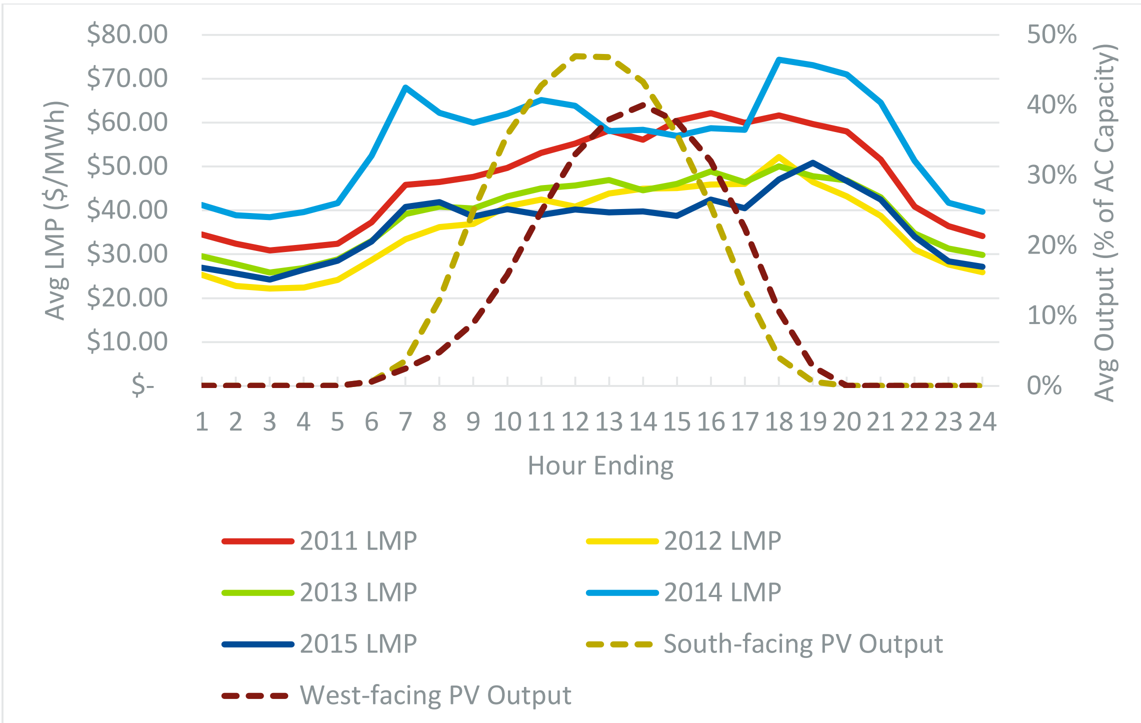

Figure 18: Choptank Solar Shapes vs. 2011-2015 DPL Zone Hourly Average Real Time LMP

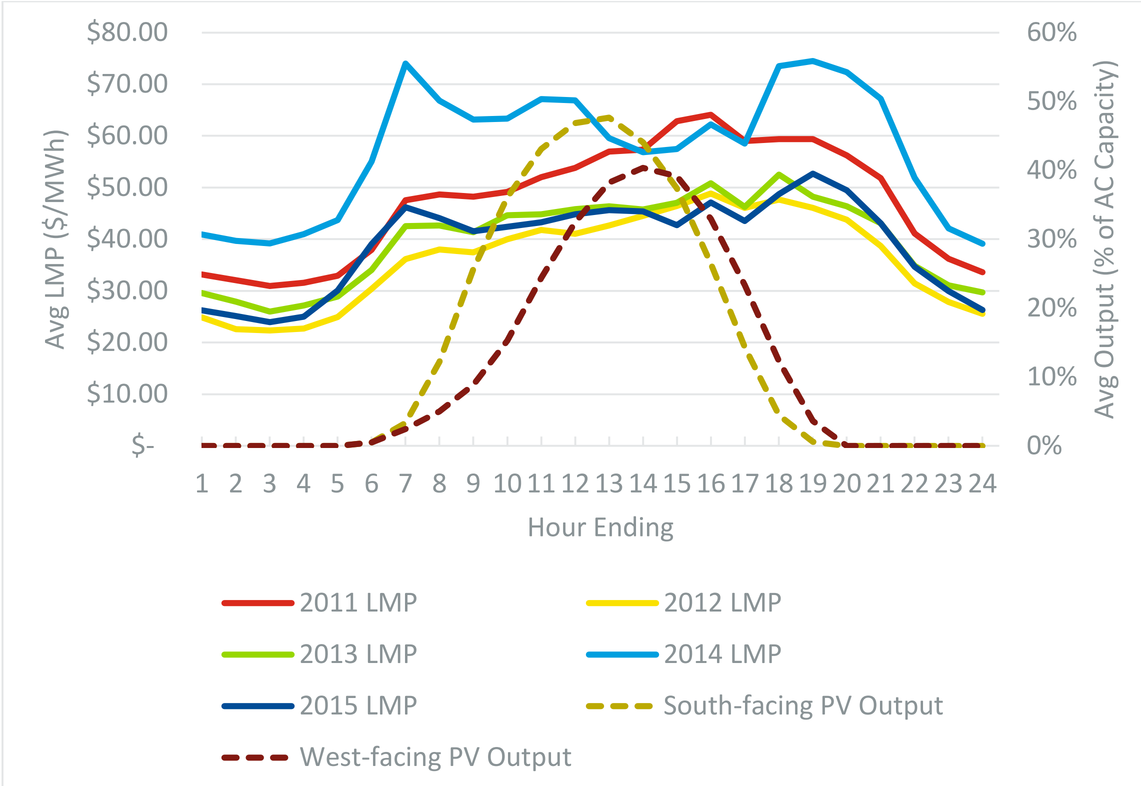

Figure 19: SMECO Solar Shapes vs. 2011-2015 PEPCO Zone Hourly Average Real Time LMP

The solar output-weighted value of solar in Choptank and SMECO service territories were calculated for the years 2011-2015 based on the AC output from the load shapes and the historical hourly LMPs for their respective load zones in those years. This was compared to the flat annual average LMPs for their respective load zones in those years. The average premium for solar output weighted LMPs verses average LMPs are shown for each cooperative and solar shape in Table 7 below.

Table 7: 2011 – 2015 Average premium of solar output-weighted LMP to average LMP by cooperative and PV shape

	SOUTH-FACING PV	WEST-FACING PV
SMECO	14%	19%
CHOPTANK	15%	17%

These historical premiums can be then applied to the LMP projections from the PJM forecast to provide a forecast of avoided energy prices resulting from the solar production installed within Choptank and SMECO. In addition, another 13.5 percent is added to account for marginal T&D line losses that are avoided at the end-user level. This adjustment is further described in the avoided capacity section below.

The results of the avoided energy calculation for the reference case are shown in Table 8.

Table 8: Reference Case Avoided Energy Values ($/MWh)

YEAR	SOUTH FACING		WEST FACING	
	CHOPTANK	SMECO	CHOPTANK	SMECO
2018	40.41	40.24	41.22	41.70
2019	44.66	44.47	45.56	46.09
2020	46.25	46.06	47.19	47.74
2021	48.78	48.58	49.76	50.34
2022	50.91	50.70	51.93	52.54
2023	52.63	52.42	53.69	54.32
2024	53.43	53.21	54.51	55.14
2025	54.63	54.40	55.73	56.38
2026	55.29	55.06	56.41	57.06
2027	56.49	56.25	57.63	58.30
2028	57.29	57.05	58.44	59.12
2029	59.01	58.77	60.20	60.90
2030	59.41	59.17	60.61	61.32
2031	61.14	60.89	62.37	63.10
2032	62.47	62.21	63.73	64.47
2033	63.80	63.53	65.08	65.84
2034	65.39	65.12	66.71	67.49
2035	68.32	68.04	69.69	70.51
2036	70.44	70.15	71.86	72.70
2037	71.91	71.61	73.36	74.21

Avoided Capacity

To calculate avoided capacity, the first step is to determine an appropriate forecast of the price of capacity in the marketplace. The other steps are to determine if the solar generation gets full credit for its nameplate capacity. Then adjustments are made to recognize that the solar generation is at the point of consumption and therefore its output is not reduced by losses that occur when generated energy must be delivered through the transmission and distribution systems. These effects are described more fully in the paragraph entitled "Capacity Contribution Credited for Solar" later in this section.

The avoided costs associated with electric generating capacity are based on PJM's forward capacity market represented by the Base Residual Auction (BRA). In PJM, actual capacity prices are known for the current delivery year as well as the next three delivery years. A delivery year runs from June through May (e.g., the current delivery year is June 1, 2016 through May 31, 2017). Thus, actual capacity market prices are already set through May 2020.

Consistent with the electricity price forecast, the estimated capacity prices are differentiated by location. SMECO is part of PJM's PEPCO zone, while Choptank is part of the DPL South zone. **Table 11** further below provides the capacity prices forecast using two approaches: 1) escalating actual capacity prices and 2) relying on a published source for projections of capacity prices. Each approach is explained below.

Actual capacity prices are escalated. The average nominal value of capacity prices from the 2010/11 delivery year through the 2019/20 delivery year is used to represent the value of capacity in 2020 for each zone. The choice of an average over the period mitigates the volatility experienced in the PJM capacity prices. This value is then escalated annually at a rate of 3.06 percent to provide nominal capacity prices through 2040[9]. The 3.06 percent escalator is based on the latest United States Bureau of Labor Statistics (BLS) Composite Index to reflect changes in generating plant construction costs. This index is used by PJM to escalate the Cost of New Entry (CONE) when developing the Variable Resource Requirement (VRR) curve for each BRA.

This escalation is a simplified approach since it is not based on any historic trends with respect to solar installation nor does it include any assumptions with regard to

[9] PJM's 2019-2020 BRA parameters

technological improvements and their impact on heat rate for example. Figure 20 denotes the calculated *escalated* prices for DPL South and PEPCO.

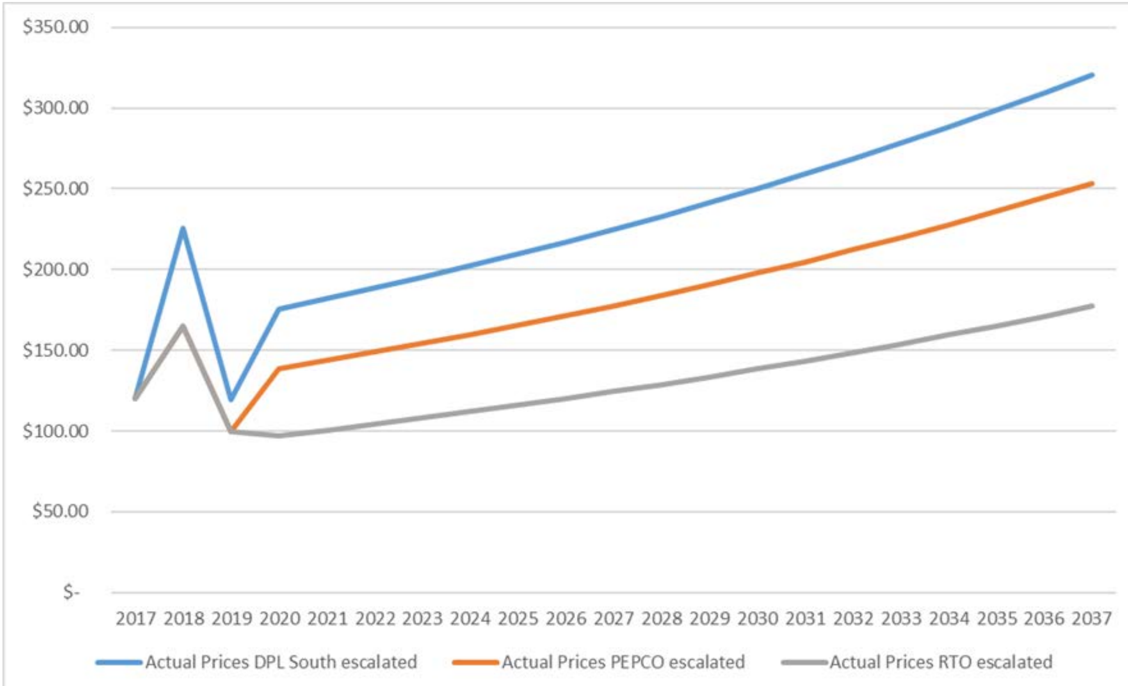

Figure 20: Escalation of Capacity Prices

Published Source for Capacity Prices. As explained in the avoided energy section, Daymark relied on the capacity price forecast produced by PJM for the Clean Power Plan Impact Report to the PJM energy and capacity markets. Figure 21 provides a graphic representation of the capacity prices associate with the reference case, low gas price case, and the reference RPS case produced in the PJM CPP Impact Report.

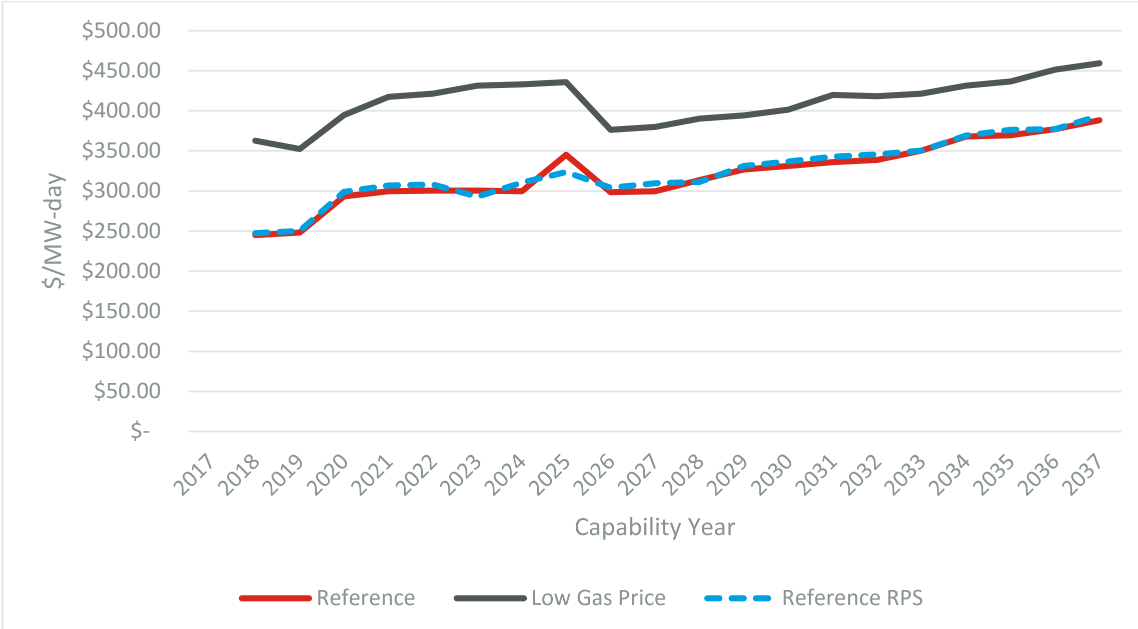

Figure 21: Clean Power Plan Impact Report to PJM Energy and Capacity Market, Capacity Price Forecasts by Scenario

Since one MW of demand reduction for an end-user is equivalent to more than one MW of avoided generation capacity, two adjustments must be made to convert capacity prices produced from the capacity market into the avoided cost of electric generating capacity.

First, capacity prices are increased by approximately 8.8% to account for PJM's unforced capacity (UCAP) reserve margin requirement for electric generating capacity. In order to ensure resource adequacy, PJM procures excess capacity to accommodate uncertainties around outages and load changes in the region.

Second, the capacity prices are increased by an additional 13.5 percent to account for marginal transmission and distribution (T&D) line losses that are avoided at the end-user level. Estimated T&D line losses are based on historical data from the US Department of Energy's Energy Information Administration (EIA) State Electricity Profile for Maryland Between 1994 and 2014. During this period, the average T&D losses in Maryland were approximately 9.037 percent, which compares to the national average of about 7 percent. Based on a 2011 research paper published by the

Regulatory Assistance Project[10], marginal distribution losses are 1.5 times the average line losses. Therefore, the 13.5 percent adjustment is the result of the multiplication between 1.5 and 9.037%.

With the projection of capacity prices, the level of capacity accredited to solar must be determined. The capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand. We determined this level for solar by projecting solar output during hours typically associated with high system demand as described below.

PJM uses the Peak Load Contribution (PLC) metric - an entity's share of usage during periods of maximum usage on the electricity grid - to determine each utility's consumption. On an annual basis, each Local Distribution Company is required to calculate and report its peak load contribution to PJM. At the end of a summer season, PJM identifies the five highest peak load hours that occurred on different days during the period from June 1 through September 30. The LDC then determines each customer's specific load during these hours and the customer's PLC will be an average of these five hours' usage. This average is called a "Capacity Tag" and applies to the next capacity year (June – May).

The five highest peak load hour observations made by PJM were identified for the years 2012-2015, all of which fell between the hours of 2:00 to 6:00pm (see **Table 9**). The capacity factors based on AC capacity ratings were calculated for our model load shapes for Choptank and SMECO. The average, minimum and maximum capacity factors were calculated for the specific peak load hour observations occurring between the months of June to September. The values were calculated for both south-facing and west-facing load shapes for each cooperative.

10 Jim Lazar and Xavier Baldwin, Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements, the Regulatory Assistance Project, August 2011.

Table 9: Count of Peak Load Contribution hours (5 summer peak hours) by Month and hour, 2012-2015

COUNT OF PEAK HOUR OCCURRENCES	2 – 3PM	3-4PM	4-5PM	5-6PM
Jun	0	0	1	1
Jul	2	1	9	3
Aug	1	0	0	0
Sep	0	1	1	0

The capacity factor calculated by averaging the average capacity factors from the peak load hour observations, gives us an indication of the impact that solar would tend to have on the Capacity Tags for SMECO and Choptank. The impact of solar on the Choptank capacity tags ranges between 19.4% to 28.0% for the south and west facing orientations.

For SMECO the impact of solar ranges between 22.1% to 33.9% for the south and west facing orientations. The results are shown in the table below. We note that these estimates are probably conservative because the system peak hours likely occur on hot, sunny days when solar production would likely be higher than average for the given month.

Table 10: 2012 – 2015 Average Capacity Tag Offset of Solar by Solar Orientation

	SOUTH-FACING SOLAR	WEST-FACING SOLAR
SMECO	22.1%	33.9%
Choptank	19.4%	28.0%

The value of avoided capacity for solar is given by multiplying the capacity tag offset (AC-rated solar generation capacity multiplied by the capacity values shown in Table 10 above) by the adjusted capacity prices.

Table 11 denotes the result of the adjustments described above on the capacity prices. Actual prices in Table 11 are based on the escalated approach described as an option to projecting capacity prices above. They are depicted in this table for comparison to the published price approach.

Table 11: Adjusted Capacity Price Projections

2016$/MW-day YEAR	Published Source Approach			Escalated Approach		
	Reference	Low Gas Price	Reference RPS	Actual Prices DPL South escalated	Actual Prices PEPCO escalated	Actual Prices RTO escalated
2018	$ 302.55	$ 448.01	$ 305.39	$ 278.37	$ 203.47	$ 203.47
2019	$ 306.37	$ 435.17	$ 309.09	$ 147.90	$ 123.49	$ 123.49
2020	$ 362.19	$ 487.28	$ 368.86	$ 215.65	$ 170.45	$ 119.99
2021	$ 369.85	$ 515.56	$ 379.11	$ 222.25	$ 175.67	$ 123.66
2022	$ 371.08	$ 520.13	$ 380.47	$ 229.05	$ 181.04	$ 127.44
2023	$ 371.08	$ 532.60	$ 361.82	$ 236.06	$ 186.58	$ 131.34
2024	$ 370.09	$ 534.46	$ 383.55	$ 243.28	$ 192.29	$ 135.36
2025	$ 426.40	$ 538.04	$ 399.48	$ 250.73	$ 198.18	$ 139.51
2026	$ 368.61	$ 464.56	$ 375.40	$ 258.40	$ 204.24	$ 143.77
2027	$ 370.09	$ 469.13	$ 382.32	$ 266.31	$ 210.49	$ 148.17
2028	$ 387.01	$ 481.97	$ 384.17	$ 274.46	$ 216.93	$ 152.71
2029	$ 403.31	$ 486.67	$ 408.75	$ 282.85	$ 223.57	$ 157.38
2030	$ 409.12	$ 495.68	$ 416.03	$ 291.51	$ 230.41	$ 162.20
2031	$ 415.04	$ 518.53	$ 423.32	$ 300.43	$ 237.46	$ 167.16
2032	$ 418.50	$ 516.55	$ 426.77	$ 309.62	$ 244.73	$ 172.28
2033	$ 432.70	$ 520.38	$ 432.70	$ 319.10	$ 252.22	$ 177.55
2034	$ 454.31	$ 532.60	$ 455.67	$ 328.86	$ 259.93	$ 182.98
2035	$ 456.41	$ 539.27	$ 464.81	$ 338.92	$ 267.89	$ 188.58
2036	$ 465.80	$ 557.30	$ 465.80	$ 349.29	$ 276.09	$ 194.35
2037	$ 479.26	$ 567.18	$ 486.30	$ 359.98	$ 284.53	$ 200.30

Values Recommended for Avoided Energy and Capacity Costs for Value of Solar

Daymark recommends use of the reference scenario for avoided energy and capacity costs, which represents a future without the Clean Power Plan, inclusion of the Regional Greenhouse Gas Initiative, and excludes any additional CO_2 emissions limitations within the PJM footprint. The reference scenario excludes the impact of externalities such as gas prices and potential environmental regulations and provides a consistent view of the energy and capacity market through the evaluation period.

3.5.2 Avoided Transmission Costs

It is important to consider the effects of solar resources on the transmission grid when evaluating avoided costs. Future fixed cost capital investment and potentially some operation and maintenance costs can be avoided by solar installations, but not the fixed costs of already existing plant.

In this study, the transmission avoided costs component describes and considers as potential avoided costs due to solar installation:

1. The potential for avoiding the construction and maintenance of new transmission infrastructure; and
2. The impact on transmission charges due to the reduction in load realized by the installation of solar resources.

Both categories of potential transmission avoided costs are described in more detail below.

Background on SMECO's and Choptank's Transmission System

Before beginning the transmission avoided cost analysis discussion, it is important to understand a little bit about how each cooperative interacts with the larger PJM transmission system.

SMECO's territory is within PJM's PEPCO zone. In 2016, the North American Electric Reliability Corporation (NERC) determined that SMECO's 230 kV facilities must be considered as part of the bulk electric system operated by PJM. On November 1, 2016, PJM and SMECO submitted a joint filing with the Federal Energy Regulatory Commission (FERC) in Docket No. ER17-282 proposing to make SMECO subject to PJM transmission operations and planning protocols. FERC approved the new relationship between SMECO and PJM, in effect making SMECO a transmission owner subject to PJM's regional planning processes.

In September 2016, PJM's planning department, in accordance with PJM's Regional Transmission Expansion Planning (RTEP) Process, conducted a Baseline Integration Report to identify potential transmission issues in SMECO's system. The findings of the report showed that for the period 2016-2020, SMECO's system was in compliance with established regional reliability criteria and identified no thermal issues, short circuit issues or voltage issues.[11]

According to SMECO, over the past 5 years the cooperative placed in service only one project as part of the "Southern Maryland Reliability Project" effort. The project was needed to provide service reliability to Calvert and Saint Mary's County members by creating a 230 kV transmission loop feed through the aforementioned area.[12] The total capitalized cost of the project in the past five years, 2012-2016, was $107,303,050.

Since the project was needed for reliability purposes, it could not be avoided by increased solar penetration and therefore was not considered in the calculation of avoided transmission costs.

Choptank owns 6,255 miles of power lines and is not considered a transmission owner by NERC and PJM; therefore, there is no information at the PJM regional level in regards to its transmission system needs.

Avoided Transmission Investment Analysis

The present value of avoided transmission investment that may occur far off in the future is considerably lower than the value that may be ascribed to current or near-term avoided transmission costs. This is an important consideration given the tens of billions of dollars in transmission investment made over the last decade or so in the PJM control area or approved for construction by 2020, and the fact that current transmission rates reflect most of this sunk investment.

For this study Daymark completed a thorough review of publicly available PJM and other regional transmission planning reports in order to understand and potentially quantify the impact of solar to the regional transmission system. More specifically, our review focused on how solar can minimize any transmission enhancements needed to mitigate congestion or load growth.

Generally, transmission planners estimate the need for transmission enhancements in an area by assessing multiple system characteristics, including load growth,

11 http://www.pjm.com/~/media/planning/rtep-dev/baseline-reports/smeco-baseline-integration-rtep-report.ashx

12 In response to PSEC 3.2.1 Data Request 03, Item No. 3-1 "The project included a new source interconnection with the Pepco electric system (Aquasco), two new 230 kV: 69 kV switching stations (Holland Cliffs and Sollers Wharf), a 2.0 mile 230 kV single-circuit submarine cable circuit [2330], and 31.5 line miles of dual-circuit 230 kV transmission conductor circuits [2330, 2335], [2340, 2345], and [2350, 2355]"

generation, applicable reliability standards and cost of potential upgrades. Solar generation is usually modeled as a load reduction with the potential to defer transmission upgrades needed to accommodate load growth. Benefits can only be captured to the extent that solar is producing during the area's peak demand periods that drive regional load-related transmission investments. The area's peak demand periods are captured by PJM, which is a summer peaking system. In 2016, PJM experienced its peak demand on August 11, 2016. Therefore, there is a potential for avoided transmission cost in PJM because the regional system peak mostly aligns with the peak period for solar production.

Daymark reviewed PJM's Regional Transmission Expansion Planning (RTEP) process. Under this process, PJM conducts long-range planning studies and evaluates future demands on the regional transmission system due to various needs such as load growth, reliability and other. Since solar can primarily offset transmission upgrades needed for load growth, our evaluation focused on identifying potential projects that could be avoided by increased solar penetration.

Table 12 identifies projects that are scheduled to be in service within the next few years in the areas where SMECO's and Choptank's territories are included (DPL and PEPCO zones).

Table 12: Identified Transmission Projects

Description	Projected In Service Date	Transmission Owner	Driver	Voltage
Convert 138 kV network path from Vienna Piney Grove to 230 kV, add 230/138 kV transformer to Loretto 230 kV	5/31/2019	DPL	Baseline Load Growth Deliverability & Reliability	230/138
Add a second Loretto 230/138 kV transformer	5/31/2019	DPL	Baseline Load Growth Deliverability & Reliability	230/138
Build a 2nd Vienna-Steele 230 kV line	5/31/2019	DPL	Baseline Load Growth Deliverability & Reliability	230
Rebuild the Wattsville - Kenney - Piney Grove 69 kV and build a new 138 kV line from Piney Grove - Wattsville on the same tower	5/31/2018	DPL	Baseline Load Growth Deliverability & Reliability	138
Reconductor the Harmony - Chapel St 138 kV circuit	6/1/2018	DPL	Baseline Load Growth Deliverability & Reliability	138
Construct 230 kV high-side bus and install 800 MVA PAR at Potomac River 230 kV (Station C)	6/1/2020	PEPCO	Baseline Load Growth Deliverability & Reliability	230
Replace Terminal equipment at Silverside 69 kV substation	6/1/2019	DPL	Baseline Load Growth Deliverability & Reliability	69
Interconnect the new Silver Run 230 kV substation with existing Red Lion - Cartanza and Red Lion - Cedar Creek 230 kV lines	6/1/2019	DPL	Operational Performance	230
Implement high speed relaying utilizing OPGW on Red Lion - Hope Creek 500 kV line at Red Lion Substation	6/1/2019	DPL	Operational Performance	500
Install OPGW on the Red Lion - Hope Creek 500 kV line (Delaware Portion)	NA	DPL	Operational Performance	500
Rebuild Worcester - Ocean Pine 69 kV ckt. 1 to 1400A capability summer emergency	12/31/2017	DPL	Congestion Relief - Economic	69

The projects identified in the RTEP process are primarily within the DPL territory. Only one project, estimated at $10 million, is slated to be in service in 2020 within PEPCO's area. None of the projects included in the table above are needed to address only load growth; most identify reliability as a justification as well and these investments typically cannot be avoided. Therefore, increased solar penetration in the area will not have significant impact in deferring these transmission projects.

