Actual Benefits of Distributed Generation in Mississippi

Prepared on behalf of
Mississippi Public Service Commission

David E. Dismukes, Ph.D.
Acadian Consulting Group
5800 One Perkins Place Drive, Suite 5-F
Baton Rouge, Louisiana 70808
Phone: (225) 769-2603
Fax: (225) 769-2608

URL: www.acadianconsulting.com

ACADIAN CONSULTING GROUP

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Executive Summary

On December 3, 2015, the Mississippi Public Service Commission ("the Commission") adopted the Mississippi Renewable Energy Net Metering Rule ("MRENMR," "NEM Rule," or "the Rule"). The purpose of the NEM Rule was to provide net metering service at non-discriminatory rates for behind-the-meter, customer-owned generation resources. The Commission's NEM Rule adopted what is often called a "two-channel billing" or "net billing" approach, where electricity sales from a distributed energy resource ("DER") is valued at a rate separate from the retail rate charged to the customer for all use of electricity from the electric utility. The Commission adopted a methodology that values electricity generation provided by DER installations to the utility distribution grid at avoided costs.

The Commission's NEM Rule also includes a 2.5 cent per kilowatt-hour ("kWh") "adder" to the avoided cost reimbursement rate to account for additional, difficult to quantify benefits that could arise from DER generation. The Commission, at the time of adopting the NEM Rule, recognized that there is a high degree of uncertainty surrounding the specific values for these difficult to quantify DER benefits. Because of this uncertainty, the Commission stated that its 2.5 cents per kWh adder would be replaced within three years by an updated value developed from a Mississippi-specific independent study.

On June 5, 2018, the Commission hired the Acadian Consulting Group, LLC ("ACG") to serve as an independent consultant to quantify the direct and measurable benefits associated with DER generation in Mississippi. This Report, and its recommendations, represent the culmination of ACG's research analyzing the quantifiable and measurable benefits of Mississippi-based DER generation development. The estimates arise from three primary benefit areas that include those associated with:

(1) avoided generation capacity costs; (2) avoided transmission and distribution ("T&D") capacity costs; and (3) the avoidance of a host of other types of smaller costs and expenses such as line losses and ancillary services costs.

One of the first steps in this analysis is to quantify the Mississippi-specific contributions that solar energy makes to offset investor-owned utility ("IOU") peak electrical loads. The extent to which a DER supplements a utility's generation capacity planning requirements is determined primarily by the degree to which DER installations, collectively, are available at the time the utility system is peaking. The measure used to determine this capacity contribution is referred to as the "effective load carrying capability" (or "ELCC") of that generation resource. A high ELCC value entails that the DER makes a substantial contribution in helping a utility meet its peak load service requirements, while a lower value entails that a resource's contribution to meeting a system peak is relatively low (or non-coincident).

Renewable resources can often have relatively low ELCCs since they tend to peak at times that are not coincident with the system peak. This Report estimates a 28.7 percent ELCC for Entergy Mississippi, LLC. ("EML") based upon its reported summer peaks. Mississippi Power Company ("MPC"), on the other hand, reports both summer and winter peaks. A blended annual average ELCC of 26.1 percent, therefore, has been estimated for MPC.

This Report also develops a range of unit cost estimates for each of the major avoided capacity cost items identified above and, for a final recommendation, selects the median result across each of these individual methods. Avoided generation capacity cost benefits, for example, were calculated using four separate approaches: (1) a cost-of-new-entry ("CONE") analysis based on recent forecasts from the Energy Information Administration ("EIA"); (2) A CONE analysis based on recently-reported generation development costs in the southeast region; (3) the implied capacity premium included in historic wholesale market prices; and (4) the results of the recent Planning Resource Auction ("PRA") for the Planning Year ("PY") 2018-19 in the organized market created by the Mid-Continent Independent System Operators ("MISO").

Benefit estimates for avoided T&D capacity costs were developed using three different methods that include: (1) an examination of the average annual utility addition to deferrable T&D plant; (2) an alternative approach that estimates the current carrying cost of a utility's total T&D plant in service; and (3) a modification of the second estimation method that examines the current carrying cost on a utility's deferrable (not total) T&D plant in service.

Figures ES-1 and ES-2 present a summary of the quantifiable benefits of Mississippi-specific DER and the recommended adders the Commission could adopt for EML and MPC, respectively. In total, a reasonable and quantifiable adder for EML would be 0.35 cents/kWh and 0.27 cents/kWh for MPC's service territory.

Table ES-1: Total Avoided Costs (EML)

	Hourly Avoided Cost ($/MWh)	Effective Load Carrying Capacity (%)	Effective Hourly Avoided Cost ($/MWh)	Effective Hourly Avoided Cost (cents/kWh)
Avoided Generation Capacity				
Net Cost of New Entry ("CONE")	$ 9.45	28.7%	$ 2.71	0.2712
Southeast Generation Costs	$ 5.42	28.7%	$ 1.55	0.1555
Implied Capacity Premium	$ 7.23	28.7%	$ 2.07	0.2074
MISO RPA - Zone 10	$ 0.79	28.7%	$ 0.23	0.0228
Median Value	$ 6.32	28.7%	$ 1.81	0.1815
Avoided T&D Capacity				
Average Annual Deferrable Additions	$ 3.70	28.7%	$ 1.06	0.1061
Hypothetical Revenue Requirement -- Total Plant	$ 14.16	28.7%	$ 4.06	0.4063
Hypothetical Revenue Requirement -- Deferrable Plant	$ 4.63	28.7%	$ 1.33	0.1327
Median Value	$ 4.63	28.7%	$ 1.33	0.1327
Avoided Other Costs				
Net Cost of New Entry ("CONE")	$ 1.80	28.7%	$ 0.52	0.0517
Southeast Generation Costs	$ 1.03	28.7%	$ 0.30	0.0296
Implied Capacity Premium	$ 1.38	28.7%	$ 0.40	0.0395
MISO RPA - Zone 10	$ 0.15	28.7%	$ 0.04	0.0043
Median Value	$ 1.20	28.7%	$ 0.35	0.0346
Total Avoided Cost Benefits				
Avoided Generation Capacity	$ 6.32	28.7%	$ 1.81	0.1815
Avoided T&D Capacity	$ 4.63	28.7%	$ 1.33	0.1327
Avoided Other Costs	$ 1.20	28.7%	$ 0.35	0.0346
Total Avoided Cost Benefits	**$ 12.16**		**$ 3.49**	**0.3488**

Table ES-2: Total Avoided Costs (MPC)

	Hourly Avoided Cost ($/MWh)	Effective Load Carrying Capacity (%)	Effective Hourly Avoided Cost ($/MWh)	Effective Hourly Avoided Cost (cents/kWh)
Avoided Generation Capacity				
Net Cost of New Entry ("CONE")	$ 5.93	26.1%	$ 1.55	0.1546
Southeast Generation Costs	$ 2.50	26.1%	$ 0.65	0.0651
Implied Capacity Premium	$ 5.34	26.1%	$ 1.39	0.1392
Median Value	$ 5.34	26.1%	$ 1.39	0.1392
Avoided T&D Capacity				
Average Annual Deferrable Additions	$ 2.46	26.1%	$ 0.64	0.0641
Hypothetical Revenue Requirement -- Total Plant	$ 8.38	26.1%	$ 2.19	0.2187
Hypothetical Revenue Requirement -- Deferrable Plant	$ 3.45	26.1%	$ 0.90	0.0899
Median Value	$ 3.45	26.1%	$ 0.90	0.0899
Avoided Other Costs				
Net Cost of New Entry ("CONE")	$ 1.57	26.1%	$ 0.41	0.0409
Southeast Generation Costs	$ 0.66	26.1%	$ 0.17	0.0172
Implied Capacity Premium	$ 1.41	26.1%	$ 0.37	0.0369
Median Value	$ 1.41	26.1%	$ 0.37	0.0369
Total Avoided Cost Benefits				
Avoided Generation Capacity	$ 5.34	26.1%	$ 1.39	0.1392
Avoided T&D Capacity	$ 3.45	26.1%	$ 0.90	0.0899
Avoided Other Costs	$ 1.41	26.1%	$ 0.37	0.0369
Total Avoided Cost Benefits	**$ 10.20**		**$ 2.66**	**0.2659**

1. Introduction

1.1. Study Overview: On December 3, 2015, the Mississippi Public Service Commission ("the Commission") adopted the Mississippi Renewable Energy Net Metering Rule ("MRENMR," "NEM Rule," or "the Rule"). The purpose of the NEM Rule was to provide net metering service at non-discriminatory rates for behind-the-meter, customer-owned generation resources.[1] The goal was to establish rates that are identical, with respect to rate structures, levels, and retail rate components to those that a net metered customer would have been charged absent the presence of a net metered renewable generation resource.[2] The analytic support for the NEM Rule included a three year cost-benefit analysis ("CBA") conducted by a consultant for the Commission, Synapse Energy Economics, Inc. (the consulting report will be hereafter referred to as the "Synapse Report"). The Synapse Report found a wide range of benefits arising from the promotion of distributed energy resources ("DER"), including solar.

The final Commission NEM rule was comprehensive in coverage and defines the process by which DER installations will be interconnected, charged, and reimbursed for both electricity sales and electricity purchases coming to and from the utility distribution grid. The NEM Rule provisions include:

- Requiring utilities to provide net metering to all customers using a renewable energy resource.
- A limitation on residential systems to 20 kW and non-residential systems up to 2 MWs.

[1] *In re: Order Establishing Docket to Investigate the Development and Implementation of Net Metering Programs and Standards*, Mississippi Public Service Commission Docket No. 2011-AD-2. Order Adopting Net Metering Rule (December 03, 2015). Exhibit A, p. 3. ("Mississippi Renewable Energy Net Metering Rule").

[2] *Id.*

- The imposition of system DER installation caps if renewable energy capacity exceeds three percent of system peak for the prior calendar year.
- A requirement that all net metered customers must follow the provisions of the Commission's interconnection rule.
- The utilization of a "two-channel" or net billing approach for valuing DER generation.
- A 2.5 cent per kilowatt-hour ("kWh") "adder" to residential generation put to the grid and a 2.0 cent per kWh adder to lower-income household net metered generation.

The Commission's use of a 2.5 cent per kilowatt-hour ("kWh") "adder" to the avoided cost reimbursement rate is of particular interest in defining the current study's purpose. The Commission's NEM Rule found that energy exported from qualifying DER installations in Mississippi[3] will be reimbursed at an avoided cost energy-based rate, plus an adder to account for "non-quantifiable" benefits associated with solar DER.[4] The avoided cost rate itself is based simply on the marginal cost of electricity that is avoided by DER generation.

The Commission allows utilities to establish an avoided cost rate through some kind of direct measurement process or the use of a market-based avoided cost proxy. For instance, Entergy Mississippi, Inc. ("EML") has been allowed to utilize an average of the real-time locational marginal prices ("LMPs") that are reported by its regional transmission organization ("RTO") as a measure of its avoided generation cost.[5] Mississippi Power Corporation ("MPC"), on the other hand, which is not a member of an

[3] *Id.*, Order Adopting Net Metering Rule (December 3, 2015) at 5-6. The Commission determined that its rules would not apply to state Electric Power Associations ("EPAs") voluntarily participating in a net metering program offered through the Tennessee Valley Authority ("TVA").
[4] *Id.* at 14.
[5] *Id.*

RTO, has utilized a direct measurement approach using a model-based avoided cost valuation methodology.[6]

The "adder" to avoided costs was not a measurable item when the Commission adopted its NEM rule. In fact, the adder was adopted by the Commission in order to recognize the findings of the Synapse Report indicating that DER can provide a number of positive system and public benefits that are often very difficult to measure and quantify such as generation capacity benefits, avoided transmission and distribution capacity benefits, avoided emissions benefits, and risk mitigation/hedging benefits.[7] The Commission also adopted a similar 2.0 cents/kWh adder for low income households but limited this adder to the first 1,000 qualifying low-income customers.[8]

The Commission clearly recognized, in adopting the use of a non-measurable adder, that these benefits are probable, but difficult to measure with precision.[9] The Commission's decision to utilize a 2.5 cents/kWh adder was not directly tied to a specific estimate of the benefits of NEM, but as a compromise between the disparate positions of parties to the original NEM rulemaking proceeding. The Commission also recognized that the adder approach was something that was also utilized by TVA.[10] This 2.5 cent per kWh adder, however, was never intended as being permanent and has been explicitly referenced as being a "temporary adder" until such time that a later, independent analysis can by conducted by the Commission.[11] The Commission's NEM rule requires that this

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[6] *Id.*

[7] Elizabeth A. Stanton et al. (September 19, 2014). Synapse Energy Economics, Inc., *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations*. P. 4.

[8] *In re: Order Establishing Docket to Investigate the Development and Implementation of Net Metering Programs and Standards*, Mississippi Public Service Commission Docket No. 2011-AD-2, Order Adopting Net Metering Rule (December 3, 2015) at 8.

[9] *Id.* at 14.

[10] *Id.* at 15-16.

[11] *Id.* at 15.

temporary adder be re-evaluated after a three year period and replaced with a value, estimated by an independent third party consultant that "can be demonstrated to have been realized and quantified as a result of the adoption of distributed generation in Mississippi.[12]

On June 5, 2018, the Commission hired the Acadian Consulting Group, LLC ("ACG"), from Baton Rouge, Louisiana, to act as its independent consultant to quantify the direct and measurable benefits associated with DER generation in Mississippi. The Commission directed ACG to perform the following specific tasks in preparation of a study for consumption by the Commission:

(1) Gather and assess relevant information and data from regulated utilities and other interest parties and stakeholders that may provide guidance in developing a calculation and quantification of the actual benefits of distributed generation as anticipated by the Commission's MRENMR.

(2) Work collaboratively with the utilities to gather Mississippi-specific data regarding the benefits that have been realized as a result of the adoption of distributed generation in Mississippi since implementation of the MRENMR.

(3) Use Mississippi-specific data to calculate the actual, quantifiable benefits realized by installed distributed generation over and above the cost of wholesale power in Mississippi.[13]

This Report represents the culmination of these three analytic tasks. Over the past five months, ACG has reached out to all stakeholders, including the regulated IOUs to collect information, discuss the study's intent, and to define a process by which the study would progress. In fact, ACG, working closely with the Commission's Executive Staff, as well as the Mississippi Pubic Utilities Staff ("MPUS"), engaged stakeholders in a workshop after being hired by the Commission.

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[12] *Id.*

[13] *Id.*, The Mississippi Public Service Commission Requires the Assistance of an Independent Consultant in Docket No. 2011-AD-2 to Perform a Study Calculating the Actual Benefits of Distributed Generation in Mississippi (May 8, 2018).

This stakeholder meeting, held on August 2, 2018, was open to all interested parties and stakeholders. ACG prepared an exhaustive overview of what it interpreted as its charge from the Commission in terms of study scope, as well as spending considerable time working with stakeholders in addressing a number of issues raised by the Sierra Club, 25x'25 Alliance, and the Gulf Coast Renewable Energy Industries Association ("GSREIA") in a motion to amend the study's procedural schedule before the Commission.[14] Each of these stakeholders were allowed to respond to ACG's presentation and discuss their own study concerns and interests. Likewise, Raymond Jordan, who owns his own residential solar installations, prepared remarks to parties.[15] The presentation provided by ACG to stakeholders during this meeting is attached to this Report as Appendix A.

ACG noted its study intent at the time of the August 2, 2018 stakeholder meeting and clearly indicated to the parties that:

- Study participants are welcome to reach out and contact the project team at any time. We will attempt to respond to inquiries at a timely fashion.
- Study participants wishing to provide information for consideration in this proceeding are welcome to submit directly to the study team.
- Study participants wishing to provide detailed information can request to have that protected under confidentiality provisions as defined by Commission rule.
- Project team welcomes all relevant information in this process and open communication.

Since that time, ACG has received no information from non-utility parties on this matter despite the assertions and representations made at the August public workshop. On November 16, 2018, ACG provided an initial draft of this Report ("Draft Report") to the

[14] *Id.*, Motion to Amend Schedule for Review Study of Distributed Generation Benefits (July 18, 2018).

[15] *Id.,* Remarks of Raymond Craig Jordan (August 2, 2018).

Commission. The Commission, in turn, made the Draft Report available for parites/ comment on November 19, 2018. The Commission originally set a forty-five day formal comment period,[16] which was subsequently extended for an additional 30 days.[17] ACG received a number of comments from stakeholders on the Draft Report, including comments from 25x'25 Alliance; EML; Mississippi Solar Energy Society; MPC; and the Sierra Club. Additionally, the Sierra Club also submitted comments to the Draft Report prepared by Synapse Energy Economics, Inc. ("Synapse") on behalf of GSREIA, the Sierra Club, and 25x'25 Alliance. A summary of those comments, and ACG's response to those comments, have been provided in Appendix B to this Report.

1.2. Study Purpose: The Commission's charge to ACG in conducting its analysis has been to quantify the "actual benefits of distributed generation" using specific Mississippi-data provided by EML and MPC.[18] The scope of this study, therefore, differs substantially from the one conducted by Synapse during the initial phases of the Commission's NEM rulemaking process. The purpose of the original Synapse study was to identify a broad range of costs and benefits associated with DER in order to support a public interest finding either accepting or rejecting the adoption of an NEM rule for Mississippi. Synapse used broad brushstrokes in painting a canvas of DER costs and benefits that included a recommendation that adopting a NEM Rule would be in the public interest. The Commission, in examining the final canvas, adopted a NEM rule based on these findings, and also adopted a financial "adder" that provides additional above-cost support for all

[16] Order Requesting Comments.

[17] Order Granting Motion to Extend Comment Period.

[18] *Id.,* The Mississippi Public Service Commission Requires the Assistance of an Independent Consultant in Docket No. 2011-AD-2 to Perform a Study Calculating the Actual Benefits of Distributed Generation in Mississippi (May 8, 2018).

DER generation put to the grid. The adder, however, was envisioned by the Commission as a "temporary" measure until such time that more definitive benefits could be explicitly quantified from actual Mississippi data.

The purpose of this study is to focus more clearly on a single topic: quantifying the specific economic benefits associated with DER in Mississippi. While Synapse's investigation was somewhat theoretical and conceptual in nature, the current investigation is more focused and has been framed to address quantifiable DER-related benefits within the stricter regulatory ratemaking standards of "known and measurable." This known and measurable standard is consistent with the Commission's definition of "actual benefits" of DER included in its NEM Rule which defines these benefits as those that are "actual and quantifiable" and "over and above the [value of energy reflected in wholesale power markets]."[19]

The consistency between the known and measurable standard for ratemaking, and the "actual benefits" included in the Commission's NEM Rule appears to be no coincidence. Utilities, following the directions of the Commission's NEM Rule, will pay DER installations for their self-generated electricity, and utilities, in turn, will pass the cost of that purchased DER electricity along to ratepayers, just like any other wholesale energy purchase, through their fuel adjustment charges to ratepayers. Thus, the charges utilities incur in making these DER purchases are part of their regulated cost of service and, therefore, need to be tied to costs that are reasonably known and measurable. If DER reimbursements are not based on known and measurable costs, they simply become wealth transfers away from ratepayers and to NEM installations.

[19] Mississippi Renewable Energy Net Metering Rule, p. 1.

Table 1, presented below, highlights a wide range of system and public benefits that are associated with DER, particularly solar energy. The list includes most of the ones identified by Synapse in its original report to the Commission, as well as a number of additional benefits that are included in "value of solar" studies that have been conducted in other regulatory jurisdictions and will be discussed in greater detail later in this Report. The challenge with many of these benefits, as the Commission noted in its original NEM rulemaking, is that these benefits are speculative and difficult, if not impossible, to quantify.

In some instances, the benefits commonly attributable to DER are not relevant to states like Mississippi. Consider, for instance, the DER benefits associated with the avoided costs of Renewable Portfolio Standard ("RPS") compliance and those associated with avoided carbon emissions. Neither of these benefits are relevant for Mississippi since it (a) does not have an RPS standard and (b) does not participate in a regional greenhouse gas ("GHG") emissions program like states in the mid-Atlantic and New England regions.

Table 1: Potential DER Benefit Categories
Source: Authors construct.

Potential Benefit Category	Description	Study Relevance/Appropriateness
Avoided Energy	All fuel, variable operations and maintenance expenses, emission allowance costs, wheeling charges.	No since these are already established by market-based avoided costs utilized by utilities and defined by Commission rule.
Avoided Capacity	Capacity purchases avoided or improvements to reserve margins created by DER capacity.	Yes.
Avoided Transmission and Distribution Capacity	T&D capacity avoided by DER capacity.	Yes.
Avoided System Losses	Avoided T&D electrical losses from localized electricity generation	Yes.
Avoided RPS Compliance	Reduced payments to comply with RPS requirements.	No since MS does not have an RPS.
Avoided Environmental Compliance Costs	Reduced environmental compliance costs not otherwise captured in avoided energy.	No since carbon regulation is not known and measurable regulatory change in foreseeable future and MS does not participate in any regional GHG market.
Market Price Suppression	Price impact caused by introduction of new supply.	Potentially if these can be estimated in known and measurable fashion. The overall impact will be largely determined by installed DER capacity which is very limited in MS.
Avoided Risk (Hedge)	Reduction in price volatility created by DER resources.	No since DER resources are not supplied on a fixed cost/price basis. The generation for DER is based in large part on variable avoided cost/price market information.
Avoided Grid Support	Ancillary service benefits.	Yes.
Avoided Outage Costs	Avoided interruptions from DER.	Yes, however, for MS, this will be very small value given limited number of current installations and capacity and will also have to be examined with the context of the resources' intermittancy. Solar-based DER will have highly discounted outage benefits.
Non-energy benefits	Wide range of benefits that have dificult to quantify value that can range from economic development, to technological innovation to customer satisfaction and empowerment benefits.	No given Commission rule provisions that clearly require a movement away from non-measurable benefits.

Thus, this Report takes a more focused look at only those potential categories in Table 1 that result in a clear, known, and measurable benefit to the utility system. The Report will not focus on more societal-type benefits that are difficult to measure, but may help to inform a public interest finding on NEM from a general and conceptual basis (like the Synapse Report). The majority of the benefits estimated in this Report will be associated with assessing the avoided capacity-related benefits of NEM, particularly capacity avoided across the generation, transmission, and distribution functions of Mississippi's electric utilities. The methodologies and results of this estimation process will be discussed in greater detail later in this Report.