Furthermore, avoided transmission-related costs and benefits for solar are very location-specific. Incremental solar development in a transmission constrained area usually have greater impact than in a non-constrained area. The areas of the system where Choptank and SMECO are located have experienced more congestion historically than the rest of PJM. According to the Ten-Year Plan (2016-2025) of Electric Companies in Maryland, there has been a significant decrease - close to 30% - in congestion costs in the region over the past couple of years. This suggests reduced need for future upgrades to reduce congestion, therefore, less opportunity for solar to reduce planned transmission investment in the near term.[13]

In addition, to further mitigate congestion in the region, PJM has recently approved the construction of some major transmission projects. More specifically, on August 9, 2016, PJM announced the authorization of $636 million in electric transmission projects to strengthen the grid and reduce congestion costs.[14] The largest of the transmission projects is estimated to cost $320 million and is expected to mitigate transmission congestion across the Pennsylvania and Maryland border. The project includes upgrades to existing substations, two new substations, two new transmission lines and enhancements to existing lines. The expected in-service date is 2020.

Decreased congestion in the SMECO and Choptank areas in conjunction with the newly approved PJM transmission projects minimize the need for additional enhancements in the area.

The review of the RTEP process and Maryland's ten-year plan identified no avoidable transmission upgrades needed to accommodate load growth in either SMECO's or Choptank's service area. As a result, Daymark concluded that there are no avoided transmission benefits of solar installations related to deferred transmission investments.

13 http://www.psc.state.md.us/wp-content/uploads/Final-2016_2025_TYP-12_8_16.pdf page 24

14 http://www.pjm.com/~/media/about-pjm/newsroom/2016-releases/20160809-rtep-news-release-market-efficiency-project.ashx

Avoided Transmission Charges Analysis

Although we conclude no savings related to deferred transmission investment, SMECO and Choptank members could realize savings due to reduced transmission charges due to the reduction in load realized by the installation of solar resources. This savings is explained in this section.

Each utility must obtain Network Integration Transmission Service (NITS) within its respective PJM transmission zone (Delmarva for Choptank, PEPCO for SMECO). NITS rates are set so that network customers within each transmission zone collectively pay the annual transmission revenue requirement according to each customer's share of zonal network transmission service peak loads. If solar decreases a cooperative's contribution to the zonal peak (by reducing the cooperative's load at the times when load in the entire zone is highest), then the cooperative's NITS costs would be reduced, all else equal. These savings are partially (but not fully) offset by the increase in zonal rates that would be required to ensure that the full annual revenue requirement is still collected in the zone. In effect, with solar installations in the cooperative service territories reducing their load, the cooperative's NITS costs are shifted to other customers in the same region.

In order to estimate NITS savings, we first estimated solar performance during the hours when Network Service Peak Load (NSPL) is most likely to be determined. Both Delmarva and PEPCO determine NSPL using the previous year's five hours with the highest zonal load occurring on different days (i.e. no two hours from the same day). Reviewing four years of history for the Delmarva and PEPCO zones, we noted that most transmission peak hours occurred on summer (June or July) afternoons between 2:00 and 7:00pm, with some peaks also occurring on February mornings (7:00 – 8:00am) or evenings (7:00 – 8:00pm). Table 13 shows the distribution of zonal peak occurrences by month and hour for the 2012 to 2015 period. The table also shows the average expected capacity factor of the south-facing solar orientation during those hours. Based on a weighted average analysis, we assume that solar generation will offset Choptank's NSPL by 14% of nameplate capacity and SMECO's NSPL by 16% of nameplate.

Table 13: Zonal Peak Occurrences, 2012-2015 and Projected Coincident Solar Production

Month	Feb	Feb	Jun	Jun	Jul	Jul	Jul	Jul	Jul	Weighted
Hour Ending	8	20	17	18	15	16	17	18	19	Average
	Number of Zonal Peak Occurrences, 2012-2015									
Delmarva	2	1	1	2	2	1	3	6	2	
PEPCO	1	0	2	3	1	3	7	3	0	
	Average PV Capacity Factor									
Choptank South-facin	6%	0%	24%	11%	37%	29%	20%	9%	3%	**14%**
SMECO South-facing	4%		24%	11%	48%	35%	22%	11%		**21%**

We assumed that the NITS tariff rate is equal to the average of the rate for the past three years in order to establish a benefit whereby the short term savings are given by the NSPL offset multiplied by the NITS rate. However, since we assume that this is a cost shift rather than cost savings at the zonal level, we must account for the change in rate to assure collection of annual transmission revenue requirements. Choptank and SMECO are assumed to absorb a pro-rata share of this re-adjustment based on their share of their respective transmission zonal peaks. The table below shows the calculation of estimated NITS charges savings per kWh of solar generation.

Table 14: Estimated NITS Savings Calculation

Line	Element	Formula	Units	SMECO	Choptank
(1)	Transmission Zone			Delmarva	PEPCO
(2)	NITS Rate ($/MW-year)		$/MW-year	$ 24,811	$ 31,966
(3)	Coop Share of Zonal Peak (%)		%	12.1%	5.7%
(4)	NSPL Offset (% of DC rating)		% of DC rating	21%	14%
(5)	First Year NITS Savings per MW(DC) solar install *Line (2) * Line (4)*	(2) * (4)	$/MW-year	$ 5,281	$ 4,440
(6)	Coop Share of Rate Increase to meet Revenue Requirements	(3) * (5) * -1	$/MW-year	$ (638)	$ (253)
(7)	NITS Savings per MW-DC solar install	(5) + (6)	$/MW-year	$ 4,644	$ 4,187
(8)	Annual PV Output		kWh/kW[DC]	1,376	1,217
(9)	**NITS Savings per kWh**	**(7) / [(8) * 1,000]**	**$/kWh**	**0.0034**	**0.0034**

3.5.3 Distribution

Similar to transmission, solar installations can defer the cost of building and maintaining new distribution infrastructure. Since the majority of solar installations are residential, the wear and tear of the distribution system is minimized because electricity produced by solar systems is consumed on-site. Also, various studies have shown that the benefit of solar is greater on the distribution system when solar installations are located close to systems that serve commercial loads, which have daily demand peaks in the afternoon, closer to the time of peak solar output.[15]

Distribution benefits are largely dependent on solar generation taking place at the time of local distribution peaks. However, in areas - such as those served by Choptank and SMECO - considered winter-peaking, solar has very little impact, as its output does not coincide with the peak of the distribution system. Likewise, if there is minimal or limited load growth and distribution capacity upgrades are not anticipated, then solar installation will most likely not avoid any future capital investment.

A variety of techniques have been utilized to assess the distribution costs and benefits of solar, which identified a minimal to modest amount of avoided capacity-related distribution costs because of solar deployment. Since the impact to the distribution system is very location-specific, the quantification of costs and benefits is largely dependent on the characteristics of the individual circuit on which the solar installation is located. These characteristics include customer mix, system age and condition, and other reasons. For example, the solar impact on a circuit that supplies a mostly single-family residential load that is most likely to rise fairly smoothly to a peak in early evening will be different when compared with a circuit that primarily feeds commercial customers that typically peaks in the early afternoon.

Daymark assessed the SMECO and Choptank systems and had discussions with the planning departments of both entities. Based on discussions with the planning departments of both entities, the impact of solar penetration is not completely and accurately captured in their future planning studies. The potential impacts on distribution from increased solar penetration levels are not fully known, and they could realistically result in either a net cost or net benefit. With this uncertainty of

[15] http://www.growsolar.org/wp-content/uploads/2014/10/A-Regulators-Guidebook-Calculating-the-Benefits-and-Costs-of-Distributed-Solar-Generation.pdf page 27

potential benefits and costs, Daymark determined that there will be little or no effect at these low penetration levels.

3.5.4 Ancillary Services

In order to ensure system reliability, system operators need reserve capacity to be able to respond to contingencies, such as those caused by unexpected system outages. The unloaded[16] capacity of generating resources—either on line (spinning) or offline (not spinning)—that can provide energy and mitigate these system disturbances within 10, or in some cases 30 minutes, are called operating reserves. PJM has two categories of spinning reserves that can be attained in 10 minutes called Synchronous Reserve Tier 1 and Tier 2. Tier 1 reserve is provided by any resource that is on-line, following economic dispatch and has unloaded capacity. It is not reserved through a market mechanism but instead is simply the amount of operating reserves available on the system due to economic dispatch. PJM dispatches Tier 2 reserve when, after a system disturbance, Tier 1 is exhausted. Besides the Synchronized reserves, PJM also procures Quick Start Reserves (offline resources) and Supplemental Reserves (resource that can provide energy within 30 minutes).

Besides operating reserves, the reliability of the system requires resources to provide black start and reactive control services. Black start is required for the reliable restoration of the transmission system following a blackout. Reactive power (measured in MWAr) helps maintain appropriate voltage levels on the power system and is critical to the flow of real power (measured in MW).

PJM allocates its costs of all reserve products to its Load Serving Entities (LSE) on the basis of their relative loads on an hourly basis. However, market participants have the ability to meet their reserve obligations by entering into bilateral arrangements with other PJM market participants or purchasing any reserve products from the PJM markets. Historically, the cost of ancillary services to the LSEs in PJM has been low when compared with energy and capacity costs. During the first 9 months of 2016, payments to Tier 1 synchronized reserve resources for PJM were $4,566,478[17] representing a minor charge when compared with total energy and capacity.

16 Unloaded capacity is the difference between a generator's economic maximum MW and actual MW dispatched.

17 Page 393 of the 2016 Quarterly State of the Market Report for PJM: January through September page 393 "During the first nine months of 2016, payments to tier 1 synchronized reserve resources when the NSRMCP is above $0.00 were $4,566,478"

The continuous integration of renewable resources such as solar and wind prompted PJM and other RTOs to evaluate the impact of increased integration of intermittent resources and the need for additional reserves or products to continue the reliable operation of the power grid. More specifically, PJM published a report[18] that describes how continuous large integration of renewable resources results in impacts on the operability of the system. As an example, the report concluded that additional regulation was required to compensate for the increased variability introduced by the renewable generation. Thus, in some cases, increased renewable penetration was more costly to the system.

Grid support services represent a relatively minor element of the value of solar calculation, with little to no effect at low solar penetration levels. Even at higher penetration levels, benefits could be negligible with the potential of additional system costs as shown in the PJM study. As such, Daymark recommends not including ancillary services benefits or costs in this evaluation.

3.5.5 Market Price Impacts

This component reflects the broader market impacts resulting from the reduction to net load that occurs with the addition of behind the meter (BTM) solar resources. This effect is sometimes referred to as demand reduction induced price effects (DRIPE), and it can be either a cost or a benefit in certain circumstances.

The addition of BTM solar resources onto the grid can cause several effects on energy and capacity market prices. These effects are described in this section. The concept of market price effects as a component of the value of BTM solar is to attempt to quantify these broader effects, and determine the portion of any cost or benefit that should be allocated to the solar resource itself.

There is a fundamental issue with including market price effects in a value of BTM solar quantification because the beneficiaries of a market price decline (or payers of market price increase) include all market participants. Assigning a fixed cost or benefit to solar for an effect that is variable and experienced across a broad market can be problematic. This issue is discussed in more detail below.

[18] https://www.pjm.com/~/media/committees-groups/subcommittees/irs/postings/pris-executive-summary.ashx

Energy Market Price Effects

Solar-induced energy market price effects can occur when the addition of BTM solar capacity causes a shift in the dispatch of other grid resources and thus a change in LMPs. Since rooftop solar effectively acts as a reduction to net load, the impact on energy market pricing is similar to the difference between a higher and lower load period. All else equal, this should reduce system-wide LMPs.

Since all load pays market prices, a reduction in LMPs yields a benefit to all load purchasing energy from the wholesale market. The total market price effect benefit of the incremental BTM solar is the change in LMPs multiplied by the load across the whole system.

There is a possibility that the addition of BTM solar can increase market prices in some circumstances, particularly when the solar capacity being assessed is only a small amount of capacity. This can result in a price increase when the solar production alters the commitment and dispatch of resources. The grid operator, PJM, keeps the system in balance by committing and dispatching sufficient capacity to meet load while also ensuring that the appropriate types and amounts of reserves are available to operate the system. It is possible that a small adjustment in net load resulting from the added BTM solar resource can make a small change in which specific resources are committed and dispatched in the market. This small change can result in higher system-wide production cost if higher cost generators must be dispatched. In addition, higher penetrations of solar could eventually increase the need for more reserves on the system.

The primary method other studies have used to identify the energy market price effect is the use of production cost modeling. Typically, this type of analysis includes a "base case" run, and a "study case" run which includes the incremental BTM solar. The change in LMPs between the runs indicates the energy market price effect of the solar. One issue reflected in other studies is that when modeling a small change in a large integrated system, results are sometimes inconsistent or counterintuitive. For example, modeling an addition of 50 MW of solar could result in LMP increases in one year, and decreases in the next. To address this, one approach is to model a large amount of solar to ensure directionally consistent results, then prorating the impact for smaller solar additions. This approach, however, ignores the other market dynamics (such as unit commitment) that can be effected by modeling large solar additions.

The prior paragraphs discuss the effects on the LMPs associated with more solar generation (or even lower loads). This discussion assumes that the generation resources available to the market are the same with and without the additional solar generation. This is true in the short-term. However, as we apply the avoided costs for longer term economic comparisons this is not necessarily true. The presence of additional solar generation may result in different capacity being added and perhaps a different amount of generation that gets retired. This dynamic means that LMPs may be higher or lower in the long-term depending upon the effect the solar generation has on the other resource decisions in the market place.

Capacity Market Price Effects

The addition of BTM solar resources can also have an impact on capacity market clearing prices. The ultimate effect of BTM solar on these market prices, however, is difficult to determine with certainty, since additional solar can increase or decrease clearing prices depending on the time frame being evaluated, as well as actions of market participants.

At a fundamental level, a capacity market operates in a straightforward way. A capacity supply stack is created with low-cost resources at the bottom and high-priced resources at the top. The clearing price is defined as the point where capacity demand crosses the supply curve. Since BTM solar effectively acts to reduce demand, the addition of solar should shift the point at which demand meets the supply curve and result in lower capacity prices. Since a lower clearing price reduces capacity payments for all load, this benefit would be spread widely across a market.

The total capacity price effect is not quite this straightforward, however, and there are additional considerations to take into account. For example, high levels of BTM solar penetration can actually shift the system peak out of daylight hours, in which case incremental solar would not have any impact on capacity demand. Also, the planning reserve margin (which determines the amount of capacity procured in the auction) is recalculated each year, and the penetration of variable resources like solar is one of the factors that may alter the system-wide margin.

Some studies have noted that the addition of BTM solar can affect capacity market clearing prices in an alternative way as well. The two main sources of revenue to a generator are energy revenues and capacity revenues. Therefore, if incremental solar decreases energy market LMPs (as discussed above), that change could reduce generator energy revenues, and generators could look to make up that revenue loss in their capacity auction bids. These studies conclude that such a market shift could theoretically increase capacity market clearing prices.

It is important to note that this upward pressure on clearing prices is theoretical, as it assumes that bid pricing is simply structured to yield a preset generator revenue target. In reality, capacity market bids are the result of competitive behaviors by numerous market actors. It is therefore very difficult to calculate with specificity the effect of a decline in energy prices on future long-term capacity prices.

Market Price Effects from SMECO and Choptank BTM Solar

After a review of the potential energy and capacity market price effects of BTM solar development by SMECO and Choptank, Daymark determined that it was not appropriate to include either effect as a cost or a benefit of solar for the purposes of this study.

On the energy market side, Daymark determined that the current methods of modeling and quantifying this impact do not produce reliable results for small amounts of incremental BTM solar. In a system as large as PJM, the market is too complex to measure the impact of a small perturbation. As noted above, many production cost modeling methods do not produce consistent results when attempting to quantify small changes in a large system.

Likewise, while the addition of a resource with no marginal cost will generally provide a benefit to system costs, there is reason to conclude that the addition of a small amount of solar to the PJM system could theoretically increase market prices in some circumstances due to the changes in unit commitment described above.

In other words, the effects of a relatively small amount of incremental BTM solar energy are difficult to effectively model, and even if they are modeled appropriately, they may not have consistent impacts on system-wide market prices. Given that the goal of this study is to develop a standard set of long-term cost and benefit components to apply to solar projects, it was decided that energy market price effects would be excluded.

Regarding the capacity market price effect, Daymark similarly concluded that there is insufficient basis for concluding that a predictable, long term impact can be determined for solar resources. As discussed above, there are multiple ways in which incremental BTM solar can affect capacity auction clearing prices, and the effects can vary in the long-term and short-term.

Daymark believes that these issues should be reevaluated in the future as solar penetrations increase, but that these market price effects should not be included in the value of solar at this time.

3.5.6 Fuel Price Hedge

There is another question that comes up when one looks at the resource portfolios used to serve customers and the potential for avoided or deferred costs from customer actions. The total costs to provide generation service can be mitigated or exacerbated at times if hedges are used to minimize risks of fuel price volatility and thus energy market price volatility. These hedges usually serve to stabilize a significant portion of a utility's costs but not affect a utility's marginal costs. This practice means that market priced avoided costs are not changed through investment in financial hedges. Upon considering this characteristic of any use of hedges the Daymark team position is that the use of PJM market prices for energy and capacity are the best estimates for SMECO and Choptank's avoided costs.

3.5.7 Avoided Renewable Energy Certificates

Load serving entities in Maryland are required to provide a certain percentage of renewable energy to customers to comply with Maryland's Renewable Energy Portfolio Standard (RPS). The RPS requirements are divided into two Tiers with carve-outs for solar and offshore wind included in Tier I. The offshore wind carve-out is yet to be determined by the PSC.

The Maryland RPS requirements for years 2017 as of January 1, 2017 and beyond is shown in the table below.

Table 15: Maryland RPS Requirements[19]

	2017	2018	2019	2020	2021	2022 AND BEYOND
Solar	0.95%	1.40%	1.75%	2.00%	2.00%	2.00%
Other Tier I	12.15%	14.40%	15.65%	16.00%	16.70%	18.00%
Tier II	2.50%	2.50%	0.00%	0.00%	0.00%	0.00%

19 This is based on the RPS as of January 1, 2017. On February 3, 2017, the Senate overrode the Governor's 2016 veto of a bill that would expand the RPS requirements from 20% by 2020 to 25% by 2020. This bill will also increase the solar carve out and delay the schedule for ACP declines.

By adding distributed solar to the system, the cooperatives avoid purchasing generation for their customers and therefore avoid RPS compliance for the level of the avoided generation purchases. For each kWh of distributed solar that is generated, the avoided RPS compliance costs are the percentage requirement of each tier times the renewable energy credit (REC) cost for that tier. So for 2017, the avoided RPS compliance cost would be .95% times SREC price plus, 12.15% times Tier I REC price plus, 2.5% times Tier II REC price.

To determine the REC price for this analysis, we looked at the currently traded REC price and the Alternative Compliance Payment (ACP). Maryland has aggressive carbon reduction goals that require a 40 percent reduction in carbon emissions by 2030. Because the RPS is a likely mechanism by which to achieve these goals, we assumed that REC prices would remain at their current levels through 2025, but would begin increasing in 2026 and reach ACP by 2030. The REC Prices and Avoided Compliance Costs are shown in the table below.

Table 16: REC Prices and Avoided REC Purchases

	REC Price			**Avoided REC Purchases**
	Tier 1	**Solar**	**Tier II**	
2017	$7.50	$23.00	$0.65	$1.30
2018	$7.65	$23.46	$0.66	$1.64
2019	$7.80	$23.93	$0.68	$1.86
2020	$7.96	$24.41	$0.69	$2.00
2021	$8.12	$24.90	$0.70	$2.10
2022	$8.28	$25.39	$0.72	$2.27
2023	$8.45	$25.90	$0.73	$2.31
2024	$8.62	$26.42	$0.75	6
2025	$8.79	$26.95	$0.76	$2.41
2026	$15.03	$31.56	$3.61	$3.79
2027	$21.27	$36.17	$6.46	$4.89
2028	$27.51	$40.78	$9.30	$5.77
2029	$33.76	$45.39	$12.15	$6.48
2030+	$40.00	$50.00	$15.00	$9.31

Choptank does not currently need to comply with the RPS due to its long term contract with Old Dominion Electric Cooperative. Despite the fact that Choptank does not currently have the same requirements as SMECO, we believe it is appropriate to include the avoided RPS compliance costs for both cooperatives in case this exemption was to change in the future and because ODEC is required to comply on Choptank's behalf.

3.5.8 Avoided Emissions

Adding distributed solar reduces the amount of energy that the cooperatives are purchasing and therefore the amount of carbon and other pollutant emissions. Emission reductions benefits can be divided into two categories:

- Avoided compliance costs; and
- Societal benefits.

The avoided compliance costs are the costs associated with complying with federal and state programs that require emission reductions and the societal benefits are the benefits to society of emissions reductions from such effects as improved health from clean air and the reduction of climate change impacts. These benefits are described in detail for carbon emissions below.

Compliance Benefit

Maryland is a participant in the Regional Greenhouse Gas Initiative (RGGI) and as such has made commitments to reduce carbon emissions as part of this regional effort. Additionally, the state recently renewed its GHG emission reduction goals under the Greenhouse Gas Reduction Act and aims to reduce GHG emissions by 40% by 2030 (using a 2006 baseline). The energy sector programs under this plan that will drive post 2020 reductions are:

- Energy Jobs – Renewable Energy Portfolio Standards Revisions Act of 2016;
- RGGI;
- Potential Clean Power Plan; and
- Empower Maryland.

Costs of compliance with RGGI are included in the avoided energy analysis described above. We have also already calculated the avoided cost of RPS compliance through our avoided REC purchases which was discussed earlier in this report. The value of avoided REC purchases at least partially accounts for the Greenhouse Gas Reduction Act compliance.

Similar to carbon emissions, the avoided cost of other environmental emissions is included in the avoided energy analysis as the cost of complying with any emissions regulations is included in the LMP forecasts.

Based on the fact that the compliance costs for both carbon and other environmental emissions have already been quantified in the avoided energy and avoided REC purchases, there is no need to quantify additional avoided compliance costs in this section.

Societal Benefits of Carbon and NO_x

While some states have established societal cost benefits for environmental emissions, Maryland has not. The EPA has calculated societal benefits of carbon and N_2O as part of its Regulatory Impact Analysis for the Clean Power Plan.[20] The Technical support document[21] provides cost estimates and annual growth rates for CO_2 and these estimates have been used in multiple value of solar studies across the country.

EPA's societal cost of carbon is calculated using Integrated Assessment Models (IAM) (PAGE[22], DICE[23], FUND[24]) with inputs on climate sensitivity, socioeconomic and emissions trajectories and discount rates. Depending on the chosen discount rates of 5, 3 and 2.5% the social cost of carbon estimates from the IAM's as published by the EPA are \$12, \$40 and \$60 per short ton of CO_2 emissions in the year 2020. (2011\$). We have used the 3% discount rate scenario.

Using the same source of data from the EPA to value the societal benefits of NOx, we utilized the estimates for N_2O. This is calculated in a manner similar to the calculation of the societal cost of carbon by using the same set of three integrated assessment models, scenarios, discount rates etc. The cost estimates are provided in the

20 https://www.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule-ria.pdf

21 https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf

22 PAGE – Policy Analysis of the Greenhouse Effect (Chris Hope). PAGE simulates the economic and environmental impact of policies to address climate change.

23 DICE – Dynamic Integrated Climate- Economy (William Nordhaus). The model integrates in an end to end fashion the economics, carbon cycle, climate science, and impacts in a highly aggregated model that allows a weighing of the costs and benefits of taking steps to slow greenhouse warming.

24 FUND – Climate Framework for Uncertainty, Negotiation and Distribution (Waldhoff, S., D.Anthoff, S.Rose and R.S.J. Tol) is an integrated assessment model linking projections of populations, economic activity and emissions to simple greenhouse gas cycle, climate and sea-level rise models and to a model predicting and monetizing welfare impacts.

Addendum to technical support document on social cost of carbon for the Regulatory Impact Analysis.[25] The 3% discount rate value was also used in this case to calculate avoided N_2O emissions. Depending on the chosen discount rates of 5, 3 and 2.5% the social cost of N_2O estimates as published by the EPA are $4,700, $15,000 and $22,000 per metric ton of N_2O in the year 2020. (2007$)

The PJM emissions report[26] provides marginal emission rates for both carbon and NO_x. We have calculated the societal benefits of avoiding these emissions by multiplying the on peak marginal emissions rate for both carbon and NO_x by the EPA societal benefit for each emission using the 3% discount rate scenarios.

The results of this analysis are included in Table 17 below. These benefits are quite significant starting at almost $36 and $14 per MWh for carbon and NO_x respectively in 2018 and growing to $72 and $32 per MWh for Carbon and NO_x respectively in 2037. This puts the societal benefit at roughly the magnitude of the avoided energy benefits.

[25] https://www.epa.gov/sites/production/files/2016-12/documents/addendum_to_sc-ghg_tsd_august_2016.pdf

[26] Page 4 and 6 of PJM's 2012-2015 CO_2, SO_2 and NO_x Emission Rates report. http://www.pjm.com/~/media/library/reports-notices/special-reports/20160318-2015-emissions-report.ashx

Table 17: Societal Benefits of Carbon and NOx per MWh of distributed solar generation

	SOCIETAL BENEFITS OF CO_2 REDUCTION	SOCIETAL BENEFITS OF NO_X REDUCTION
2018	$ 35.93	$ 13.74
2019	$ 37.60	$ 14.38
2020	$ 39.37	$ 15.37
2021	$ 40.23	$ 16.13
2022	$ 42.11	$ 16.93
2023	$ 44.03	$ 17.77
2024	$ 45.96	$ 18.63
2025	$ 47.99	$ 19.38
2026	$ 50.13	$ 20.35
2027	$ 52.37	$ 21.38
2028	$ 54.65	$ 22.44
2029	$ 55.85	$ 23.56
2030	$ 58.24	$ 24.19
2031	$ 60.69	$ 25.23
2032	$ 63.17	$ 26.30
2033	$ 65.69	$ 27.39
2034	$ 68.22	$ 28.51
2035	$ 70.79	$ 29.54
2036	$ 73.43	$ 30.73
2037	$ 76.13	$ 31.95

3.5.9 Other Benefits

There are other potential benefits to distributed solar development that have not been fully quantified in this report in part because a larger study would be required to understand exactly how these benefits accrue to Choptank and SMECO customers. These benefits include:

- Local economic development benefits;
- Employment benefits;
- Water savings; and

- Land savings.

Solar provides social benefits to the local community through creation of jobs for installation and maintenance of the equipment, other related employment opportunities and also provides local economic development in the form of generated tax revenue. Before the reauthorization of Maryland's Greenhouse Gas Reduction Act in 2016, it was estimated that the State's economy would benefit by $2.5 billion to $3.5 billion while creating and maintaining 26,000 to 33,000 new jobs by 2020.[27]

The Renewable Energy Policy Report's study, "The work that goes into renewable energy"[28] estimates that for a solar project of 2 kW, each MW of solar translates to 35.5 person-years, or 69,650 hours of labor. Multiple studies conducted in the US and globally suggest that the number of jobs generated per MW of renewable energy is higher than the fossil fuel based energy sector. Development of solar will lead to jobs and investment in areas of the country that manufacture the parts that make up a solar system, in addition to locations that install the systems.

Land and water use impacts are savings related to avoiding new power plant construction. As distributed solar reduces the need for conventional power plant additions, the land where these facilities would have been built is saved and any impact to surface water sources that would have been used as cooling water is avoided.

3.6 Total Value of Solar

Based on the results of the individual components described above, we have created a combined value of solar for the distributed solar systems installed in the Choptank and SMECO service territories. For each system, we completed this analysis for both a south facing and west facing orientation. A south facing system orientation would produce the largest total MWh, but a west facing system orientation produces more energy during PJM's summer peak. Looking at both compass orientations will allow the cooperatives to understand if incentivizing a west facing system orientation would be beneficial. The combined analyses are shown below in Figure 22 through Figure 25 below.

[27] http://marylandclimatecoalition.org/factsheets/greenhouse-gas-reduction-act/
[28] http://www.globalurban.org/The_Work_that_Goes_into_Renewable_Energy.pdf

Four of the benefits, avoided energy, avoided capacity, avoided REC purchases and avoided transmission charge accrue directly to the cooperatives. The societal benefits accrue to cooperative customers, but do not directly impact the cooperatives' cost structure to serve their customers.

The graphs show that for both cooperatives, the west facing system orientations yield a higher value of solar. Including the carbon and NO_x societal benefits almost doubles the value as compared to the sum of the four benefits that directly accrue to the cooperatives.

The next section of the report will use the value of solar developed here and evaluate the rate impact on different rate classes of potential rate designs.

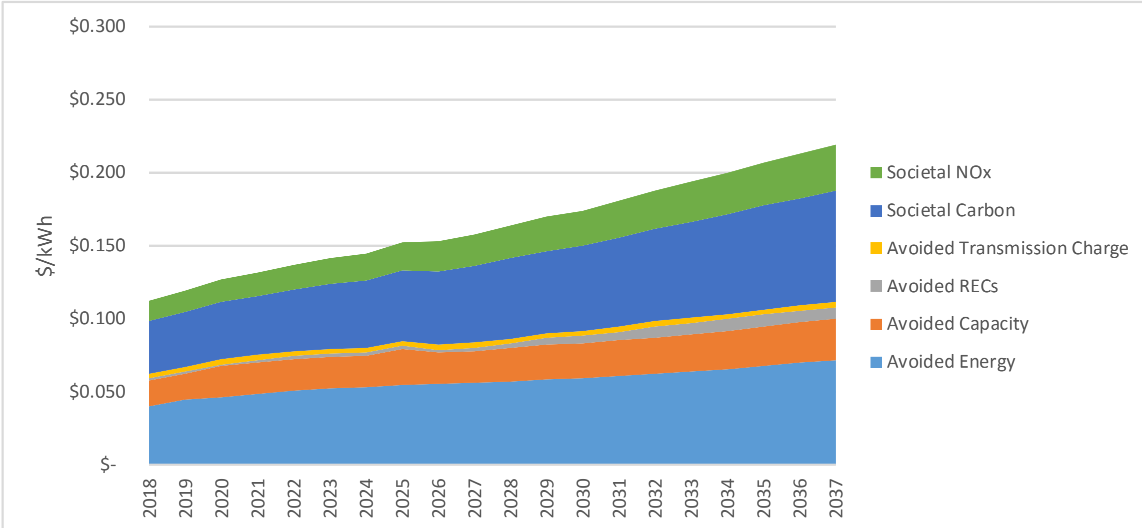

Figure 22: SMECO South Facing Solar System – Value of Solar

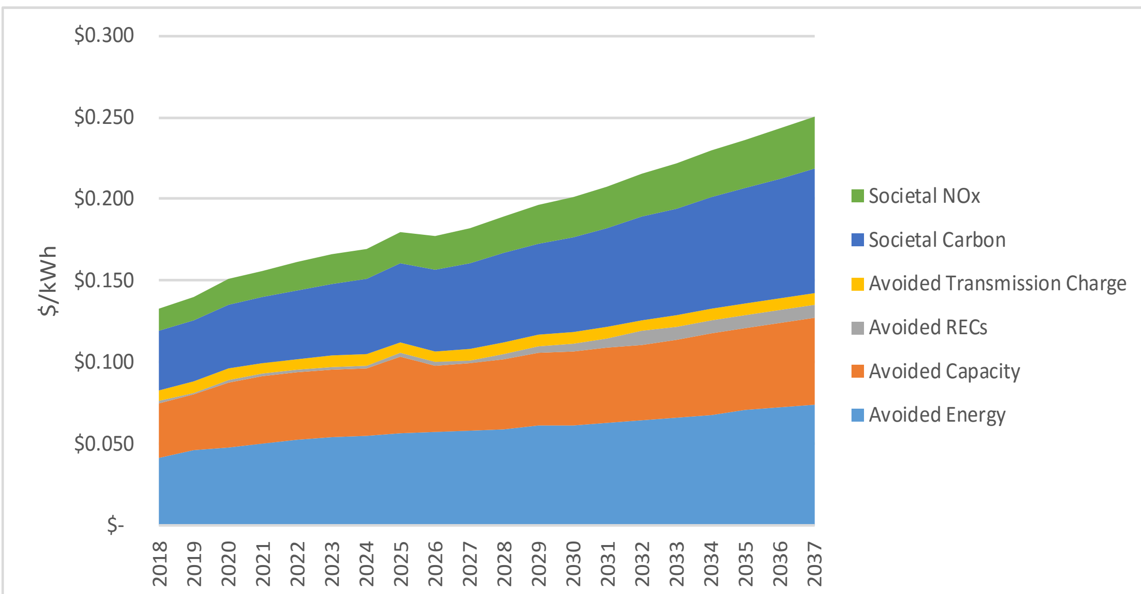

Figure 23: SMECO West Facing Solar System – Value of Solar

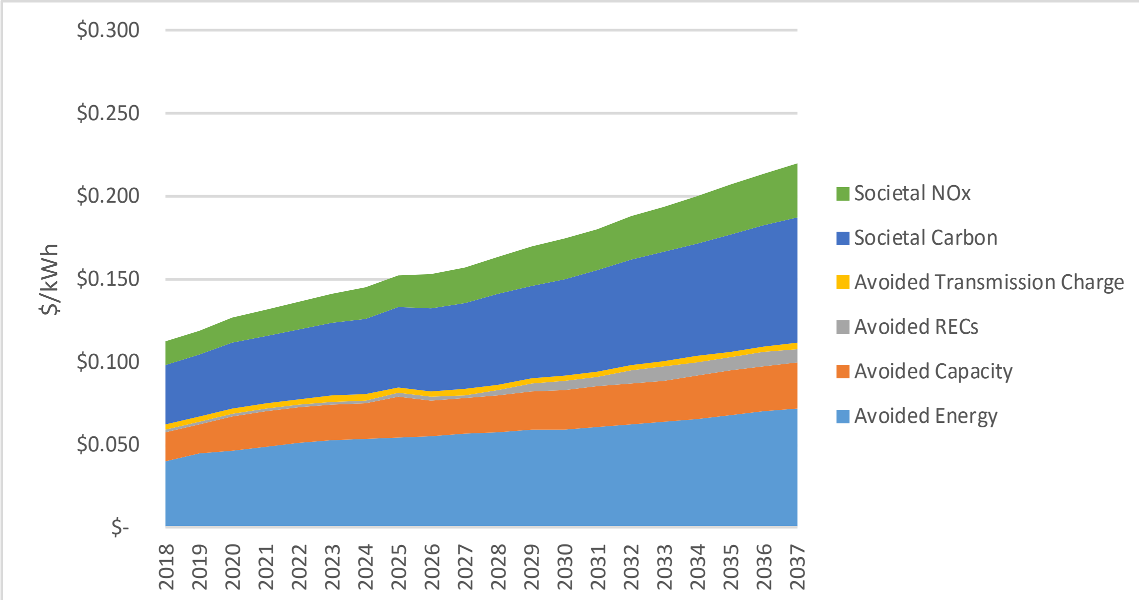

Figure 24: Choptank South Facing Solar System – Value of Solar

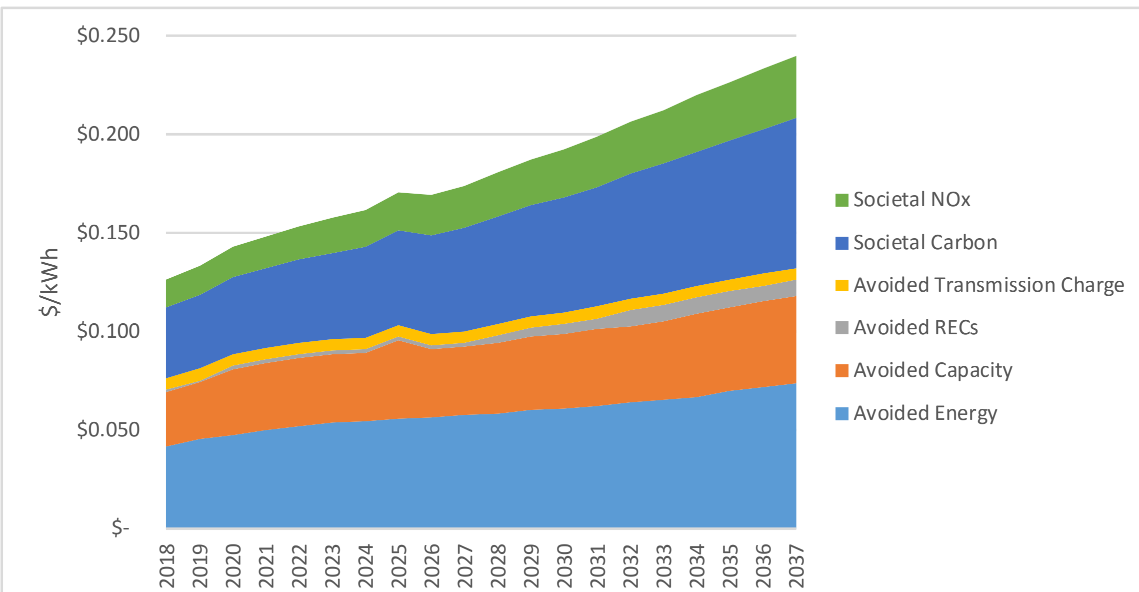

Figure 25: Choptank West Facing Solar System – Value of Solar

4. RATE DESIGN MECHANISMS AND IMPACTS

4.1 Rate Design and DER

Rate design is an exercise in balancing a variety of principles and objectives that can often be in tension with one another. Concepts such as revenue sufficiency and stability, efficiency of price signals, fairness of cost allocation, customer understanding and acceptance, and gradualism in rate impacts are generally agreed to be desirable in theory but in practice require decisions about trade-offs. Effective rate design strikes a balance among these various objectives.

As an example of trade-offs inherent in rate design decisions, consider that every individual customer has a unique cost profile due to variations in size, load shape, service drop requirements, and other customer specific characteristics. Perhaps the ultimate rate design for achieving fairness in cost allocation would assign unique rates to each customer based on the customer's unique cost profile. Of course, such an approach violates other principles of rate design such as simplicity and understandability of rates and feasibility of implementation (the allocated cost of service study required to support such a rate design is staggering to contemplate!). As a trade-off, customers are grouped into rate classes representing customers with generally similar profiles. A certain amount of imbalance in cost allocation among diverse customers within a rate class is the commonly accepted trade-off for a simpler and more feasible rate structure.

Another consideration in rate design is general policy that considers and implements rate design strategies intended to derive outcomes that address the common good or societal preferences. These policies may be legislative or regulatory initiated and are designed to achieve specific goals. These policy considerations have historically included regulators' preference for reliance on higher levels of variable pricing as opposed to fixed prices to encourage conservation of natural resources or the use of lifeline rates to address the unique requirements of low income families. These policy related considerations involve tradeoffs within the regulatory rate setting process.

In the context of the many trade-offs and compromises inherent in any rate design, the introduction of net energy metering (NEM) for distributed energy resources (DER) adds another set of trade-offs that must be considered in the rate design process. The following is a brief summary of a few key rate design considerations raised by NEM:

- **Policy priorities and societal benefits** – The generation resources that are eligible for NEM may be prioritized by policymakers, the Commission and stakeholders for reasons other than direct cost of service benefits. For instance, societal benefits such as environmental protection and job creation might be reasons to incentivize solar or other DER development over and above direct cost savings to the utility. The effective payment rate[29] for NEM generation may be a key consideration, particularly ensuring that sufficient compensation is provided to support a desired level of eligible DER development.

- **Revenue recovery sufficiency for utilities** - If NEM reduces participating customers' bills by more than the energy supplied reduces the utility's overall cost of service, then NEM can impact the utility's ability to collect its approved revenue requirements under existing rates. Conversely, if NEM generation reduces cost of service by more than the overall reduction in participants' bills, then NEM can lead to over-collection of revenue requirements.

- **Fairness of cost allocation** – To the extent that there is a mismatch between NEM compensation and the cost savings associated with NEM generation, cross-subsidies may occur between NEM participants and non-participants.

Our analysis is intended to help the Commission, policymakers, cooperatives and other stakeholders understand the trade-offs made under the cooperatives' current rate design and NEM policy. To the extent that the Commission may be interested in pursuing changes that alter the status quo balance of trade-offs, we explore some of the more common rate design and DER compensation approaches to balancing the impacts of DER.

In its manual on Distributed Energy Resources (DER) Rate Design and Compensation, National Association of Regulatory Commissioners (NARUC) staff note the following:

> *Rate making is often the result of a regulator balancing a variety of interests and goals of the parties, as well as technological and political considerations. The prevailing rates for any given utility represent a history of compromises –*

29 Effective payment rate is the total reduction in a NEM customer's bills plus any direct payments for net excess generation, divided by the total output of the generator.

> *on goals, on the balancing of different rate design philosophies, on the practicality of a given rate component based on available data, and so forth. Given this history of compromises, there have always been 'winners' and 'losers' in rate design; DER just potentially shifts who are those winners and losers.*[30]

Outside the context of a full rate case it is impossible to recommend specific rate design choices because the impact of DER is only one of many considerations in balancing the many trade-offs inherent in rate design as discussed previously.

Our purpose is to highlight and, to the extent possible, quantify the tradeoffs for Maryland's cooperatives and their customers based on current levels of solar NEM penetration. We do not offer any recommendations on the appropriate balance to strike among competing objectives discussed here, in particular targeting policy, customer equity, and compensation levels for NEM. The Commission and state policymakers must balance not only the competing objectives contemplated here but also the full complement of principles and objectives considered in general rate design and social policy in order to determine the appropriate way forward.

4.2 Measuring Current NEM Impacts

Participants in the net metering programs of SMECO and Choptank, which are comprised primarily of solar customer-generators, can reduce their electricity bill by netting the amount of energy produced by their eligible facility against their own usage during a single billing period. To the extent that net excess generation accumulates beyond a single billing cycle, participants can also reduce their bill by a payment from the cooperative for all energy generated in excess of their consumption needs when the customer terminates service, or at the end of the net metering year (*i.e.* by the end of April each year). The energy consumed on premises allows the participant to avoid up to the entire variable energy charge which recovers both generation supply and delivery costs of the cooperatives.

We examine the impact of the NEM program as currently designed and with current levels of solar DER penetration[31] on the three key rate design objectives discussed

30 NARUC (November 2016). Distributed Energy Resources Rate Design and Compensation Manual, p 75.

31 Because the vast majority of participants in the net metering programs for SMECO and Choptank have installed distributed solar, our analysis assumes that NEM participants are all solar customer-generators.

above: revenue sufficiency, fairness of cost allocation, and policy priorities/societal benefits. Later in this report we will compare these impacts under alternative rate design and DER compensation approaches. It is important to recognize that the comparison in Sections 3.2.1 and 3.2.2 below excludes societal benefits- focusing on the benefits that are direct impacts to the cooperatives. Section 3.2.3 addresses the policy perspective.

4.2.1 Revenue Sufficiency

Under the current NEM program design, customers can offset their entire variable rate component of their bills with DER generation. From the revenue sufficiency perspective, the question that must be addressed is whether the utility benefits exceed their costs of NEM. The benefits of NEM include directly avoided costs to the cooperatives resulting from the NEM generator output, and these are estimated in Section 3.5 of this report. The "cost" of NEM generation for the cooperative can be viewed as revenue lost to the cooperatives in a cost/benefit analysis. If lost revenues ("costs") exceed the estimated direct value of solar ("benefits"), then the cooperative's ability to collect sufficient revenue to cover costs could be negatively impacted.

Maryland is a restructured state with retail choice, so bills are divided between the Distribution Service component (covering delivery of power over the cooperatives' distribution system) and the Standard Offer Service (SOS) component (covering supply of energy, capacity and transmission charges). Customers may choose to obtain energy supply from retail suppliers rather than the host cooperative, but distribution service must be provided by the cooperative. NEM customers can offset the variable rate components for both components of the bill, regardless of retail choice status. In some cases, we distinguish cost/benefit impacts between Distribution and SOS charges because customer-generators on retail choice would not impact SOS costs and benefits to the cooperative.

Daymark has not found there to be any measurable reduction in the cost for distribution service as a result of solar installations. Thus, in the short term, prior to a rate adjustment for all customers and after installation of new DER solar facilities, the cooperative experiences a reduction in fixed cost recovery from approved delivery rates due to a reduction in use by participants.

We estimated the net impact of current solar penetration levels based on our estimates of the value of solar energy to the cooperatives presented in Section 3.5 of this report and current rate schedules for customer classes participating in the State's NEM program. Value of solar, which includes avoided costs related to energy, capacity, RPS compliance and transmission charges, is taken from the first year of our forecast (2018) for comparison to current rates. For the purposes of this analysis we assume that all solar generation is either directly offsetting the member's usage in the same month, or banked as a net metering credit and applied against usage in a future month. Net excess generation credits remaining in a member's account at the end of April are "cashed out" at the generation supply rate, without the delivery component. We assume that most NEM members would size their systems to minimize the excess generation credits that are cashed out at the lower rate.[32]

The cost/benefit analysis incorporates the benefits and lost revenue realized by each cooperative and does not include societal benefits or costs. We did consider a sensitivity cost/benefit analysis that includes some societal benefits associated with avoided emissions, which is discussed in Section 4.2.2 below. The tables below show the results of our cost/benefit analysis for all classes that are currently participating in NEM. The estimated net cost of NEM solar to the cooperatives by class ranges from 2.2 to 6.8 cents per kWh for SMECO and 3.1 to 7.5 cents per kWh for Choptank[33]. In other words, for every kWh of solar generation by NEM customer-generators, the lost revenue due to bill offsets exceeds the avoided energy, capacity, transmission, and REC procurement costs to the cooperative by somewhere between 2.2 and 7.5 cents, depending on the rate class. In general, the net cost is least for the larger general service and large power customer classes because they are less reliant on volumetric charges in their rate design, and therefore the cooperatives lose less in revenue from lost sales due to NEM.

32 If this assumption were relaxed and some systems are large enough to generate net excess generation each year, the lost bill revenue due to solar would be lessened.

33 In the tables, see row labeled "Total VOS Net Benefit/(Cost)".

Table 18: SMECO Benefit/(Cost) of solar by class with estimated rate impacts

SMECO		Residential Schedule R	Gen'l Service Non-Demand Schedule GSND	Gen'l Service Demand Schedule GSD	Large Power Schedule LP
Lost Distribution Charge Revenue	$/kWh	$ (0.052)	$ (0.039)	$ (0.024)	$ (0.030)
Distribution System Benefit	$/kWh	$ -	$ -	$ -	$ -
Net Distribution Benefit/(Cost)	$/kWh	$ (0.052)	$ (0.039)	$ (0.024)	$ (0.030)
Lost Standard Offer Service Revenue	$/kWh	$ (0.079)	$ (0.072)	$ (0.061)	$ (0.067)
SOS Benefit	$/kWh	$ 0.062	$ 0.062	$ 0.062	$ 0.062
Net SOS Benefit/(Cost)	$/kWh	$ (0.016)	$ (0.010)	$ 0.002	$ (0.004)
Total VOS Net Benefit/(Cost)	$/kWh	$ (0.068)	$ (0.049)	$ (0.022)	$ (0.034)
Estimated Solar PV Output	MWh	43,009	259	2,915	2,323
Total Benefit/(Cost)	$/000	$ (2,915)	$ (13)	$ (65)	$ (79)
Total Sales (2015 actual less Solar PV Output)	MWh	2,129,596	120,260	982,714	151,266
Estimated Rate Impact	$/kWh	$ 0.0014	$ 0.0001	$ 0.0001	$ 0.0005

Table 19: Choptank Benefit/(Cost) of solar by class with estimated rate impacts

Choptank		Residential Schedule R	Commercial Service Schedule C	Gen'l Svc - Small Schedule S	Gen'l Svc - Medium Schedule M	Primary Service Schedule P
Lost Distribution Charge Revenue	$/kWh	$ (0.049)	$ (0.052)	$ (0.030)	$ (0.030)	$ (0.026)
Distribution System Benefit	$/kWh	$ -	$ -	$ -	$ -	$ -
Net Distribution Benefit/(Cost)	$/kWh	$ (0.049)	$ (0.052)	$ (0.030)	$ (0.030)	$ (0.026)
Lost Standard Offer Service Revenue	$/kWh	$ (0.086)	$ (0.085)	$ (0.063)	$ (0.063)	$ (0.090)
SOS Benefit	$/kWh	$ 0.062	$ 0.062	$ 0.062	$ 0.062	$ 0.062
Net SOS Benefit/(Cost)	$/kWh	$ (0.024)	$ (0.023)	$ (0.000)	$ (0.001)	$ (0.027)
Total VOS Net Benefit/(Cost)	$/kWh	$ (0.072)	$ (0.075)	$ (0.031)	$ (0.031)	$ (0.053)
Estimated Solar PV Output	MWh	8,256	507	6,423	4,040	2,261
Total Benefit/(Cost)	$/000	$ (598)	$ (38)	$ (197)	$ (126)	$ (121)
Total Sales (2015 actual less Solar PV Output)	MWh	711,776	53,187	85,480	71,059	88,030
Estimated Rate Impact	$/kWh	$ 0.0008	$ 0.0007	$ 0.0023	$ 0.0018	$ 0.0014

4.2.2 Fairness of Cost Allocation

Cross subsidies occur when some customers pay more than they incur in costs to make up for other customers who pay less. Cross subsidies are inherent and unavoidable in rate design. To return to an earlier example, the only way to eliminate cross subsidies completely is to design unique rates for each individual customer, which is clearly infeasible.

The net cost of NEM solar introduces two basic cross subsidy issues. The first issue is *intra*-class subsidies from non-participants to NEM customers within a rate class. The second issue is *inter*-class cross subsidies between classes where a class is disproportionately impacted by NEM effects. We discuss these impacts in turn.

Intra-class Cross Subsidies

Our findings are that for all customer classes with NEM solar, the lost revenue due to self-supply exceeds the avoided costs realized by the cooperative from the reduction in load. Distribution and SOS rates for all customers will likely be adjusted to assure appropriate cost recovery by the cooperatives during the subsequently adjudicated rate case, resulting in potential cross-subsidies. Based on the current levels of solar penetration and the latest sales data available to us, we estimate that the class rate increases required to recover the net cost of NEM solar ranges from $0.0001 to $0.0014 per kWh for SMECO and from $0.0007 to $0.0023 per kWh for Choptank (see tables above). As solar penetration increases, the rate impacts will accelerate as greater lost revenue is collected through lesser (all else equal) sales.

It is important to bear in mind that cross subsidies are inevitable in rate design due to the diversity of members in each rate class. The customer consumption patterns within a rate class vary, creating some degree of cross subsidy. Net metering is only one of many factors that could contribute to cross subsidies. For instance, customers with higher load factors typically "subsidize" customers with lower load factors within a rate class when rate structures include very high energy charges relative to demand charges.

To the extent that NEM causes or exacerbates a disconnect between revenue collection and cost of service-based revenue requirements for different classes, there is a potential issue of inter-class cross subsidies. Though it is theoretically possible for each rate class to adjust its rates to address its own shortfall, it is also possible that a less-impacted class may be asked to subsidize a more-impacted class for reasons related to rate stability, gradualism or public acceptability.

Policy Priorities and Societal Benefits

The net cost estimates shown in the revenue sufficiency analysis above include only direct costs and benefits to the cooperatives, and do not include externality benefits such as the societal value of avoided emissions. If we include those benefits as well, the net cost of solar declines dramatically, and for many customers even becomes a net benefit overall but not within the utility perspective of electric costs and recovery of those costs. The tables below show the cost-benefit analysis results when the estimated societal benefits of avoided emissions are included in the calculation.

Table 20: SMECO Benefit/(Cost) of solar including societal value of emissions

SMECO		Residential Schedule R	Gen'l Service Non-Demand Schedule GSND	Gen'l Service Demand Schedule GSD	Large Power Schedule LP
VOS Direct Net Benefit/(Cost)	$/kWh	$ (0.068)	$ (0.049)	$ (0.022)	$ (0.034)
Societal Value of Avoided Emissions	$/kWh	$ 0.050	$ 0.050	$ 0.050	$ 0.050
VOS Net Benefit/(Cost) Including Societal Value of Avoided Emissions	$/kWh	$ (0.018)	$ 0.001	$ 0.027	$ 0.016

Table 21: Choptank Benefit/(Cost) of solar including societal value of emissions

Choptank		Residential Schedule R	Commercial Service Schedule C	Gen'l Svc - Small Schedule S	Gen'l Svc - Medium Schedule M	Primary Service Schedule P
VOS Direct Net Benefit/(Cost)	$/kWh	$ (0.072)	$ (0.075)	$ (0.031)	$ (0.031)	$ (0.053)
Societal Value of Avoided Emissions	$/kWh	$ 0.050	$ 0.050	$ 0.050	$ 0.050	$ 0.050
VOS Net Benefit/(Cost) Including Societal Value of Avoided Emissions	$/kWh	$ (0.023)	$ (0.025)	$ 0.019	$ 0.018	$ (0.004)

We provide this potential approach to valuing societal benefits of avoided emissions as a sensitivity case in considering the impacts of solar, but note that estimates of these externality values vary widely and are not currently incorporated in the cooperatives' cost of service structure. Our rate design analysis considers only direct impacts to the cooperatives and their customers, so we did not include the societal value of avoided emissions or any other societal benefit of solar generation. While externality values do not impact revenue recovery adequacy, they may have some bearing in rate design decisions such as how much tolerance there should be for cross subsidies to NEM solar customers. The decision of how much to weigh externality values such as these is ultimately a policy decision that must be made between the cooperatives, the Commission and other stakeholders.

The following charts illustrate the balance of effective NEM compensation rates and the direct and externality value of solar for the various rate classes in each cooperative.