1.3. Study Outline: This Report is organized into the following sections outside of this introduction.

- ***Mississippi DER development trends:*** this section will discuss the recent trends in Mississippi DER development and how those trends have progressed since the adoption of the Commission's NEM Rule.

- ***Avoided generation capacity cost estimates:*** this section will discuss the literature, methodologies, and data used to estimate the avoided generation capacity benefits of Mississippi DER installations.

- ***Avoided transmission and distribution (T&D) cost estimates:*** this section will discuss the literature, methodologies, and data used to estimate the avoided T&D capacity benefits of Mississippi DER installations.

- ***Other avoided cost estimates:*** this section will discuss the literature, methodologies, and data used to estimate the other avoided benefits of Mississippi DER installations. This includes those associated with avoided line losses and grid support benefits.

- ***Conclusions and recommendations:*** the last section will provide the specific findings and recommendations for this Report that the Commission should adopt a 0.35 cents per kWh adder in EMI's service territory and 0.27 cents per kWh adder in MPC's service territory as the permanent actual DER benefit for which NEM installations will be reimbursed and as defined in the NEM Rule. ACG also finds that the Commission should update this estimate at least every five years, depending upon market conditions.

2. Development Trends in Distributed Generation

There have been a number of important changes in DER development, as well as state regulatory policies supporting DER that have arisen since the publication of the Synapse Report in September 2014. This section will provide an overview of the policy trends that have impacted DER development nationally, as well as provide the descriptive statistics on how DER has developed since the issuance of the Commission's NEM Rule.

2.1. Policy Trends: As noted earlier, DER refers to a variety of technologies that generate electricity at or near a retail electricity customer's location. In the residential and small commercial sectors, DER systems are typically associated with renewable energy technologies, such as solar photovoltaic cells ("PV") or small-scale wind turbines. However, DER can also include fossil-fuel powered backup generators (internal combustion units, micro-turbines) and combined heat and power ("CHP") systems that produce thermal energy for heating and cooling needs in addition to the generation of electricity.

The utilization of DER is not new. Historically, manufacturing and industrial customers have utilized DER as a backup or even replacement for utility-provided electricity. DER has also been used for many "high reliability" commercial applications such as for hospitals and telecommunications centers where there is an above average need for reliability and, in some instances, power quality. However, the recent explosion in the growth of DER over the past decade has been motivated by the growth of renewable energy technologies and the growth of these applications that are installed at residential customer locations, which again, are typically solar.

DER growth has also been facilitated by numerous state legislatures and public utility commissions around the country seeking to diversify energy resources or seeking to promote more environmentally-friendly generation resources. NEM policies, in fact, reflect early state initiatives to support the development of small-scale DER. The first and earliest NEM policies date back to the implementation of the Public Utility Regulatory Policies Act ("PURPA") of 1978. During this time, several state regulators attempted to construct a distribution-level equivalent to PURPA that would help create a standardized access/interconnection process, and a system of on-site generation buy-back and back-up provisions, for smaller distribution-level generation resources. By the early 1980s, there were as many as ten states enacting or promulgating NEM legislation, policies, or rules.

These early NEM policies had a number of common elements. For instance, energy use and generation at NEM installations are generally measured in a fashion that creates a customer "credit" for behind-the-meter generation "put" to the distribution grid and then "charges" that same customer at times when usage is greater than the on-site generator's capacity. Hence, the prefix "net:" these energy charges and credits are reconciled to calculate a "net" usage (and financial payment) for the on-site generation customer. In addition, NEM policies usually include a relatively streamlined and consistent process for distribution level interconnection and a regulatory-established set of rates or credits that are offered as reimbursement for NEM-generated electricity put to a regulated electric utility's distribution grid. It is important to recognize, however, that NEM applications are a subset of a broader class of DER: while all DER systems are not net metered, all NEM systems do represent a form of DER.

Another significant development in the rise of DER occurred in 1992 when Congress passed the Energy Policy Act ("EPAct 1992"). Several states during the 1990s, as part of reviewing and implementing policies outlined in EPAct 1992, adopted utility-specific or statewide NEM policies.[20] These policies represent the more "modern" period of NEM adoption and are reflected by an increased sophistication and understanding of small-scale DER systems, the potential benefits of such systems, and the potential abuses that can arise from DER installations. As such, many states adopted policies that restricted NEM eligibility to only those resources delivering renewable or efficiency benefits, as opposed to those that simply offering simple cycle generation opportunities. For instance, all but two state-level net metering programs implemented during the 1990s limited NEM eligibility to only renewable technologies. During the 1990's, twelve more states had enacted NEM polices.[21]

Over the past decade, state-level NEM policies have been driven in large part by the adoption of RPS and other policy initiatives promoting the development of renewable generation. As shown in Figure 1 below, 38 states and the District of Columbia currently have adopted an RPS or renewable energy goal. NEM policies have now expanded to most of the country including 47 states and the District of Colombia. Currently, only three states do not have explicit NEM polices or programs: Alabama; South Dakota; and Tennessee.

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[20] Public Law 102-486 (October 24, 1992).

[21] Wan, Yih-huei and H. James Green. 1998. Current Experience with Net Metering Programs, National Renewable Energy Laboratory, Presented at Wind Power '98 (Bakersfield, CA), pp. 7-9.

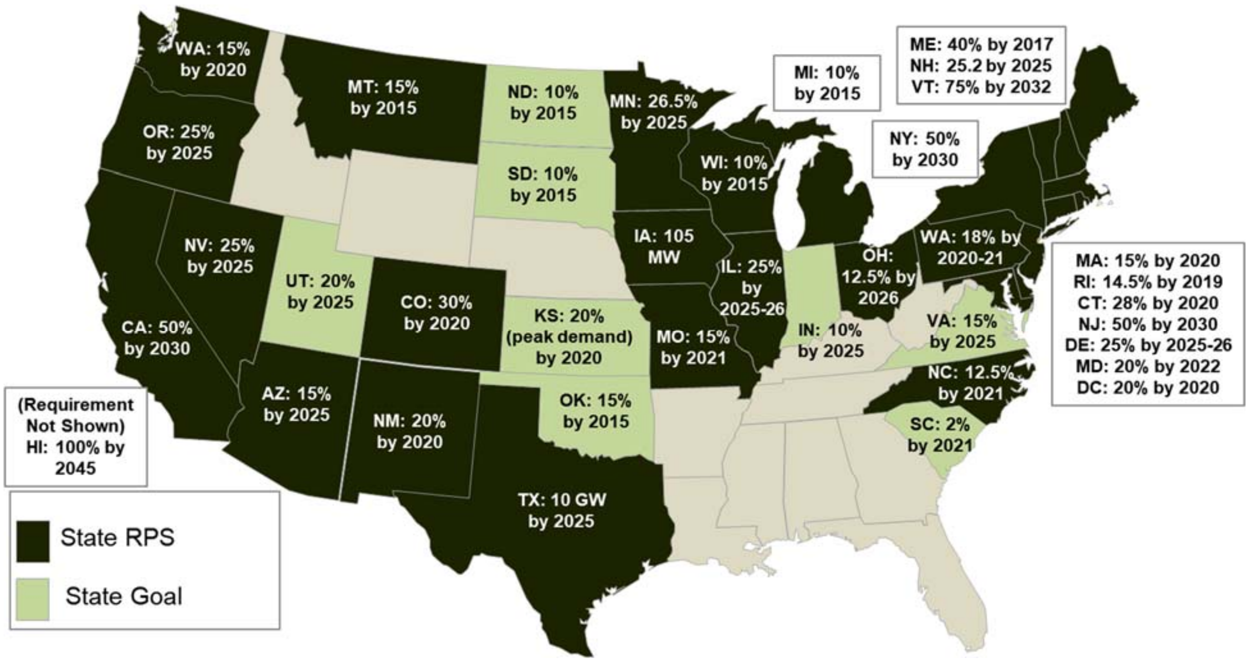

Figure 1: State Renewable Portfolio Standards as of July 2018
Source: National Conference of State Legislatures ("NCSL")

The recent considerable and nation-wide growth of NEM installations, particularly solar PV systems, has transformed state-level NEM participation from a niche application to one that can include an important percentage of a utility's retail customer base. As a result, several states have entered into proceedings reexamining their respective NEM policies, even those adopted as recently as the 1990s. These regulatory review processes have led to a number of instances where individual states have modified their NEM policies.

Three important modifications to NEM policies have arisen over the past several years. The first NEM policy modification is associated with how DER electricity usage and on-site generation are measured for "netting" purposes. Increasingly, more states are moving to a measurement methodology referred to as "two-channel billing" or "net billing" wherein all electricity exported by the DER is valued at a rate consistent with the associated utility's avoided cost of electricity and all of the electricity used by the DER host is valued at a retail price.

Nevada is one of the earlier adopters of the two-channel billing approach, adopting the structure in February 2016 after the Public Utilities Commission of Nevada ("PUCN") rejected an alternative proposal made by Nevada Power Company and Sierra Pacific Power Company ("NV Energy") for approval of a revised cost-of-service study approach resulting in modified NEM-specific tariffs.[22] Other states have also followed suit including Arizona,[23] Hawaii,[24] and Indiana.[25] Michigan recently adopted an NEM approach that could be considered as being two-channel in nature,[26] and Louisiana, which has adopted a two-channel approach as an interim measure, is currently considering moving to this form of NEM measurement on a permanent basis.[27] Further, Mississippi's NEM Rule adopts this two-channel billing approach.[28] While many states are moving in the two-channel direction, interestingly, in June 2017, the Nevada Legislature passed a statute that effectively overturned the PUCN's earlier 2016 decision and reinstated a traditional net metering methodology.[29]

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[22] *Application of Nevada Power Company d/b/a NV Energy for approval of a cost-of service study and net metering tariffs,* Docket No. 15-07041 and *Application of Sierra Pacific Company d/b/a NV Energy for approval of a cost-of-service study and net metering tariffs*, Docket No. 15-07042, Modified Final Order, ¶¶ 94 and 326 (February 12, 2016).

[23] *In the Matter of the Commission's Investigation of Value and Cost of Distributed Generation,* Arizona Corporation Commission Docket No. E-00000J-14-0023, Decision No. 7859 (January 3, 2017).

[24] *Instituting a Proceeding to Investigate Distributed Energy Resource Policies,* Docket No. 2014-0192, Order No. 33258, pp. 126-127 (October 12, 2015).

[25] Indiana Senate Bill 309, Chapter 40, §§ 10 and 17.

[26] *In the matter, on the Commission's own motion, to implement the provisions of Sections 173 and 183(1) of 2016 PA 342, and Section 6a(14) of 2016 PA 341*, Case No. U-18383, Order (April 18, 2018).

[27] *See*, *In re: Review of Policies Related to Customer-Owned Solar Generation and Possible Modification of the Commission's Current Net Metering Rules*, Louisiana Public Service Commission Docket No. R-33929, Phase II Notice of Proposed Modified Rules and Request for Comments (November 28, 2017).

[28] Mississippi Renewable Energy Net Metering Rule, pp. 3-4.

[29] *Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of Tariff Schedules and Rates Pursuant to Assembly Bill 405,*

A second important NEM policy modification includes the development and use of "value of solar" ("VOS") estimates as part of the NEM reimbursement process. VOS-based reimbursement rates attempt to recognize the "additional value" created by solar resources. This approach is not extended to other non-renewable DER technologies. VOS-based reimbursements use study results to estimate NEM reimbursement rate "adders" that provide additional DER financial support that is over and beyond a market-based avoided generation cost reimbursement only. The components of the VOS adder can include, but are not limited to, generation capacity benefits, avoided transmission and distribution capacity benefits, avoided line loss benefits, merit order/price suppression benefits, avoided environmental benefits, and potential other factors important to policy makers in each individual state. The Mississippi Commission's existing approach that includes a temporary 2.5 cent per kWh premium, or adder, can be thought of as a form of VOS-based pricing approach.[30]

A third and important NEM policy modification includes limitations on the portion of exported electricity from a DER application that can be applied against a customer's electric utility service bill. For instance, in March 2017, the Maine Public Utilities Commission completed a rulemaking process to replace its traditional net metering rules with a modified version that would phase-out the ability of net metered customers to use DER systems to net charges associated with transmission and distribution service over a 15 year period.[31] Shortly after Maine adopted this revised net metering approach, New

Docket No. 17-07026, Order Granting in Part and Denying in Part Joint Application by NV Energy on Assembly Bill 405, pp. 14-17 (September 1, 2017).

[30] Mississippi Renewable Energy Net Metering Rule, p. 3.

[31] *Public Utilities Commission Amendments to Net Energy Billing Rule (Chapter 313)*, Public Utilities Commission of Maine Docket No. 2016-00222, Order Adopting Rule and Statement of Factual and Policy Basis (March 1, 2017).

Hampshire approved a similar policy change that reduced the creditable portion of distributed generation to only 25 percent for distribution purposes.[32]

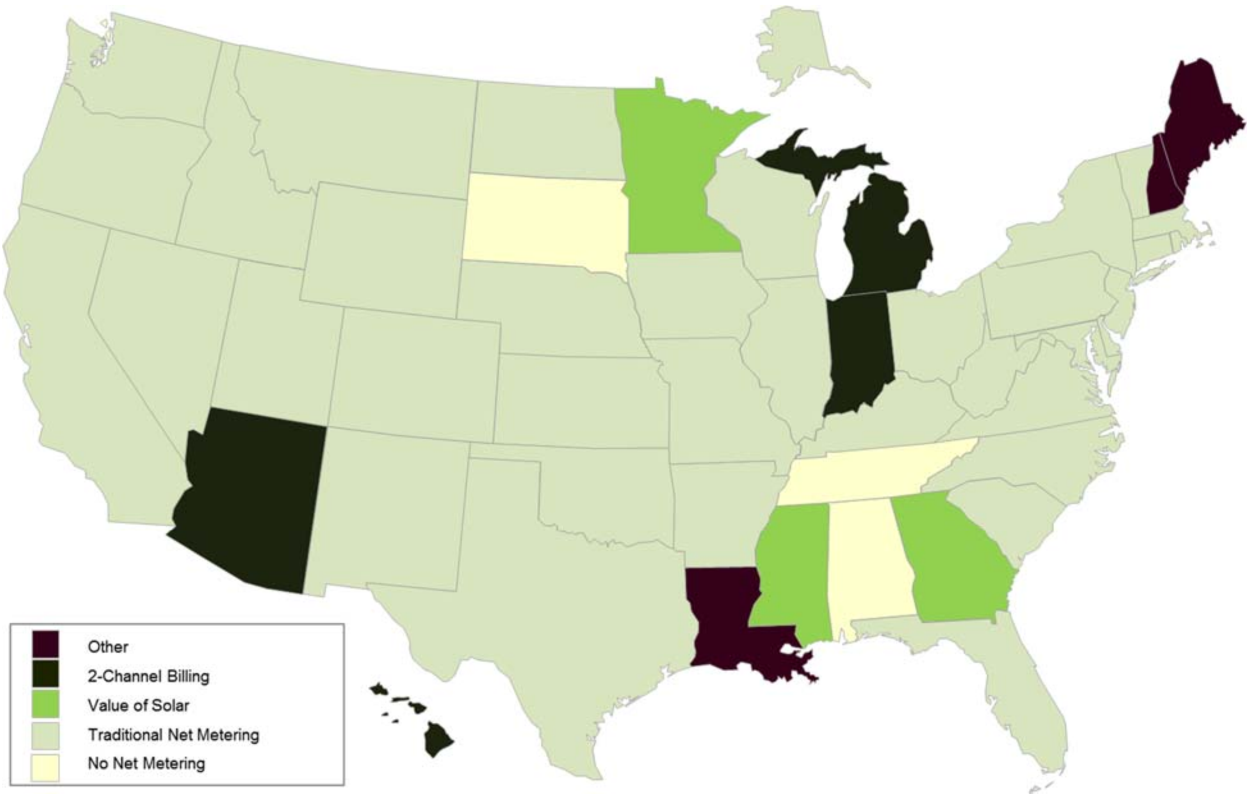

Figure 2: Alternative Net Metering Policies
Source: State Statutes and Regulations

2.2. Recent DER Installation and Capacity Development Trends: The Energy Information Administration ("EIA") collects NEM data as part of the "Monthly Electric Sales and Revenue with State Distributions Report" that is filed by electric utilities and suppliers on what is known as the Form EIA 826. The purpose of this form is to collect information from electric utilities, energy service providers, and distribution companies that sell or deliver electric power to end users. The survey was expanded in

[32] *Development of New Alternative Net Metering Tariffs and/or Other Regulatory Mechanisms and Tariffs for Customer-Generators*, Docket No. DE 16-576, Order Accepting Settlement Provisions, Resolving Settlement Issues, and Adopting a New Alternative Net Metering Tariff ("Order No. 26,029"), p. 72 (June 23, 2017).

2011 to include data on NEM installations, NEM installation types, NEM capacities, and NEM net generation.[33] While national and state level comparisons can be conducted with this data, these comparisons are unfortunately limited to the last six years.

Figure 3 shows the trend in U.S. and Mississippi NEM capacity over the past several years.[34] This chart includes NEM installations across the entire state, not just those NEM installations associated with the investor-owned utilities ("IOUs") that are the subject of the current investigation. As of early 2018, there are over 1.7 million NEM customers in the U.S. that have installed 17,515 MW of NEM capacity: over 94 percent of this national NEM capacity is associated with solar behind-the-meter installations. Over the past four years, U.S. NEM capacity has grown at an average annual rate of 35 percent compared to Mississippi NEM capacity, which grew at an average annual rate of about 269.5 percent over the same period. Since January 2013, Mississippi, while relatively low in total installations, boasts one of the nation's fastest growth in both NEM capacity and NEM customers. However, Mississippi ranks 42nd among states in total NEM installed capacity and 47th in terms of total number of NEM installations, indicating that the average size of Mississippi NEM installations is larger than those average NEM capacities observed in other states.

[33] Net generation is defined as gross NEM system generation less on-site electricity consumption.
[34] This data is based on statewide totals even though the Commission's NEM Rule is restricted to investor-owned electric utilities.

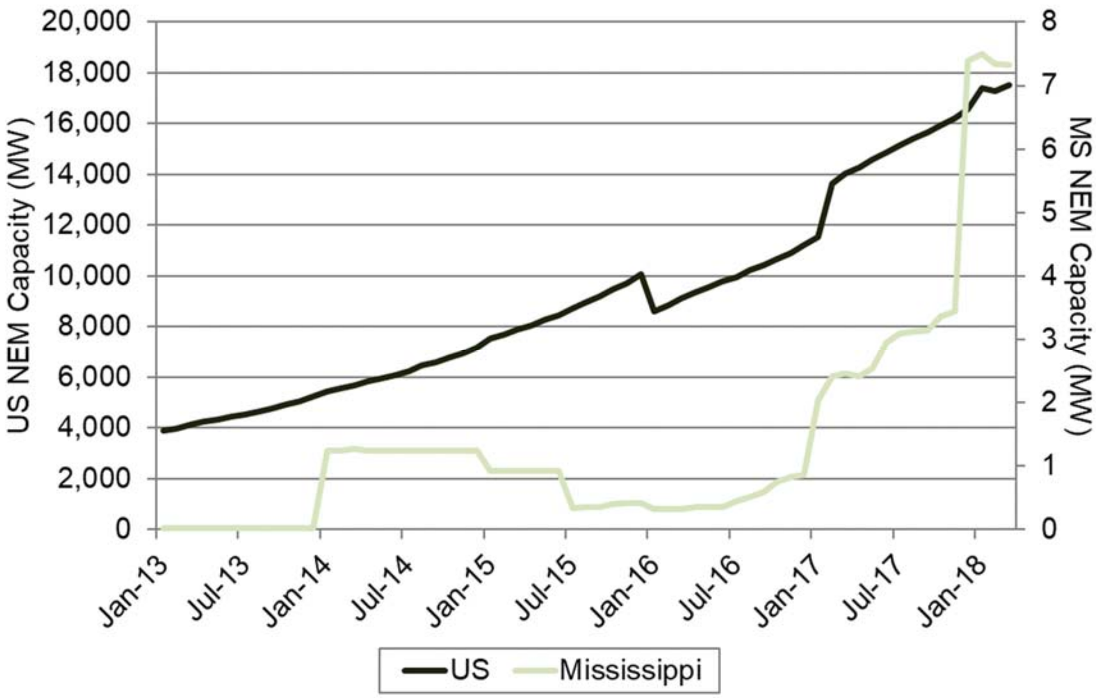

Figure 3: U.S. and Mississippi Installed NEM Capacity (MW)
Source: Energy Information Administration, Form 826.

Figure 4 compares Mississippi and total U.S. NEM capacity growth over the past five years. Mississippi's NEM capacity growth, on a percentage basis, is one of the fastest in the entire U.S., outpacing traditional renewable energy promoting states such as California and Oregon.

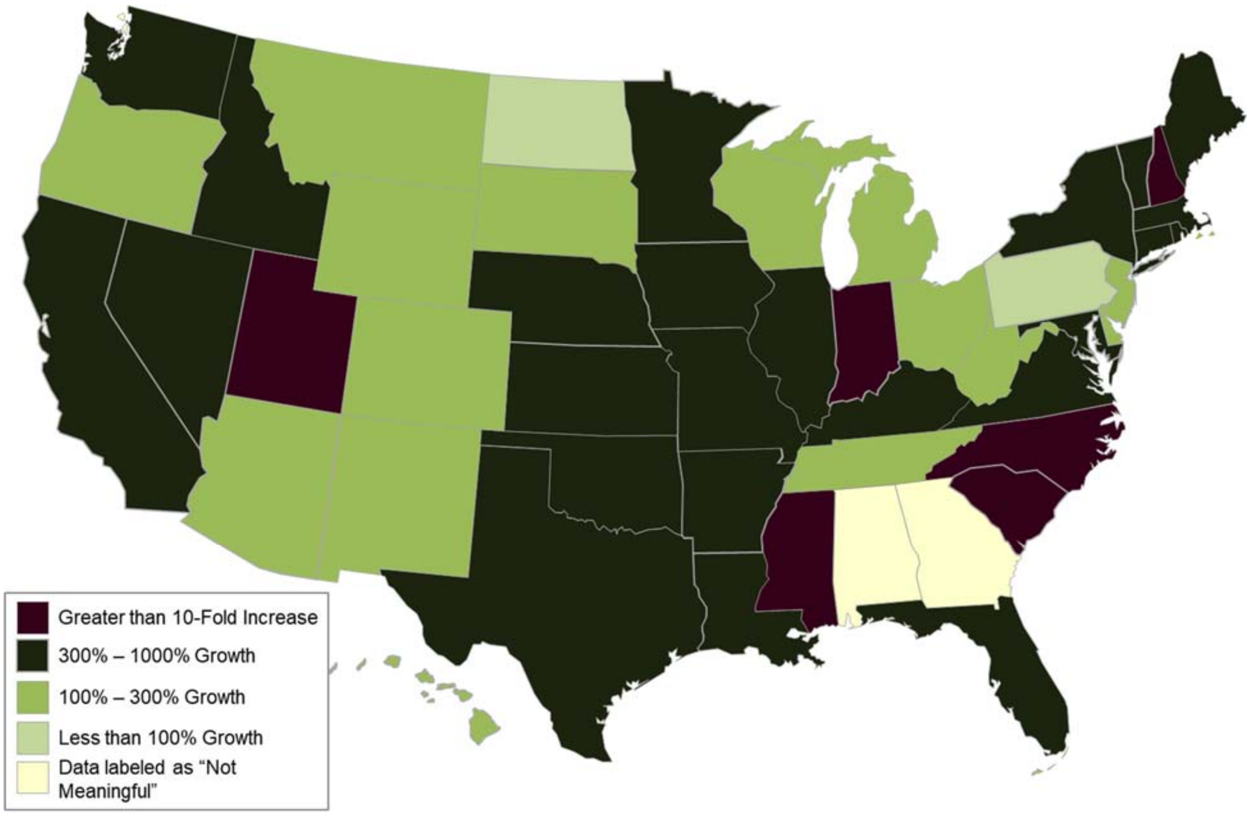

Figure 4: Net Metered Capacity Growth (January 2013 through March 2018)
Source: Energy Information Administration, Form EIA-826.

2.3. Solar Panel Cost Trends Supporting Solar DER Installation Growth: Dramatic cost decreases over the past several years for solar installations has been an important factor facilitating the development of NEM installations throughout Mississippi and the U.S. A good part of this cost decrease can be attributed to the increasingly competitive global market for PV modules. Figure 5 shows that PV exports across the globe have experienced a 53 percent compound annual growth rate from 2000 through 2010, reaching 17 gigawatts ("GW") of PV capacity shipped in 2010. In addition, the individual country concentration for PV module imports has varied over the last several years. In 2000, the U.S. accounted for 30 percent of global PV supply,[35] but quickly ceded

[35] Afrin, David et. al. 2012. SunShot Vision Study. U.S. Department of Energy, pp. 3-4.

that large concentration, first to Japan, which experienced significant growth due to residential subsidies enacted in the mid-1990s; then to Germany, whose generous feed-in tariff subsidy produced substantial growth in domestic solar demand; and finally to China and Taiwan, which invested heavily in PV manufacturing during the 2006 to 2010 timeframe. In fact, by 2010, China and Taiwan accounted for 53 percent of global PV supply.[36]

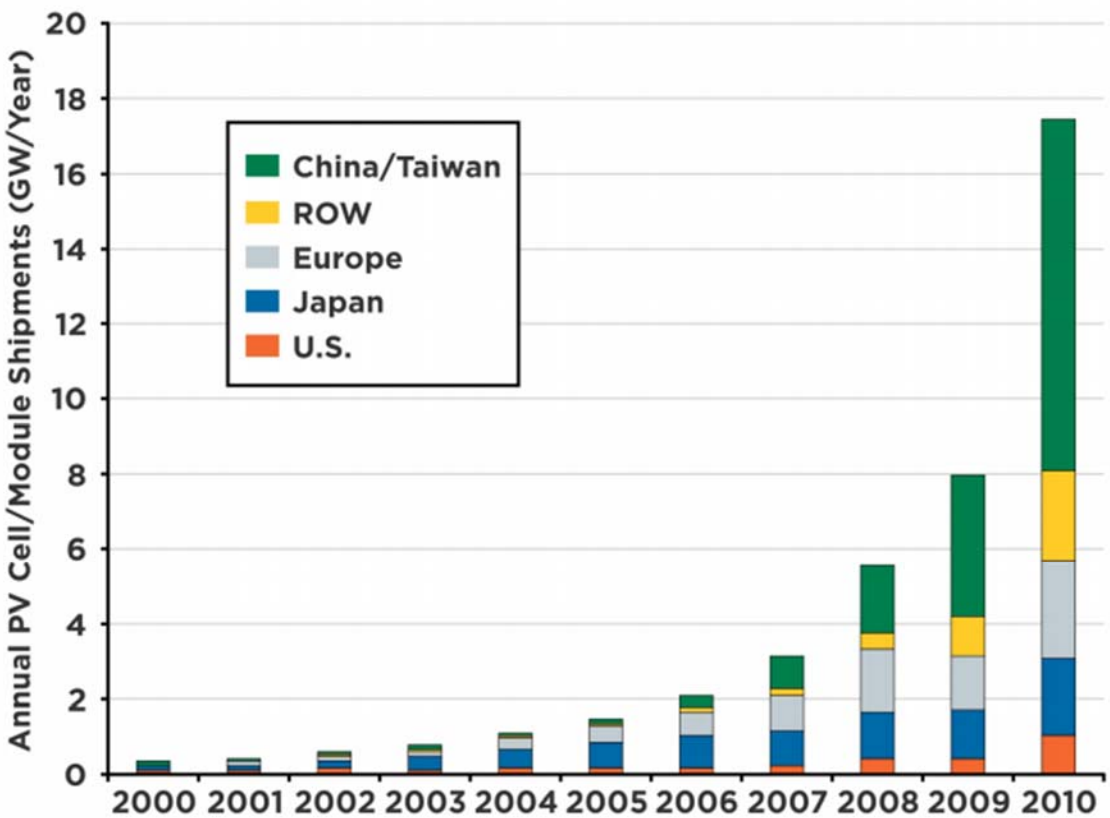

Figure 5: Photovoltaic Module Exports
Source: Afrin, David et. al. 2012. SunShot Vision Study. U.S. Department of Energy, Figure 1-1

The use of Chinese/Taiwanese manufactured PV modules is part of the reason for the relatively large and fast PV price decreases. Installations using Chinese manufactured PV modules have been consistently less expensive than non-Chinese

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[36] *Id.*, p. 26.

product installations (Figure 6).[37] However, the massive growth in PV manufacturing around the world has also increased supply and put downward pressure on PV module prices globally.[38]

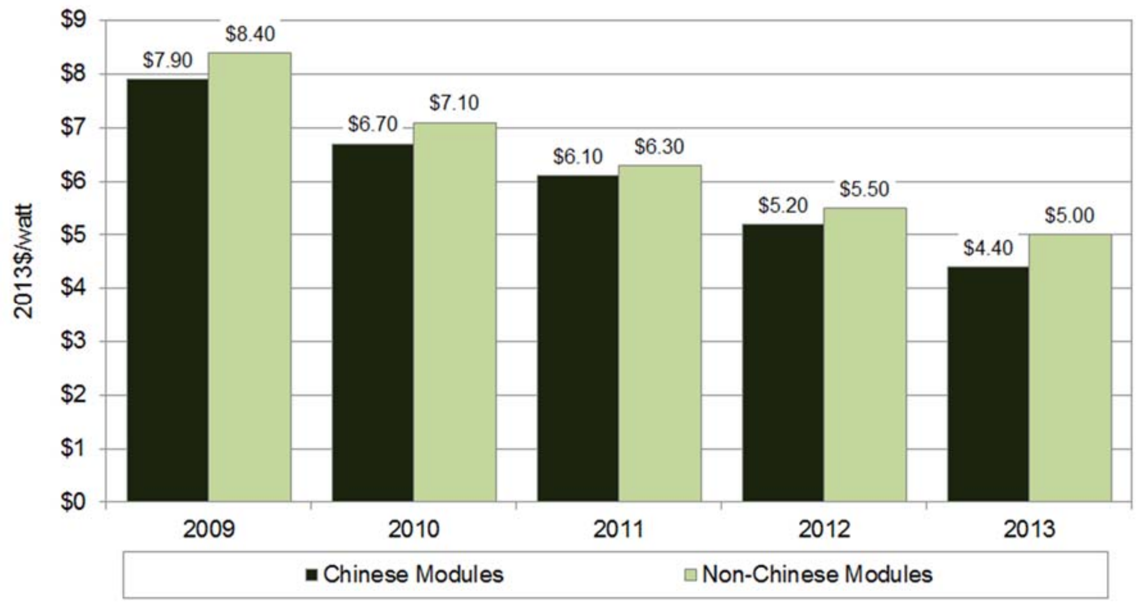

Figure 6: Price Differences between Chinese and non-Chinese Solar PV Installation for <10 kW Systems in the U.S. (2013 $)

Source: Barbose, Galen et. al. 2014. Tracking the Sun VII: An Historical Summary of the Installed Price of Photovoltaic in the United States from 1998 to 2013. U.S. Department of Energy Lawrence Berkeley National Laboratory, p. 32.

Figure 7 shows that the cost of solar PV modules in 1998 was slightly less than $5 per watt of DC capacity, a level that held relatively constant until 2007, after which time prices plunged to current levels of under $1 per watt, a critical threshold point for the

[37] Barbose, Galen et al. 2014. Tracking the Sun VII: An Historical Summary of the Installed Price of Photovoltaic in the United States from 1998 to 2013. U.S. Department of Energy Lawrence Berkeley National Laboratory, pp. 31-32.

[38] It should be noted that in January 2015, the U.S. International Trade Commission determined that the U.S. PV industry is being materially injured by imports of "certain crystalline silicon photovoltaic products from China and Taiwan that the U.S. Department of Commerce has determined are sold in the United States at less than fair value and are subsidized by the government of China." This decision will result in the U.S. Department of Commerce imposing countervailing duties and antidumping duties on solar imports from China. See Pentland, W. 2015. Trade duties on solar imports from China and Taiwan clear final hurdle. Forbes.com. Available at: http://www.forbes.com/sites/williampentland/2015/01/22/trade-duties-on-solar-imports-from-china-and-taiwan-clear-final-hurdle/.

industry. Total installed costs have generally followed similar trends. The total "all-in" installed cost in 1998 for a smaller, residential solar system was around $12 per watt, but by 2013 has fallen to nearly $4 per watt. The increase in low-cost solar panel imports has resulted in a boon for solar customers making rooftop installations more affordable for a wide range of applications.[39]

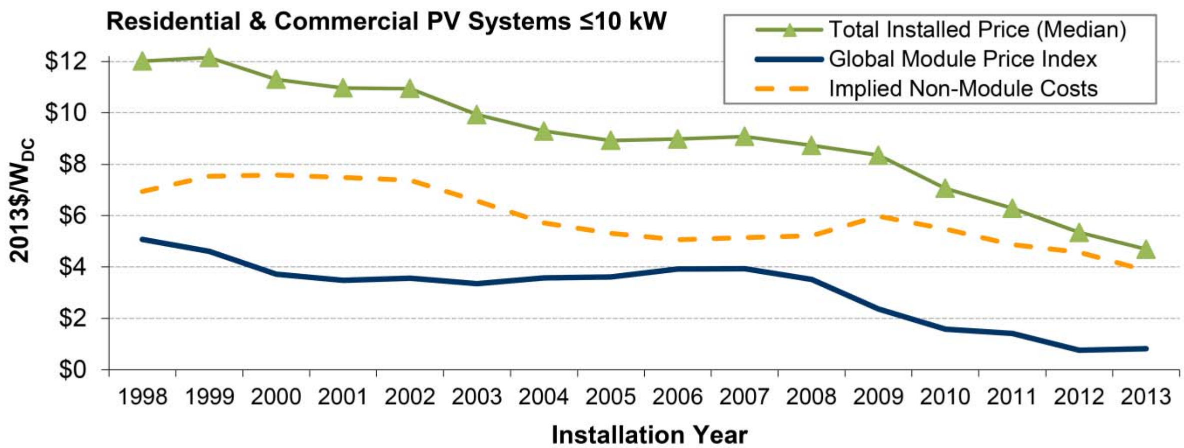

Figure 7: Total Installed PV Price is Decreasing Due to Low Module Costs
Source: Barbose, Galen et. al. 2014. Tracking the Sun VII: An Historical Summary of the Installed Price of Photovoltaic in the United States from 1998 to 2013. U.S. Department of Energy Lawrence Berkeley National Laboratory, Figure 8.

The total cost of a PV system is made up of the module costs, the inverter costs and "balance of system" or "BOS" costs.[40] As module prices have fallen, BOS costs now account for a large share of the total PV system cost (see Figure 8). As of late 2013, the module and inverter costs were approximately $1 per watt for residential installations, while the BOS costs were over $2 per watt.[41] While BOS costs are declining (from

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[39] Barbose, Galen et. al. 2014. Tracking the Sun VII: An Historical Summary of the Installed Price of Photovoltaic in the United States from 1998 to 2013. U.S. Department of Energy Lawrence Berkeley National Laboratory, p. 15.

[40] Balance of system costs include items such as permitting fees, installation labor, overhead, racking, customer acquisition costs and sale tax.

[41] Fu, Ran et. Al. (September 2017), U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017, U.S. Department of Energy National Renewable Energy Laboratory, Figure ES-1; see also, Feldman, David et. al. (September 2014), Photovoltaic System Pricing Trends, U.S. Department of Energy National Renewable Energy Laboratory, p. 17.

approximately $4 per watt for residential systems in 2010 to approximately $2 per watt in 2017), their fall has not been as precipitous as the fall in PV module costs.

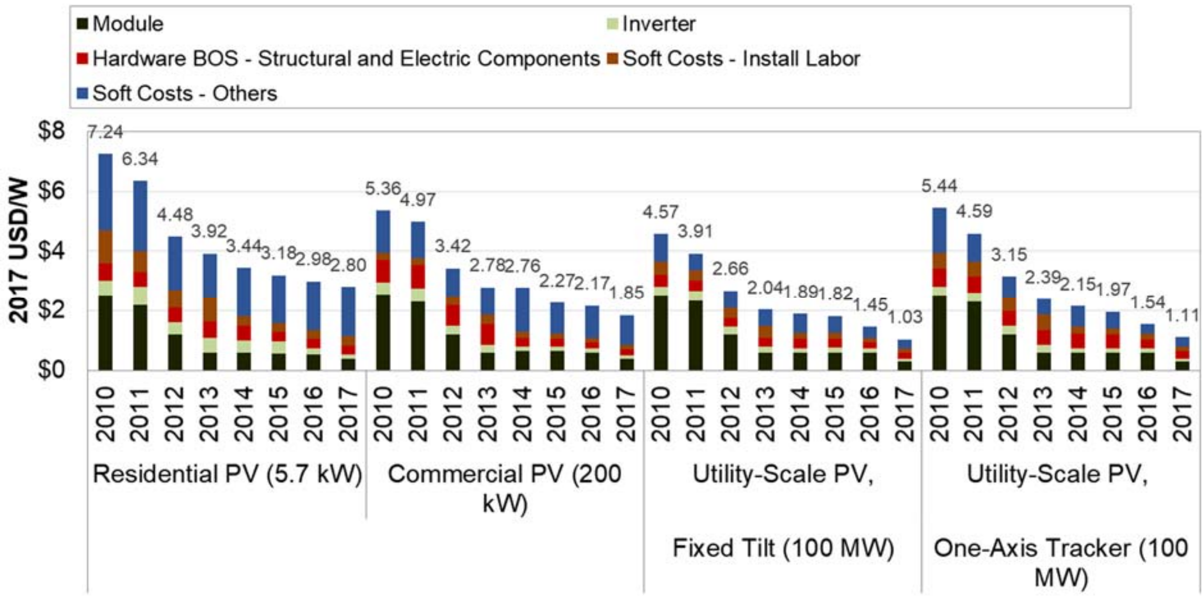

Figure 8: Module, Inverter and Balance of System Costs, 2010-2017

Source: Fu, Ran et. Al. (September 2017), U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017, U.S. Department of Energy National Renewable Energy Laboratory, Figure ES-1.

2.4. Mississippi Solar NEM Trends: Mississippi has seen a dramatic increase in the development of solar NEM installations over the past two years (Figure 9). Prior to 2015 there were fewer than 10 annual installations across the service territories of EML and MPC combined. Since 2015, this rate has steadily increased, such that there were 55 annual solar installations across both utilities in 2017. As a result of this expansion, the number of cumulative solar installations across the utilities increased from four in 2012 to 132 by July 2018.

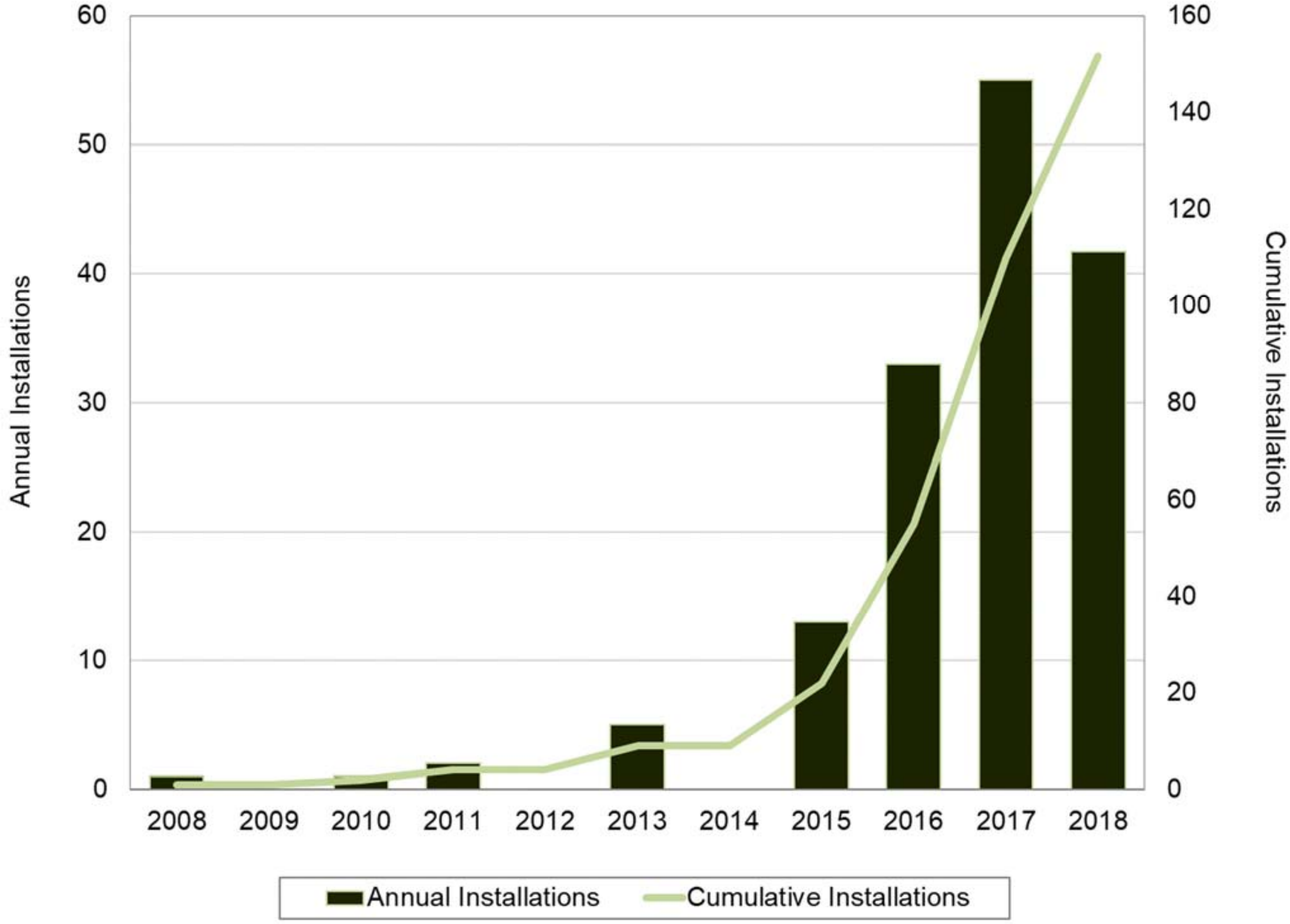

Figure 9: Solar NEM Installations

Note: Figure only includes installations in EML and MPC service territory.
2018 installations represent pro-rated installations based on January through July data.
Source: Responses to Utility Data Requests

Figure 10 shows the trends in the development of solar NEM capacity in the utilities from 2008 through 2018. Prior to 2015, annual capacity installations were relatively small, being less than 50 kW, or 0.05 MW during the entire period. After 2015, cumulative NEM capacity expanded greatly, reaching a maximum of 789 kW in 2017, or nearly one MW of capacity added.