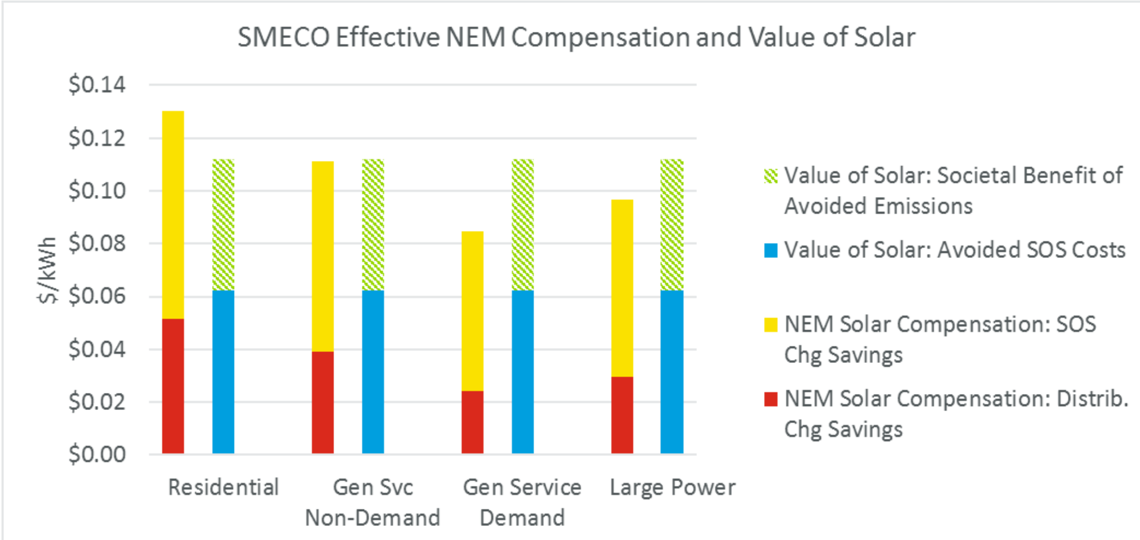

Figure 26: Comparison of Effective NEM Compensation and Value of Solar for SMECO Rate Classes

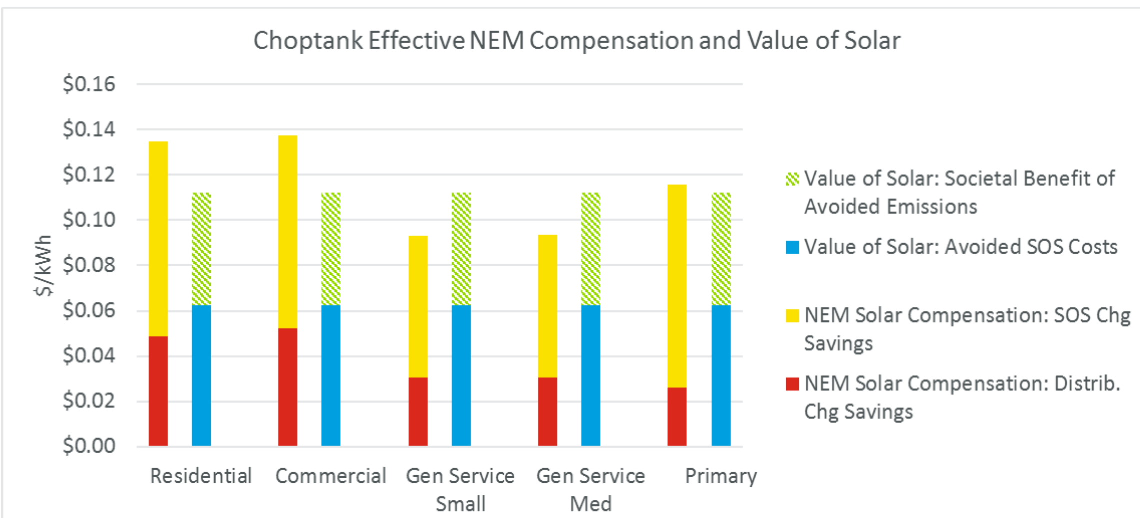

Figure 27: Comparison of Effective NEM Compensation and Value of Solar for Choptank Rate Classes

Another policy priority consideration is the sufficiency of the effective payment rate to solar customer-generators to incentivize development. If solar development is a policy priority for reasons beyond direct cost-effectiveness to cooperatives (i.e. job creation benefits- which are not valued in this report or other societal benefits discussed above), then ensuring a sufficient payment rate to solar generators becomes a key consideration. The table below shows effective NEM payment rates to solar generators under current rates.

Table 22: Effective Current NEM Compensation Rates for Average Customer by Rate Class and Cooperative

SMECO		Residential Schedule R	Gen Service Non-Demand Schedule GSND	Gen Service Demand Schedule GSD	Large Power Schedule LP	
Effective NEM Solar Compensation	$/kWh	$0.1301	$0.1113	$0.0846	$0.0965	
Choptank		Residential Schedule R	Comm Svc Schedule C	Gen Svc - Small Schedule S	Gen Svc - Med Schedule M	Primary Svc Schedule P
Effective NEM Solar Compensation	$/kWh	$0.1349	$0.1375	$0.0932	$0.0937	$0.1159

Under current Maryland policy, NEM customer-generators are also entitled to the SRECs associated with their generation, which can provide an additional income stream. Section 3.4 discussed the cost considerations for residential solar and the estimated level of payments required under various policy and SREC market scenarios to make residential solar projects economically attractive.

4.3 Compensation Arrangements for Distributed Energy Resources

How customers are compensated for the generation produced by the customer-generator can be accomplished in a variety of approaches. In this section we address the current approach in Maryland and alternatives, including their benefits and trade-offs.

NEM was established for eligible customer generators with distributed energy resources (DER) under MD Public Utility Code §7-306. NEM customers are billed for their net consumption (energy used from the grid over and above self-supply from the customer's DER system) less any net exports to the grid from the DER system. At times when a NEM customer's generation exceeds the customer's consumption, the meter runs backward to offset net consumption at other times in the billing cycle. When a NEM customer has a negative reading at the end of a billing cycle, the net excess generation can be "banked" as a credit to offset usage in future months. Credits can be banked for up to a year, but each April the credits are "cashed out" at the generation supply rate in effect.

The current method of compensation through net energy metering for eligible customer-generators is a direct requirement of MD Public Utility Code §7-306(f). Nevertheless, to aid policymakers as well as the Commission in considering alternatives to current NEM tariffs we provide an overview of other approaches that would only be possible with changes to current statutes.

In considering alternative compensation models for DER it is first necessary to understand the billing data that can be recorded with current or planned metering infrastructure. The graphic below provides a schematic representation of a NEM customer-generator's consumption and generation on a given day. Our understanding is that SMECO and Choptank meters currently vary in their ability to specifically measure the individual components shown in the figure. Very few customers are metered such that total consumption and total generation (the blue and yellow dashed lines, respectively) are recorded. Some meters are able to separately measure and record net consumption (green area) and net export (red area), while the simplest NEM meters only spin forward or backward with a running tally of net consumption less net exports, with the balance recorded at each meter reading.

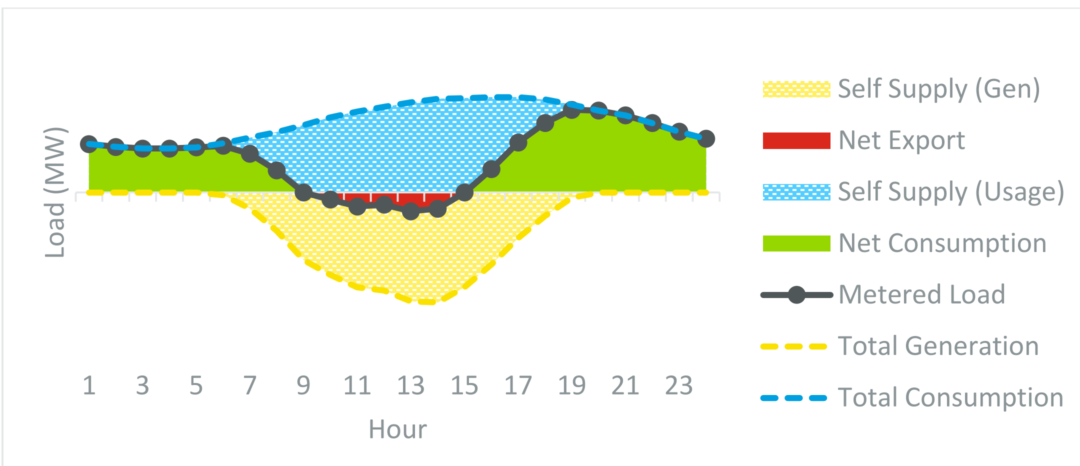

Figure 28: Net Energy Metering net consumption/export schematic

4.3.1 Alternative DER compensation mechanisms

Other DER compensation mechanisms and variants exist that may allow Maryland's cooperatives to better align solar costs and benefits independent of any rate design changes on the consumption side. Some of the alternative mechanisms are dependent on changes to metering infrastructure, but some could technically be implemented with the current systems in place. Some common options to consider are described in the sections that follow. All of these alternative approaches would require changes in statute prior to implementation.

Treatment of Net Exports

Up to a certain point, net exports (the red area in Figure 28 above) are treated as an offset to net consumption (green area) under Maryland's NEM rules. As such, net exports to the grid are compensated at the full retail volumetric rate, provided they do not exceed net consumption on a cumulative basis over an annual period. There are other options for treating net exports that differentiate the treatment of net exports from reduced net consumption. Net exports could be given no compensation, encouraging NEM customers to size their systems to only offset their own load without exporting any excess energy to the grid. Hawaiian Electric Company has recently introduced a Customer Self-Supply (CSS) program that provides no compensation for exports to the grid.[34] This approach is unlikely to be appropriate for Maryland's cooperatives because it undervalues the energy provided to the grid through net exports. Customer self-supply options are typically more appropriate in jurisdictions with higher penetration of DER to the point that excessive net exports could begin having negative impacts on the distribution system.

Another alternative is to compensate net exports at a special "Value of Solar" rate rather than allowing the exported energy to offset consumption at other times in the billing period. Another variant of this approach is to exclude some elements of the retail volumetric rate from the compensation rate for net exports, such as non-bypassable charges or distribution delivery rates. This approach requires meters capable of separately recording net consumption and net exports over a billing period rather than simply recording a running tally. Barriers to this approach include resistance to (presumably) reducing[35] the compensation rate for solar installations, and metering and billing challenges associated with separately tracking net exports.

[34] https://www.hawaiianelectric.com/clean-energy-hawaii/producing-clean-energy/customer-self-supply-and-grid-supply-programs.

[35] In some cases, the VOS rate could exceed the volumetric retail rate, resulting in this approach increasing compensation for net exports. In the Maryland electric cooperatives' context our findings are that the value of solar is less than the full distribution and generation supply retail rate, so this approach would result in a compensation reduction.

Credit Banking provisions

Under the current NEM tariffs, credits for net exports in excess of the amount required to "zero out" a customer's volumetric charges within a monthly billing period can be "banked" forward through April. After the billing period ending before the end of April, any remaining banked credits are cashed out at the generation supply rate. NEM customers can use these banking provisions to zero out their volumetric charges completely even if they rely on the grid for significant net consumption.

Alternative credit banking provisions could reduce the period over which excess credits may be retained. One example would be to cash out excess credits on a seasonal rather than annual basis. At the end of each summer and winter period, the excess credits could be paid out at the seasonally appropriate generation supply rate, removing the ability for summer net exports to offset winter usage, and vice versa.

Another alternative credit banking provision that could be considered, particularly in conjunction with some of the rate design approaches described above, would be to differentiate the credits with attributes related to appropriate billing determinants. For instance, if a TOU rate is in effect, then excess net generation would be tagged with the appropriate TOU period when it occurred. Credits generated during winter off-peak hours, for instance, could only offset winter off-peak usage. Excess credits within each TOU period would be credited at the generation supply rate, regardless of the usage/credit balance in other TOU periods.

NEM Alternative: Buy All/Sell all

The purpose of NEM is often to encourage development of solar and other DER by compensating generation at the full retail rate. If greater policy priority is placed on aligning DER compensation with the value of solar received, an alternative mechanism that may be considered is the "buy all/sell all" approach. The figure below provides a schematic illustration. Under a buy all/sell all tariff, customer-generators pay for their total consumption or usage (the blue area in the figure) through the applicable retail electric service tariff and sell all of their DER generation (the yellow area) at a "Value of Solar" (VOS) tariff rate. A value of solar rate considers the benefits and costs of solar for the cooperatives and establishes a level that represents these considerations. By aligning compensation for solar with the value it provides, this approach can greatly reduce the cross subsidies caused by NEM.

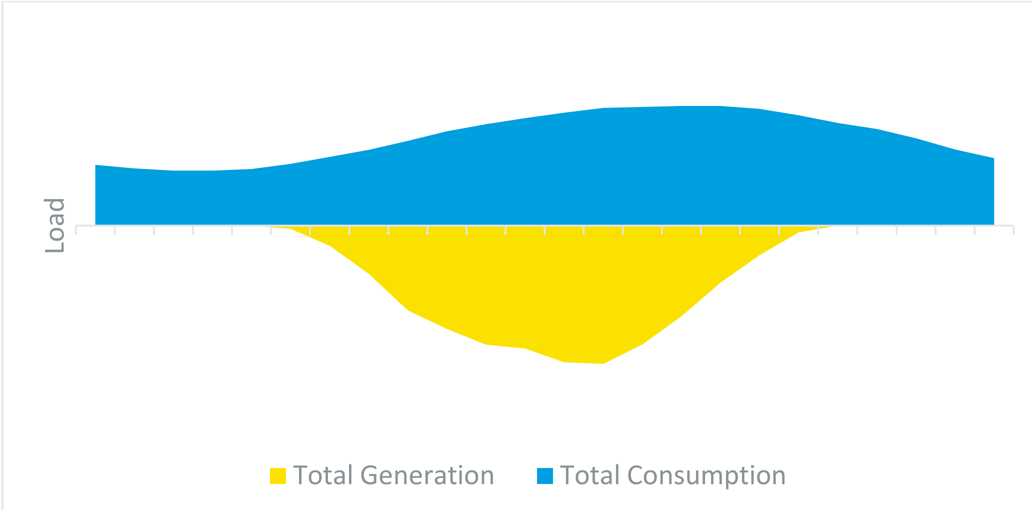

Figure 29: Buy all/sell all schematic

A value of solar rate considers the benefits and costs of solar for the cooperatives and establishes a level that represents these considerations. By aligning compensation for solar with the value it provides, this approach can greatly reduce the cross subsidies caused by NEM. The approach requires separate metering of load and generation, which can add significant metering infrastructure cost.

Buy all/sell all approaches have been widely discussed but rarely implemented to date in the mass-market classes (i.e. residential and small commercial). There are several different methods currently in place for determining the compensation rate for DER generation offered to customers. One method is to set the price at an agreed upon Value of Solar rate. A second method is to tie the compensation rate to the levelized cost of energy of the DER resource.

Currently, Austin Energy in Texas is the only utility in the United States that has fully implemented a buy all/sell all tariff using the value of solar as the compensation rate. The state of Minnesota passed legislation in 2013 requiring the Minnesota Department of Commerce to establish a state-wide value of solar methodology that would allow for a voluntary buy all/sell all tariff.[36]

The Rhode Island Renewable Energy Growth is an example of a buy all/sell all program where the compensation rate for DER generation is tied to the levelized cost of the

[36] NREL (March 2015). Value of Solar: Program Design and Implementation Considerations (Technical Report), pp 13-18. www.NREL.gov/publications

resource. Residential and commercial projects less than 250 kW are offered a price per kWh that is determined based upon the calculated levelized cost of those projects. Projects larger than 250 kW are competitively bid, with the price capped at ceiling price based on the levelized cost of those projects. The prices for the smaller projects and the ceiling prices for the larger projects are established each year in a proceeding at the Rhode Island Public Utilities Commission.

Customers participating in Rhode Island's Renewable Energy Growth program have two meters: one to measure the output from the distributed generation system and one to measure their energy usage. They are credited the established price per kWh for the distributed generation for all solar produced and charged for all electricity used according to their rate class.

4.3.2 Alternative DER Compensation Case Studies

In order to explore the trade-offs associated with potential compensation structure alternatives to Maryland's present NEM program, we constructed case studies focusing on two particular approaches. The assumptions about current rates and average customer profiles are detailed in Section 4.4.1 below.

Case Study #1: Net Exports Paid VOS

While a full buy all/sell all approach may difficult to implement due to metering requirements, there is a hybrid approach that applies a separate "Value of Solar" payment rate to all net exports rather than netting exports against usage at other times in the billing cycle. This approach would likely require changes to MD Public Utility Code §7-306.

For this case study we assumed that net exports are recorded separately from net consumption, and that net exports are compensated at the value of solar estimate for south-facing solar in each cooperative's respective service territory. This mechanism is similar to a tariff for distributed generation this is currently in effect for Kauai Island Utility Cooperative (KIUC).[37]

The table below shows that this approach cuts the net cost of NEM solar by more than 50% compared to current rates. The net cost reductions are commensurate with the share of total generation that is modeled as net exports for our average NEM customer shape. For both cooperatives the residential, small commercial, and some large power

[37] Schedule "Q" Modified Purchase From Qualifying Facilities 100kW or Less. http://website.kiuc.coop/content/tariffs

class NEM customer shapes are all projected to export more power to the grid than offset load on an instantaneous basis.

Table 23: SMECO Net Exports Paid VOS Case

		Residential Schedule R	Gen Service Non-Demand Schedule GSND	Gen Service Demand Schedule GSD	Large Power Schedule LP
Net Exports Paid VOS					
Current Distribution Vol. Rate	$/kWh	$ 0.0516	$ 0.0390	$ 0.0190	$ 0.0173
Current SOS Vol. rate	$/kWh	$ 0.0788	$ 0.0727	$ 0.0548	$ 0.0530
Combined Volumetric Rate	$/kWh	$ 0.1304	$ 0.1117	$ 0.0738	$ 0.0703
Cash Credit for all net exports	$/kWh	$ 0.0624	$0.0624	$0.0624	$0.0624
Distribution + SOS Net Cost per kWh existing NEM solar generation					
Current Rates	$/kWh	$ 0.0678	$ 0.0489	$ 0.0222	$ 0.0341
Net Exports Paid VOS	$/kWh	$ 0.0321	$ 0.0228	$ 0.0182	$ 0.0341
Total Distribution + SOS Net Cost					
Current Rates	$/000	2,915	13	65	79
Net Exports Paid VOS	$/000	1,382	6	53	79
Difference	$/000	(1,533)	(7)	(12)	(0)

Table 24: Choptank Net Exports Paid VOS Case

		Residential Schedule R	Comm Svc Schedule C	Gen Svc - Small Schedule S	Gen Svc - Med Schedule M	Primary Svc Schedule P
Net Exports Paid VOS						
Current Distribution Vol. Rate	$/kWh	$ 0.0485	$ 0.0521	$ 0.0294	$ 0.0279	$ 0.0139
Current SOS Vol. rate	$/kWh	$ 0.0864	$ 0.0854	$ 0.0614	$ 0.0592	$ 0.0554
Combined Volumetric Rate	$/kWh	$ 0.1349	$ 0.1375	$ 0.0908	$ 0.0870	$ 0.0693
Cash Credit for all net exports	$/kWh	$ 0.0625	$ 0.0625	$ 0.0625	$ 0.0625	$ 0.0625
Distribution + SOS Net Cost per kWh existing NEM solar generation						
Current Rates	$/kWh	$ 0.0724	$ 0.0750	$ 0.0307	$ 0.0312	$ 0.0213
Net Exports Paid VOS	$/kWh	$ 0.0283	$ 0.0338	$ 0.0158	$ 0.0189	$ 0.0166
Total Distribution + SOS Net Cost						
Current Rates	$/000	598	38	197	126	48
Net Exports Paid VOS	$/000	233	17	102	76	37
Difference	$/000	(364)	(21)	(96)	(50)	(11)

The bill impacts for the average customer with and without NEM are shown in the tables below. The bill impacts are much greater for NEM customers in all but the large power classes, reducing the cross subsidies for solar.

Table 25: SMECO Net Exports Paid VOS Bill impacts

		Residential Schedule R	Gen Service Non-Demand Schedule GSND	Gen Service Demand Schedule GSD	Large Power Schedule LP
Average Customer					
Monthly Bill, Current Rates	$/mo	$ 169.66	$ 160.93	$ 1,292.46	$ 23,316.26
Bill Increase with Net Export at VOS	$/mo	$ 0.80	$ 0.06	$ 0.65	$ 124.22
Adjusted Monthly Bill	$/mo	$ 170.46	$ 160.99	$ 1,293.11	$ 23,440.48
Average Customer with NEM					
Monthly Bill, Current Rates	$/mo	$ 28.13	$ 24.90	$ 512.55	$ 17,780.98
Bill Increase with Net Export at VOS	$/mo	$ 39.17	$ 31.96	$ 34.94	$ 98.88
Adjusted Monthly Bill	$/mo	$ 67.30	$ 56.86	$ 547.50	$ 17,879.86
Effective NEM Solar Compensation	*$/kWh*	*$ 0.095*	*$ 0.085*	*$ 0.086*	*$ 0.115*

Table 26: Choptank Net Exports Paid VOS Bill Impacts

		Residential Schedule R	Comm Svc Schedule C	Gen Svc - Small Schedule S	Gen Svc - Med Schedule M	Primary Svc Schedule P
Average Customer						
Monthly Bill, Current Rates	$/mo	$ 181.03	$ 189.75	$ 874.27	$ 4,685.09	$36,303.52
Bill Increase with Net Export at VOS	$/mo	$ 0.41	$ 0.40	$ 8.44	$ 43.16	$ 130.33
Adjusted Monthly Bill	$/mo	$181.44	$190.15	$882.72	$4,728.25	$36,433.85
Average Customer with NEM						
Monthly Bill, Current Rates	$/mo	$ 11.61	$ 18.91	$ 212.40	$ 922.18	$29,023.90
Bill Increase with Net Export at VOS	$/mo	$ 55.69	$ 51.43	$ 110.21	$ 516.60	$ 110.46
Adjusted Monthly Bill	$/mo	$ 67.30	$ 70.34	$ 322.61	$ 1,438.78	$29,134.36
Effective NEM Solar Compensation	*$/kWh*	*$ 0.091*	*$ 0.096*	*$ 0.079*	*$ 0.082*	*$ 0.116*

Case Study #2: NEM Solar Facilities Charge

The NEM statute expressly prohibits enacting special charges on NEM customer-generators in excess of charges that would apply to other members of the same rate class.[38] However, as an illustrative example we analyzed the impacts of a rate change in which the net costs of existing NEM solar were recovered through a facilities charge tied to the capacity of the installed system. In effect, this approach aligns solar compensation with the estimated value of solar without the need to separately meter total generation, provided that average capacity factors are relatively consistent across individual installations. This approach would likely require changes to MD Public Utility Code §7-306.

[38] MD Pub Util §7-306(e).

The tables below show the facilities charge per DC-rated kW of current NEM solar installations required to zero out the net cost of solar for each customer class. The values range from $2.55 to $7.77 per kW for SMECO and $3.46 to $8.45 per kW for Choptank. Policy support for solar could still be maintained using this approach by recovering something less than 100% of net costs through the facilities charge. We analyzed a fully loaded facilities charge to illustrate the higher end of the spectrum.

Table 27: SMECO NEM Facility Charge Case

		Residential Schedule R	Gen Service Non-Demand Schedule GSND	Gen Service Demand Schedule GSD	Large Power Schedule LP
NEM Facility Charge					
Net Cost of Existing NEM	$/000	$ (2,915)	$ (13)	$ (65)	$ (79)
Installed NEM Solar	kW-DC	31,260	188	2,119	1,688
Facility Charge to recover 100% net cost	$/kW-mo	$ 7.77	$ 5.61	$ 2.55	$ 3.91
Distribution + SOS Net Cost per kWh existing NEM solar generation					
Current Rates	$/kWh	$ 0.0678	$ 0.0489	$ 0.0222	$ 0.0341
NEM Facility Charge	$/kWh	$ -	$ -	$ -	$ -
Total Distribution + SOS Net Cost					
Current Rates	$/000	2,915	13	65	79
NEM Facility Charge	$/000	-	-	-	-
Difference	$/000	(2,915)	(13)	(65)	(79)

Table 28: Choptank Facility Charge Case

		Residential Schedule R	Comm Svc Schedule C	Gen Svc - Small Schedule S	Gen Svc - Med Schedule M	Primary Svc Schedule P
NEM Facility Charge						
Net Cost of Existing NEM	$/000	$ (598)	$ (38)	$ (197)	$ (126)	$ (121)
Installed NEM Solar	kW-DC	6,106	375	4,750	2,988	1,672
Facility Charge to recover 100% net cost	$/kW-mo	$ 8.16	$ 8.45	$ 3.46	$ 3.52	$ 6.02
Distribution + SOS Net Cost per kWh existing NEM solar generation						
Current Rates	$/kWh	$ 0.0724	$ 0.0750	$ 0.0307	$ 0.0312	$ 0.0534
NEM Facility Charge	$/kWh	$ -	$ -	$ -	$ -	$ -
Total Distribution + SOS Net Cost						
Current Rates	$/000	598	38	197	126	121
NEM Facility Charge	$/000	-	-	-	-	-
Difference	$/000	(598)	(38)	(197)	(126)	(121)

The bill impacts for the facilities charge approach are shown below. This mechanism does the most to reduce cross subsidies between non-participants and NEM customers.

Table 29: SMECO NEM Facility Charge Bill Impacts

		Residential Schedule R	Gen Service Non-Demand Schedule GSND	Gen Service Demand Schedule GSD	Large Power Schedule LP
Average Customer					
Monthly Bill, Current Rates	$/mo	$ 169.66	$ 160.93	$ 1,292.46	$ 23,316.26
Bill Increase with NEM Facility Charge	$/mo	$ -	$ -	$ -	$ -
Adjusted Monthly Bill	$/mo	$169.66	$ 160.93	$ 1,292.46	$ 23,316.26
Average Customer with NEM					
Monthly Bill, Current Rates	$/mo	$ 28.13	$ 24.90	$ 512.55	$ 17,780.98
Bill Increase with NEM Facility Charge	$/mo	$ 73.55	$ 59.55	$ 192.80	$ 1,651.69
Adjusted Monthly Bill	$/mo	$ 101.67	$ 84.46	$ 705.35	$ 19,432.67
Effective NEM Solar Compensation	*$/kWh*	*$ 0.063*	*$ 0.063*	*$ 0.068*	*$ 0.080*

Table 30: Choptank NEM Facility Charge Bill Impacts

		Residential Schedule R	Comm Svc Schedule C	Gen Svc - Small Schedule S	Gen Svc - Med Schedule M	Primary Svc Schedule P
Average Customer						
Monthly Bill, Current Rates	$/mo	$ 181.03	$ 189.75	$ 874.27	$ 4,685.09	$36,303.52
Bill Increase with NEM Facility Charge	$/mo	$ -	$ -	$ -	$ -	$ -
Adjusted Monthly Bill	$/mo	$181.03	$189.75	$874.27	$4,685.09	$36,303.52
Average Customer with NEM						
Monthly Bill, Current Rates	$/mo	$ 11.61	$ 18.91	$ 212.40	$ 922.18	$29,023.90
Bill Increase with NEM Facility Charge	$/mo	$ 90.95	$ 93.21	$ 218.15	$ 1,254.07	$ 3,356.47
Adjusted Monthly Bill	$/mo	$ 102.56	$ 112.12	$ 430.55	$ 2,176.25	$32,380.37
Effective NEM Solar Compensation	*$/kWh*	*$ 0.062*	*$ 0.062*	*$ 0.062*	*$ 0.062*	*$ 0.062*

4.4 Alternative Rate Design Approaches

Given the mismatches that exist between the value of solar and the compensation provided to NEM customers for solar output, it may be appropriate for the cooperatives to consider changes in rate design that will 1) equitably allocate the responsibility for the cooperative's costs among customers and 2) send an appropriate economic signal for determining whether to install solar facilities. Many other jurisdictions are wrestling with similar issues related to DER, and there is a growing body of theory and practical application for a variety of mechanisms to address NEM impacts.

In order to assist the cooperatives, the Commission and stakeholders in determining the appropriate rate design mechanism, if any, to address revenue sufficiency and cost shifting issues related to NEM, we have selected a few of the more commonly considered mechanisms and analyzed the cost and rate impacts on participants and non-participants. Our analysis is intended to supplement and extend the earlier Synapse report published in December, *Rate Design Impacts for Customers of Maryland's Electric Cooperatives*.[39]

4.4.1 Rate Design Study Assumptions

There are some common assumptions that are used throughout the rate design analysis. We focused on the customer classes for each cooperative that include NEM customers. SMECO customer classes studied were Residential (Schedule R), General Service Non-Demand (Schedule GSND), General Service Demand (GSD), and Large Power (Schedule LP). Choptank customer classes studied were Residential (Schedule R), Commercial Service (Schedule C), General Service – Small (Schedule S), General Service – Medium (Schedule M) and Primary Service (Schedule P).

We assumed existing rates based on current tariffs, without including the Purchased Power Cost Adjustment (PPCA) or the Bill Stabilization Adjustment that vary from month to month. Non-bypassable charges such as the Maryland Environmental Surcharge are included in the distribution rates. The tables below summarize the existing rates assumed in our analysis.