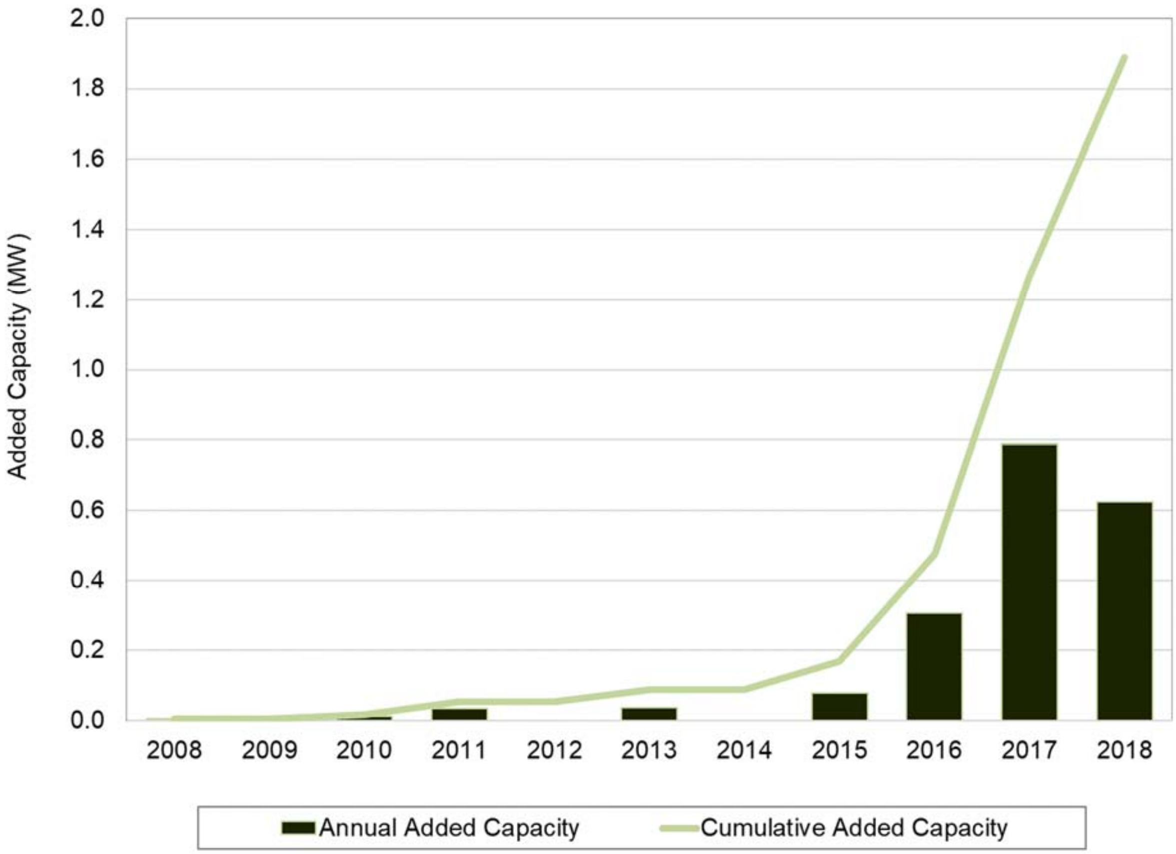

Figure 10: Solar NEM Capacity
Note: Figure only includes installations in EML and MPC service territory.
2018 installations represent pro-rated installations based on January through July data.
Source: Responses to Utility Data Requests

Figure 11 presents the trends in the average size of Mississippi solar NEM installations from 2008 through 2018. Prior to 2015, solar installations were intermittent and relatively large, ranging from approximately 6 kW in 2008 to 18 kW in 2011. After 2015 and the implementation of the Commission's net metering rules, annual solar installations have increased, but have remained relatively large, averaging greater than 10 kW in each of the last two years.

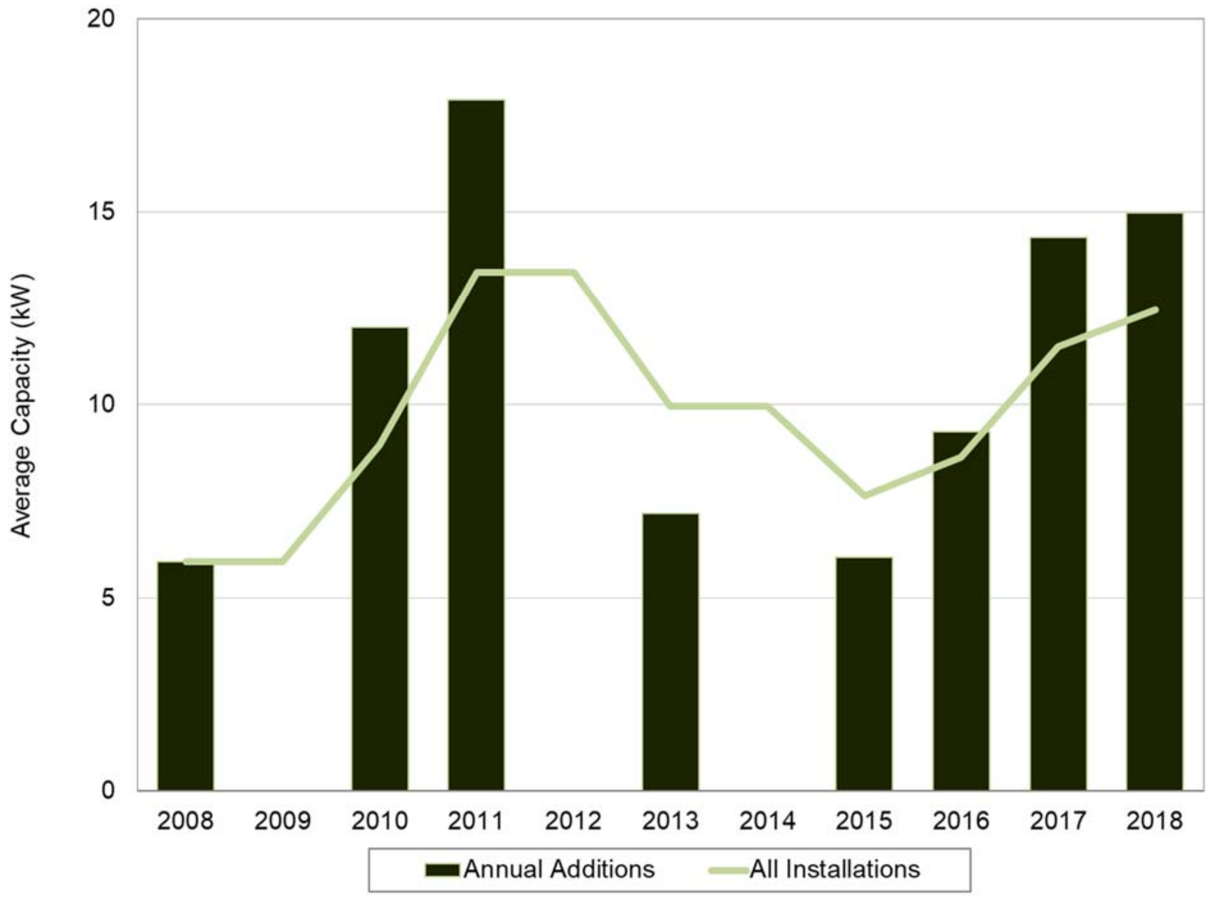

Figure 11: Total Mississippi NEM Average Capacity
Note: Figure only includes installations in EML and MPC service territory.
2018 installations represent pro-rated installations based on January through July data.
Source: Responses to Utility Data Requests

2.4.1. Mississippi IOU Solar NEM Installation Trends: Table 2 provides the annual installation trends for solar NEM installations by utility, while Figure 12 graphs those trends, also by utility. As noted earlier, statewide NEM installations were minimal until 2015. NEM solar installations increased significantly at this time across both utility companies.

Table 2: NEM Installations by Utility and Year
2018 installations represent pro-rated installations based on January through July data.
Source: Responses to Utility Data Requests

Company	Annual Solar Installations 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Entergy Mississippi LLC	-	-	-	2	-	2	-	2	10	19	14
Mississippi Power Co	1	-	1	-	-	3	-	11	23	36	28
Total State	**1**	**-**	**1**	**2**	**-**	**5**	**-**	**13**	**33**	**55**	**42**

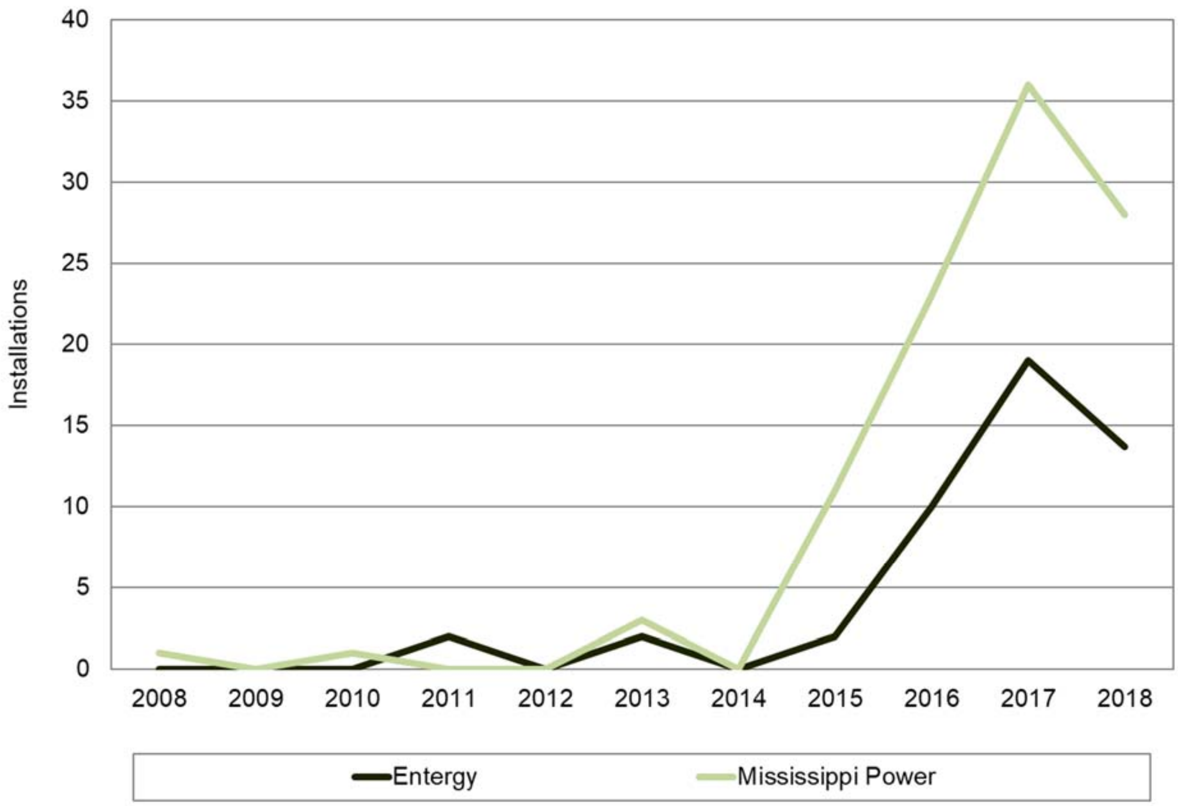

Figure 12: NEM Installations by Utility and Year
2018 installations represent pro-rated installations based on January through July data.
Source: Responses to Utility Data Requests

Mississippi solar NEM installations have increased dramatically since the implementation of the Commission's 2015 net metering rule. From 2008 to 2015, the number of installations for the two IOU utilities never exceeded more than four in a single year. After 2015, annual installations have increased such that by 2017, the last year of complete data, MPC saw 36 installations while EML saw 19.

Table 3 and Figure 13 provide comparable information on the number of cumulative NEM solar installations on an annual and per utility basis. Currently, MPC has the largest number of solar NEM installations in Mississippi, accounting for approximately two-thirds of all installations across the state's two investor owned utilities.

Table 3: Cumulative NEM Installations by Utility and Year
2018 installations represent pro-rated installations based on January through July data.
Source: Responses to Utility Data Requests

Company	Cumulative Solar Installations										
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Entergy Mississippi LLC	-	-	-	2	2	4	4	6	16	35	49
Mississippi Power Co	1	1	2	2	2	5	5	16	39	75	103
Total State	**1**	**1**	**2**	**4**	**4**	**9**	**9**	**22**	**55**	**110**	**152**

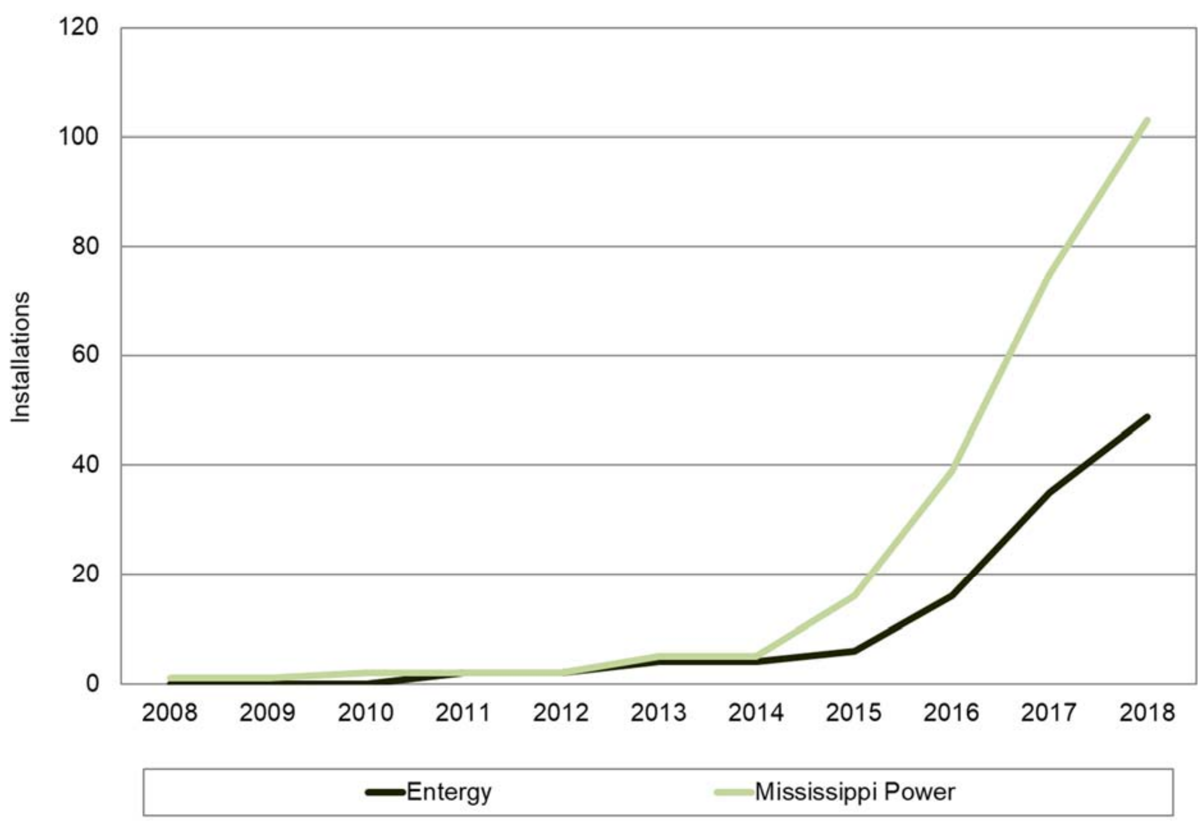

Figure 13: Cumulative NEM Installations by Utility and Year
2018 installations represent pro-rated installations based on January through July data.
Source: Responses to Utility Data Requests

Table 4 provides a geographic break-down of IOU solar NEM installations on a per-county basis. The highest concentration of IOU solar NEM installations is located in Harrison County (31.8 percent), and the next highest concentration of solar NEM installations is located in Hancock County (12.9 percent), Hinds County (12.9 percent), and to a lesser extent in Forrest County (9.9 percent) and Jackson County (6.1 percent).

Table 4: Cumulative NEM Installations by County and Share of State Total

Note: Totals only include data for Entergy Mississippi and Mississippi Power Co.
Source: Responses to Utility Data Requests

County	Number of Installations	Percent of Total (%)
Clarke County	1	0.76%
Copiah County	1	0.76%
DeSoto County	2	1.52%
Forrest County	13	9.85%
George County	2	1.52%
Hancock County	17	12.88%
Harrison County	42	31.82%
Hinds County	17	12.88%
Jackson County	8	6.06%
Jefferson Davis County	1	0.76%
Lauderdale County	1	0.76%
Lincoln County	2	1.52%
Madison County	3	2.27%
Pearl River County	4	3.03%
Pike County	4	3.03%
Quitman County	1	0.76%
Rankin County	6	4.55%
Simpson County	1	0.76%
Stone County	1	0.76%
Sunflower County	1	0.76%
Tallahatchie County	1	0.76%
Warren County	1	0.76%
Washington County	1	0.76%
Wilkinson County	1	0.76%
Total State	**132**	**100.00%**

2.4.2. Mississippi IOU Solar NEM Capacity Trends: Table 5 and Figure 14 provide the annual solar NEM installation capacity trends for each Mississippi IOU. The solar NEM installation capacity trends are similar in nature, on a per utility basis, to those discussed above on installations. Annual solar NEM installations have increased rapidly over the last several years, since the Commission implemented its NEM Rules in 2015.

Table 5: NEM Capacity by Utility and Year

2018 installations represent pro-rated installations based on January through July data.
Source: Responses to Utility Data Requests

	Annual Capacity (kW)										
Company	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Entergy Mississippi LLC	-	-	-	36	-	20	-	10	152	135	134
Mississippi Power Co	6	-	12	-	-	16	-	68	155	654	491
Total State	**6**	**-**	**12**	**36**	**-**	**36**	**-**	**79**	**307**	**789**	**625**

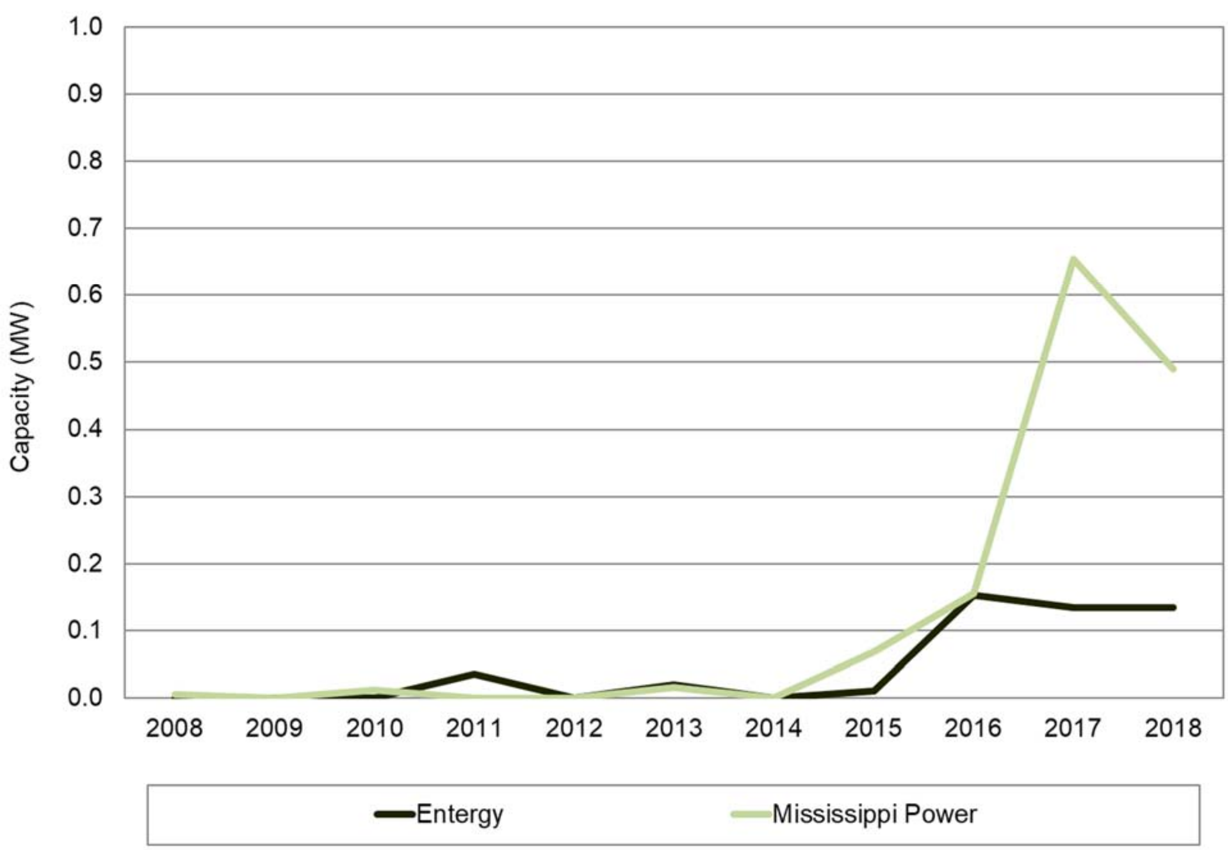

Figure 14: NEM Capacity by Utility and Year

2018 installations represent pro-rated installations based on January through July data.
Source: Responses to Utility Data Requests

Table 6 and Figure 15 provide summaries of the cumulative annual capacity of solar NEM installations in the state. MPC and EML had similar concentrations of NEM solar capacities through 2016. In the last two years, 2017 and 2018, MPC has seen a noticeably higher growth rate in installed solar capacity when compared to EML. Between the two utilities, nearly three-fourths of NEM capacity is found within MPC's service territory.