[39] Synapse Energy Economics, Inc. December 30, 2016. Rate Design Impacts for Customers of Maryland's Electric Cooperatives.

Table 31: SMECO Current Rate Structure

		Residential Schedule R	Gen'l Service Non-Demand Schedule GSND	Gen'l Service Demand Schedule GSD	Large Power Schedule LP
Distribution					
Customer Charge	$/cust-mo	$9.50	$22.24	$22.24	$47.54
USP Charge for average customer	$/cust-mo	$0.36	$2.66	$17.71	$177.07
Energy Rate (includes riders & taxes)	$/kWh	$0.0516	$0.0390	$0.0190	$0.0173
Demand Rate	$/kW-mo	n/a	n/a	$5.16	$5.02
Standard Offer Service					
SOS Summer Energy (May-Sep)	$/kWh	$0.0753	$0.0680	$0.0524	$0.0508
SOS Winter Energy (Oct-Apr)	$/kWh	$0.0813	$0.0760	$0.0567	$0.0547
SOS Demand	$/kW-mo	n/a	n/a	$5.89	$5.67

Table 32: Choptank Current Rate Structure

		Residential Schedule R	Comm Svc Schedule C	Gen Svc - Small Schedule S	Gen Svc - Med Schedule M	Primary Svc Schedule P
Distribution						
Customer Charge	$/cust-mo	$11.25	$16.25	$35.00	$43.75	$150.00
USP Charge for average customer	$/cust-mo	$0.36	$2.66	$17.71	$53.12	$177.07
Energy Rate (includes riders & taxes)	$/kWh	$0.0485	$0.0521	$0.0294	$0.0279	$0.0139
Demand Rate	$/kW-mo	n/a	n/a	$3.50	$3.70	$3.60
Standard Offer Service						
SOS Energy	$/kWh	$0.0864	$0.0854	$0.0614	$0.0592	$0.0554
SOS Demand	$/kW-mo	n/a	n/a	$6.27	$6.32	$10.04

Average customer profiles were provided by the cooperatives based on a 2015 SMECO test year and a 2012-2013 Choptank test year. Some billing determinants were determined based on historical data provided by the cooperatives.[40] No data on 15-minute demand billing determinants was provided, so we assumed the average customer's 15-minute maximum demand is 20% greater than the maximum hourly class peak load divided by total customers in each class. In our judgment this is a conservative estimate of the relationship between individual customers' maximum 15-minute demand and class hourly non-coincident peaks.

[40] SMECO Response to Commission 3.2.1 Data Request 1-4; Choptank Response to Commission 3.2.1 Data Request 1-8.

Table 33: SMECO Average Customer Profile by class

		Residential Schedule R	Gen Service Non-Demand Schedule GSND	Gen Service Demand Schedule GSD	Large Power Schedule LP
Average Customer Profile					
Monthly Usage	kWh	1,225	1,218	12,024	237,020
Avg 15-minute Max Demand	kW	3.9	3.2	33.0	601.8
Monthly Bill	$	$ 170	$ 161	$ 1,292	$ 23,316
Total Customers in Class	cust	147,775	8,246	6,831	54

Table 34: Choptank Average Customer Profile by class

		Residential Schedule R	Comm Svc Schedule C	Gen Svc - Small Schedule S	Gen Svc - Med Schedule M	Primary Svc Schedule P
Average Customer Profile						
Monthly Usage	kWh	1,256	1,243	7,103	40,160	306,071
Avg 15-minute Max Demand	kW	3.8	3.3	18.1	109.1	1,082.8
Monthly Bill	$	$ 181	$ 190	$ 874	$ 4,685	$ 36,304
Total Customers in Class	cust	47,770	3,600	1,078	156	25

We also developed assumptions about average customers installing NEM solar for each rate class. The tables below summarize NEM solar installation as of late 2016.

Table 35: SMECO NEM Solar Installations as of September 2016

SMECO PV Installations	Residential Schedule R	Gen Service Non-Demand Schedule GSND	Gen Service Demand Schedule GSD	Large Power Schedule LP
Customers with NEM Systems	3,303	9	28	4
Installed kW (DC)	31,260	188	2,119	1,688
Average Size per Install (kW-DC)	9.5	20.9	75.7	422.1

Table 36: Choptank NEM Solar Installations as of November 2016

Choptank PV Installations	Residential Schedule R	Comm Svc Schedule C	Gen Svc - Small Schedule S	Gen Svc - Med Schedule M	Primary Svc Schedule P
Customers with NEM Systems	511	16	28	6	3
Installed kW (DC)	6,106	375	4,750	2,988	1,672
Average Size per Install (kW-DC)	11.9	23.4	169.7	497.9	557.3

Neither cooperative could provide information on the usage profile of customers installing NEM solar.[41] To develop a NEM customer profile for analytical purposes we

[41] See SMECO and Choptank Responses to Commission 3.2.2 Data Request 1-2.

assumed that the average customer installs the average NEM solar system. If this assumption yielded a NEM customer shape with excess net generation on an annual basis, we reduced the size of the assumed solar installation to balance usage and net generation (exports) on an annual basis. The tables below depict the assumed NEM customer profiles and monthly bills under current rates for each cooperative.

Table 37: SMECO Assumed NEM Customer Profile by class

		Residential Schedule R	Gen Service Non-Demand Schedule GSND	Gen Service Demand Schedule GSD	Large Power Schedule LP
Average NEM Customer Profile					
Solar Install Size	kW-DC	9.5	10.6	75.7	422
Monthly Total Generation	kWh	1,085	1,218	8,676	48,396
Monthly Usage	kWh	709	647	6,370	188,627
Monthly Exports	kWh	(569)	(647)	(3,022)	(3)
Net Billed Monthly Usage	kWh	140	0	3,348	188,624
Avg 15-min Max Demand	kW	3.6	2.2	20.4	402.2
Monthly Average Bill	$/mo	$ 28	$ 25	$ 513	$ 17,781
Monthly Average NEM Savings	$/mo	$ (142)	$ (136)	$ (780)	$ (5,535)
	%	-83%	-85%	-60%	-24%
Effective NEM Solar Compensation	*$/kWh*	*$ 0.130*	*$ 0.112*	*$ 0.090*	*$ 0.114*

Table 38: Choptank Assumed NEM Customer Profile by class.

		Residential Schedule R	Comm Svc Schedule C	Gen Svc - Small Schedule S	Gen Svc - Med Schedule M	Primary Svc Schedule P
Average NEM Customer Profile						
Solar Install Size	kW-DC	11.1	11.0	63.0	356.4	557.3
Monthly Total Generation	kWh	1,256	1,243	7,103	40,160	62,799
Monthly Usage	kWh	766	683	3,736	20,146	244,221
Monthly Exports	kWh	(766)	(683)	(3,736)	(20,146)	(948)
Net Billed Monthly Usage	kWh	0	0	0	0	243,272
Avg 15-min Max Demand	kW	3.7	3.0	16.3	82.4	868.1
Monthly Average Bill	$/mo	$ 12	$ 19	$ 212	$ 922	$ 29,024
Monthly Average NEM Savings	$/mo	$ (169)	$ (171)	$ (662)	$ (3,763)	$ (7,280)
	%	-94%	-90%	-76%	-80%	-20%
Effective NEM Solar Compensation	*$/kWh*	*$ 0.135*	*$ 0.137*	*$ 0.093*	*$ 0.094*	*$ 0.116*

4.4.2 Alternative Rate Design Case Studies

Base Case: No Change

As a baseline case, we first assume no rate design change. In this case, the lost revenue from NEM customers net of the quantified benefits of solar generation are assumed to be recovered through an increase to the volumetric (energy) rate in each customer class. The rate increase required to recover the net cost of NEM was shown in Table 18 and Table 19 in Section 4.1 above. The tables below show how these rate increases would translate into bill impacts for participants and non-participants. Due to the significant reduction in billed usage for NEM customers, the bill impacts are greater on an average bill basis for non-participants.

Table 39: SMECO Bill Impacts from NEM Net Cost Recovery through Energy Rate

		Residential Schedule R	Gen Service Non-Demand Schedule GSND	Gen Service Demand Schedule GSD	Large Power Schedule LP
Energy Rate Increase for NEM	$/kWh	0.0014	0.0001	0.0001	0.0005
Average Customer					
Monthly Bill, Current Rates	$/mo	$ 169.66	$ 160.93	$ 1,292.46	$ 23,316.26
Bill Increase with volumetric adj.	$/mo	$ 1.68	$ 0.13	$ 0.79	$ 124.23
Adjusted Monthly Bill	$/mo	$ 171.34	$ 161.06	$ 1,293.26	$ 23,440.48
Average Customer with NEM					
Monthly Bill, Current Rates	$/mo	$ 28.13	$ 24.90	$ 512.55	$ 17,780.98
Bill Increase with volumetric adj.	$/mo	$ 0.19	$ 0.00	$ 0.22	$ 98.86
Adjusted Monthly Bill	$/mo	$ 28.32	$ 24.90	$ 512.77	$ 17,879.84
Effective NEM Solar Compensation	*$/kWh*	*$ 0.132*	*$ 0.112*	*$ 0.090*	*$ 0.115*

Table 40: Choptank Bill Impacts from NEM Net Cost Recovery through Energy Rate

		Residential Schedule R	Comm Svc Schedule C	Gen Svc - Small Schedule S	Gen Svc - Med Schedule M	Primary Svc Schedule P
Energy Rate Increase for NEM	$/kWh	0.0008	0.0007	0.0023	0.0018	0.0014
Average Customer						
Monthly Bill, Current Rates	$/mo	$ 181.03	$ 189.75	$ 874.27	$ 4,685.09	$ 36,303.52
Bill Increase with volumetric adj.	$/mo	$ 1.06	$ 0.89	$ 16.39	$ 71.29	$ 420.12
Adjusted Monthly Bill	$/mo	$ 182.09	$ 190.64	$ 890.67	$ 4,756.38	$ 36,723.64
Average Customer with NEM						
Monthly Bill, Current Rates	$/mo	$ 11.61	$ 18.91	$ 212.40	$ 922.18	$ 29,023.90
Bill Increase with volumetric adj.	$/mo	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 333.92
Adjusted Monthly Bill	$/mo	$ 11.61	$ 18.91	$ 212.40	$ 922.18	$ 29,357.82
Effective NEM Solar Compensation	*$/kWh*	*$ 0.136*	*$ 0.138*	*$ 0.095*	*$ 0.095*	*$ 0.117*

Case Study #3: Increased Fixed Charge

Generally speaking, a customer charge or fixed charge is a standard portion of a monthly bill reflecting the fixed costs of the utility to provide service. This charge typically includes utility costs related to existing infrastructure, maintenance, and administrative overhead.

In most jurisdictions, some fixed costs of providing retail service are also recovered in a volumetric distribution charge based on kWh consumption. When customers reduce their consumption, the utility must recover additional revenues to fully recover their fixed costs.

The Synapse report has provided analysis of significantly increasing the fixed charges for the SMECO and Choptank residential classes. We will not repeat the Synapse analysis here. As an alternative to the status quo case above in which the net cost of existing NEM solar installations (as of fall 2016) is assumed to be collected through an increase in the volumetric charge, this case assumes that the shortfall is collected through an increase to the customer charge.

Table 41: SMECO fixed charge increases to recover net cost of existing NEM solar

		Residential Schedule R	Gen Service Non-Demand Schedule GSND	Gen Service Demand Schedule GSD	Large Power Schedule LP
Net cost of Existing NEM	$/000	$ (2,915)	$ (13)	$ (65)	$ (79)
Current Fixed Charge (excl. USP)	$/cust-mo	$ 9.50	$ 22.24	$ 22.24	$ 47.54
Fixed Charge Increase Required	$/cust-mo	$ 1.64	$ 0.13	$ 0.79	$ 122.35

Table 42: Choptank fixed charge increases to recover net cost of existing NEM solar

		Residential Schedule R	Comm Svc Schedule C	Gen Svc - Small Schedule S	Gen Svc - Med Schedule M	Primary Svc Schedule P
Net cost of Existing NEM	$/000	$ (598)	$ (38)	$ (197)	$ (126)	$ (121)
Current Fixed Charge (excl. USP)	$/cust-mo	$ 11.25	$ 16.25	$ 35.00	$ 43.75	$ 150.00
Fixed Charge Increase Required	$/cust-mo	$ 1.04	$ 0.88	$ 15.25	$ 67.46	$ 409.60

Recovering the net costs of NEM solar through the fixed charge rather than the volumetric rate eliminates the disparity in bill impacts between NEM customers and non-participants. However, it would cause greater impacts (on a bill percentage basis) for low usage non-participants relative to higher usage non-participants.

Case Study #4: Winter Time of Use Distribution Rates

Time variant rates apply different rates to usage based on the time at which the customer uses the energy. Time variant rates recognize that there can be different cost structures – both on an embedded and on a marginal basis – to provide power at different times of the day and times of the year. Examples include time of use rates (TOU), seasonal rates, critical peak pricing (CPP) and real time pricing (RTP). All of these methods are intended to provide customers with better price information allowing the customer to make better decisions about consumption. This approach can provide significantly better alignment of rates with both marginal and embedded costs of producing power.

According to our analysis, DER solar does not provide quantifiable benefits to offset revenue requirements that are recovered through distribution service rates. These costs are typically either fixed or driven by customer counts or equipment needed to serve system peak load on the distribution system. SMECO is a strongly winter-peaking system, with recent annual system peaks occurring in January or February before 8:00am. It may be appropriate for SMECO to consider a time of use (TOU) distribution rate that places a premium on usage during winter peak hours.

As a case study, we analyzed a TOU rate with winter peak and off-peak periods coinciding with SMECO's 2014 proposal. The winter season extends from October through April, and peak hours are 6:00 to 10:00am and 5:00 to 9:00pm. During the summer season a flat rate remains in place at the current distribution rate. In the winter, we tested a TOU rate with peak period rates double the current rate. Off peak rates were then solved for to collect the appropriate revenue requirements despite the loss of sales due to NEM self-supply. The winter off-peak rate was less than half of the original flat volumetric rate for all classes. The off peak rates must at least be high enough to collect the appropriate non-bypassable fees and riders.

The tables below show our winter TOU case study for SMECO. With a winter TOU distribution rate design, each class sees its net cost of solar generation decline by 58% to 100%. In total, distribution-related net costs drop 98% from $2.37 to $0.4 million.

Table 43: SMECO Winter TOU Distribution Rate Example

		Residential Schedule R	Gen Service Non-Demand Schedule GSND	Gen Service Demand Schedule GSD	Large Power Schedule LP
Winter TOU Distribution Rate					
Summer Flat Rate (current)	$/kWh	$ 0.0516	$ 0.0390	$ 0.0190	$ 0.0173
Winter Peak Rate	$/kWh	$ 0.1032	$ 0.0779	$ 0.0380	$ 0.0345
Winter Peak Rate	$/kWh	$ 0.0227	$ 0.0188	$ 0.0089	$ 0.0085
Average distribution net cost per kWh existing NEM solar generation					
Current Rates	$/kWh	$ 0.0516	$ 0.0390	$ 0.0241	$ 0.0296
Winter TOU Rate	$/kWh	$ -	$ -	$ 0.0051	$ 0.0124
Total Distribution Net Cost					
Current Rates	$/000	$ 2,220	$ 10	$ 70	$ 69
Winter TOU Rate	$/000	$ -	$ -	$ 15	$ 29
Difference	$/000	$ (2,220)	$ (10)	$ (55)	$ (40)

The winter TOU rate also reduces potential cross subsidy issues by increasing revenue collection from NEM customers relative to non-participants. The table below shows expected bill impacts of the Winter TOU rate on average customers with and without NEM solar.

Table 44: SMECO Winter TOU bill impacts

		Residential Schedule R	Gen Service Non-Demand Schedule GSND	Gen Service Demand Schedule GSD	Large Power Schedule LP
Average Customer					
Monthly Bill, Current Rates	$/mo	$ 169.66	$ 160.93	$ 1,292.46	$ 23,316.26
Bill Increase with TOU	$/mo	$ 1.11	$ 0.05	$ 0.61	$ 56.25
Adjusted Monthly Bill	$/mo	$ 170.77	$ 160.98	$ 1,293.07	$ 23,372.51
Average Customer with NEM					
Monthly Bill, Current Rates	$/mo	$ 28.13	$ 24.90	$ 512.55	$ 17,780.98
Bill Increase with TOU	$/mo	$ 7.82	$ 5.14	$ 18.52	$ 137.84
Adjusted Monthly Bill	$/mo	$ 35.94	$ 30.04	$ 531.07	$ 17,918.82
Effective NEM Solar Compensation	*$/kWh*	*$ 0.124*	*$ 0.108*	*$ 0.088*	*$ 0.113*

Case #4: Demand Charges

Demand charges are assessed based on a customer's maximum demand, usually averaged over no more than 15 minutes to an hour, at any time during the billing period.[42] Demand charges are typically designed to recover costs that are incurred to serve the maximum system loads on peak days, regardless of total energy needs the rest of the year. Demand charges are most common in commercial and industrial rate classes, and relatively rare in residential rate classes. Maryland's cooperatives currently include demand charges only for their larger general service and large power customer classes.

Maryland's cooperatives might consider an increased reliance on demand charges to address cross subsidy and revenue adequacy challenges associated with NEM solar. Depending on a customer's usage profile, NEM solar may do relatively little to offset a customer's monthly demand. Increasing reliance on demand charges in rate design often has a strong cost basis and limits the net revenue loss caused by increasing NEM solar penetration. There are significant challenges to implementing demand charges in the residential and small commercial classes that may make this approach unattractive at current, relatively low levels of solar penetration. Nevertheless, other jurisdictions are beginning to consider and implement demand charge rates in the "mass-market" classes in response to DER issues.[43]

As a case study, we considered significant distribution demand charge increases or introduced rates for each class. We assume incremental demand charges of $3.00 per kW for all SMECO rate classes and $2.00 per kW for all Choptank rate classes. These incremental demand charges are roughly 50% increases over current rates for customer classes with existing demand charges.

42 Some variants of demand charges measure maximum demand at specific times, such as the hour of system peak. We consider the more common approach that measures a customer's maximum demand at any time over the billing period.

43 Rocky Mountain Institute, May 2016. A Review of Alternative Rate Designs. www.RMI.org/Alternative_Rate_Designs, at p 49.

Table 45: SMECO Demand Charge Case Study

		Residential Schedule R	Gen Service Non-Demand Schedule GSND	Gen Service Demand Schedule GSD	Large Power Schedule LP
Demand Charge Increase Example Rate					
Current Distrib. Demand Charge	$/kW-mo	$ -	$ -	$ 5.16	$ 5.02
New Distrib. Demand Charge	$/kW-mo	$ 3.00	$ 3.00	$ 8.16	$ 8.02
Current Distrib. Energy Rate	$/kWh	$ 0.0516	$ 0.0390	$ 0.0190	$ 0.0173
New Distrib. Energy Rate	$/kWh	$ 0.0430	$ 0.0311	$ 0.0108	$ 0.0101
Average distribution net cost per kWh existing NEM solar generation					
Current Rates	$/kWh	0.0516	0.0390	0.0241	0.0296
Demand Charge Increase	$/kWh	0.0423	0.0297	0.0028	(0.0096)
Total Distribution Net Cost					
Current Rates	$/000	2,220	10	70	69
Demand Charge Increase	$/000	1,820	8	8	(22)
Difference	$/000	(399)	(2)	(62)	(91)

Table 46: Choptank Demand Charge Case Study

		Residential Schedule R	Comm Svc Schedule C	Gen Svc - Small Schedule S	Gen Svc - Med Schedule M	Primary Svc Schedule P
Demand Charge Increase Example Rate						
Current Distrib. Demand Charge	$/kW-mo	$ -	$ -	$ 3.50	$ 3.70	$ 3.60
New Distrib. Demand Charge	$/kW-mo	$ 2.00	$ 2.00	$ 5.50	$ 5.70	$ 5.60
Current Distrib. Energy Rate	$/kWh	$ 0.0485	$ 0.0521	$ 0.0294	$ 0.0279	$ 0.0139
New Distrib. Energy Rate	$/kWh	$ 0.0430	$ 0.0472	$ 0.0263	$ 0.0240	$ 0.0075
Average distribution net cost per kWh existing NEM solar generation						
Current Rates	$/kWh	0.0485	0.0521	0.0303	0.0303	0.0262
Demand Charge Increase	$/kWh	0.0430	0.0467	0.0249	0.0202	(0.0116)
Total Distribution Net Cost						
Current Rates	$/000	400	26	195	123	59
Demand Charge Increase	$/000	355	24	160	81	(26)
Difference	$/000	(46)	(3)	(35)	(41)	(86)

The modeled demand charge increases would reduce net distribution costs by about 23%, or about $0.6 million across all classes for SMECO. It would reduce net distribution costs by 26%, or about $0.2 million across all classes for Choptank.

Table 47: SMECO Demand Charge Bill Impacts

		Residential Schedule R	Gen Service Non-Demand Schedule GSND	Gen Service Demand Schedule GSD	Large Power Schedule LP
Average Customer					
Monthly Bill, Current Rates	$/mo	$ 169.66	$ 160.93	$ 1,292.46	$ 23,316.26
Bill Increase with Dmd Inc.	$/mo	$ 1.06	$ 0.08	$ 0.67	$ 107.03
Adjusted Monthly Bill	$/mo	$170.72	$ 161.02	$ 1,293.13	$ 23,423.28
Average Customer with NEM					
Monthly Bill, Current Rates	$/mo	$ 28.13	$ 24.90	$ 512.55	$ 17,780.98
Bill Increase with Dmd Inc.	$/mo	$ 10.03	$ 7.22	$ 34.68	$ (139.92)
Adjusted Monthly Bill	$/mo	$ 38.16	$ 32.12	$ 547.23	$ 17,641.06
Effective NEM Solar Compensation	*$/kWh*	*$ 0.122*	*$ 0.106*	*$ 0.086*	*$ 0.119*

Table 48: Choptank Demand Charge Bill Impacts

		Residential Schedule R	Comm Svc Schedule C	Gen Svc - Small Schedule S	Gen Svc - Med Schedule M	Primary Svc Schedule P
Average Customer						
Monthly Bill, Current Rates	$/mo	$ 181.03	$ 189.75	$ 874.27	$ 4,685.09	$ 36,303.52
Bill Increase with Dmd Inc.	$/mo	$ 0.62	$ 0.56	$ 13.71	$ 59.92	$ 204.44
Adjusted Monthly Bill	$/mo	$ 181.65	$ 190.31	$ 887.98	$ 4,745.01	$ 36,507.96
Average Customer with NEM						
Monthly Bill, Current Rates	$/mo	$ 11.61	$ 18.91	$ 212.40	$ 922.18	$ 29,023.90
Bill Increase with Dmd Inc.	$/mo	$ 7.46	$ 6.01	$ 32.69	$ 164.73	$ 177.44
Adjusted Monthly Bill	$/mo	$ 19.07	$ 24.92	$ 245.10	$ 1,086.91	$ 29,201.34
Effective NEM Solar Compensation	*$/kWh*	*$ 0.129*	*$ 0.133*	*$ 0.091*	*$ 0.091*	*$ 0.116*

Incremental reliance on demand charges would significantly reduce cross subsidies from non-participants to NEM customers, particularly in the residential and small commercial classes where the cross subsidy effects are currently most acute.

4.5 Summary of Residential Class Impacts

The majority of NEM customer-generators are residential customers, accounting for nearly three quarters of installed DER solar capacity across the two cooperatives. For simplicity, we focus our summary of various rate design case studies within this critical rate class.

We have presented three key issues for which increasing penetration of DER will require careful balancing of sometimes competing objectives: revenue sufficiency, fairness of cost allocation, and policy priorities/societal benefits. We revisit these issues now with the case study approaches presented above, focusing on the residential class.

4.5.1 Revenue Sufficiency

In this analysis, we assumed that rates would be adjusted to ensure that pre-NEM revenues levels are maintained even after losing sales due to self-supply. Typically, revenue requirements are determined as part of a rate case prior to beginning rate design, so this assumption ensures that rate designs are compared on an "equal footing". This summary analysis focuses only on distribution charge revenues. Any net revenue loss after the rate design change in focus was assumed to be collected through a uniform increase in the volumetric rate, similar to a rate decoupling mechanism. The net distribution revenue shortfall to be recovered through rate adjustments is currently \$2.2 million for SMECO and \$0.4 million for Choptank residential classes.

4.5.2 Fairness of Cost Allocation

In order to compare intra-class cross subsidies in the residential classes for our various rate design examples, we analyzed the breakdown between total billing revenue increases for NEM customer-generators versus non-participants relative to maintaining current rates. Based on our conclusion that reductions in distribution charge revenues are not offset by any direct avoided cost to the cooperatives, a cross subsidy occurs when non-participants help recover those lost revenues to any extent. The charts below show the relative degree of cross subsidy that occurs in each rate design (based on the many assumptions detailed in the descriptions of the case studies above), with the highest cross subsidies occurring with a simple volumetric rate adjustment, and cross subsidies eliminated with the fully-loaded NEM facility charge.

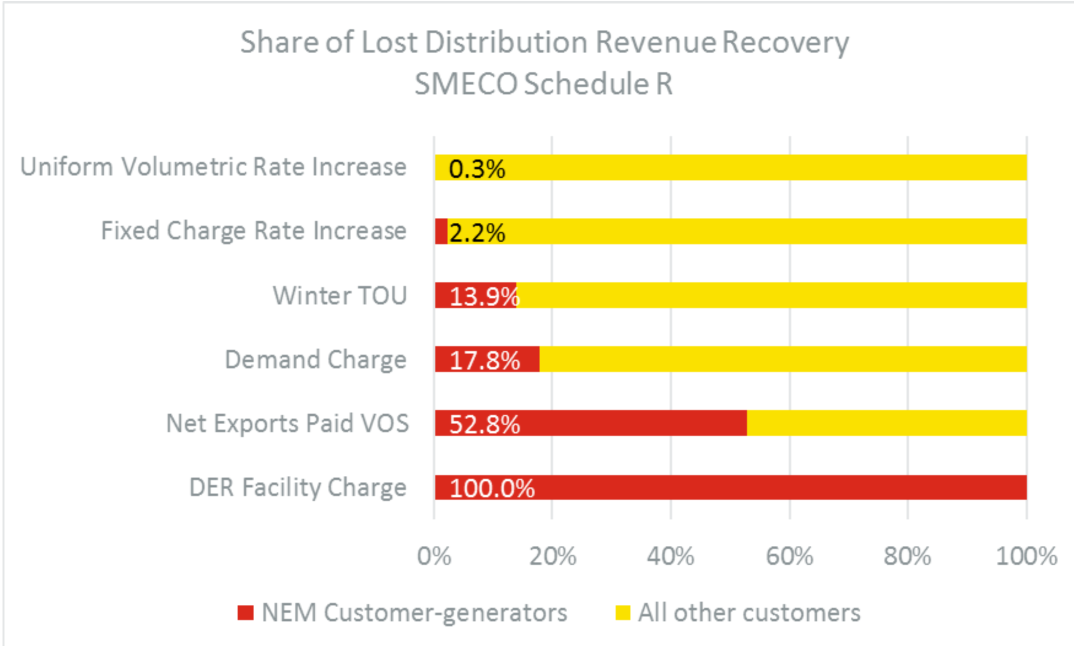

Figure 30: SMECO Residential Class NEM/Non-participant Share of Lost Distribution Revenue Recovery by Rate Design Case Study

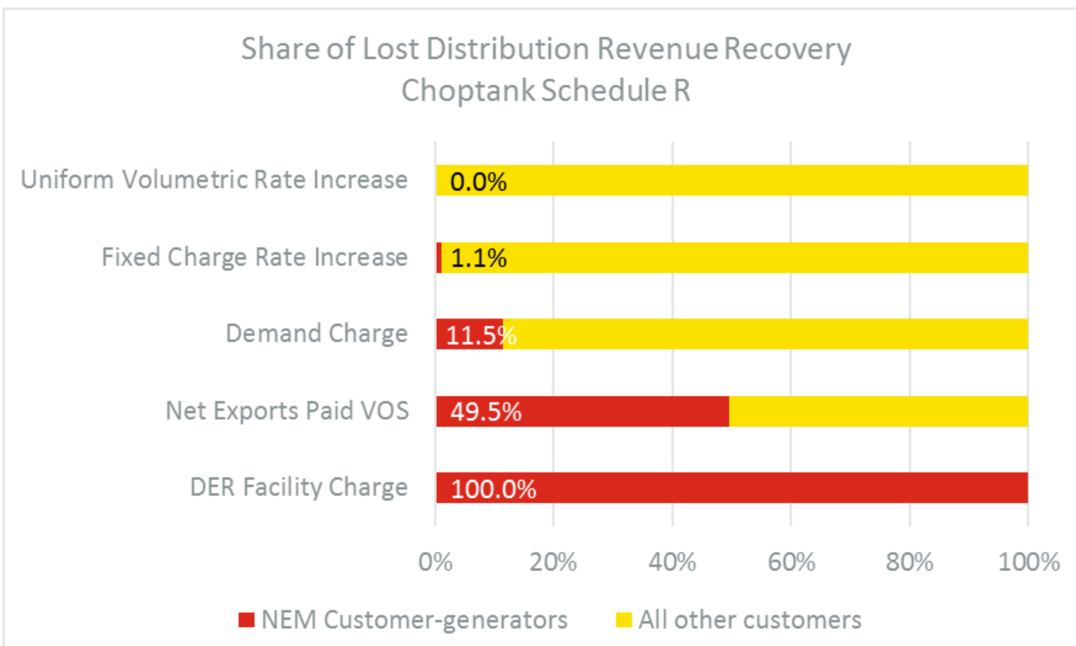

Figure 31: Choptank Residential Class NEM/Non-participant Share of Lost Distribution Revenue Recovery by Rate Design Case Study

4.5.3 Policy Priorities and Societal Benefits

We have previously discussed the many reasons that the Commission, policymakers and some stakeholders may value solar above its direct cost of service impacts to the cooperatives. For this reason, it is also important to examine the various rate design case studies from the perspective of how well they might incentivize further development of solar. In Section 3.4 we explored the levelized cost of energy for residential solar installed in 2018, as well as some of the additional revenue streams and incentives available to solar developers in addition to NEM rate treatment. The figures below show that with SRECs at the average 2016 level, the status quo and four of the rate design options analyzed earlier in this report would provide enough compensation to solar customers to incent solar development. Two of the options, compensating net exports at the value of solar rate or instituting a DER facilities charge would not provide the necessary compensation to incent solar development.