Table 6: Cumulative NEM Capacity by Utility and Year

2018 installations represent pro-rated installations based on January through July data.
Source: Responses to Utility Data Requests

	Cumulative Capacity (kW)										
Company	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Entergy Mississippi LLC	-	-	-	36	36	55	55	66	218	352	486
Mississippi Power Co	6	6	18	18	18	34	34	103	258	912	1,403
Total State	**6**	**6**	**18**	**54**	**54**	**90**	**90**	**168**	**476**	**1,264**	**1,889**

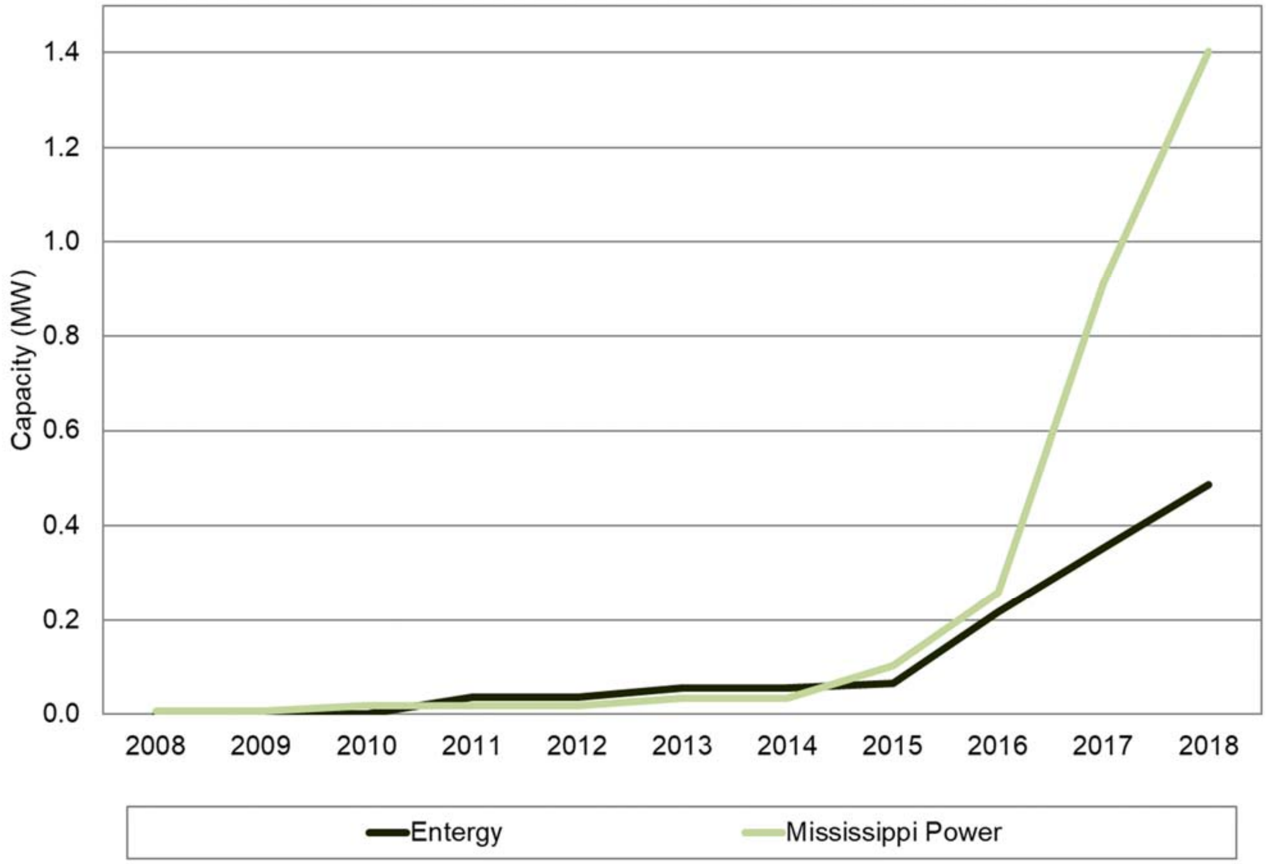

Figure 15: Cumulative NEM Capacity by Utility and Year
2018 installations represent pro-rated installations based on January through July data.
Source: Responses to Utility Data Requests

Table 7 summarizes the geographic breakdown of the Mississippi IOUs' solar NEM capacity. Similar to installations, most of the state's solar NEM capacity is concentrated generally along the Mississippi Gulf Coast (Harrison County), with lower, but significant, concentrations around the cities of Jackson (Hinds County and Madison County) and Hattiesburg (Forrest County).

Table 7: Cumulative NEM Capacity by County

Note: Totals only include data for Entergy Mississippi and Mississippi Power Co.
Source: Responses to Utility Data Requests

County	Capacity (kW)	Percent of Total (%)
Clarke County	6.6	0.42%
Copiah County	11.0	0.69%
DeSoto County	23.1	1.45%
Forrest County	269.9	17.00%
George County	20.6	1.30%
Hancock County	123.2	7.75%
Harrison County	637.5	40.15%
Hinds County	153.0	9.64%
Jackson County	60.2	3.79%
Jefferson Davis County	6.0	0.38%
Lauderdale County	5.9	0.37%
Lincoln County	16.6	1.05%
Madison County	25.7	1.62%
Pearl River County	25.5	1.60%
Pike County	29.0	1.83%
Quitman County	15.0	0.94%
Rankin County	33.4	2.10%
Simpson County	6.5	0.41%
Stone County	8.1	0.51%
Sunflower County	72.0	4.53%
Tallahatchie County	21.6	1.36%
Warren County	4.3	0.27%
Washington County	6.0	0.38%
Wilkinson County	7.3	0.46%
Total State	**1,588**	**100.00%**

2.4.3. Mississippi IOU Solar NEM Average Capacity Trends: Table 8 and Figure 16 provide the annual solar NEM installation average capacity trends for each MS investor owned utility. The solar NEM installation average capacity trends are similar in nature, on a per utility basis, to the statewide trends discussed earlier. System sizes in Mississippi are generally highly variable between utilities and between years, due in no small part to the limited adoption of solar PV in Mississippi. Since the Commission's adoption of formal NEM Rules, average system sizes have ranged between 5 and 18 kW per system on an annualized basis.

Table 8: NEM Average Capacity by Utility and Year
2018 installations represent pro-rated installations based on January through July data.
Source: Responses to Utility Data Requests

Company	Average Annual Capacity (kW)										
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Entergy Mississippi LLC	-	-	-	17.91	-	9.75	-	5.16	15.22	7.08	9.78
Mississippi Power Co	5.94	-	12.00	-	-	5.48	-	6.22	6.74	18.18	17.52
Total State	**5.94**	**-**	**12.00**	**17.91**	**-**	**7.19**	**-**	**6.06**	**9.31**	**14.34**	**14.98**

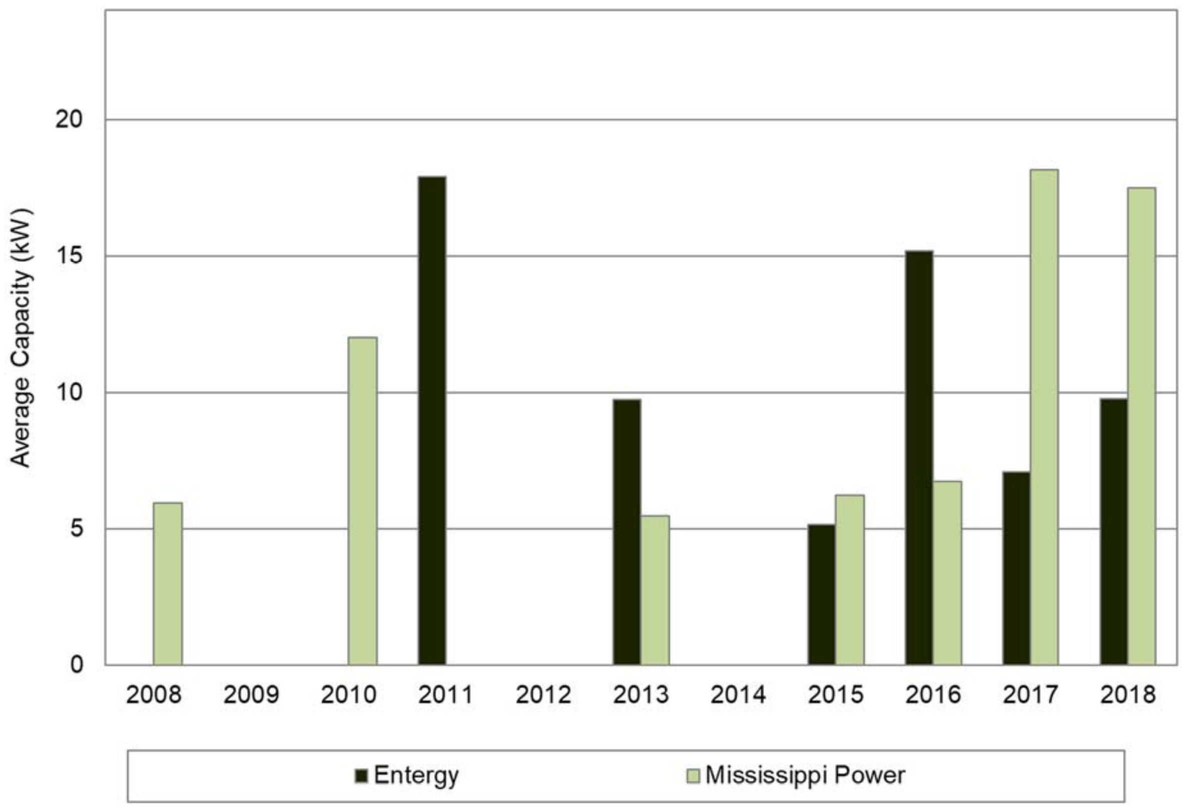

Figure 16: NEM Average Capacity by Utility and Year
2018 installations represent pro-rated installations based on January through July data.
Source: Responses to Utility Data Requests

Table 9 and Figure 17 provide summaries of the cumulative annual average capacity of solar NEM installations in the state.

Table 9: Cumulative NEM Average Capacity by Utility and Year

2018 installations represent pro-rated installations based on January through July data.
Source: Responses to Utility Data Requests

Company	Average Total Capacity (kW)										
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Entergy Mississippi LLC	-	-	-	17.91	17.91	13.83	13.83	10.94	13.61	10.07	9.99
Mississippi Power Co	5.94	5.94	8.97	8.97	8.97	6.88	6.88	6.43	6.61	12.16	13.62
Total State	**5.94**	**5.94**	**8.97**	**13.44**	**13.44**	**9.97**	**9.97**	**7.66**	**8.65**	**11.50**	**12.45**

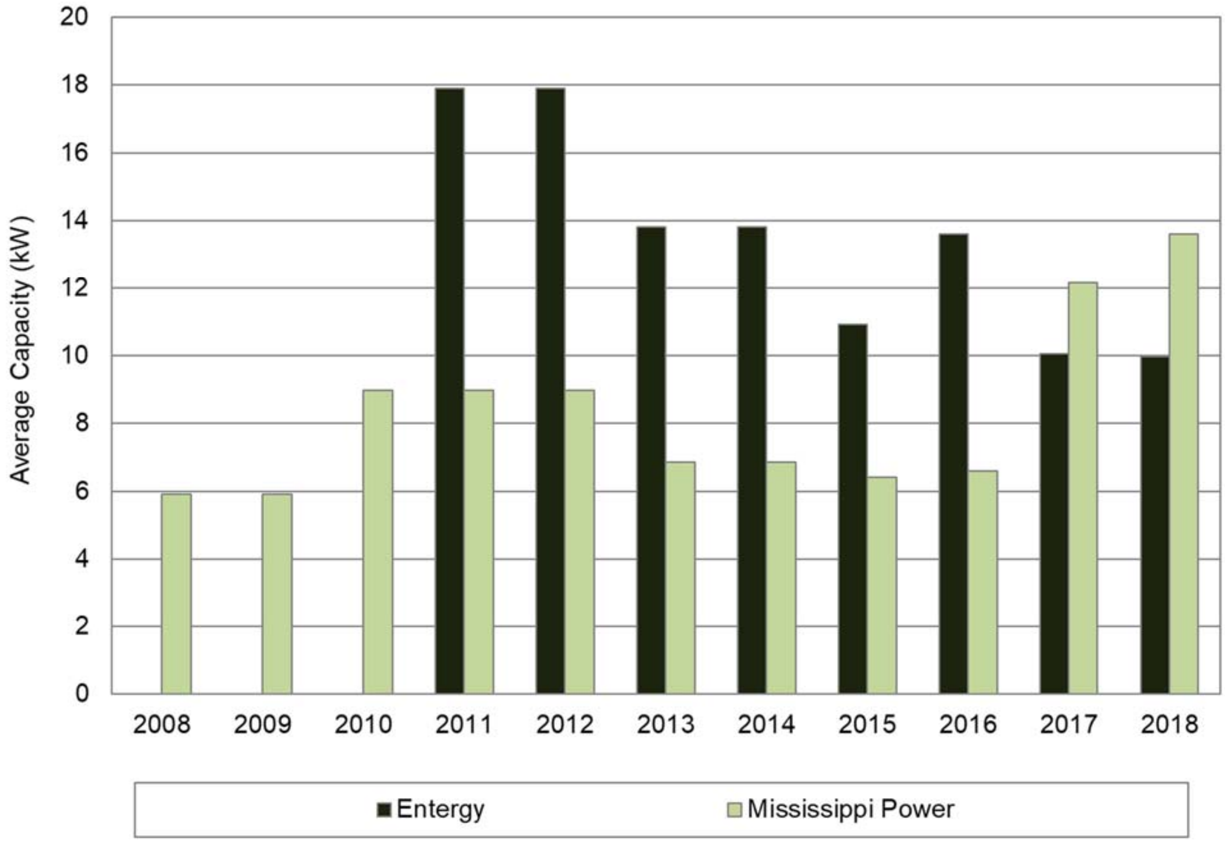

Figure 17: Cumulative NEM Average Capacity by Utility and Year

2018 installations represent pro-rated installations based on January through July data.
Source: Responses to Utility Data Requests

Table 10 summarizes the geographic breakdown of the state's IOU solar NEM capacity.

Table 10: Cumulative NEM Average Capacity by County

Note: Totals only include data for Entergy Mississippi and Mississippi Power Co.
Source: Responses to Utility Data Requests

County	Capacity (kW)
Clarke County	6.6
Copiah County	11.0
DeSoto County	11.5
Forrest County	20.8
George County	10.3
Hancock County	7.2
Harrison County	15.2
Hinds County	9.0
Jackson County	7.5
Jefferson Davis County	6.0
Lauderdale County	5.9
Lincoln County	8.3
Madison County	8.6
Pearl River County	6.4
Pike County	7.3
Quitman County	15.0
Rankin County	5.6
Simpson County	6.5
Stone County	8.1
Sunflower County	72.0
Tallahatchie County	21.6
Warren County	4.3
Washington County	6.0
Wilkinson County	7.3
Total State	**288**

3. Avoided Generation Capacity Costs

3.1. Overview: DER creates an immediate and obvious benefit that includes its ability to defer utility generation at the time this DER generation is put to the grid. Every kWh generated by a DER application displaces a kWh generated by a utility or other larger generator. Most DER applications that are net metered are reimbursed on a per kWh basis for the generation not used on-site and put to the grid. The per kWh reimbursement "value," however, can often be controversial with some NEM/DER advocates calling for a reimbursement value, or rate, to be comparable if not greater than the full retail residential rate. On the other hand, there are other parties, including some Commissions, that utilize reimbursement values set at a level often referred to as an "avoided cost."

The term "avoided cost" has a long history in utility regulation and dates back to PURPA. The term originated at a time when there were no competitive wholesale markets, electricity was not traded as a commodity, and electric utilities were vertically integrated and highly regulated. To accomplish its goals, PURPA established a new class of generating facilities that would receive special rate and regulatory treatment.[42] These facilities are known as "non-utility generators" or more commonly "qualifying facilities" ("QFs"). PURPA requires utilities to purchase electricity generated by QFs at the rate of a utility's "avoided cost," not the QF generator's cost of service. A utility's "avoided cost" is the cost a utility would incur if it chose to generate the electricity itself or purchase it from another source.[43]

[42] Federal Energy Regulatory Commission. 2018. What is a qualifying facility? Available at: https://www.ferc.gov/industries/electric/gen-info/qual-fac/what-is.asp.

[43] 18 C.F.R. § 292.101(b)(6).

As noted in the earlier policy section of this Report, NEM policies began to arise concurrently, or soon after the adoption of PURPA. Over time, regulators began to move to the use of "avoided cost" as a reimbursement value for DER generation since that value is, itself, intended to represent a value comparable to the short run marginal cost that establishes price levels in competitive markets. The Mississippi Commission, in fact, utilizes an "avoided cost" measure to value per unit (per kWh) generation that a NEM DER customer provides to the grid.[44] The Commission currently allows each IOU to use their own methodology for estimating this avoided costs.

EMI, for instance, uses an avoided cost that is measured as the locational marginal price ("LMP") reported by the Midcontinent Independent System Operator ("MISO"), including an adjustment for average line losses. This LMP-based avoided cost measure is used since it is a transparent and readily available measure of the marginal cost of electricity being sold in regional wholesale markets. MPC, on the other hand, is not a member of an RTO or ISO and does not have the ability to rely on a comparable market-based measure and must estimate this cost using a production model-based approach.[45]

There are, however, additional potential generation-related benefits that can arise from DER that go beyond this "energy-only" based measure. These additional generation-related benefits include the avoided need for additional generation capacity to meet future demand or load requirements.

Consider that capacity in the electric power industry is usually thought of as the maximum generation capability of an electric generating resource during periods of

[44] *In Re: Order Establishing Docket to Investigate the Development and Implementation of Net Metering Programs and Standards,* Docket No. 2011-AD-2, Order Adopting Net Metering Rule at 7-8.
[45] *Id.*

system maximum needs or demand.[46] Evaluating current capacity capabilities and future capacity needs are important aspects of reliability planning, since one important reliability consideration is ensuring that enough capacity exists to meet anticipated or unanticipated changes in load.[47] In this manner, DER can provide value to utility system planners in potentially two manners.

First, DER can reduce overall customer demand requirements over an extended period of time since load formerly served by utility generation is now being served by behind-the-meter generation. This displacement of utility generation capacity with DER generation capacity, in theory, reduces a utility's generation capacity planning requirement. Second, in addition to displacing generation capacity, DER also has the ability, in theory, to supplement the generation needs of a utility to serve loads at times in which the system is hitting critical peaks, often arising during extremely hot or cold days when air conditioning or heating loads, respectively, are at their highest.

3.2. Estimating Effective Load Carrying Capabilities: The extent to which a DER supplements a utility's generation capacity planning requirements is determined primarily by the degree to which that resource is available at the time the utility system is peaking. The measure used to determine this contribution is referred to as the "effective load carrying capability" (or "ELCC") of that resource. The California Public Utilities Commission ("CPUC") defines ELCC as "…a percentage that expresses how well a resource is able to meet reliability conditions and reduce expected reliability problems or

[46] Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners, p. 5.

[47] Mazer, Auther (2007). *Electric Power Planning for Regulated and Deregulated Markets.* John Willey & Sons, Inc. P. 129.

outage event (considering availability and use limitations)."[48] A high ELCC value entails that the DER makes a substantial contribution in helping a utility system meet its peak load service requirements, while a lower value entails that a resource's contribution to meeting a system peak is relatively low (or non-coincident). Renewable resources can often have relatively low ELCCs since they tend to peak at times that are not coincident with the system peak.

Table 11 provides a table highlighting the annual system peaks for Mississippi's IOUs during 2013 to 2017. EML's annual system peak has consistent occurred during late July or during the month of August. Likewise, these system peaks have occurred at either 4:00 p.m. or 5:00 p.m. MPC, on the other hand, has dual peaks with the overall annual system peak occurring in some years during the winter heating season, and in others or during summer cooling season. MPC's winter peak consistently has occurred during the month of January at 8:00 a.m. MPC's summer peak tends to occur between late June to early August at either 3:00 p.m. or 4:00 p.m.

[48] Effective Load Carrying Capacity and Qualifying Capacity Calculation Methodology for Wind and Solar Resources (January 16, 2014), California Public Utilities Commission Resource Adequacy Proceeding R.11-10-023, at 1.

Table 11: Annual System Peak, EML and MPC (2013-2017)
Source: Annual Report, FERC Form 1

	2013	2014	2015	2016	2017
Entergy Mississippi					
Date	August 8	August 20	August 10	August 4	July 26
Hour	1700	1700	1600	1600	1600
Megawatts	3,173	2,954	3,180	3,089	2,953
Mississippi Power - Summer					
Date	June 27	August 20	July 23	August 2	July 20
Hour	1600	1500	1600	1500	1500
Megawatts	2,422	2,415	2,477	2,453	2,387
Mississippi Power - Winter					
Date	December 16	January 30	January 8	January 11	January 8
Hour	0700	0800	0800	0700	0800
Megawatts	2,217	2,688	2,620	2,244	2,428

The generation capabilities for solar installations are tied to the amount of solar radiation present at any given time and are often correlated with the timing of utility system peaks, particularly those that peak in summer months. Figure 18 below shows the hourly solar angle for Jackson, Mississippi on June 28, 2018 (roughly the time of the summer solstice on June 21, 2018). Peak solar intensity for Jackson occurred at 1:00 p.m. (or 12:00 noon without daylight-savings time), with the sun overhead at an angle of nearly 81 degrees to the horizon. However, by the late afternoon, when Mississippi utilities experience summer system peak conditions, the solar angle had decreased to less than 51 degrees by 4:00 p.m., and less than 38 degrees by 5:00 p.m. This chart clearly shows that solar intensity during late summer afternoon hours is approximately half, if not less, than that seen during peak afternoon conditions.

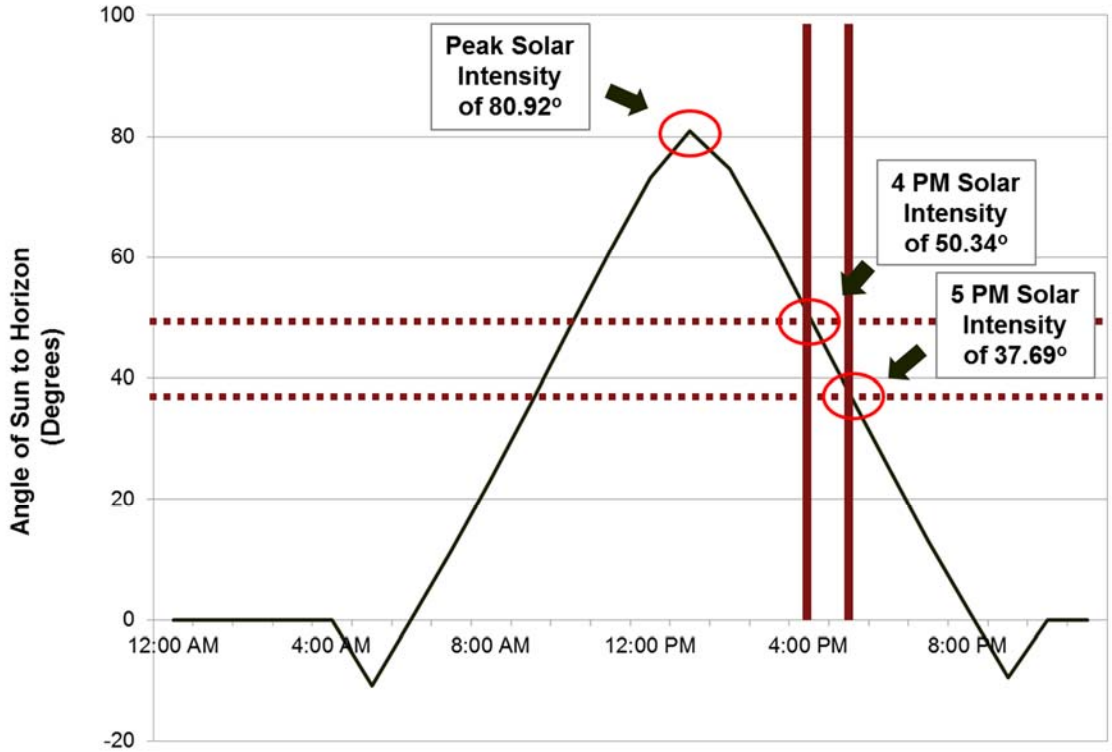

Figure 18: Hourly Solar Angle, Jackson, MS (June 28, 2018)
Source: National Oceanic and Atmospheric Administration

3.2.1. Evaluating ELCC Using Estimated Generation During Representative System Peak "Window:" An ELCC for each Mississippi IOU can be calculated using the historic system peak information provided earlier, and data included in the National Renewable Energy Laboratory's ("NREL") PVWatts calculator.[49] A Mississippi-specific solar installation's contribution to meeting peak load can be estimated by taking AC system output (using PVWatts' Mississippi estimate) as a percentage of the system size at the peak hour for each Mississippi IOU.