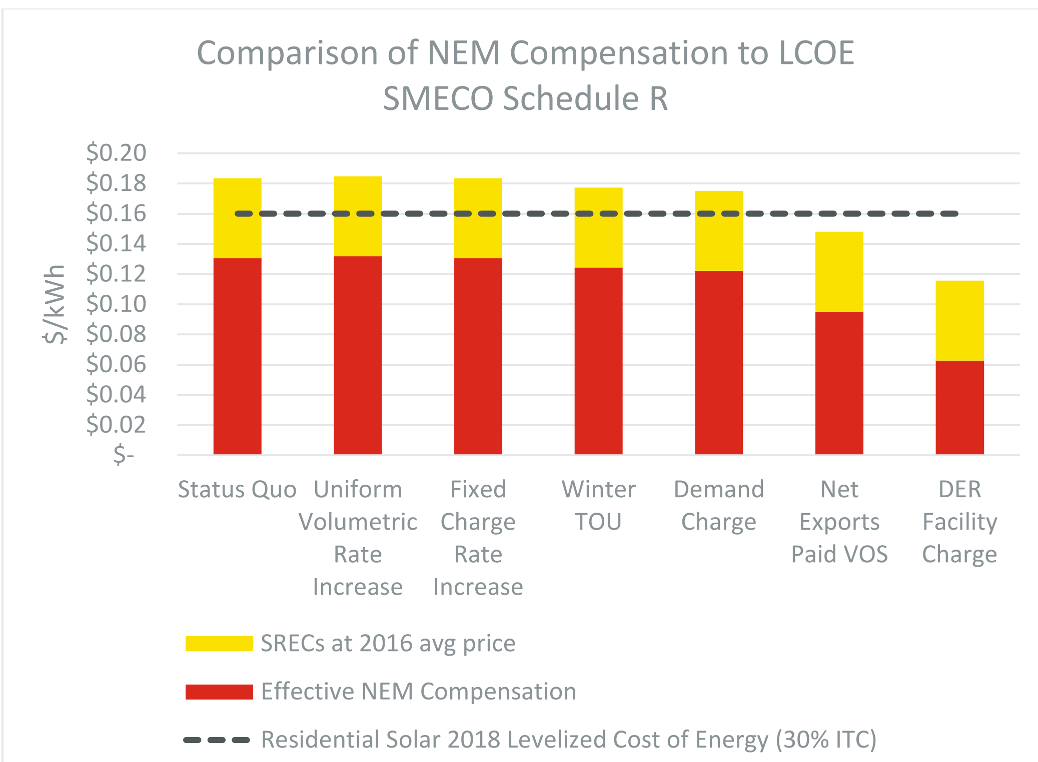

Figure 32: SMECO Residential Class, Comparison of NEM Compensation to LCOE

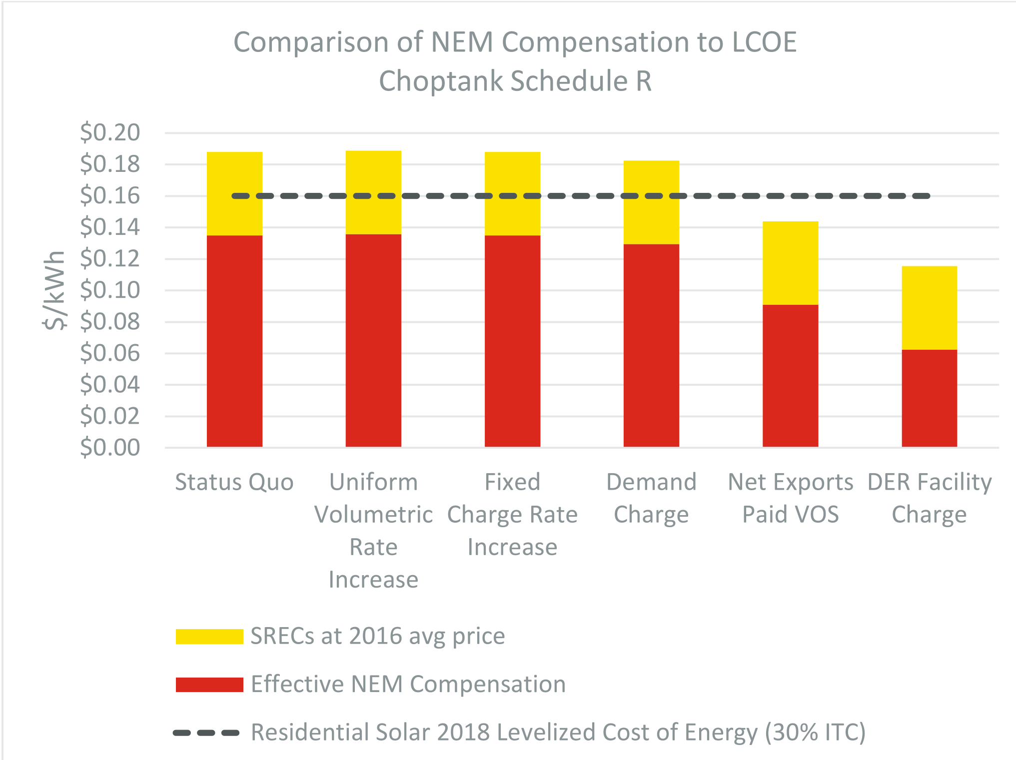

Figure 33: Choptank Residential Class, Comparison of NEM Compensation to LCOE

Predictably, there is an inverse relationship between the rate design approaches that address cross subsidy issues and the approaches that best support solar development. This provides a good example of trade-offs that must be weighed in determining appropriate rate design.

BEFORE THE PUBLIC SERVICE
COMMISSION OF MARYLAND

IN THE MATTER OF THE EXPLORATION INTO THE BENEFITS AND COSTS OF DISTRIBUTED SOLAR AND THE ASSOCIATED POTENTIAL RATE DESIGN OPTIONS APPLICABLE TO THE SERVICE TERRITORIES OF THE MARYLAND ELECTRIC COOPERATIVES	* * * *	Administrative Docket PC 48

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COMMENTS OF SOUTHERN MARYLAND ELECTRIC COOPERATIVE AND CHOPTANK ELECTRIC COOPERATIVE ON THE VALUE OF SOLAR REPORT PREPARED BY DAYMARK ENERGY ADVISORS

Southern Maryland Electric Cooperative ("SMECO") and Choptank Electric Cooperative ("Choptank") (collectively the "Cooperatives") provide these comments on the Value of Solar Report produced by Daymark Energy Advisors (the "Report") in response to the Commission's February 24, 2017 Notice of Public Conference and Opportunity to Comment.

Introduction

The Cooperatives welcome Public Conference 48 as a long-overdue reckoning as to the actual, calculable value of solar for the purpose of establishing appropriate electric rates. For much of the last decade the understandable zeal for encouraging and incentivizing solar has led to a cart-before-horse approach, where stakeholders advanced their relative positions using qualitative, rather than quantitative assessments. Maryland experienced this first with net metering, then virtual aggregate net metering, and most recently with community solar. In each case the rates established – equal to full retail rates in each instance – were policy driven, intended to promote the particular program instead of reflecting the particular resource's actual value to the system. This approach has undeniably contributed to solar's explosive growth; but, it has also resulted in rate distortion and cost-shifting that is unfair to certain customers and customer groups, probably unsustainable, inconsistent with the federal Public Utility Regulatory Policies Act ("PURPA") and its implementing regulations, and likely unnecessary going forward.

The timing is fortuitous. Current solar penetration is shown to be 28 MW and 16.4 MW[1] in SMECO and Choptank's service territories, respectively, and Daymark claims the potential additions at an extraordinary 1315 MW and 923 MW. In a scheme already revealing inequities at current levels, it is imperative that proper valuation and rate adjustments occur now to discipline the market in a non-discriminatory and equitable way.

Daymark's report provides a solid foundation for beginning this discussion in earnest. The Cooperatives agree with and support Daymark's calculations for core components including capacity, transmission and distribution. However, as the Cooperatives' comments below explain, there are important adjustments and recalculations that are needed before the Commission and stakeholders will have in hand an objective and correctly calculated value of solar that will then facilitate a truly transparent and fully-informed policy debate over solar compensation rate structures. At this point the time has come for rate reform.

[1] This is the total installed net metered solar for Choptank as of November 2016. Rpt. Table 2 at 23 shows current residential installed capacity for Choptank as 5.55 MW.

Comments

Daymark's summary findings are generally consistent with the Cooperatives' own conclusions, *i.e.*,

> that the current compensation approach in Maryland may overcompensate distributed generation customers when the direct costs and benefits of the cooperatives alone are considered. Incorporating societal emission costs in the analysis improves the situation but overcompensation may still be the case.[2]

And Daymark has correctly captured the core elements for the value of solar, *i.e.*, capacity, energy, transmission and distribution. The Cooperatives' disagreement is largely one of degree, though it starts with Daymark's equivocal use of "may." It is a simple matter of math to see that Daymark's own numbers show costs outstripping benefits. But beyond semantics, more important is that several of Daymark's assumptions have resulted in an understatement of the distributed generation subsidy for capacity and energy. Additionally, the majority of the benefit components Daymark considered do not accrue to cooperative members in their capacity as ratepayers. Considering factors like job and water impacts effectively puts a thumb on the scale on the side of benefits and contradicts more than a century of accepted rate design principles.

A. The Report overstates actual avoided costs.

Several errors within the Report lead to a substantial overstatement of actual avoided costs. These include Daymark's assumptions for array orientation, the impact of temperature on output, summer peak month and hour selection, and the use of market-based capacity value as the basis for avoided capacity. Individually these issues are significant; cumulatively they result in a seriously inaccurate net increase in solar's value within the Cooperatives' territories.

[2] Value of Solar Report, Daymark Energy Advisors (hereinafter "Rpt.") at 5.

Perhaps the most significant error stems from Daymark's unverified assumption that residential rooftop solar is optimally-sited facing south. SMECO has a sample of over 2400 customers out of 3300 installed units with the actual orientation data. From that sample the average panel tilt is 28 degrees, not the 30 degrees assumed by the Report. The range of panel tilt is from 5 to 80 degrees. The range of azimuth is from a low of 7 degrees to a high of 323. Using 180 degrees for estimating energy results in more kWh than can possibly be produced by SMECO distributed generation solar customers because 180 degrees represents the maximum kWh output, and any azimuth that differs from the maximum produces fewer kWh. Rather than relying on SMECO's data, Daymark elected to assume the orientation most favorable to solar output, resulting in the highest value of solar. This input is so critical to the value of calculations for both avoided energy costs and avoided capacity costs that any deviation from known data would have demanded empirical testing to determine the actual values for energy and capacity.

The consequence of this faulty assumption is an overstatement of not only avoided capacity costs but also both the magnitude and the hours of solar production. The magnitude of the kWh error increases production by over 21% compared to the simple average of 90 degrees and 270 degrees at the SMECO panel tilt of 28 degrees and by over 24% at the tilt used by Daymark of 30 degrees using the same PVWatts data. The average azimuth of 180 degrees cannot be used for the Cooperatives' systems. It is particularly critical for the production in the afternoon hours for the summer peak because kW output in the Daymark report is higher during peak hours than the actual combination of tilt and azimuth without adjusting for temperatures that are expected under peak conditions.

Additionally, Daymark has used load shape data that fail to properly reflect the impact of temperature on rooftop solar DG output. Under extreme temperature conditions solar output is reduced by about 0.4 to 0.5% per degree Celsius for temperatures above 25 degrees Celsius (about 77 degrees Fahrenheit); likewise output increases by this same amount when temperature is below 25 degrees Celsius.

For example, the maximum temperature modeled in the production data is a temperature of 94 degrees Fahrenheit between 3:00 and 4:00 p.m. in June and August. In 2012 the highest summer temperature recorded at Andrews AFB was 102 degrees Fahrenheit (38.9 degrees Celsius) at 17:00 in July. Panel temperatures will likely be even higher than the ambient temperature. Over the five year period 2012-2016 the annual average days above 94 degrees Fahrenheit has been just over 20 hours. The report at page 9 seems to acknowledge this issue when they state “the variability between certain months and seasons throughout multiple years would have the potential to be greater.” Still, no attempt was made to adjust the load shape for the impact these higher temperatures have solar output.

Next, Daymark’s assumptions for both the summer peak valuation hours and months are incorrect. The Report uses 2:00 p.m. through 5:00 p.m. instead of the PJM requirement of 3:00 p.m. through 6:00 p.m. And contrary to PJM’s Manual 21 definition of the Summer period for determining solar and wind capacity (June-July-August), Daymark also includes September as a summer month. The result is an overstatement of the value of the summer peak contribution for SMECO and Choptank. This is a meaningful error that gets compounded by other errors such as the loss multiplier and the reserve adjustment for capacity value that already included reserves in the auction.

This is further compounded by the failure to recognize that the avoided peak capacity of solar that occurs at a design day peak temperature in the summer has not been used along with the correct load shape data. Nor does the Report account for the utility peak summer load trend to a later hour as shown on Table 9 in the Report where 15 of the 20 hourly peaks occurred in hours ending 5:00 and 6:00 p.m. For SMECO, five of its PJM system peak days occurred at hours ending 6:00 and 7:00 p.m., and on three of those days the maximum summer system peak occurred at 7:00 p.m. and was between about 70 and 100 MWs higher than the other four peaks. Given this trend, the Report also overstates the contribution of solar to a PJM peak that may be shifting later in time over the course of the period evaluated. This later peak trend has also been noted by CASIO. This calls into question estimates for future periods.

Finally, the Report uses market-based capacity value as the basis for avoided capacity. This is a serious logical error because eligibility for market-based capacity value is premised on unit being fully dispatchable and dependable on an hourly basis. This is not a proxy value for solar as demonstrated in PJM Manual 21 Rules and Procedures for Determination of Generating Capability Revision: 12 Effective Date: January 1, 2017. This manual sets forth separate, special rules for capacity determination of intermittent resources including solar. Additionally, the auction value for intermittent resources is determined in a separate category for summer only available capacity (this applies to solar because it has no winter capacity value in peak hours). Simply put, solar is an intermittent resource and thus not dispatchable or dependable, and it is not a year-round capacity resource for meeting system peaks. The capacity value instead must be calculated based on availability during certain hours in each day of the summer.

B. Calculations of avoided energy costs are exaggerated.

Daymark has omitted many details of its calculations of avoided energy costs rendering difficult a detailed analysis. Nevertheless, from what is available the energy calculations appear to suffer significant problems.

The process used in the report for energy cost estimates relies on a historic year's locational marginal prices (LMPs) and then escalates those prices based on the forecast of average energy prices. As the Report describes the approach:

> The hourly distribution of prices over the year is obtained from an analysis of historic data. Then a forecast of annual average energy prices through the study period is established. An hourly profile of solar generation output must also be estimated. The final step is to combine the historic energy pricing hourly distribution, the forecast of future energy price trends, and the hour by hour solar electric output profile to estimate the value of energy displaced by solar generation.[3]

The use of historic LMPs escalated by an average fuel cost escalation is neither reasonable nor accurate. The historic period reflects only the capacity available in that year and does not recognize known retirements and additions that alter future dispatch including increasing solar DG behind the meter. By failing to model the impact of solar penetration on the summer peak loads, the results also overstate the avoided costs and provide a credit in excess of the avoided cost. It does not reflect plant upgrades, changes in maintenance schedules, nuclear refueling cycles, variability of forced outage rates, dispatch changes resulting from load changes in an LMP zone, changes in transmission constraints from new transmission facilities, distribution upgrades that reduce losses and so forth. It also does not recognize the impact of growing penetration of behind the meter solar DG or utility scale solar DG that reduce the load at the PJM load node for the Cooperatives. The following is a list of six errors in the calculation of the avoided energy costs that cause that value to be substantially overstated:

1. The report double counts marginal transmission losses since that value is already included in the LMP price and the LMP price is multiplied by the total peak LMP losses including transmission and distribution.

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[3] Rpt. at 28.

2. The energy loss factor is the same as the peak loss factor which is impossible because energy losses and peak demand losses are different.

3. The loss factor used is about three times greater than the actual average energy loss factor for the SMECO system. This means that marginal losses are also higher. It is also likely to be far higher than the Choptank average loss factor as it is based on dated information and information not developed for either Cooperative.

4. The marginal loss factor is significantly overstated by not recognizing that no load or core losses do not change at the margin and those losses account for a significant portion of losses for substations and transformers energy losses.

5. The avoided loss factor does not account for the increased I^2R losses associated with delivery of excess energy back to the system that creates additional losses on services and secondary lines, transformers and even primary lines when excess generation exceeds load on the solar DG customer's transformer. This reduces the value of avoided losses.

6. The use of any value greater than the avoided cost at time of delivery violates not only PURPA but the FERC regulations as well. Using a discounted present value of energy cost for screening options in an IRP context is reasonable but has demonstrably inefficient impacts on customers as can be seen from the contracts entered into under PURPA in the 1980s that resulted in billions of dollars of excess costs to electric customers across the country.

Each of these objections is discussed below.

1. Marginal transmission losses are being double-counted.

There are two sources of marginal transmission losses: (1) transmission losses from generation to the load node (PJM losses) and (2) transmission losses on the Cooperatives' systems from the load node to system substations. The former losses are being double-counted because the marginal loss value is already included in the LMP price that is being escalated in the calculation of the avoided energy costs. This is shown in the below excerpt from the PJM calculation of LMP.

Table 1
PJM- PEPCO SMECO Hourly LMP

LMP Price $/MWh	Energy Price $/MWh	Congestion Price $/MWh	Loss Price $/MWh
26.914	24.89	0.4894	1.5346

As the data show, LMP is the sum of the energy price, congestion and the energy losses in that hour. The energy loss in the LMP is the hourly marginal loss. The Report ignores this impact and thus double counts this loss value.

The exact amount of this double counting is not known because the use of a combined Transmission and Distribution loss factor in the report excludes any opportunity to adjust the loss factor to eliminate this portion of transmission loss. Further, as calculated by PJM this is the marginal loss value. For SMECO, the maximum marginal loss value occurs at the winter peak not the summer peak and this results in an inflated avoided cost value also. Similarly, the Choptank maximum annual peak load occurs in the winter based on weather. At a minimum this adjustment for the Cooperatives will be significant because the highest marginal loss occurs in the winter and summer months and at hours when solar is not operating or operating only at a fraction of the nameplate capacity. The marginal loss at the summer peak will be less than the value used in the Report for both peak losses and energy losses.

2. Energy and Peak Loss Factors cannot be the same.

The Report claims that marginal energy losses are equal to the marginal peak load losses by using the same value for capacity and energy losses.[4] This is a mathematical impossibility. First, peak demand losses occur coincident with system peak, *i.e.*, the highest load hour of the year. Every other hourly marginal loss value necessarily must be less than the peak hour

[4] Rpt. at 28.

marginal loss because losses are related to load. In SMECO's case, the highest load hours uniformly occur in the winter (early morning before or shortly after dawn) when there is no solar generation. This means that the peak load marginal losses must be substantially less than the energy losses used in the Report to escalate the LMP.

SMECO's average loss factor is 4.19% according to the most recent SMECO loss study (2014). Adding in the PEPCO allocated loss the total average loss factor is 4.56% or about half of the average loss used in the Report. Further, the 4.56% loss factor includes both load losses and no load or core losses. Because core losses do not vary with load, they have no impact on marginal losses. The Report's calculation of peak demand losses ignores this fact. Further, the peak demand losses avoided by solar DG would be less than the system peak demand losses because solar has zero or near zero output at the winter system peak hour.

Also relevant to this issue, the sum of marginal hourly losses must be less than average losses simply based on mathematics of losses. If the marginal losses equaled 13.5% as used in the report, this would require system average losses to be more than 2.96 times higher than the actual losses. Simply, average system losses must be equal to the sum of the hourly marginal losses plus the no load losses for the same period. Based on this equation, average system load losses (the same value as the sum of the hourly marginal losses) must be less than the system average losses. The following table provides the energy losses by system component for the SMECO system and separates those losses between load and no load losses:

Table 2
SMECO Energy Losses

Category	Load Loss %	Core or No load Loss %	Total Losses
PJM Loses	0.734%*		0.734%*
Transmission System	0.308%	0.193%	0.501%
Substations	0.227%	0.277%	0.504%
Distribution Lines	1.214%		1.214%
Distribution Transformers	0.332%	1.807%	2.139%
Secondary and Services	0.211%		0.211%
Total	2.292%	2.277%	4.569%

*Included in LMP Price and excluded from total system losses

As Table 1 shows, energy losses at the margin must be less in total than load loss percent. Thus, the maximum avoided marginal cost for losses would be less than 3% as compared to a value used in the Report of 13.5%. That lower value would reflect the impacts of the fact that solar is not available in the highest load loss hours, in summer months with maximum solar DG output average losses are lower than the system average and the Report ignores the increased losses when solar DG is exported to the system.

3. Loss factor used is based on dated information.

By using the average losses for a historic period from 1994-2014, the loss analysis fails to recognize the expected losses going forward. Historic losses will be higher than current losses because of changes in technology and system operations. For example, SMECO has recently completed a transmission system upgrade that raised the operating voltage. This reduces losses as does increasing the conductor size and reducing the amount of secondary conductor on the system. These changes are consistent with utility trends over the 20-year period used to estimate losses. The source data used in the report reflects this trend albeit by smaller amounts.

4. "No load"/core losses were not excluded from marginal loss factor.

Daymark has included "no load" losses in its marginal loss factor. As noted above, the no load losses make up almost 50% of the total delivery losses for the SMECO system. These losses will not change with load and must be excluded from any analysis of marginal losses. Failing to exclude these losses compounds the error in adjusting both avoided energy costs and avoided capacity costs for losses. Although not entirely clear because details have been omitted, it is reasonable to assume that this over-allocation of losses is quite large because much of the solar production occurs in lower load hours. This can be seen from Figure 18 in the Report, where solar from south facing facilities uniformly misses the high LMP cost hours in the morning and evening and peaks in the middle of the day. In the middle of the day in the non-summer months loads tend to be lower and most export power occurs in those hours. That is significant because exporting power increases losses rather than decreasing losses as discussed below.

5. Increased marginal loss should be deducted from the marginal avoided loss.

Net-metered solar production that exceeds on-site demand is exported to the system for resale by the Cooperatives to other customers. This amount of export power is highly variable because it is a function of both intermittent solar output and variable hourly customer loads. It is beyond debate that solar production is characterized by a particular load shape that exhibits little variation as to peak production by hours and by seasons. Peak hourly production occurs at midday. That hourly production will exceed the nameplate capacity rating when ambient temperature is less than 77 degrees Fahrenheit and will be less than nameplate capacity when temperature exceeds 77 degrees Fahrenheit. The nature of solar production is such that the optimal installed capacity is greater than the customer's peak hourly load. The logic for this conclusion is based on the fact that the capacity factor for solar production is less than the typical load factor for use necessitating more solar kW than load kW to produce the same amount of energy as the customer's annual use. This means that the excess solar output during low load periods is potentially larger than the host customer's non-coincident peak (NCP) demand. The export load increases the load loss portion (I^2R) on the service line, on the transformer and on the conductor used to move power back to the load. The magnitude of these losses is a function of the size of the export relative to loads in proximity to the point of delivery to the system.

In the case of the Cooperatives, which have few customers per transformer, it is likely that for the system to absorb the excess deliveries more than one transformer and some amount of primary conductor would be used, effectively raising marginal losses for delivery. This increased marginal loss should be deducted from the marginal avoided loss. The net result is ultimately lower than the average load loss on the system even if we ignore the fact that the highest marginal loss hours for a winter peaking system occur when there is little or no solar output.

6. Intermittent resources are entitled only to avoided cost at the time of production.

The Report calculates a discounted present value of a future stream of avoided energy or capacity costs for rooftop solar. There is no basis for doing so. Federal Energy Regulatory Commission ("FERC") regulations are unambiguous that an intermittent resource like solar DG is entitled only to avoided cost at the time of production. Using a discounted stream of future avoided energy costs is only appropriate where power is provided under a "legally enforceable obligation."[5] As a practical matter, payment at the time avoided costs are incurred is more profitable and economic for the solar customers because that matches costs as they are incurred rather than providing excess payments initially and undercompensating in later periods.

C. Federal law prohibits compensating net metered facilities more than avoided costs.

As discussed in detail in the Cooperatives' comments on community solar,[6] current net metering programs in Maryland do not appropriately recognize federal preemption and the compensation limits imposed by the Federal Power Act ("FPA") and PURPA.

In summary, the FPA vests the power to regulate electric sales in interstate commerce and sales for resale in FERC. PURPA Sections 201 and 210 carve out a very limited state pricing authority for a portion of the sales for resale under regulations developed by FERC. This state pricing authority is limited to sales for resale by Qualifying Facilities ("QFs"). This arrangement draws a bright line and eliminates any dispute between federal and State jurisdiction while making sure that rates are consistent with the legislative mandates in both the FPA and PURPA.

For the purposes of solar distributed generation, the import of the FPA is that, while the State has pricing authority, it cannot exceed avoided costs. This is defined as PURPA as "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source."[7] This federal restriction further buttresses the conclusion that only core components,

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[5] 18 CFR 292.304(d)(2)(ii) (rates for purchases).

[6] *Comments on the Synapse Report by Southern Maryland Electric Cooperative and Choptank Electric Cooperative*, PC 46, ML 211435 (January 24, 2017).

[7] PURPA section 210(d).

i.e., avoided energy, capacity, transmission, distribution and ancillary services should be considered in determining solar's value.

D. Only direct, calculable benefits should be included.

Daymark includes 14 components in its calculations. Five of these components – avoided energy, capacity, transmission, distribution and ancillary services – are reasonable and fair to include. However, the remaining nine components, ranging from fuel price hedge savings to carbon impacts to job impacts, are simply too difficult to value and measure. Daymark poses the question as to "how much to weigh externality values such as these," acknowledging it is "ultimately a policy decision that must be made between the cooperatives, the Commission and other stakeholders."[8]

Considering speculative, indirect components skews the analysis and is a sharp departure from historic ratemaking principles. As Professor Bonbright explained:

> The reasons for caution and skepticism in use [of social benefits in rate design] are indeed forcible. First, there is the extreme difficulty of prophesying and measuring indirect social benefits and social costs. Secondly, and in the absence of objective tests, there is the certainty that exaggerated claims of community benefits and costs will be put forward by various interest groups. And thirdly, there is the question whether the indirect benefits from the production of any given public utility service will be greater than those that would result from the alternative production of other commodities and services offered for sale at market prices that do not take social benefits into account.[9]

As important as many consider solar to be, it is not appropriate to ignore these warnings. If the Commission ultimately elects to ignore the calculations in favor of promoting a policy it can do so through mechanisms other than avoided cost rates, but the foundation for the decision should rest on solid, accurate calculations.

[8] Rpt. at 69.

[9] Principles of Public Utility Rates, James C. Bonbright, 173 (1988).

Conclusion

The Cooperatives appreciate that the Commission has undertaken this Public Conference, and has elected to begin with the cooperative territories. Daymark's Report provides a good starting point, but the Cooperatives hope that the Commission will consider the corrections and revisions recommended in these comments.

Respectfully submitted,

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March 15, 2017

Via Electronic Filing

David J. Collins, Executive Secretary
Maryland Public Service Commission
William Donald Schaefer Tower
6 St. Paul Street, 16th Floor
Baltimore, MD 21202

RE: Public Conference 48 – Joint Comments of Baltimore Gas and Electric Company, Potomac Electric Power Company, and Delmarva Power & Light Company on Daymark Energy Advisors Value of Solar Report

Dear Mr. Collins:

Baltimore Gas and Electric Company ("BGE"), Potomac Electric Power Company ("Pepco"), and Delmarva Power & Light Company ("Delmarva") (collectively the "Joint Utilities") submit these comments in response to the Maryland Public Service Commission's (the "Commission") Notice of Public Conference and Opportunity to Comment (the "Notice") issued on February 24, 2017 in Public Conference ("PC") 48. As the Commission explained in its Notice, the purpose of PC48 is to receive comments on the report of the Commission's independent consultant, Daymark Energy Advisors ("Daymark"), on the valuation of costs and benefits associated with distributed solar, alternative rate design, and compensation models in the territories of the Maryland electric cooperatives (the "Daymark Report"). The Joint Utilities appreciate the opportunity to provide comments on the Daymark Report in PC48 and look forward to further discussions with the Commission and other stakeholders about the value of solar energy resources in connection with Public Conference 44 ("PC44").

The goal of the Daymark Report was "to provide an independent assessment with respect to solar for the two largest electric cooperatives in the State of Maryland, Southern Maryland Electric Cooperative (SMECO) and Choptank Electric Cooperative (Choptank)."[1] Specific key objectives of the Daymark Report included, "(1) quantifying the comprehensive value of distributed solar in the two largest Maryland electric cooperatives in 2016, and (2) taking the value of solar from the first objective into account, developing rate design options that facilitate solar development with

[1] Daymark Report at p. 1.

minimum impact to non-participating ratepayers."[2] The Joint Utilities submit that overall, the Daymark Report provides an in-depth assessment of the value of solar resources specific to the two largest Maryland electric cooperatives.

The Joint Utilities support the advancement and integration of solar and other distributed resources into the energy system in Maryland. With respect to the Daymark Report, the Joint Utilities are generally aligned with the goals of the study, and specifically, Daymark's efforts to identify a value of solar for Maryland and the utility distribution systems. Moreover, the Joint Utilities appreciate Daymark's recognition of the dependence of solar participants and non-participants on the utility distribution system and contributions to the costs of operating the system.

The Joint Utilities are not providing detailed comments on specific cost or benefit values, including the energy and capacity price forecasts, described in the Daymark Report, as they are specific to the Maryland electric cooperatives that are the subject of the Daymark Report. Nevertheless, there are several general points that the Commission should keep in mind as it reviews and evaluates the Daymark Report, including the following:[3]

- The Daymark Report used the highest value of each benefit stream associated with the characteristics of the installed solar. Not all solar energy systems, however, are optimally sized or oriented for the intended application – meaning that a maximum value may not necessarily represent the value to be derived from all installations, especially given the possibility of inverter failures and other potential maintenance issues affecting performance.

- The statement in the Daymark Report that since the majority of solar installations are residential systems "the wear and tear of the distribution system is minimized because electricity produced by solar systems is consumed on-site"[4] does not appear to factor in the impact that such solar systems have on voltage regulation devices such as line regulators and line capacitors. If these commonly used devices are used in either Choptank's or SMECO's distribution systems, they must operate more frequently throughout the day due to the intermittent energy output of solar. Over time, this decreases the lifespan of the devices. Moreover, the Joint Utilities do not necessarily agree that the "electricity produced by solar systems is consumed on-site" since solar systems may have to export into the distribution system a portion of the time that they are generating in order to net out the energy consumed at the site when they are not generating, and given that Maryland regulations permit generation up to 200% of the amount consumed on-site annually. Also, solar systems can be installed and operated as wholesale generation projects, having no native load, coordinated through PJM.

- No mention is made of the impact to system reliability that high solar energy system penetration can bring due to potential interference with distribution automation

[2] *Id.*
[3] For accuracy and completeness, the Joint Utilities also note that the first three transmission projects listed in Table 12 of the Daymark Report (p. 42) are no longer active projects. In addition, in Line (1) of Table 14 (p. 45), Delmarva and PEPCO appear to be transposed.
[4] *Id.* at p. 46.

systems (automatically locating and isolating faults and switching non-faulted sections of a distribution feeder to other feeders). High concentrations of solar on a feeder may make it more difficult to locate faults, which can cause potential voltage issues when solar systems turn back on after loads are switched.

- As the quantity of distributed solar energy increases, there is a corresponding increase in system planning and operation efforts, with associated costs. All customers bear these costs, including those not participating in solar.

Additionally, the Joint Utilities encourage the Commission to evaluate the value elements identified in the Daymark Report along with the cost or benefit streams through which a solar participant might receive that value. For example, societal benefits may be reflected in state and federal incentives and credits, while reductions (or additions) to distribution utility costs may be reflected in rates. Additionally, the subsequent cost shift from solar participants to non-participants inherent in current policies should be recognized and minimized.

In regards to the rate design mechanisms and impacts included in the Daymark Report, the Joint Utilities are encouraged that the report discusses a variety of potential options and impacts, from a "buy all/sell all" tariff to time-of-use rates, increased fixed charges, and implementing residential demand charges. First, the Joint Utilities strongly endorse the Daymark Report's finding that cross-subsidies currently exist as a result of the current net metering rate design policy. The rate design options discussed in the Daymark Report are currently being considered in the context of the ongoing PC44 proceeding. The PC44 proceeding is a significant and valuable opportunity to study and better understand the impact of these potential rate design options before implementing changes on a wider basis. The Joint Utilities agree with the Daymark Report that some of these options, including residential demand charges, have the ability to mitigate some of the cross-subsidization inherent in the current rate design. Hence, the Joint Utilities encourage the Commission to evaluate a variety of these options, including residential demand charges, in the context of the planned PC44 rate design pilots.

Finally, the Joint Utilities recognize that the PC44 proceeding contemplates a study with similar objectives as the Daymark Report, but specific to Maryland investor owned utilities. The Joint Utilities believe that such a study will undoubtedly provide valuable insight into the grid modernization discussions that are the focus of those proceedings.

Respectfully submitted,

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March 15, 2017

David J. Collins
Executive Secretary
Public Service Commission
Of Maryland
6 St. Paul Street, 16th Floor
Baltimore, Maryland 21202

Re: Public Conference 48

Dear Mr. Collins:

Enclosed for filing, please find an original and seventeen (17) copies of the Office of People's Counsel's Comments in the above-referenced case.

Should you have any questions or concerns, please feel free to contact me.

Sincerely,

/electronic signature/

William F. Fields
Senior Assistant People's Counsel

WFF:eom
Enclosure

BEFORE THE
PUBLIC SERVICE COMMISSION
OF MARYLAND

IN THE MATTER OF THE EXPLORATION	*	
INTO THE BENEFITS AND COSTS OF	*	
DISTRIBUTED SOLAR AND THE	*	
ASSOCIATED POTENTIAL RATE DESIGN	*	PC 48
OPTIONS APPLICABLE TO THE SERVICE	*	
TERRITORIES OF THE MARYLAND	*	
ELECTRIC COOPERATIVES	*	
	*	

* *

COMMENTS OF THE OFFICE OF PEOPLE'S COUNSEL

Pursuant to the February 24, 2017 Notice of Public Conference and Opportunity to Comment of the Public Service Commission ("Commission"), the Office of People's Counsel ("OPC" or "People's Counsel") submits these comments regarding the Value of Solar Report prepared by Daymark Energy Advisors ("Daymark") at the request of the Commission.

OPC appreciates the Commission action in retaining Daymark to prepare this Report, and establishing this Public Conference to receive comment on the Report before its submission to interested members of the General Assembly in March, 2017. As the Commission states in its Notice, this Public Conference, PC 48, was established to "complete its study of the exploration of the benefits and costs of distributed solar" with regard to the Maryland electric cooperatives, and examine "potential rate design options and alternative compensation models that could facilitate solar deployment . . . with minimal impact to non-participating ratepayers." Daymark Report addresses all of these issues in its Report.

Daymark notes that it had two key objectives: (1) quantifying the comprehensive value of distributed solar with regard to Southern Maryland Electric Cooperative ("SMECO") and

Choptank Electric Cooperative ("Choptank"); and, in light of those quantified values, presenting different rate design options to address the twin objectives identified by the Commission.

VALUATION STUDY

The Report includes relevant background information regarding the cooperatives' customer base, transmission and distribution systems, the state of the solar installations on the cooperatives' system, and the technical potential for solar distributed generation in the cooperatives' service areas. With regard to the quantification of the costs and benefits of solar for each of the two electric cooperatives, Daymark followed a straightforward approach in its valuation study. The Report identifies the benefit components evaluated in the study,[1] and provides a clear description of the methodologies for calculating the impact of distributed solar on those components, and the results of Daymark's analysis of those impacts.[2] As part of its analysis, Daymark analyzed avoided cost categories typical of such a valuation study – that is, whether energy, capacity, transmission, distribution and ancillary services would be avoided by solar distributed generation ("DG") on the cooperatives' systems.[3] Additionally, Daymark analyzed other factors, such as energy and capacity market price response (also referred to as "demand reduction induced price effects" or "DRIPE"), fuel price hedge savings, and avoided Renewable Energy Credit (REC) purchases. Of these categories of potential benefits that directly accrue to the cooperatives, Daymark determined that only four categories represent actual benefits, including avoided energy, avoided capacity, avoided REC purchases and avoided transmission charges.

Of particular note, Daymark determined that there was no evidence of avoided transmission investments related to load growth for these two cooperatives.[4] This finding underscores the

[1] Report, pp. 2-3.
[2] Report, p. 26.
[3] Report, pp. 25-61.
[4] Report, p. 43.

importance of conducting utility-specific valuation studies of these types of avoided costs. With regard to the cooperatives' distribution systems, Daymark indicated a considerable amount of uncertainty in assessing any cost or benefit impacts, particularly since the impacts are very location specific and the cooperatives' planning studies do not include this information.[5] Given the potential significance, either as a cost or benefit, of these impacts, this appears to be an area where the cooperatives need to establish the means to measure location-specific (i.e., circuit level) impacts.

Daymark did address potential societal cost benefits for environmental emissions, specifically carbon and NO2 emissions, relying on data provided by the U.S. Environmental Protection Agency ("EPA") and PJM.[6] Other categories of potential societal benefits, such as local economic benefits, employment, and water and land savings, were not quantified. There is a significant difference in Daymark's calculation of impacts from solar distributed generation, depending on whether avoided societal emission costs, as reflected in Daymark's calculations, are included in the valuation analysis.[7] Without the inclusion of these avoided costs, Daymark reports that the current net energy metering ("NEM") model results in a significant rate impact on non-participating customers.[8]

RATE DESIGN AND DER

As requested by the Commission, Daymark provides a general description of different types of compensation mechanisms for solar DG customers, as well as some alternative rate designs. Daymark quite rightly highlights the importance of balancing the various rate design principles and objectives (the Bonbright principles), and the trade-offs that a Commission must

5 Report, p. 46.
6 Report, pp. 55-56
7 Report, p. 5, Figure 3.
8 Report, p. 66 and p. 67, Tables 18 and 19.

evaluate in a company specific evidentiary proceeding when designing rates for an electric company.[9] With specific reference to NEM and rate design, Daymark has noted that the key issues arising in Maryland and national discussions are (1) sufficiency of revenue recovery by utilities; (2) fairness of cost allocation, including the potential for cross-subsidies, and (3) the policy priorities of a State, which may impact the discussion of potential categories of societal costs and benefits in a valuation study, and the policies on providing incentives for solar DG. OPC expects that these broad principles will be addressed and reflected in the comprehensive valuation of solar study that the Commission intends to pursue in PC 44. This Report, while specific to the electric cooperatives, will be a helpful addition to that broader, State-wide valuation process.

OPC agrees with Daymark's comments regarding rate design principles generally and as they relate to NEM compensation. Daymark's discussion of NEM compensation and rate design alternatives is a useful, although abbreviated, discussion of potential options, particularly as a supplement to the Synapse Energy Economics, Inc. Report on "Rate Design Impacts for Customers of Maryland's Electric Cooperatives."[10] For that reason, OPC notes in particular the importance of Daymark's qualifying remarks. Daymark noted that its analysis is intended to assist the Commission, policymakers, cooperatives, and stakeholders such as OPC, in understanding the trade-offs involved in establishing NEM compensation mechanisms and reasonable rate designs. Citing the recent NARUC Distributed Energy Resources Rate Design and Compensation Manual (November 2016), Daymark noted the importance of assessing rate design options in the context of a full rate case, in order to ensure that a balancing of rate design principles and public policy

[9] Report, pp. 62-64.
[10] See Synapse Report in PC 46.

preferences can be carried out in an open and engaged process. For that reason, Daymark does not offer any specific recommendations in favor of one or the other options.

In sum, OPC believes that this Report is a very useful initial step to aid the Commission, the electric cooperatives, OPC and other interested stakeholders in future assessments of NEM compensation and consideration of appropriate and reasonable rate design options for customer classes, and within customer classes.

Respectfully submitted,

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/electronic signature/
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Senior Assistant People's Counsel

IN THE MATTER OF THE EXPLORATION	*	BEFORE THE
INTO THE BENEFITS AND COSTS OF	*	PUBLIC SERVICE COMMISSION
DISTRIBUTED SOLAR AND THE	*	OF MARYLAND
ASSOCIATED POTENTIAL RATE DESIGN	*	
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TERRITORIES OF THE MARYLAND	*	PC 48
ELECTRIC COOPERATIVES	*	

Comments of Pace Energy and Climate Center and Earthjustice

on behalf of

Maryland Solar United Neighborhoods (MD SUN),
Chesapeake Climate Action Network,
Fuel Fund of Maryland, and
Institute for Energy and Environmental Research

March 15, 2017

Comments of Pace Energy and Climate Center and Earthjustice

Introduction

On February 24, 2017, the Public Service Commission of Maryland ("Commission") initiated Public Conference 48 ("PC 48") to complete its study of the exploration of the benefits and costs of distributed solar, specific to the service territories of the Maryland electric cooperatives ("utilities"), and further, to assess potential rate design options and alternative compensation models that could facilitate solar deployment in the utilities' service territories with minimal impact to non-participating ratepayers. In its notice establishing PC 48, the Commission invited written comments on a report written by consultant Daymark Energy Advisors ("report") addressing the issues in this conference.

Pace Energy and Climate Center ("Pace") and Earthjustice submit these comments on the Daymark report on behalf of Maryland Solar United Neighborhoods (MD SUN), Chesapeake Climate Action Network, Fuel Fund of Maryland, and the Institute for Energy and Environmental Research.

These comments include a general statement and comments specific to sections of the report.

1. General Comments

The Daymark report reflects the results of a value of solar estimation process and then uses those results in comparing results associated with hypothetical alternative rate design structures. The report describes the methods used in the estimation process in general terms. The report lacks specific documentation in several key areas. The report reflects conclusions on the part of the consultant to ignore or assign a value of zero to several components of the valuation analysis. The report than uses some of the estimated value of solar in comparing alternative rate designs.

According to Daymark, the stated purpose of the report is comprised of two objectives:

1. Quantifying the comprehensive value of distributed solar in the two largest Maryland electric cooperatives in 2016; and
2. Taking the value of solar from the first objective into account, developing rate design options that facilitate solar development with minimum impact to non-participating ratepayers.[1]

We do not believe the methodological approach taken by Daymark achieves its stated objective. In general, some parts of the report, notably the list of components of value of solar in Table 6, constitute a reasonable starting point for discussing and addressing the value of distributed solar generation in the utilities' service territories, providing a helpful background on the state of solar penetration in two utility territories, cataloging potential areas of value, and assessing some of these areas fairly. However, several value categories are not accurately reflected in the Daymark analysis, including transmission and distribution value, ancillary services, market price impacts, and price hedges, as we will discuss further on. In some cases, broad methodological questions remain, for example around Daymark's process of levelizing energy costs or discounting future benefits, or whether it has adequately measured sensitivities to address areas of quantitative uncertainty. Finally, it appears that Daymark did not review values and methodologies used in other publicly-conducted value of solar studies in order to internally test methods used in the study and as a source for value estimates that could not be calculated

[1] Daymark report at p. 1.

due to lack of utility data. These methodological shortcomings undermine Daymark's stated goal of supporting just and reasonable rates and rate design analysis. As such, Daymark's analysis should only be used as a starting point in developing a value of solar methodology in consultation with stakeholders and Commission staff. Pace and Earthjustice provide the following high-level recommendations, with further detail below:

- The report would benefit from substantially more transparency about and sharing of data, assumptions, and calculation methods used to derive results. Daymark should make its models available to Commission Staff and the public in order to allow validation and comparison of results under alternative assumptions.
- The report should greatly expand the use of sensitivities to address areas of quantitative uncertainty.
- The report should review values and methodologies used in other publicly-conducted value of solar studies in order to internally test methods used in the study and as a source for value estimates that Daymark could not calculate due to lack of utility data.

The Commission's final report in this conference is due to be presented to the Maryland legislature sometime in March 2017. The Daymark report was released as a final report on the same date that this conference was initiated. Comments on the study are due to the Commission by March 15, 2017. Pace and Earthjustice are deeply concerned that this will not provide Daymark or the Commission sufficient time to consider and incorporate stakeholder feedback into the final report. Further, the development of the report included one public workshop, on January 12, 2017 with the opportunity to ask questions and provide feedback, but did not include the opportunity to review and comment on draft versions of the report or on the scoping and research that had already been completed prior to the January workshop. The public and interested parties had one other prior opportunity to submit comments on rate design issues for Maryland's electric cooperative customers in November 2016.

More study and a more open process for valuing distributed solar and other distributed energy resources is required to inform the Commission's broader undertakings in PC 44. At the very least, the findings in the Daymark report must be considered alongside the ongoing discussions in the PC 44 rate design working group, and the findings of the upcoming solar cost-benefit analysis.[2] The Daymark report should not be used as the justification for any rate making action by the Commission, particularly since rate designs founded on the incomplete analysis in the Daymark report may distort the economics of grid modernization decision making and impede the grid modernization progress.

2. Comments by Daymark Report Section

2.1. Section 3 – Solar Development Status and Potential Value of Solar

§ 3.4 Assumptions

The report seems to use an assumption of a solar project life of only 20 years. The standard in value of solar analysis is 25 years, with sensitivity analysis out to 30 years or more. An assumed life of 25 years matches the warranties provided on solar panels by virtually all manufacturers in the USA today. The shorter assumption reduces the levelized present value of solar generation benefits. The report does not indicate what discount rate is used in valuing any future streams of benefits associated with solar generation. It is not clear that the report uses a

[2] Maryland Public Service Commission, Public Conference 44, In the Matter of Transforming Maryland's Electric Distribution Systems to Ensure that Electric Service is Customer-Centered, Affordable, Reliable and Environmentally Sustainable in Maryland, Notice (January 31, 2017).

levelization approach at all. A high discount rate, such as the utility weighted average cost of capital, would tend to reduce the value of benefits in the later years of the project life.

§ 3.5 Value of Solar Development

The list of cost and benefit categories, "Value of Solar Components" is comprehensive. Pace and Earthjustice appreciate the inclusion of Job Impacts and Local Economic Development Impacts in the report, based on feedback during the January 12 conference.

§ 3.5.1 Energy value

Market prices are not an indicator of the full marginal cost of incremental energy. Market prices are an artifact of bidding strategies, financial positions, and other competitive behaviors by numerous market actors. Market prices should, but do not necessarily, reflect long run marginal costs, and therefore are not necessarily "efficient." The report authors expressly note, at page 51, that market prices for capacity are also the result of "competitive behaviors by numerous market actors," and are therefore unreliable as a means for calculating value. The report should address alternative approaches to estimating the energy value of generation from NEM systems.

§ 3.5.2 Transmission capacity costs

The report erects an impossible set of hurdles to realize value associated with avoided transmission capacity investments. While theoretically recognizing the possibility of such value, the report then sets a threshold that any distributed solar must not be reliability-related, because the report defines such investments as not avoidable; that any transmission investment must be related to load growth; and that the utilities must have identified the transmission project and included it in planning. The approach ignores the fact that distributed generation does in fact reduce reliance on transmission, and that therefore, the answer to question of the value of distributed generation in reducing transmission costs is any answer except zero. The report assumes zero, and is therefore certainly wrong.

§ 3.5.2 Transmission operating charges

The report focuses on the price of Network Integration Transmission Service and weights solar capacity factor by the single hour zonal peak on the system. Price is not the same as value. The gap between price and value is nowhere more apparent than in organized markets, like PJM. Many valuable utility investments are severely challenged by market prices, even where both energy and capacity price mechanisms operate. Net metered solar generation facilities operate as resources and value-based analysis is intended to capture the resource value of these facilities. NEM customers are by definition and law not sellers of electricity like generator participants in organized markets.

Transmission operating charges are socialized costs translated into prices for service. Moreover, the value of distributed generation in reducing transmission requirements is not just limited to the capacity of solar operating during the peak hour. Solar generation reduces load on the network for several hours leading up to the system peak. This pre-cooling impact can and should be quantified in estimating the value of avoided transmission costs, particularly because, as the report recognizes, marginal transmission costs such as line losses increase with peak.

§ 3.5.3 Distribution

The report continues its excessive focus on peak hour impacts in its analysis of distribution avoided costs. The report also repeats the irrational standard that to earn value for avoided distribution capacity costs, the utility must have already planned a distribution project that is now too big and too much related to reliability for distributed generation to help avoid those costs. The standard in the report is that in order to be an avoidable project, the project must be unavoidable by rooftop solar. This position is reminiscent of outdated arguments used about the efficacy of demand side management to defer or avoid capital investments or operating costs, and is just as incorrect. The issue is not whether solar can avoid a planned project, but whether, and how to quantify, its potential to avoid future projects not yet required by the utility to maintain reliability. This may require forecasting and planning beyond current planning horizons, but these horizons are certainly not longer than the useful lives and amortization periods of many transmission and distribution investments. The report states that neither of the utilities have adequately or accurately assessed the impact of increased solar penetration, and for this reason the value of solar in avoiding distribution costs is zero. Again, an assumption of a value of zero is the least correct assumption for potential cost or benefit value.

§ 3.5.4 Ancillary services

The report limits consideration of the value of solar in avoiding ancillary services costs or generating ancillary services benefits very narrowly. The report focuses only on ancillary services at the PJM level, and as embodied in two categories of spinning reserves. The report concludes that while distributed solar produces ancillary services value, because this value is minor, perhaps even negligible, it will assume a value of zero.

§ 3.5.5 Market price impacts

The report also proposes to ignore the potential for distributed generation to impact market prices. The justification for this proposal is that it would be difficult to model the impact of small amounts of solar in such as large system as the PJM. Other value of solar studies, available to the consultants, have quantified the market price impact benefits of distributed solar. A detailed methodology is set out in the Maine Value of Solar report at pages 36-38.[3]

§ 3.5.6 Fuel price hedge

The report unreasonably narrows its consideration of the fixed fuel price benefits of distributed solar generation. Rather than attempting to quantify the value of energy produced with a guaranteed fixed fuel price (zero), such as through the cost of a fuel price guarantee for the marginal generation unit that solar displaces, the report instead discusses hedging contracts. The report asserts that PJM market prices internalize the price of fuel price hedging contracts, and therefore ignores the fixed fuel price benefit of solar generation entirely.

§ 3.6 Total Value of Solar

The report fails to reveal two important assumptions: (1) the method used to calculate total value of solar, such as discounting to a levelized (present) value, and (2) the discount rates used for each value component. As already noted, the report unreasonably reduces the value of solar with the limiting assumption that solar systems only have a useful life of 20 years. The report also tends to undervalue solar systematically in some areas by assuming certain benefits are zero.

2.2 – **Section 4 – Rate Design Mechanisms and Impacts**

§ 4.2.1 Revenue Sufficiency

The report addresses "revenue sufficiency" from the perspective of whether a NEM customer can earn sufficient credits to offset the variable rate portion of their bill. This approach

[3] Maine Public Utilities Commission, Maine Distributed Solar Valuation Study (April 14, 2015), *available at* http://www.maine.gov/mpuc/legislative/archive/2014-2015ReportstoLegislature.shtml.

makes absolutely no sense when evaluating the question of revenue sufficiency. Revenue sufficiency is a question of whether the utility can charge a fair rate for the cost of serving a customer with energy so as to recover costs that the customer creates. The report implies that if a customer earns enough bill credit to pay a bill that is lower than the average bill for the class, an issue of revenue sufficiency is raised. This cannot be true. In any given billing period, many customers pay less than the average bill because they had less than average usage. While average rates are used to offset the complexity inherent in evaluating the cost of service for every single customer, this does not support the assumption that a customer creates an issue of revenue sufficiency either by generating electricity with a distribution generation facility or by reducing their use through efficiency or conservation.

The report also fails to point out that the utility's failure to recover in bills what it expected is also an issue of forecasting error. There is no regulatory principle that holds that a utility has a right to recover costs associated with over-building or under-forecasting. While cooperatives do not have shareholders to whom they can assign stranded costs associated with overbuilding or under-forecasting, the assumption that such costs should be assigned to NEM customers is unfair in the absence of a full, fair, and comprehensive assessment of the net benefits that are created by NEM generation—something that this report does not provide. The report's failure to identify distribution cost savings associated with customer generation (p. 65) is an artifact of a failure by the utilities to assess the full impacts of NEM, and not an indicator that the savings will not accrue. (See § 3.5.3.)

§ 4.2.2 Intra-class Cross Subsidies

The report advances a flawed logic in its assertion that increased solar penetration would only increase revenue recovery and subsidy issues (to the extent that these issues actually result from solar facility operation and NEM). High solar penetration could also make more apparent the several avoided cost benefits that the report ignored in Chapter 3 because they were considered by Daymark to be too small to quantify. As noted above, the report's failure to accurately capture the value of distributed solar undermines its conclusions on how that value affects other ratepayers.