EML's 2017 peak load was 2,953 MW at 4:00 PM on July 26, 2017.[50] A roof-mounted system in Jackson, MS, therefore, is estimated to be operating at 46.3 percent

[49] National Renewable Energy Laboratory. PVWatts Calculator. https://pvwatts.nrel.gov/.
[50] Federal Energy Regulatory Commission. Annual Report of Major Electric Utilities, Licensees and Others. Form 1. Entergy Mississippi, Inc. 2017. p. 401.

of its maximum potential output using Mississippi-specific PVWatts data. MPC, on the other hand, reports a 2017 winter peak of 2,428 MW occurring at 8:00 AM on January 8, 2017.[51] The PVWatts calculator estimates that the capabilities for a roof-mounted system located in Gulfport, MS at this time would be operating at 26.3 percent of its maximum potential output.

While the above calculation shows the estimated ELCC for 2017, no utility's peak system condition occurs at a known or fixed time period (hour) every year. EML's system peaks, for example, have occurred in late July through mid-August for nine of the past ten years, and have always occurred during the hours of 3:00, 4:00, and 5:00 PM, with more recent system trends showing system peak conditions shifting later in the day for the utility to the 4:00 PM to 5:00 PM time period. Thus, for purposes of this report, an average time period, or "window," was developed to estimate each utility's system peak conditions. A solar generation system located in Jackson, Mississippi during the hours of 4:00 PM and 5:00 PM across the time period of July 20th to August 20th is estimated to have an ELCC of 28.7 percent, lower than the individual peak noted earlier for just 2017 alone.

Likewise, ELCC estimates for MPC are more nuanced since it reports both winter and summer peaks. Thus, a combined calculation can be made that considers these dual peaks relative to the likely availability of solar generation at the time of these summer and winter peaks. MPC reports summer peaks occurring between mid-June to mid-August based on the past 10 years of historical records, but consistently during the early afternoon at either 3:00 PM or 4:00 PM. Thus, a typical roof-mounted system in Gulfport, Mississippi, between the hours of 3:00 PM and 4:00 PM during the period of June 15

[51] Federal Energy Regulatory Commission. Annual Report of Major Electric Utilities, Licensees and Others. Form 1. Mississippi Power Company. 2017. p. 401.

through August 15 is estimated to have a summer average ELCC of 37.7 percent. MPC's winter peak has occurred during the month of January for 9 of the past 10 years, and always at either 7:00 or 8:00 AM. An average ELCC for a typical roof-mounted system in Gulfport, Mississippi during these hours in the month of January is 14.5 percent. The simple average ELCC for MPC, across summer and winter, therefore, is estimated to be 26.1 percent.

Table 12: Estimated ELCC during selected Peak System Load Periods

Mississippi Power				Entergy Mississippi	
Summer Jun. 20 - Aug. 20		Winter Jan. 1 - 31		(Summer Only) July 20 - Aug. 20	
Hour	Average	Hour	Average	Hour	Average
15	41.64%	7	5.87%	16	34.47%
16	33.70%	8	23.11%	17	22.91%
ELCC Average		**ELCC Average**		**ELCC Average**	
37.67%		**14.49%**		**28.69%**	

3.2.2. Evaluating ELCC Using Probabilistic Model: Another approach to calculating utility-specific ELCCs involves the use of a probabilistic model of expected DER generation relative to utility system conditions. This model recognizes that the variation in DER generation in any given hour is relative to the variation in utility operating conditions across the same time period. For example, a portion of a utility's system may experience cloudy weather (low DER generation) during an extreme peak. The use of a probabilistic model, therefore, accounts for the variability in both the availability of renewable generation, and utility operating conditions.

This probabilistic approach has been used historically by the Southwest Power Pool ("SPP") to calculate the capacity contribution of wind generation resources.[52] The SPP method utilizes the highest 10 percent of monthly system load hours and then pairs these operating conditions against renewable generation occurring across its system. Renewable generation levels are then ranked from highest to lowest, with the value that exceeds 85 percent of the time (the 85th percentile) being used.[53] In other words, this analysis examines the renewable generation amount that can be expected at least 85 percent of the time during the top 10 percent of system load hours. Later version of this analysis used by SPP aggregated all wind generation in a balancing authorities' area, and examined the 60th percentile level during the top three percent of system load hours.[54]

The SPP method was employed utilizing data provided by each IOU on their hourly load profiles for eligible net metering rate classes for the past five years. Consistent with SPP's historic approach, a set value of maximum system load hours for each month was selected and paired with the hourly generation estimates of representative systems in Jackson and Gulfport. The solar generation expected at a selected confidence level was then chosen for each month and averaged across five years' worth of load profiles. For this analysis, an 85 percent confidence level during the top 10 percent of monthly hours, and a 60 percent confidence level during the top three percent of monthly hours was used (consistent with the past and current SPP methodologies).

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[52] *See,* Michael Milligan and Kevin Porter (March 2006), "The Capacity Value of Wind in the United States: Methods and Implementation," *The Electricity Journal*, Vol. 16, Issue 2, pp. 95-96.

[53] *Id.*

[54] Wind and Solar Report (May 23, 2017), Supply Adequacy Working Group, Southwest Power Pool, p. 3.

Table 13: Monthly Estimated ELCC Using Probabilistic Approach

Month	Entergy Mississippi, LLC. 85% Confidence During Top 10% Load Hours	Entergy Mississippi, LLC. 60% Confidence During Top 3% Load Hours	Mississippi Power Company 85% Confidence During Top 10% Load Hours	Mississippi Power Company 60% Confidence During Top 3% Load Hours
January	0.00%	8.78%	0.00%	2.45%
February	0.00%	14.86%	0.00%	6.97%
March	0.00%	17.71%	0.39%	10.31%
April	1.33%	27.03%	6.37%	32.92%
May	8.26%	35.32%	15.20%	42.52%
June	15.33%	36.66%	19.12%	36.60%
July	17.83%	41.40%	17.04%	41.14%
August	11.18%	38.90%	18.73%	41.96%
September	8.84%	34.89%	17.89%	34.76%
October	0.00%	29.12%	4.61%	32.88%
November	0.00%	6.94%	0.00%	14.74%
December	0.00%	5.34%	0.00%	2.33%
	Summer Peak (July and August):		**Summer Peak (June - August):**	
	14.51%	**40.15%**	**18.30%**	**39.90%**
			Winter Peak (January):	
			0.00%	**2.45%**

Table 13 presents the resulting monthly ELCC for each Mississippi IOU using each of the probabilistic approaches historically used by SPP. This analysis demonstrates the variable nature of renewable energy generation like solar power, as the estimated ELCC changes noticeably with changes in the probabilistic parameters assigned. For example, the estimated ELCC during the summer system peaking months of July and August for EML is 14.5 percent when examined from a rigorous 85 percent confidence interval during top 10 percent of experienced load hours. However, this estimated ELCC grows to 40.2 percent when this statistical threshold is lowered to only the 60 percent confidence interval during the top three percent of experienced system loads. A similar pattern emerges when examining hourly solar ELCC for MPC during the summer peaking months of June through August.

3.2.3. Recommended ELCC: Based on the ELCC approaches presented above, this Report uses the results determined by an analysis of estimated generation during a representative system peak demand window. The results from the probabilistic approach, while informative, will be a function of the critical value used in screening results. An 85 percent confidence interval, for instance, is already a relatively low screening threshold for any statistical analysis, much less one estimating ELCCs. The results from the probabilistic model, at the 85 percent level, however, are considerably lower than other commonly recognized estimation methods. Lowering the critical value threshold to 60 percent increases the ELCC, but results in an estimate that is considerably outside commonly recognized norms for most statistical analyses and even for reliability planning purposes. In fact, SPP itself has raised questions about its current probabilistic modeling methodology, noting that the methodology results in volatile and less accurate capacity accreditations that ultimately results in reliability concerns with increasing wind and solar penetration levels.[55] Ultimately SPP has found that further evaluation may be needed in the future to consider alternatives methods to its current practices.[56] Thus, this Report will utilize a more standard approach which results in ELCC values identified in Table 12.

3.3. Estimating Capacity Prices and Values: The generation capacity value of DER is a product of its peak contribution times the value of that capacity at the time of the capacity contribution (i.e., the ELCC). There are three primary ways in which the "unit" capacity values for DER (i.e., the price on a per kW, kW-year, or kWh basis) are commonly estimated. The first is more theoretic and based on the cost of developing a new fossil-fueled generation resource. This method is referred to as "cost of new entry"

[55] *Id.*, p. 1.
[56] *Id.*

(or "CONE") approach to estimating capacity value. The second approach for estimating generation capacity values can be thought of as a "comparable markets" approach that examines the actual cost of recent fossil fuel projects and contracts as being indicative of the marginal value of new capacity in the market. The third approach is a variation of the comparable markets approach and rather than using recently-announced prices for projects being developed in the market, this approach uses reported market values for capacity that are traded across regional wholesale power markets as being indicative of the prevailing market-based value of capacity.

The one factor that all three of these methods have in common is that the final generation capacity value estimate is a function of the basic supply and demand conditions that are prevailing in regional power markets. Generation capacity values can be low at times when there is excess generation (supply) and can be high when there is a limited amount of generation in the market to supply demand, or load requirements. Unfortunately, most regional power markets are currently over-supplied and are anticipated to remain in an over-supply position for some time. This, on its face, will tend to result in lower per-unit generation capacity values.

The regional markets in which Mississippi participates are long on capacity at the current time. In fact, this excess capacity situation has been called to the Commission's attention before including the original NEM rulemaking.[57]

> With respect to a NEM customer receiving credit for avoided capacity costs, [Entergy Mississippi, Inc.] EMI has documented to the Commission that the Company is long on generation today (i.e. it has more owned and contracted capacity than its peak load plus its planning reserve margin).

[57] *In Re: Order Establishing Docket to Investigate the Development and Implementation of Net Metering Programs and Standards,* Docket No. 2011-AD-2, Comments of Entergy Mississippi, Inc. on Commission's Proposed Rule at 32.

> Therefore, no amount of customer self-generation will avoid EMI capacity costs today. Additionally, even if EMI were short on capacity, a generating facility only has capacity value if it is under EMI control and available to produce energy when that energy is needed (i.e., dispatchable.)[58]

Little has changed over the past several years to reverse this excess generation capacity situation. However, there are potential reasons to believe that both EML and MPC may see some degree of generation capacity benefits from DER in the future, even if both IOUs currently have a surplus of available generation capacity both from a planning perspective, and within the markets in which they each operate. One factor that may influence both utilities' relative excess capacity positions will be the degree to which the Commission requires either to begin retiring older legacy, less-efficient fossil generation, and the time-frame the Commission requires such retirements if this is its decision.

The Commission, for instance, is currently investigating the potential for implementing an Integrated Resource Planning ("IRP") requirement in Mississippi.[59] In fact, EML submitted a "Model 2018 IRP" in recent comments in this ongoing IRP rulemaking.[60] In this submission, EML noted that its current planning assumptions include the potential retirement of three existing legacy gas generating units, totaling as much as 3,000 MW of capacity, sometime during the 2018 to 2037 time period.[61]

EML also noted that it could, under some scenarios, see a growing generation capacity deficit that is expected to exceed 700 MWs by 2023.[62] This shortfall, however, is just within its own known resources and load, and is not impacted by its ability to secure

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[58] *Id.*

[59] *In Re: Order Establishing Docket to Investigate the Development and Implementation of an Integrated Resource Planning Rule,* Docket No. 2018-AD-064.

[60] *Id.*, Comments of Entergy Mississippi, Inc. Regarding Proposal of the Mississippi Public Service Commission to Develop and Implement an Integrated Resource Planning Rule, Attachment A.

[61] *Id.*, at 24.

[62] *Id.*, at 27.

longer term capacity, through a purchased power agreement ("PPA") or unit purchase, to meet this shortfall. EML's current resource planning document generally includes a natural gas combined cycle unit ("NGCC") as a placeholder to meet future year requirements, recognizing that no specifics to secure such a resource have been made at the current time.[63]

Likewise, while MPC has an abundance of generation capacity relative to its current load requirements, a significant share of this generation includes older units with relatively poor thermal efficiencies. MPC's Stipulation in Docket No. 2017-AD-0112 resolving the ongoing issues with the Kemper County facility, included a requirement that MPC file a reserve margin plan with the Commission to formally facilitate Commission review of the MPC's aging generation fleet.[64] It is possible that the result of this proceeding will be an agreement that MPC retire some of this legacy generation which, in turn, could have some implications for the value of marginal generation capacity in the future. However, it is unlikely that this proceeding will significantly constrain the existing excess capacity situation in MPC's service territory. This Report assumes that it is highly unlikely that the Commission will take any actions, whether it be for MPC or EML, that will retire generation units in a fashion that would push reserve/capacity margins to levels that would lead to unnecessary increases in overall regional capacity values and compromise the cost and reliability of power generation capacity for Mississippi ratepayers.

3.4. Prior Studies: The significant growth of DER applications utilizing NEM has raised a host of important policy and ratemaking questions that have motivated state

[63] *Id.*

[64] *In Re: Encouraging Stipulation of Matters in Connection with the Kemper County IGCC Project,* Docket No. 2017-AD-112, Rebuttal Testimony of David F. Schmidt, 13:11-13.

regulators to open investigations and/or commissioned studies examining the costs and benefits of NEM supported on-site generation. Most of these studies include an estimation of avoided generation capacity costs.

One component of the Synapse Report, provided to the Commission as part of the original NEM rulemaking included an estimate of avoided generation capacity.[65] The Synapse Report included a multi-ranged set of avoided generation capacity value estimates (low, mid, high). The "low-range" estimate was developed using a market capacity price based approach discussed earlier. This low-range estimate was based upon market clearing prices reported in MISO's 2014-2015 capacity auction that ultimately cleared at $6/kW-year.[66] The Synapse Report also developed a "high-range" avoided generation capacity estimate of $57/kW-year using the CONE analysis discussed earlier. [67] The mid-range estimate was simply a hybrid of both of these methodologies.[68]

The Rocky Mountain Institute has prepared an oft-cited "meta-study" (or survey of studies) that includes the results of several avoided generation capacity cost estimates.[69] Table 14 below provides a summary of the results from this meta-study. Nearly three-fourths of all studies included in this survey found an avoided generation capacity value as being in the range of zero to as much as $30/MWh (or three cents/kWh).

[65] Stanton, Elizabeth A., *et. al.* (September 19, 2014), Net Metering in Mississippi: Costs, Benefits, and Policy Considerations.

[66] *Id.*, p. 25.

[67] *Id.*

[68] *Id.*

[69] Hansen, Lena, *et. al.* (September 2013), A Review of Solar PV Benefit & Cost Studies: 2nd Edition, at 29.

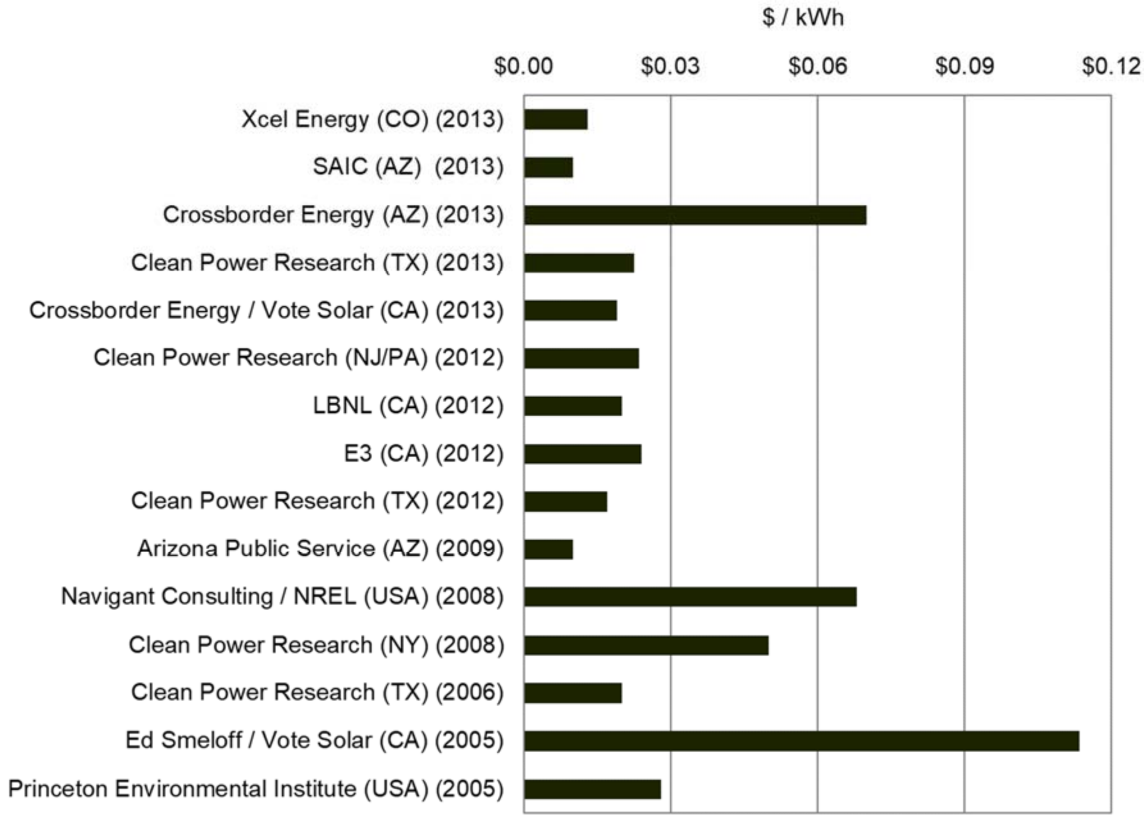

Table 14: Survey of Generation Capacity Benefit Estimates (cents / kWh)
Source: Rocky Mountain Institute

Another common-cited report estimating generation capacity value estimation methods was prepared by Energy + Environmental Economics ("E3"), a consulting firm headquartered in San Francisco, California, that has prepared a considerable number of reports examining DER benefits. In its first cost-benefit analysis of solar net metering for the State of California in 2010, E3 noted that the calculation of avoided generation capacity values was originally rooted in the proceedings evaluating the cost-effectiveness of conservation and demand-side management programs. Because of this prior regulatory precedent, E3 utilized trended values traded in California's Resource

Adequacy ("RA") markets as a proxy for generation capacity values.[70] This is similar to the low-case methodology used in the Synapse Report for Mississippi.

E3 conducted a number of subsequent studies in California that expanded upon this methodology. For instance, in a 2013 follow-up study, E3 noted that historical RA values were relatively low because of excess generation capacity supply existing with California wholesale markets (i.e. California Independent System Operator or "CAISO").[71] E3 theorized that this surplus situation would not last indefinitely, and RA market prices would eventually rise as economic growth induced peak demand growth.[72] E3 therefore used a linear extrapolation between near-term avoided capacity prices based on CAISO RA market prices and a theoretical value of avoided capacity based on the lesser avoided cost of a natural gas combined cycle or combustion turbine plant for five years.[73] After this point, the value of avoided generation capacity was assessed fully at the theoretical value of avoided generation mentioned previously.[74]

In subsequent studies in other states, such as those conducted in Nevada (in 2014, 2016), E3 initially retained this linear extrapolation methodology with minor modifications to reflect the fact that utilities in Nevada do not participate in a regional RTO like utilities in California.[75] However, E3's 2016 study, under Nevada Commission direction, only utilized the theoretical value of avoided generation costs for all years, eliminating the

[70] Sachu Constantine. E3 Consulting. Introduction to the Net Energy Metering Cost Effectiveness Evaluation. March 2010. P. 44.

[71] Ehren Seybert. E3 Consulting. Introduction to the California Net Energy Metering Ratepayer Impacts Evaluation. October 28, 2013. P. C-29.

[72] *Id.*

[73] *Id.*

[74] *Id.*

[75] Price, Snuller, et. al. (July 2014), *Nevada Net Energy Metering Impacts Evaluation*, E3 Consulting, pp. 162-163.

distinction of near-term avoided generation capacity cost.[76] Furthermore, E3 made explicit that the avoided generation capacity value of a natural gas combustion turbine plant was used in both of these studies, instead of the lesser of a natural gas combustion turbine ("CT") or combined cycle ("CC") plant like that used in the 2013 California study.[77]

Other studies have likewise made similar distinctions between short-run and long-run marginal costs of avoided generation capacity. The American Council for an Energy-Efficient Economy ("ACEEE"), for example, makes a similar distinction in noting that in the short term, a utility may decide to purchase an existing generation asset given time and resource constraints, yet, over the longer term, may opt to build such an asset.[78] However, ACEEE notes that avoided generation capacity benefits, by definition, occur at the margins, so the value of avoided generation capacity costs depend on the configuration of the electric generation unit being avoided. ACEEE states that, while most utilities assume a conventional natural gas CT operates as the marginal unit to meet peak system demand, most hours of the year see larger natural gas CC generation units operating as the marginal unit.[79]

The Environment Protection Agency's *Quantifying the Multiple Benefits of Energy Efficiency and Renewable Energy: A Guide for State and Local Governments* specifies a number of methods to estimate the value of avoided generation capacity costs based on

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[76] Horii, Brian, et. al. (August 1, 2016), *Avoided Costs 2016 Interim Update*, E3 Consulting, p. 18.

[77] Price, Snuller, et. al. (July 2014), *Nevada Net Energy Metering Impacts Evaluation*, E3 Consulting, pp. 162-163; and, Horii, Brian, et. al. (August 1, 2016), *Avoided Costs 2016 Interim Update*, E3 Consulting, p. 9.

[78] Baatz, Brendon (June 2015), *Everyone Benefits: Practices and Recommendations for Utility System Benefits of Energy Efficiency*, American Council for an Energy-Efficient Economy, p. 13.

[79] *Id.*

the operating characteristics of avoided electric generation plants, including the commonly used proxy plant method described in the E3 and ACEEE analyses.[80]

In addition to this method, the guide specifies a range of alternative methods to define a proxy plant for marginal generation capacity, including a method that utilizes the average costs of all electric generating units on a utility's system, allowing for the detailed development of a dispatch order or displacement curve under different system conditions, allowing for a more detailed determination of the characteristics of a displaced marginal power plant.[81] Likewise, EPA states that a utility's dispatch order could be developed based on historical dispatch data, essentially a detailed analysis of the amount of time various units on a utility's system is "on the margin."[82] Importantly, these methods are simply more detailed methods to determine the characteristics of marginal generation systems, and all rely on the identification of an appropriate generation proxy in valuing the benefits of avoided generation capacity.

3.5. Generation Capacity Benefit Estimation Methods

3.5.1. CONE Methodologies: As mentioned previously, cost valuations for avoided generation capacity are sometimes performed via theoretical approaches. As noted earlier, the CONE analysis utilizes the estimated cost of a chosen new generation resource as a representation for the value of avoided capacity costs. This analysis is typically utilized under a method referred to as a "net CONE analysis," where the energy revenues the unit will receive from future operations are applied against the cost of a new

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[80] Energy Information Administration. *Quantifying the Multiple Benefits of Energy Efficiency and Renewable Energy: A Guide for State and Local Governments*. Part two. Chapter 3.
[81] *Id.* pp. 12-14.
[82] *Id.* p. 14-17.

generation unit to identify only the capital premium required in the installation of new generation capacity.

Multiple organizations, including PJM Interconnection ("PJM"), MISO, and other regional transmission organizations publish annual estimates of capacity costs using this net CONE method. PJM, for example, published multiple estimates for avoided capacity in its 2018 Cost of New Entry publication; however, all of its published CONE estimates apply to geographic regions in the Northeast US. Likewise, MISO has published a CONE estimate associated with its current 2018-2019 Planning Resource Auction, which found an estimated the cost of new entry for zone 10 (Mississippi) as $236.30 per MW-day, or approximately $86.25 per kW-year.[83] This MISO analysis is based on the costs of a hypothetical advanced natural gas CT constructed in Mississippi. However, Miso's analysis importantly did not consider the anticipated net revenue from the sale of energy.[84]

This Report utilizes a CONE methodology using EIA data included in its *Annual Energy Outlook* ("AEO"). As part of its report, EIA publishes an annual levelized cost of electricity ("LCOE") across all types of generation resources.[85] Moreover, EIA's cost estimates use industry data to determine appropriate assumptions related to new plant development and furthermore breaks these cost estimates out across various categories (capital cost, fixed Operations and Maintenance Expenses ("O&M"), etc.). Using this EIA data from the 2018 AEO, two proformas have been developed, each corresponding to a

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[83] 2018/2019 Planning Resource Auction Results (April 13, 2018). Mid-Continent Independent System Operators ("MISO"), p. 8.

[84] *Filing of the Midcontinent Independent System Operator, Inc. Regarding LRZ CONE Calculation,* FERC Docket No. ER17-2416-000, filing dated September 1, 2017, pp. 4-5.

[85] "Assumptions to the Annual Energy Outlook 2018: Electricity Market Module." (April 2018) U.S. Energy Information Administration, p. 4.

new natural gas CC plant with a heat rate of 6,300 btu/kWh installed in the year 2020, the first year such a plant would be available given lead times noted in the 2018 AEO. These estimates are inclusive of capital costs, financing costs, fixed O&M and taxes. The analysis also takes into account forecasted revenues net of fuel and variable O&M expenses from sales using relevant forecasts also published within the 2018 AEO.

Using data published by EIA in its 2018 AEO, this Report estimates a net CONE value of $43.50 per kW-year for EML and $27.28 per kW-year for MPC. As mentioned previously, this CONE analysis covers a CC unit with a heat rate of 6,300 btu/kWh installed in 2020, or what is noted as an "advanced combined cycle plant" in the 2018 AEO.

3.5.2. Recently-Reported Generation Development Costs: The analysis presented above relied on estimates obtained from EIA's 2018 AEO. However, there have been a number of recent CC projects announced or completed by utilities in the southeast region neighboring Mississippi. Table 15 below presents the total nominal costs of these recent projects. As shown in this analysis, the average cost for construction of recent CC units in the southeast has been approximately $919 per kW.

Table 15: Recent Southeast Natural Gas CC Projects

Source: Various Press Releases

	Capacity (MW)	Cost (Millions)	$/kW	Project Type	Construction Start Date
Lake Charles Power Station - Entergy LA	994	$ 872	$ 877	New Construction	2018
St. Charles Power Station - Entergy LA	980	869	886	New Construction	2017
New Orleans East Power Station - Entergy LA	128	210	1,641	New Construction	N/A
Washington Parish Power Station - Entergy LA	361	261	723	New Construction	2018
Ninemile 6 CCGT Gas Fired Plant - Entergy LA	550	721	1,311	Repowering	2012
West County Energy Center - FPL	3,750	2,200	587	New Construction	2007/2008
Dania Beach - FPL	1,163	888	764	Repowering	2018/2019
Riviera Beach Next Generation - FPL	1,250	1,300	1,040	Repowering	2012
Cape Canaveral Next Generation - FPL	1,250	900	720	Repowering	2011
Putnam County - Seminole	1,122	727	648	New Construction	2019
Citrus County - Duke Energy	1,640	1,500	915	New Construction	2016

This information can be combined with the earlier CONE analysis to provide a more accurate estimate of generation capacity costs in the southeastern region. The prior analysis assumed that a CC unit with a 6,300 btu/kWh heat rate would have a total overnight installation cost of $1,108 per kW based on information contained in EIA's 2018 AEO. Indeed, the 2018 AEO estimated that even a less advanced CC with a heat rate of 6,600 btu/kWh would have a total overnight installation cost of $982 per kW. Generation technology in the southeast region appears to be noticeably less expensive than that published by EIA in its 2018 AEO based on national information.

Using information published by EIA in its 2018 AEO, paired with the average cost of recent CC projects in the southeast of $919 per kW, it is estimated that the CONE net of forecasted revenues is $24.94 per kW-year for EML and $11.49 per kW-year for MPC. This analysis relies on EIA estimates of the variable and fixed O&M expenses of a CC unit with a heat rate of 6,600 btu/kWh installed in 2020, or what EIA labels a "conventional combined cycle plant."

3.5.3. Implied Capacity Premium from Market Prices: The third major category of capacity valuations are those based on the implied prices reported in observed wholesale power markets. Economic theory, for instance, suggests that when scarcity arises, prices will increase to allocate excess demand. In wholesale power markets, "premiums" can arise in "tight" markets that allow for the development of more efficient capacity should prices remain high over a sustained period. This "premium" can be estimated as the difference between observed hourly prices and the levelized cost of developing new CC unit.

This Report estimates the implied capacity premium embedded in wholesale market prices as the difference between what can be referred to as the market clearing heat rate (thermal efficiency or ratio of energy input to energy output on a Btu/kWh basis) versus the heat rate of a new CC unit. If the market-clearing heat rate is greater than a new natural gas CC unit, then a capacity premium is said to exist.

Two different capacity premium analyses were conducted for this Report. One that utilizes real-time prices observed at MISO-designated locational marginal price ("LMP") hubs, and one that relied upon the average daily "into Southern" prices as reported by Platts MegaWatt Daily based on bi-lateral contracts. This method was used since EML is part of a formal RTO but Southern Company, and MPC, is not part of a formalized RTO or regional power market.

Table 16 below shows the results of this analysis for EML. For this analysis, MISO Mississippi hub prices were used for the period December 1, 2017 to June 30, 2018. For the period December 19, 2013, to November 30, 2017, MISO Arkansas and Louisiana hub prices were averaged to approximate Mississippi prices as MISO had not yet created a Mississippi hub price in its real-time market. As shown in Table 16, wholesale electricity prices for this period averaged $31.00, implying a market-clearing heat rate of 9,979 MMBtu per kWh. These rates were compared against a heat rate of 7,652 MMBtu per kWh, which is the 2016 average heat rate of a CC generation unit per the EIA. This implies capacity premiums greater than the operating costs of a CC unit in MISO Mississippi region of approximately $7.23/MWh, or 0.723 cents/kWh, over the last four and a half years.

Table 16: Implied Capacity Premium in MISO Mississippi
Source: MISO Real-Time Market LMP

	(a) Mississippi Hub Price ($/MWh)	(b) Henry Hub Price ($/MMBtu)	(c = a / b) * 1000 Implied Heat Rate (MMBtu/kWh)	(d) Henry Hub Price ($/MMBtu)	(e) EIA 2016 NGCC Heat Rate (MMBtu/kWh)	(f = d / e) * 1000 Implied NGCC Fuel Cost ($/MWh)	Implied Capacity Premium ($/MWh)
2014	$ 39.81	$ 4.37	9,105	$ 4.37	7,652	$ 33.46	$ 6.35
2015	$ 27.18	$ 2.62	10,357	$ 2.62	7,652	$ 20.08	$ 7.10
2016	$ 25.96	$ 2.52	10,317	$ 2.52	7,652	$ 19.25	$ 6.70
2017	$ 29.70	$ 2.99	9,939	$ 2.99	7,652	$ 22.86	$ 6.83
Jan, 2018 to Jun, 2018	$ 33.51	$ 2.94	11,398	$ 2.94	7,652	$ 22.49	$ 11.01
Jan, 2014 to Jun, 2018	**$ 31.00**	**$ 3.11**	**9,979**	**$ 3.11**	**7,652**	**$ 23.77**	**$ 7.23**

Table 17 presents a similar analysis to the above analysis for MPC. For the period June 2014 to July 2018, daily average Into Southern prices averaged $27.62 per MWh, implying a market-clearing heat rate of 9,485 MMBtu per kWh. These rates were compared against a heat rate of 7,652 MMBtu per kWh, which is the 2016 average heat rate of a CC generation unit per the EIA. This implies capacity premiums of approximately $5.34/MWh, or 0.534 cents/kWh, greater than the fuel costs of a CC unit over past four years throughout the Southern Company territory, which include MPC.

Table 17: Implied Capacity Premium Into-Southern
Source: Platts Megawatt Daily

	(a) Mississippi Hub Price ($/MWh)	(b) Henry Hub Price ($/MMBtu)	(c = a / b) * 1000 Implied Heat Rate (MMBtu/kWh)	(d) Henry Hub Price ($/MMBtu)	(e) EIA 2016 NGCC Heat Rate (MMBtu/kWh)	(f = d / e) * 1000 Implied NGCC Fuel Cost ($/MWh)	Implied Capacity Premium ($/MWh)
Jun, 2014 to Dec, 2014	$33.96	$3.97	8,560	$3.97	7,652	$30.36	$3.60
2015	$26.55	$2.63	10,099	$2.63	7,652	$20.12	$6.43
2016	$23.95	$2.52	9,512	$2.52	7,652	$19.27	$4.68
2017	$25.70	$2.99	8,604	$2.99	7,652	$22.85	$2.84
Jan, 2018 to July, 2018	$33.11	$2.93	11,295	$2.93	7,652	$22.43	$10.68
Jun, 2014 to July, 2018	**$27.62**	**$2.91**	**9,485**	**$2.91**	**7,652**	**$22.28**	**$5.34**

3.5.4. MISO Capacity Auction Prices: A final means of quantifying the value of generation capacity in a region is an examination of defined capacity markets in organized markets. MISO annually holds a Planning Resource Auction ("PRA") to meet resource adequacy requirements across the RTO footprint. Each auction covers a two year period and begins in September of the year prior to the period covered by the auction, with final results posted in early April of the first year of the period covered by the auction. In this manner, MISO is currently in the process of settling the PRA for the Planning Year ("PY") 2019-20, which began in September 2018. The most recent PRA with final market clearing results is for PY 2018-19, which MISO announced on April 12, 2018.

Table 18 below shows the auction clearing price for PRAs since the integration of the Entergy systems into the PRA process starting with PY 2014-15. For the first two years after the integration, i.e. the PRAs associated with PY 2014-15 and PY 2015-16, the market clearing price for capacity in Mississippi was priced with Louisiana and Texas as Zone 9, being separated out as a separate planning zone, specifically Zone 10, starting with PY 2016-17. Table 18 shows that auction clearing prices in the PRAs across all MISO planning zones have been low for many years with few exceptions limited entirely to areas far north of Mississippi. MISO South, i.e. Zones 8, 9, and 10, have consistently seen low market-clearing capacity prices, with the highest recorded price occurring the first year after the Entergy integration with an auction clearing price of only $16.44 per MW-day. Importantly, however, the most recent auction, PY 2018-19, resulted in an auction clear capacity price for the region of $10 per MW-day, or $3.65 per kW-year, noticeably greater than prices seen in MISO capacity auctions since the initial auction covering PY 2014-15.

Table 18: MISO Planning Reserve Auction Results
Source: MISO Annual Resource Auction Results

	Zone 1 (MN, ND, Western WI)	Zone 2 (Eastern WI, Upper MI)	Zone 3 (IA)	Zone 4 (IL)	Zone 5 (MO)	Zone 6 (IN, KY)	Zone 7 (MI)	Zone 8 (AR)	Zone 9 (LA, TX)	Zone 10 (MS)
			($ per MW-Day)							
PY 2014-15	$3.29	$16.75	$16.75	$16.75	$16.75	$16.75	$16.75	$16.44	$16.44	(see Zone 9)
PY 2015-16	$3.48	$3.48	$3.48	$150.00	$3.48	$3.48	$3.48	$3.29	$3.29	(see Zone 9)
PY 2016-17	$19.72	$72.00	$72.00	$72.00	$72.00	$72.00	$72.00	$2.99	$2.99	$2.99
PY 2017-18	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50
PY 2018-19	$1.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00

3.6. Generation Capacity Value Recommendations: Table 19 presents the monetary hourly avoided cost benefits of a CC unit under the various methods presented in this section as they pertain to EML. Under the methods presented in this section, the results of MISO's PRA for PY 2018-2019 results in the lowest monetary value for avoided capacity at $0.79/MWh (0.08 cents/kWh). This exceptionally low value of capacity is likely due to market signals indicating a substantially over-supplied market for generation capacity in the short-run. Alternatively, the CONE analysis based on information from EIA results in an hourly monetary capacity value of $9.45/MWh (0.95 cents/kWh).

Table 19: Monetary Value of Avoided Generation Capacity (EML)

	Annual Capacity Value ($/kW-Year)		Hourly Capacity Value ($/MWh)		Generation Capacity Factor (%)	CCGT Hourly Capacity Value ($/MWh)		CCGT Hourly Capacity Value (cents/kWh)
Net Cost of New Entry ("CONE")	$	43.50	$	4.97	52.54%	$	9.45	0.9452
Southeast Generation Costs	$	24.94	$	2.85	52.54%	$	5.42	0.5420
Implied Capacity Premium - EMI		-	$	7.23	-	$	7.23	0.7230
MISO RPA - Zone 10	$	3.65	$	0.42	52.54%	$	0.79	0.0793

Table 20 presents the equivalent hourly monetary avoided cost benefits of a CC unit under the various method presented in this section as they pertain to MPC. Under the methods presented in this section, a CONE analysis based on historical costs for recent electric generation units in the Southeast results in the lowest monetary value for avoided capacity at $2.50 per MWh (0.25 cents per kWh). Alternatively, a CONE analysis based on information from EIA results in an hourly monetary capacity value of $5.93 per MWh (0.59 cents per kWh).

Table 20: Monetary Value of Avoided Generation Capacity (MPC)

	Annual Capacity Value ($/kW-Year)	Hourly Capacity Value ($/MWh)	Generation Capacity Factor (%)	CCGT Hourly Capacity Value ($/MWh)	CCGT Hourly Capacity Value (cents/kWh)
Net Cost of New Entry ("CONE")	$ 27.28	$ 3.11	52.54%	$ 5.93	0.5928
Southeast Generation Costs	$ 11.49	$ 1.31	52.54%	$ 2.50	0.2495
Implied Capacity Premium - MPC	-	$ 5.34	-	$ 5.34	0.5337

These results, however, are overstated since they do not discount values for solar availability. As noted earlier, the extent to which a DER supplements a utility's generation capacity planning requirements is determined primarily by the degree to which that resource is available at the time the utility system is peaking. In this manner, the values presented in Table 19 and Table 20 above assume 100 percent generation capacity availability, which, as established in the ELCC discussion earlier, is not true for solar DER. Thus, the values reported above will need to be adjusted for the earlier-calculated ELCCs to get a final avoidable generation capacity estimate for the development of a measurable and quantifiable "adder" for NEM purposes.

Table 21 below presents the hourly effective capacity contribution for solar generating system in EML's service territory under the various methods discussed in this section. Effective hourly solar capacity benefits from avoided generation capacity costs range from $0.23/MWh (0.02 cents/kWh) when priced at the results of MISO's PRA for PY 2018-2019, to $2.71/MWh (0.27 cents/kWh) when evaluated using a Net CONE analysis using information from the EIA.

Table 21: Effective Hourly Solar Benefits from Avoided Generation Capacity (EML)

	Hourly Capacity Value ($/MWh)		Effective Load Carrying Capabilities (%)	Effective Hourly Capacity Value ($/MWh)		Effective Hourly Capacity Value (cents/kWh)
Net Cost of New Entry ("CONE")	$	9.45	28.7%	$	2.71	0.2712
Southeast Generation Costs	$	5.42	28.7%	$	1.55	0.1555
Implied Capacity Premium - EMI	$	7.23	28.7%	$	2.07	0.2074
MISO RPA - Zone 10	$	0.79	28.7%	$	0.23	0.0228

Table 22 below presents the hourly effective capacity contribution for solar generating system in MPC's service territory under the various methods discussed in this section. Effective hourly solar capacity benefits from avoided generation capacity costs range from $0.65 per MWh (0.07 cents per kWh) when priced at rates consistent to the CONE estimate for recent southeast generation natural gas CC projects, to $1.55 per MWh (0.15 cents per kWh) when priced at rates consistent to the CONE estimate based on information published by the EIA.

Table 22: Effective Hourly Solar Benefits from Avoided Generation Capacity (MPC)

	Hourly Capacity Value ($/MWh)		Effective Load Carrying Capabilities (%)	Effective Hourly Capacity Value ($/MWh)		Effective Hourly Capacity Value (cents/kWh)
Net Cost of New Entry ("CONE")	$	5.93	26.1%	$	1.55	0.1546
Southeast Generation Costs	$	2.50	26.1%	$	0.65	0.0651
Implied Capacity Premium - MPC	$	5.34	26.1%	$	1.39	0.1392

For purposes of this analysis, the median value of estimated avoided generation capacity cost was used for each utility as the DER generation capacity benefit. This has the benefit of recognizing the range of reasonable possible estimates for each component, while leaving the final estimate of the total benefit of DER not dependent on outlying estimates. On an effective basis, the median estimate for avoided generation capacity benefits from DER is $1.81 per MWh (0.18 cents per kWh) for EMI, and $1.39 per MWh (0.14 cents per kWh) for MPC.

4. Avoided Transmission and Distribution Costs

4.1. Overview: DER has the ability to avoid, not only upstream generation capacity investments, but also downstream capacity investments in power transmission and distribution ("T&D" or "lines"). The installation of more behind-the-meter generation, in theory, can alleviate the need to carry more electricity across the grid to end users. In fact, the implementation of larger amounts of DER can have important implications, both positive and negative, on the grid's operation and future investment requirements.

T&D systems serve a number of functions. While they are primarily developed to facilitate peaks, they also facilitate the movement of electricity that arises from customer growth during both peak and off-peak periods. In other words, T&D investments are used to serve peaks and facilitate the movement of the primary commodity being sold from the grid, which is electricity. The relative importance of these peak versus off-peak functions is often debated in utility ratemaking proceedings, particularly when evaluating different class cost of service ("CCOSS") methodologies. This ratemaking debate has implications for evaluating avoided costs and the benefits arising from DER technologies like solar.

In terms of background, a CCOSS is an important tool used in ratemaking, particularly cost allocation and rate design. This tool allocates and reconciles utility costs and revenues across differing customer classes. The goal of a CCOSS is to determine the cost of providing service to a particular customer class, and the revenue contribution each class makes to cover those costs. The results of these studies produce actual class-specific rates of return and revenue requirements. If a CCOSS finds that a particular class' actual revenues are below the costs that are attributable to that class, the class specific rate of return will be considered deficient, and rates will usually be increased.

A CCOSS takes a utility's cost information and then transforms that data in a number of different ways including: (1) "functionalizing" the cost information; (2) "categorizing" the cost information; and (3) "allocating" the cost information. The functionalization process simply categorizes costs based upon the functions they serve within a utility's overall operations (i.e. production, transmission, and distribution). The next step of the process "categorizes" each of these respective costs into a particular type of cost, including those that are either demand-related, commodity-related, or customer-related. The last step of the process "allocates" each of these costs to a respective jurisdiction or customer class, as appropriate.

Demand-related costs are associated with meeting maximum energy demands. Electric substations and line transformers at the distribution level are designed, in part, to meet maximum customer demand requirements. The most common demand allocation factors used in a CCOSS are those related to system coincident peaks ("CP") or non-coincident customer class peaks ("NCP"). Energy-related costs, on the other hand, are defined as those that tend to change with the amount of electricity (i.e., kWh) sold. Electric generation costs and high-voltage transmission lines, for instance, can be allocated using composite factors that account for both peak and non-peak (energy-related) considerations. Lastly, customer-related costs are those associated with connecting customers to the distribution system, metering household or business usage, and performing a variety of other customer support functions.