The entire discussion of potential intra-class (and inter-class) subsidies also ignores the very real environmental and other subsidies embedded in current rates and means of production, transmission, and distribution. To assert that environmental impact reductions are an indirect benefit of NEM generation is to assert that the environmental costs of the current system are likewise indirect. Under this logic, electricity prices should never account for the environmental damage resulting from the operation of the electric system. Excluding these very real costs of existing systems and the avoidance of those costs through NEM generation in the design of rates guarantees that rates do not reflect costs caused by the customers (cost-causers) and distorts economic decision making.

§ 4.3.1 NEM Alternative: Buy All/Sell All

The report is categorically wrong in characterizing the Austin Energy tariff as a "buy all/sell all" tariff design, notwithstanding a citation to a report from researchers at the National Renewable Energy Laboratory. Customers who generate for use are not jurisdictional "sellers" of electricity under federal law, under the Austin Value of Solar tariff, or under current Maryland NEM law—even if they export energy to the grid. The Austin tariff expressly provides that the VOS rate is used to quantify a credit and not as a purchase price. The Minnesota law likewise does not create a buy all/sell all tariff structure. Finally, the Rhode Island Renewable Energy Growth program provides only for incentives to residential and small systems and is not a buy all/sell all program. Rhode Island's large-scale program is more akin to a feed-in tariff than a true buy all/sell all tariff.

§ 4.3.2 Alternative DER Compensation Case Studies

These exercises are distorted views of the impacts of alternative rate designs in as much as they rely on an incomplete valuation analysis and exclude environmental and other societal benefits of NEM generation.

§ 4.5 Summary of Residential Class Impacts

This section of the report is an example of results-based rate making, and is therefore flawed. It compounds the errors in the body of the report and creates the impression that the purpose of rate making is to "solve for" a subsidy that exists only if an incomplete cost benefit analysis is used as a foundation. It also creates the impression that SREC value is part of the value calculation that impacts sound rate making. This conflates incentives with compensation and distorts efficient economic decision making.

Conclusion

Pace Energy and Climate Center and Earthjustice appreciate this opportunity to provide feedback on the Daymark Value of Solar report. The report includes a good set of cost/benefit categories, but also presents a number of flaws that, if not addressed, will result in distorted valuation and rate design for Maryland's co-op customers. In some respects, the report tends to undervalue solar by assuming some benefits are zero.

The short time frame between the comments deadline (March 15) and the target of submitting the report to the legislature in March risks making it effectively impossible for stakeholder feedback to be meaningfully considered and incorporated. Based on the foregoing, Pace and Earthjustice respectfully request that the Commission ensure that stakeholder feedback is incorporated into the report, and look forward to continuing to work with the Commission, Daymark, and the stakeholders.

Maryland Energy ADMINISTRATION
Powering Maryland's Future

Larry Hogan, ***Governor***
Boyd K. Rutherford, ***Lt. Governor***
Mary Beth Tung, ***Director***

SUBJECT: **MARYLAND ENERGY ADMINISTRATION COMMENTS on PC 48**

DATE: **MARCH 15, 2017**

COMMENTS FROM THE MARYLAND ENERGY ADMINISTRATION (MEA)

The Maryland Public Service Commission (Commission) has initiated Public Conference 48 (PC 48) for the purpose of receiving comments on the report of the Commission's independent consultant, Daymark Energy Advisors (Daymark). Specifically, PC 48 addresses (1) whether current policies contribute to rate class cross subsidies, (2) whether cost shifting is occurring between distributed solar providers and non-solar ratepayers, (3) whether or not current compensation models improperly value the contributions of distributed solar, and (4) whether there are other potential rate design alternatives to facilitate solar with minimal cost to non-solar ratepayers.

Introduction:

The Daymark report's goal is to analyze the value of distributed solar in Maryland's cooperative territories. As MEA noted in its comments in PC 44,[1] distributed energy resources (DERs), particularly solar, are important tools in meeting environmental and other policy objectives of the state. For example, distributed solar can assist Maryland with goals related to the Greenhouse Gas Reduction Act, which Governor Hogan signed into law in 2016,[2] and Maryland's newly revised Renewable Portfolio

[1] http://webapp.psc.state.md.us/intranet/AdminDocket/CaseAction_new.cfm?CaseNumber=PC44
[2] http://www.abc2news.com/news/state/gov-larry-hogan-signs-the-greenhouse-gas-reduction-act

Standard (RPS).[3] If implemented properly and in the right location, DERs could offer useful benefits, such as avoided costs, environmental benefits, and benefits to the electric grid. At the same time, distributed solar has costs, which are important to consider.

Value of Solar:

While there are various ways of calculating both the direct and indirect costs and benefits of distributed solar, MEA views the direct costs and benefits approach as the most appropriate for PC 48. MEA admits that there may also be indirect societal benefits of solar, but compensating for these benefits through the electric rate structure may not be the best path forward.

Rate design is based on principles such as simplicity, fairness, and the ability to generate the revenue to pay for the maintenance of the electric grid.[4] Therefore, using indirect benefits to compensate solar through rates undermines the simplicity of the rate design and the ability to effectively generate the revenue required to maintain a reliable grid. Additionally, as the Daymark report suggests, it also may undermine fairness by contributing to cross subsidization and cost shifting.[5]

Maryland's current net energy metering statute was first enacted in 1997[6] and was intended to "encourage private investment in renewable energy resources, stimulate in–State economic growth, enhance continued diversification of the State's energy resource mix, and reduce costs of interconnection and administration."[7] Maryland has been successful in each of the areas listed in the statute.

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[3] http://www.utilitydive.com/news/maryland-senate-passes-25-rps-in-clean-energy-jobs-bill/417006/
[4] http://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0
[5] Daymark Energy Advisors, *Value of Solar Report*, Page 62
[6] http://programs.dsireusa.org/system/program/detail/363
[7] http://mgaleg.maryland.gov/webmga/frmStatutesText.aspx?article=gpu&section=7-306&ext=html&session=2015RS&tab=subject5

While net metering may have been the best way to compensate and incentivize solar development at the time, there are now other manners of compensation. For example, Maryland's RPS compensates customer generators, allowing them to sell renewable energy credits. The sale of these credits provides customer generators with an additional revenue stream. Additionally, the State provides grants for residential customer generators through MEA's Clean Energy Grant Program.

These developments help provide incentives for solar development. For example, when Governor Hogan took office in January 2015, there were only 258 MW of solar generation capacity in the State. Since then, the number has more than doubled. According to PJM Interconnection, Maryland had 721 MW of deployed solar as of March 2017,[8] enough to power approximately 65,000 homes. In 2015, Maryland's solar industry supported over 4,200 jobs.

Maryland's legislature has already indicated that it values distributed solar, above its direct benefits, and has shown this through the development of alternative means to subsidize solar. Because indirect benefits to society may be awarded to distributed solar producers through mechanisms other than rate design, it need not be addressed through increases to utility charges.

Comments on Consultant Report:

In general, both the methodology and conclusions of the report appear to be reasonable and well founded. As such, outside of including societal benefits, MEA concurs with the findings of the report, i.e., that it is likely that under current conditions, distributed solar is overcompensated – particularly at the residential level – in these cooperative territories.[9] Additionally, existing policies appear to be causing cost shifting from distributed solar providers to non-participating ratepayers. In addition, existing policies appear to contribute to cross subsidization.

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[8] https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS

[9] Daymark Energy Advisors, *Value of Solar Report*, Page 5

MEA would mention, however, that given the variability of solar renewable energy credit (SREC) prices and RGGI compliance costs, the estimated compliance benefits[10] in Daymark's report are likely subject to change in the future. So far, the variability of SREC prices and RGGI auction revenues have been difficult to predict and these estimates affect the specifics of the cost-benefit calculation.

Given that SMECO and Choptank have some unique characteristics, MEA cautions against applying these same findings to Maryland's investor-owned utilities. This is due to the fact that some of the assumptions may not hold when applied to the traditional utilities and that the regulated utility grids may be more complex. Specifically, Daymark's assumptions regarding avoided transmission costs, effects of the distribution system, and ancillary service benefits may differ in the other service areas, not least of all, because the total number of distributed solar installations would be higher. Similar studies of Maryland's regulated utilities are worth exploration.

Despite the alternative policy structures that Daymark highlights in its *Value of Solar Report*,[11] MEA recognizes Maryland's current statutory prohibition on alternative rate designs for solar customers as a result of the net energy metering statute. MEA supports increasing the regulatory flexibility in rate design for net energy metering ratepayers to address the inequities that have built up in the electric rate development process. Finally, as technology changes and as the electric grid becomes more modern, the value of solar may change. MEA supports regulatory flexibility for the Commission to be able to adapt to these changes.

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[10] Daymark Energy Advisors, *Value of Solar Report*, Page 24
[11] Daymark Energy Advisors, *Value of Solar Report*, Page 85

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March 14, 2017

VIA EFILE AND FEDEX OVERNIGHT

David J. Collins, Executive Secretary
Maryland Public Service Commission
William Donald Schaefer Tower
6 St. Paul Street, 16th Floor
Baltimore, MD 21202

Re: Administrative Docket PC 48
In the Matter of the Exploration Into the Benefits and Costs of Distributed Solar and the Associated Potential Rate Design Options Applicable to the Service Territories of the Maryland Electric Cooperatives

Dear Secretary Collins:

Enclosed please find an original and seventeen (17) copies of The Potomac Edison Company's Comments in the above-referenced matter.

Please contact me if you have any questions regarding this matter.

Very truly yours,

Teresa K. Schmittberger

dlm
Enclosures

BEFORE THE
PUBLIC SERVICE COMMISSION
OF MARYLAND

In the Matter of the Exploration Into the Benefits and Costs of Distributed Solar and the Associated Potential Rate Design Options Applicable to the Service Territories of the Maryland Electric Cooperatives	: : : : : :	**Administrative Docket PC 48**

COMMENTS OF THE POTOMAC EDISON COMPANY

I. INTRODUCTION

On February 24, 2017, the Maryland Public Service Commission ("Commission") initiated Public Conference ("PC") 48 to further evaluate the costs and benefits of distributed solar within the service territories of the Maryland electric cooperatives. As part of PC 48, the Commission is seeking comments from stakeholders regarding a study by Daymark Energy Advisors ("Daymark") entitled "Value of Solar Report" ("Report"). This Report identifies costs and benefits associated with solar distributed energy resources ("DER") in the Southern Maryland Electric Cooperative, Inc. ("SMECO") and the Choptank Electric Cooperative, Inc. ("Choptank") service territories and evaluates appropriate rate design mechanisms for customer-generators. The Report ultimately concludes that customer-generators in the service territories of the Maryland electric cooperatives are currently overcompensated for solar DER.[1]

The Potomac Edison Company ("Potomac Edison") is an electric utility serving approximately 262,000 customers in Maryland. Like SMECO and Choptank, Potomac Edison is a winter-peaking utility, meaning the highest demand on Potomac Edison's system occurs when

[1] Report, p. 5.

solar output is less productive. While Potomac Edison expects that the Commission will conduct further studies on solar DER within utilities' service territories, this Report provides a useful starting point for discussions regarding the true costs and benefits of solar DER in Maryland and the need for modification to customer-generator compensation levels. Potomac Edison respectfully submits the following Comments in response to the Report.

II. COMMENTS

After an extensive analysis of the costs and benefits of distributed solar, the Report concludes that customer-generators of solar DER in the SMECO and Choptank service territories are overcompensated for their excessive solar generation. Accordingly, the Report recommends a number of alternative rate design models for the compensation of customer-generators. Potomac Edison's Comments will respond both to Daymark's analysis of the cost and benefits of solar DER and also Daymark's proposed compensation mechanisms for customer-generators.

In order to better understand the benefits and costs of solar DER in Maryland, the Report evaluates the potential savings opportunities as a result of solar DER.[2] Although the Report considers a number of savings categories, the Report fails to evaluate certain additional costs of increased solar penetration. Specifically, the Report assumes that increased solar penetration would have either a positive or net zero impact on transmission and distribution savings and conducts no analysis of whether increased solar penetration could result in additional transmission and distribution costs.

The Report provides an analysis of the potential for future avoided transmission costs and future avoided distribution investment as a result of increased solar penetration.[3] The Report concludes that avoided transmission costs would occur, but that distributed solar is unlikely to

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[2] *Id.* at 26.
[3] *Id.* at 41-46.

eliminate the need for the costs associated with upcoming transmission projects impacting the SMECO and Choptank service territories.[4] In addition, because SMECO and Choptank are winter-peaking utilities, the current level of distributed solar has little to no effect on distribution system investment.[5] With respect to future distribution system investment, the Report states that "[t]he potential impacts on distribution from increased solar penetration levels are not fully known, and they could realistically result in either a net cost or net benefit."[6] The Report does not further explore the possible costs associated with increased solar penetration, but instead assumes zero avoided costs for future distribution investments.

In order to properly quantify the value of solar, further evaluation is necessary regarding the potential costs of future distribution and transmission investment in response to increased solar penetration. As penetration increases, both distribution and transmission investment may need to increase rather than decrease. Increased solar penetration means the electric grid would experience a continued rise in variable generation resources that may or may not be near existing transmission infrastructure. Distribution and transmission systems are currently not designed to allow for significant penetration of variable generation resources. Significant distribution and transmission upgrades could be required as a result of increased solar penetration to maintain system reliability.

Increases to distribution costs would likely be more dramatic for Potomac Edison, SMECO, and Choptank, all of which are winter-peaking. While distribution investment theoretically could be reduced through increased solar penetration for a summer-peaking utility, because solar output is more likely to coincide with the peak of the distribution system for such utilities, Potomac Edison, SMECO, and Choptank would not receive this same benefit. As the

[4] *Id.* at 41-43.
[5] *Id.* at 46-47.
[6] *Id.* at 46.

Commission continues its review of the value of solar for utilities and electric cooperatives, the Commission should evaluate the potential for both increased and decreased investment in the transmission and distribution systems in response to increased solar penetration.

Even without considering the potential distribution and transmission costs associated with increased solar penetration, the Report concludes that the costs associated with solar DER exceed the benefits.[7] As a result, the Report recommends a few different modifications to the rate design for customer-generator compensation, including: reducing the compensation for monthly net exports; shortening the timeframe for credit banking from a year to a season; and replacing the compensation of customer-generators with a value of solar payment for all solar generation.[8] Potomac Edison believes further evaluation of all proposed changes to solar compensation is warranted; however, Potomac Edison's comments only address the Report's conclusions regarding compensation for monthly net exports.[9]

Currently in Maryland, customer-generators receive credits equal to the full retail volumetric energy rate of electricity for all solar DER output.[10] The Commission also adopted this same compensation level within its Community Solar Energy Generation Systems Pilot Program ("Community Solar Pilot").[11] In order to address the cost-benefit imbalance of solar DER, the Report recommends that the Commission, and if necessary, the legislature, could consider other compensation levels, such as excluding delivery charges or non-bypassable charges, or even, under certain circumstances, providing no compensation for monthly net exports.[12]

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[7] *Id.* at 66-69.
[8] *Id.* at 73-74.
[9] PE has not previously examined the merits of a value of solar compensation mechanism for customer-generators. While PE is open to consideration of this and other proposed changes to solar compensation, PE recommends that any alternative methodology be straightforward to implement.
[10] *See* Md. Code Ann., Pub. Util. § 7-306.
[11] COMAR 20.62.02.04.
[12] Report, p. 73.

Potomac Edison agrees that revision to the compensation level of customer-generators is warranted. Although Potomac Edison is open to exploring the merits of other suggested credit methodologies, Potomac Edison submits that a credit equal to the commodity portion of a customer's rate would be more consistent with utility cost causation principles, and would help to minimize cross-subsidization among customers. A customer-generator continues to rely on the distribution and transmission systems and should be responsible for the costs associated with maintaining them.[13] Otherwise, other customers are subsidizing the use of these systems by customer-generators.

Although not specifically examined within the Report, it is worth noting that cross-subsidization is of particular concern within the Community Solar Pilot. Under the Community Solar Pilot, customers may subscribe to receive credits from community solar energy generating systems located anywhere within the same service territory. The customers may be located on an entirely different distribution feeder than the solar generating system. The customers' demand does not decrease, and the transmission and distribution facilities serving the customers continue to require the same level of capacity. Consistent with cost causation principles, the customers should continue to be charged for their distribution and transmission costs. If, as it currently stands, these customers receive a credit reflecting the retail volumetric energy rate of electricity, other customers are subsidizing their full distribution and transmission costs. If instead the Commission were to establish a credit equal to the commodity portion of a customer's rate, that would continue to hold customers responsible for their own distribution and transmission charges.

Potomac Edison welcomes further discussions regarding modified compensation mechanisms for distributed solar, particularly with respect to the Community Solar Pilot. As

[13] Net metering customers are not choosing to disconnect from the electric grid. This physical hedge and reliance on the electric grid is clearly of continued importance to these customers.

demonstrated by the Report, the costs associated with distributed solar exceed the benefits.[14] The purpose of reducing solar compensation levels is not to discourage solar DER, but rather to ensure that the compensation level more accurately aligns the costs and benefits of distributed solar. Even if solar compensation levels are reduced, economic forces would likely continue to encourage the development of distributed solar throughout Maryland. In light of the conclusions of this Report, Potomac Edison hopes that the Commission will revisit whether modification to solar compensation levels is appropriate.

III. CONCLUSION

The Potomac Edison Company appreciates the opportunity to submit these Comments.

Respectfully submitted,

THE POTOMAC EDISON COMPANY

Dated: March 14, 2017

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[14] *Id.* at 5.

Before the
Public Service Commission
of Maryland

IN THE MATTER OF THE EXPLORATION	)	
INTO THE BENEFITS AND COSTS OF	)	
DISTRIBUTED SOLAR AND THE	)	
ASSOCIATEDPOTENTIAL RATE DESIGN	)	PC 48
OPTIONS APPLICABLE TO THE SERVICE	)	
TERRITORIES OF THE MARYLAND ELECTRIC	)	
COOPERATIVES	)	

Comments of the Staff of the Public Service Commission of Maryland
in Response to the Report of Daymark Energy Advisors
regarding the Value of Solar

The Staff of the Public Service Commission of Maryland ("Staff") submits its Comments in the above-captioned matter as directed by Commission Letter Order, dated February 24, 2017.

The Value of Solar report submitted by Daymark Energy Advisors ("Value of Solar Report" or "Report") found that Maryland may overcompensate solar distributed generation customers of Southern Maryland Electric Cooperative, Inc. ("SMECO") and Choptank Electric Cooperative, Inc. ("Choptank") (together "the Cooperatives") when the direct costs and benefits of the Cooperatives alone are considered. When societal emissions costs are also included in the analysis, overcompensation only occurs for a few of the rate classes.

The Report provides a general overview of how to value solar for the Cooperatives. The Report does not completely cover all possible costs and benefits of distributed solar but rather establishes a base from which to begin analyzing the value of solar generation in Maryland. Total production for all residential solar installations in SMECO was just under 40,000 MWh as of September 2016, which amounts to about two percent of residential annual energy requirements.[1] Total solar generation from all classes was about 44,000 MWh. The amount of solar installed has increased each year since 2008, and currently there are about 3,300 net metered Residential accounts in the SMECO service territory.[2] The Residential class accounts for the vast majority of net metered customers.

Choptank's total net metered generation was 18,000 MWh as of September 2016 with 6,000 MWh of generation attributed to the Residential class.[3] The amount of solar installed has increased each year since 2013. Currently Choptank has about 500 Residential net metering accounts.[4] Choptank has a higher percentage of solar generation from commercial sources than SMECO.

The Cooperatives still have room for growth with regard to residential solar generation. According to Daymark's analysis, SMECO can add 1,315 MW and Choptank can add 923 MW to their current residential solar generation before reaching 10 percent of their respective peaks.[5] The levelized cost of energy for a Residential solar system is 16 cents/kWh with the inclusion of a 30 percent investment tax credit ("ITC") and 22 cents/kWh without the ITC.[6] The analysis also found that a west facing solar system is more valuable to the Cooperatives than a south facing system because the west facing system produces more energy during peak hours.[7]

The Report conducted an analysis designed to assign value, costs, and benefits to the Cooperatives for distributed solar energy generation. The benefits for the Cooperatives are avoided energy costs, avoided capacity, avoided transmission, avoided distribution, and avoided REC purchases. Daymark found the avoided energy values for the Cooperatives to be

[1] Value of Solar Report, page 14.
[2] Value of Solar Report, page 17.
[3] Value of Solar Report, page 19.
[4] Value of Solar Report, pages 18, 21.
[5] Value of Solar Report, page 23.
[6] Value of Solar Report, page 24.
[7] Value of Solar Report, page 31.

approximately $40/MWh with a south facing system and $41/MWh for a west facing system, within the reference case the Consultant used to determine value.[8] Daymark uses this reference case, without the Clean Power Plan but including the Regional Greenhouse Gas Initiative ("RGGI"), and excludes any additional CO2 emissions limitations in PJM Interconnection, LLC ("PJM") as a baseline scenario to conduct its analysis.[9] All values listed are calculated using the reference scenario. Daymark expects these values to continue to rise to about $70/MWh by 2037. The avoided capacity value calculated for SMECO ranges from $66.86/MWh to $102.56/MWh for south and west facing orientations, respectively. Choptank's avoided capacity value ranges from $58.69/MWh to $84.71/MWh for south and west facing orientations.[10]

The Report found that there are no avoided transmission benefits for the Cooperatives because of distributed solar installations. The Report notes that all transmission projects in the region identify reliability as the main reason for the investment; therefore the projects cannot be avoided.[11] This analysis of transmission is specific to the regions within SMECO and Choptank's service territories and therefore cannot be applied to all electric utilities. In addition, all transmission projects are not solely based on reliability. However, it should be noted that there is opportunity for avoided transmission costs. The analysis notes that the regional peak in PJM generally aligns with the peak period of solar production, which can lead to lower demand and avoided transmission projects.[12] The Report does show that customers will benefit by saving on transmission charges because of lower demand, and, as a result, the Network

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[8] Value of Solar Report, page 32.
[9] Value of Solar Report, page 38.
[10] Value of Solar Report, page 38.
[11] Value of Solar Report, page 43.
[12] Value of Solar Report, page 41.

Integration Transmission Service ("NITS") charge will decrease by \$0.0034/kWh for both SMECO and Choptank customers.[13]

The report concluded that along with transmission there would be little to no effect on distribution avoided costs at the current solar penetration levels.[14] This conclusion was reached because the Cooperatives expect to have minimal load growth, and, therefore, distributed capacity upgrades are not avoided because they are not expected. [15] The Report does note that there are no benefits at the current low solar penetration levels, but residential solar instillation is expected to continue to increase. In addition, future load growth is possible with greater adoption of EVs, and residential solar would curtail some of the increased load which would avoid distribution upgrades. The Report did not analyze the impact of solar on energy and capacity markets prices because these prices may either increase or decrease.[16] The last benefit to the Cooperatives the Report discusses is avoided REC purchases. By customers, installation of distributed solar facilities, the Cooperatives avoid purchasing renewable energy generation to meet their RPS compliance level. The Report found the avoided REC purchases to be worth \$1.30 per kWh produced by distributed solar.[17] This estimate was calculated using the former RPS not the current, higher RPS compliance levels which were passed by the Maryland Assembly in January 2017.

The Report did assign value to society for the avoided emissions of CO2 and NOx. These are the only societal benefits that were calculated by Daymark. The effect on local economic development, jobs, increased taxes, water and land savings, etc. were not quantified in the Value of Solar Report, and, as a result, not all the benefits to society are covered. In other

[13] Value of Solar Report, page 45.
[14] Value of Solar Report, page 47.
[15] Value of Solar Report, page 46.
[16] Value of Solar Report, page 51.
[17] Value of Solar Report, page 53.

words, the value given by the Report's analysis to solar for society as a whole is not complete and is lower than it would if all be all societal benefits had been considered. The Report does find the societal benefits of avoided emissions to be significant. The benefits of CO2 reductions are valued at $35.93/MWh in 2017 and $76.13/MWh in 2037. The benefits of NOx reductions are valued at $13.74/MWh in 2017 and $31.95/MWh in 2037. [18]

The report gives a Value of Solar ("VOS") estimate for 2018 of $0.06/kWh without societal impacts and $0.11/kWh considering societal emissions, which values are expected to increase every year.[19] According to the Report all customer classes for the Cooperatives are overcompensated with Net Energy Metering ("NEM") when only the direct costs and benefits to the Cooperatives are considered. According to the Report, the Residential class from SMECO is compensated $0.1301/kWh for NEM, and the Residential class for Choptank is compensated $0.1349 for NEM.[20] The VOS benefit that directly affects the Cooperatives is estimated to be approximately $0.06/kWh.[21] The lost revenue due to bill offsets from NEM ranges from 2.2 cents/kWh to 7.5 cents/kWh for both Cooperatives.[22] The estimated rate increases need to recover the lost revenue is $0.0001 to $0.0014/kWh for SMECO and $0.0007 to $0.0023/kWh for Choptank.[23] However, when the societal impacts are also considered, only the Residential class for the Cooperatives and one other rate class in Choptank are overcompensated for NEM.[24] When societal impacts are considered the VOS is estimated to be $0.11/kWh.[25] The societal impacts as analyzed include only avoided CO2 and NOx emissions; if more societal impacts were considered, it is plausible that no rate class would be overcompensated.

[18] Value of Solar Report, page 57.
[19] Value of Solar Report, page 5, 6, 60, 61.
[20] Value of Solar Report, page 71.
[21] Value of Solar Report, page 70.
[22] Value of Solar Report, page 66.
[23] Value of Solar Report, page 68.
[24] Value of Solar Report, page 69.
[25] Value of Solar Report, page 70.

In order to fix the overcompensation the NEM customer receives which leads to cross subsidies between rates classes, the Report does a brief analysis on how different rate designs effect revenue recovery and cross subsidies. The rate designs discussed are the following: (1) uniform volumetric rate increase, (2) fixed charge increase; (3) demand charge; (4) net exports; (5) paid VOS; and (5) distributed energy resource facility charge. Each rate design is meant to recover lost revenue cost by solar instillations. For the Cooperatives each rates design has a similar effect. The least effective rate in recovering lost revenue is the volumetric rate increase followed by the fixed charge increase, a demand charge, paid VOS, and the most effective, which recovers 100% of lost revenue, the DER facility charge.[26] The analysis also found that the first four rate designs would still provide enough compensation to incentivize solar development while the paid VOS and facility charge rate design would not compensate solar customers enough to incentivize solar development.[27] The analysis found that there is an inverse relationship between rate designs that address cross subsidies and revenue recovery and those rate designs which best support solar development.[28]

The Report provides a useful review of the components that should be considered when determining the value of solar photovoltaics and other distributed energy resources ("DER"). The Report does not identify a specific solution for either SMECO or Choptank, but does suggest some additional areas to explore in addition to adjustments to fixed monthly charges and volumetric rates.

As noted on page 23 of the Report, the impact of net metering on utility revenue is low, and impacts primarily Residential classes. Similar rate impacts may be present from other programs with broad ratepayer or societal benefit, *e.g.*, energy efficiency and advanced metering

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[26] Value of Solar Report, page 93.
[27] Value of Solar Report, page 94.
[28] Value of Solar Report, page 95.

programs. The Report has not presented reasons to depart from the Commission's current approach to rate design. Rather it provides an opportunity to review methods that could provide customer incentives to invest in DER to meet renewable energy goals in a manner that manages cross-subsidization in a more precise manner.

The Report has not distinguished the systems or service territories of the Maryland cooperatives as requiring different net metering or DER policies when considered along with investor-owned utilities. Since Maryland net metering law is available to all Maryland ratepayers, regardless of service territory, any changes to SMECO or Choptank tariffs made in isolation from Statewide policy may be ineffective or unfair to Cooperative members.

Although the investigation of DER benefits is currently being undertaken in PC44, Staff welcomes the opportunity to consider the specific impacts to Choptank and SMECO in this proceeding and would reserve the opportunity to provide additional comments in response to other parties.