Understanding this CCOSS process is important since it has implications for determining the true "avoidable" T&D costs attributable to DER. For instance, higher-voltage transmission systems are designed to meet broader, less localized demands that are often measured by more diversified demand metrics such as a CP demand on a singular or an average basis.[86] The Federal Energy Regulatory Commission ("FERC") has historically used a 12 month coincident peak ("12CP") methodology for allocating transmission plant costs in determining wholesale rates.[87] FERC utilizes this method based upon the position that most utilities plan their systems to meet their twelve monthly peaks" rather than a single peak.[88]

Distribution system costs, which can be more localized in nature, are allocated in a variety of manners. The Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners ("NARUC Manual") notes that distribution system components such as substations, feeders, and transformers are typically defined in a fashion that ensures sufficient capacity is available to meet the local area loads. Demand measures such as an NCP, or other measures of individual customer maximum demands, are typically used to allocate these types of system costs, particularly as distribution system components get closer to the individual customer such as secondary feeder-related costs. Primary feeder-related costs, while influenced by "downstream" individual customer peaks, are also influenced by overall or "upstream" system-peak related considerations. Thus, these higher voltage primary feeder-related costs are often allocated on a set of more diversified demand metrics such as a CP demand on a singular or an average basis.[89]

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[86] National Association of Regulatory Utility Commissioners ("NARUC"), Electric Utility Cost Allocation Manual, January 1992, pp. 77-83.

[87] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 FR 21540-01 (May 10, 1996), at 21598-21599.

[88] *Id.,* at 21599.

[89] National Association of Regulatory Utility Commissioners ("NARUC"), Electric Utility Cost Allocation Manual, January 1992, pp. 96-98.

This background on T&D cost determination and allocation underscores the difficulty in understanding the degree to which DER can avoid, or even delay, T&D investments. For instance, DER-induced reductions in peak loads can assist in avoiding system investments across a utility's grid but do little to avoid off-peak energy requirements associated with the movement of the primary commodity, electricity. Furthermore, the impact that DER deployment can have on energy usage, and the distribution level investments needed to facilitate this usage, can often be more complicated since these benefits (i.e., avoided localized distribution investments), to the extent they materialize, can tend to be more geographically-isolated to those specific areas experiencing growth.

4.2. Prior T&D avoided cost studies: Prior studies that develop estimates for avoided T&D costs can be categorized into three different sets of literature. The first set of studies that estimates avoided T&D costs comes from the energy efficiency literature which uses avoided T&D cost estimates to estimate energy efficiency program benefits. The second set of studies that utilize avoided T&D costs are included in utility ratemaking proceedings, usually those proceedings requiring a marginal cost study filing.[90] The third set of studies that provide avoided T&D cost estimates are those independent studies that have been explicitly generated to examine DER-related benefits, particularly solar, in what have been called VOS type studies and were discussed in the earlier avoided generation capacity cost discussion. The following subsection will discuss each of these

[90] Note that there is some overlap between the first set of literature (energy efficiency-utilized measures) and the second set of literature (rate proceeding/cost of service estimates) since in some instances, many energy efficiency program-based measures have come from surveyed cost information provided by utilities in their respective full base rate cases.

methods and highlight some indicative studies, or sources, used in developing avoided T&D cost estimates.

4.2.1. Avoided T&D estimates used for EE program evaluation: Utility or state-sponsored EE programs are often subjected to a variety of cost-effectiveness analyses as outlined in the California Standard Practice Manual.[91] There are four standardized "tests" that examine the cost-effectiveness of an individual EE measure or overall EE program from a major stakeholder perspective like a utility, an individual customer, all ratepayers, and the overall society. Each of these cost-effectiveness tests use avoided cost information as potential benefits associated with the adoption of energy efficiency programs.

A survey of the avoided T&D cost estimates used for EE program evaluation purposes was sponsored by Xcel Energy and prepared by the Mendota Group, LLC in 2014 (hereafter "Mendota Survey").[92] This survey examines a number of different approaches used to estimate avoided T&D costs for EE program evaluation purposes that can be generalized into three different categories: (1) systems-based methods; (2) embedded cost-based methods; and (3) the use of marginal cost study results from rate case proceedings.

The Mendota Survey notes that avoided T&D costs can be developed on a utility-system basis as part of an integrated resource planning ("IRP") process or can be estimated on a stand-alone, special purposes basis. A systems-based approach effectively models an entire utility system with and without a set of EE programs and

[91] California Energy Commission (October, 2001). *Economic Analysis of Demand-Side Programs and Projects.*

[92] Mendota Group, LLC (September 16, 2014). *Estimates of Transmission and Distribution Costs Avoided by Energy Efficiency Investments*. p. 42.

estimates avoided T&D costs from the difference between the change case (EE program adoption) and the base case (no EE program adoption). While this approach suggests a certain completeness and comprehensiveness, its data and computational requirements can be considerable. As a result, the Mendota Survey shows that the systems based approach is one of the least-utilized measures for developing avoided T&D cost estimates. This likely also underscores, or explains why two of the prior-utility studies (Vermont Electric and Tucson Electric Power) cited as systems-approach examples in the Mendota Survey are dated, with one dating back to 2003.

The second methodology discussed in the Mendota Survey is one that calculates avoided T&D cost benefits from embedded cost information. This methodology appears to be one of the more common approaches for estimating the "marginal" or "incremental" cost of avoided lines investments. These prior studies can include a number of variants. One variation, for instance, appears to use embedded "unit" cost information on individual transmission and distribution projects to estimate a typical avoided investment,[93] while an alternative variation can utilize a methodology that examines longer run changes in net transmission and distribution plant in service, and compares those changes in investment to changes in load growth over a comparable time period. This later variation is the more frequently-used approach and corresponds with more traditional ratemaking practices found in a CCOSS discussed earlier.

The last approach discussed in the Mendota Survey are the avoided T&D estimates that come from the use of values generated during the course of a regulated

[93] This approach appears to "price out" a typical set of transmission and distribution investment projects. This is similar to the methods that are used, somewhat incorrectly, by many utilities in their development of marginal cost studies for ratemaking purposes and will be discussed in more detail in the later subsections.

rate proceeding. This too appears to be a common approach since the information is utility-specific, it is often contemporaneous, and it can be readily available. The limiting factor in using this information is whether a utility employs a marginal cost study for ratemaking purposes or relies on an embedded, full-allocated cost study such as a CCOSS that was discussed earlier. Further, these utility marginal cost studies can, themselves, suffer from a number of methodological problems that can tend to overstate certain costs. These shortcomings will be discussed in more detail in the following subsection.

The Mendota Survey also points out that while a survey of avoided T&D costs estimated for EE program effectiveness can have some applicability to the evaluation of DER, the overall value of the avoided costs can differ between EE resources and DER. For instance, renewables are intermittent and can have availability issues: these types of challenges are less likely to arise with EE resources. While resource differences will likely not change the overall unit cost avoided, it can impact the overall avoided values since the intermittent nature of renewables and their ELCC can vary relative to other renewable and non-renewable resources. The surveyed values used in the Mendota Survey were all collected for EE program evaluation purposes and do not make any ELCC-type adjustments. Thus, any avoided T&D values utilized from Mendota Survey, therefore, will need to make these DER-specific ELCC adjustments.

4.2.2. Marginal cost-based avoided T&D estimates: Marginal cost-based avoided T&D estimates come from studies filed by utilities during the course of a full base rate case. These "avoided" cost estimates are usually part of a larger marginal cost study estimating the marginal costs of each utility function, and are often referred to as a marginal class cost of service study ("MCCOSS"). A MCCOSS seeks to estimate changes in cost relative to changes in output, where outputs are usually defined as energy sales, peak demand, number of customers, or various combinations of each. This differs from an embedded (or "fully-allocated") CCOSS which seeks to determine the allocation of costs across customer classes for a fixed period of time and for a fixed measure of output (often referred to as annual "billing determinants"). Further, while an embedded CCOSS can be viewed as an examination of historical cost of service, a MCCOSS can, in theory, tend to be more forward-looking in its estimation of cost of service. In addition, while an embedded CCOSS can be thought of as a more static short-term analysis of average costs, a MCCOSS is generally thought of as reflecting longer-run incremental costs of providing service. While disagreements surrounding the review of an embedded CCOSS often focus on cost allocations, disagreements associated with the review of a MCCOSS often tend to center around the development of drivers used to estimate these forward looking, incremental costs.

MCCOSS shortcomings can be particularly noticeable in developing marginal estimates for T&D functions since the primary motivator of these longer-run marginal costs is the capital investment needed to develop the infrastructure. The reliance on historical data, which is often similar if not the same as what is used for a CCOSS, raises considerable questions about the accuracy and merits of MCCOSS estimates since their results can lead to nothing more than re-formulations of embedded cost information that are more reflective of average, historical costs than they are marginal, forward-looking costs. In fact, The NARUC Electric Cost Allocation Manual notes that many marginal costing methodologies used by utilities are based upon information that is often more average in nature than it is marginal. Ironically, many utility marginal costs studies often rely on embedded (average book) costs that are in some way or another, part of the embedded CCOSS and do not differentiate themselves in any meaningful nor insightful manner. [94]

The Mendota Survey referenced earlier also notes that it is not uncommon to see utility MCCOSS estimates used as point estimates for avoided T&D costs in evaluating EE program cost-effectiveness. The same can be said for their use in evaluating the additional value provided by DER. However, a limiting constraint in the use of these marginal cost estimates is whether a utility even conducts such a study on a regular basis. There are few states, for instance, that require utilities to make marginal cost of service filings on a regular basis since as Massachusetts, North Dakota, and Montana, to name a few. No utilities in the southeast are required to use, or regularly use, marginal cost studies, including Entergy Corporation and Southern Company, and their respective individual utility operating companies.

Lastly, the use of marginal cost results, even if they are prepared accurately, can often have a high degree of geographic specificity. Customer density, for instance, is often noted as having an important role to play in estimating the marginal cost of infrastructure investments in certain places. Relative differences in customer mix can also limit the interchangeability of these estimates between and even within certain regions. Thus, the use of estimates from other states, while potentially useful as a sanity check on the range of an individual estimate, can be limited.

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[94] Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners, p. 127; citing J.W. Wilson, Report for the Rhode Island Division of Public Utilities, Public Utilities Commission and Governor's Energy Office (1978), pp. B-27-8.

4.2.3. VOS-based avoided T&D estimates: DER policies and practices over the past decade have been almost entirely dominated by solar energy. Along with this emphasis has come a corresponding set of proposed methodologies to examine solar benefits in the form of VOS studies. These studies, many dating back to the original California DER proceedings, are based upon an expansive set of variables and other considerations to assess solar value. Some of the early VOS studies were conducted by the E3 in California (2010 and 2013),[95] and later Nevada (2014 and 2016).[96] The approach and methods have been extended and used by other jurisdictions including the City of San Antonio,[97] Colorado,[98] and Utah.[99] In fact, the Synapse Report prepared for the Mississippi Commission can be thought of as a VOS study as well as components of the ACG study completed several years ago for the Louisiana Public Service Commission ("LPSC").

A VOS study considers a wide range of variables that can be categorized into such benefit categories as: (1) avoided energy and capacity benefits; (2) grid and ancillary support; (3) security (reliability, resiliency); (4) finance (hedge value); (5) environmental benefits (avoided emissions); and (6) societal benefits. Some of these categories have real, bona fide empirical estimation methodologies. For instance, the estimation of avoided energy and usually avoided generation capacity are straightforward even though

[95] California Energy Commission (March, 2010). *Introduction to Net Energy Metering Cost Effectiveness Evaluation*; and California Energy Commission (October, 2013). *California Net Energy Metering Ratepayer Impacts Evaluation.*

[96] Energy+Environmental Economics (July, 2014). *Nevada Net Energy Metering Impacts Evaluation*; and Energy+Environmental Economics (August 1, 2016). *Avoided Costs 2016 Interim Update*.

[97] Clean Power Research (March, 2013). *The Value of Distributed Solar Electric Generation to San Antonio.*

[98] Cross Boarder Energy (December 2, 2013). *Benefits and Costs of Solar Distributed Generation for the Public Service Company of Colorado.*

[99] Clean Power Research (January 7, 2014). *Value of Solar in Utah.*

some analysts can differ on assumptions used to develop the estimates. Likewise, estimating potential grid support and ancillary services benefits can have commonly-recognized approaches even though assumptions can vary. Other categories of benefits, however, can be more difficult to quantify and the estimates that come from a variety of method are usually not that robust.

For instance, societal benefits often have a very wide range and are exceptionally difficult to quantify. Figure 19, below, presents a comparison of societal environmental externalities estimates for carbon emissions between 1982 and 2006. Importantly, the vertical axis has been constructed as an exponential function to encompass all studies. The comparison shows that some studies have found societal costs for carbon emissions that is as high as nearly $1,000 per ton of CO_2 emissions. Likewise, other studies have found an appropriate societal cost for avoided CO_2 at nearly $0 per ton of avoided CO_2. Even peer-reviewed academic studies have found societal costs for CO_2 emissions as high as $200 per ton of emissions. In other words, the acceptable range of values on the benefits of avoiding CO2 emissions is a 200-fold range in values.

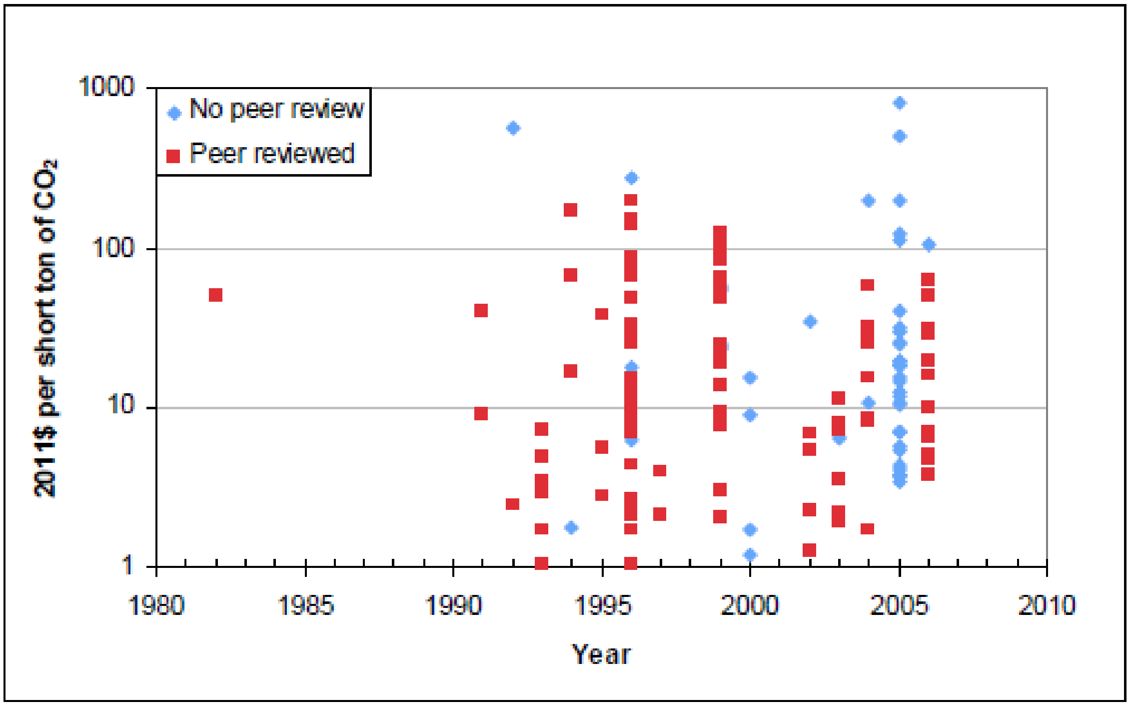

Figure 19: Estimates of the Societal Cost of Carbon (1982-2006)
Source: Included in Avoided Energy Supply Costs in New England: 2011 Report. Synapse Energy Economics. August 11, 2011; Originally in: Tol, Richard S.J. The Social cost of Carbon: Trends, Outliers and Catastrophes. Economics E-Journal. Vol 2, 2008-25. August 12, 2008.

A survey on VOS studies conducted by ICF International ("ICF") finds that these types of studies are "highly variable in generating estimated values due to different approaches used to calculate benefits and costs."[100] The ICF investigation of five key VOS studies found approaches that were "lacking in consistency, key values and cost components, and transparency."[101] The ICF survey, however, did find one area of commonality between these studies in the fact that most of the benefits tend to be concentrated in the avoided energy and generation capacity estimates, as well as the avoided T&D costs.[102]

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[100] ICF International (November 17, 2014). *The True Value of Solar.* Altenergymag.com.
[101] *Id.* p. 3.
[102] *Id.*

4.3. Proposed data, methods, and empirical estimates: The data used in most of the studies discussed earlier all utilize either FERC Form 1 data or some variation of that data. Other studies have relied upon other internal utility data, such as unit cost estimates on an individual utility project basis, to estimate component-specific marginal costs. For purposes of this study, avoided T&D estimates will be generated using FERC Form 1 data with some supplemental utility-specific data. Specific reliance on information that is not compiled directly from the Form 1 will be clearly indicated.

The second step in generating appropriate avoided T&D costs are determining which costs are deferrable versus those that are non-deferrable. By definition, deferrable costs are those that could be reduced or eliminated by the introduction and use of DER, whereas non-deferrable costs are those that will be required regardless of the level of DER implementation. The most obvious of these types of non-deferrable T&D investments would be customer meters and service drops (both are distribution-related). While these distribution investments are functionalized as part of a utility's distribution system, they are typically viewed, and allocated for CCOSS purposes, as being fully customer-related and not demand/capacity related. In other words, these are costs that are not viewed as varying with changes in peak system or customer demand needs.

Previous studies have considered different T&D plant investments as deferrable in nature. For example, a 2013 VOS-based analysis conducted by the City of San Antonio, Texas, assigned only Distribution Plant Accounts 360 – 362 as deferrable.[103] These accounts are the highest functional items in a utility's distribution system and are predominately associated with distribution substations. Lower level distribution systems

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[103] Clean Power Research (March, 2013). *The Value of Distributed Solar Electric Generation to San Antonio.* p. 22.

investments (e.g. distribution poles, line circuits, and line transformers) were viewed by the study as not avoidable by DER, with the study specifically noting that it assumed that line transformers and similar systems would require the same rating with or without distributed generation in order to serve load needs when generation is not available.[104]

A 2014 Minnesota study, however, found that, in addition to costs associated with distribution substations (Distribution Plant Accounts 360 – 362), costs associated with Distribution Plant Accounts 365 – 367 could also be considered partially deferable with reduced capacity needs.[105] These later accounts are associated with actual distribution lines, both overhead and underground, and associated devices. The Minnesota study stated that only capacity-related amounts in all deferrable distribution plant accounts should be considered for calculations of avoided distribution capacity costs on a utility-by-utility basis.[106] The Minnesota study provided as an example 100 percent of all substations costs (Distribution Plant Accounts 360 – 362) and 25 percent of all line-related costs (Distribution Plant Accounts 365 – 367) as an appropriate determination of deferrable distribution costs.[107]

Two tables are provided (Table 23 and Table 24) that identify the FERC accounts that are deferrable for purposes of this analysis. These deferrable accounts for both T&D plant are those associated with land and structures (Transmission Plant Accounts 350 - 353 and Distribution Plant Accounts 360 – 362). Being the highest functional items in each plant category, these are predominately associated with T&D substations, which are

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[104] *Id.*

[105] Minnesota Department of Commerce, Division of Energy Resources (April 1, 2014). *Minnesota Value of Solar: Methodology, pp.* 33-34.

[106] *Id.*

[107] *Id.*, p. 35.

highly scalable, and are typically fully allocated to the demand component of utility operations in CCOSS. To do this, T&D plant accounts associated with overhead and underground conductors (i.e. electric lines) and associated devices and conduits are added. However, these accounts are only assigned 25 percent of their full value in order to reflect the fact that these investments, while partially scalable, are not entirely scalable since they are usually developed to meet localized maximum demands when distributed generation is not present.

Similarly, distribution line transformer investments are assumed to not be deferrable since these devices will be required to maintain the same rating regardless of whether or not a customer has a DER installation. Finally, towers, poles, and fixtures plant investments are also assumed to be non-deferrable since utilities must meet minimum safety requirements associated with such equipment, and it is assumed that these requirements will not change with the inclusion of DER. This assumption is consistent with that used in the 2014 Minnesota VOS analysis.

Table 23: Deferrable FERC Transmission Accounts

Transmission Plant in Service Account	Percent Deferrable
(350) Land and Land Rights	**100%**
(352) Structures and Improvements	**100%**
(353) Station Equipment	**100%**
(354) Towers and Fixtures	0%
(355) Poles and Fixtures	0%
(356) Overhead Conductors and Devices	**25%**
(357) Underground Conduit	**25%**
(358) Underground Conductors and Devices	**25%**
(359) Roads and Trails	0%

Table 24: Deferrable FERC Distribution Accounts

Distribution Plant in Service Account	Percent Deferrable
(360) Land and Land Rights	**100%**
(361) Structures and Improvements	**100%**
(362) Station Equipment	**100%**
(363) Storage Battery Equipment	0%
(364) Poles, Towers, and Fixtures	0%
(365) Overhead Conductors and Devices	**25%**
(366) Underground Conduit	**25%**
(367) Underground Conductors and Devices	**25%**
(368) Line Transformers	0%
(369) Services	0%
(370) Meters	0%
(371) Installations on Customer Premises	0%
(372) Leased Property on Customer Premises	0%
(373) Street Lighting and Signal Systems	0%

This study utilized two different methodologies for estimating DER-related avoided T&D costs. Later subsections will compare the avoided T&D cost results to the survey data of T&D costs discussed earlier in the Mendota Group analysis along with additional and more contemporaneous avoided T&D cost information that has become available since that Survey's publication.

4.3.1. Average Annual Addition to Deferrable Plant: The first avoided T&D methodology utilized in this report will be based upon an examination of the capital additions made by the IOU utilities to deferrable transmission and distribution plant each year, over a fixed time period. These results are then compared to changes in utility peak load requirements during the same period to estimate the "marginal" or "avoidable" T&D plant investment associated with each utility's load growth. Mathematically, this method estimates the changes in average plant investment given average changes in demand. This method provides an advantage of examining multiple years of data, which helps to reduce large swings in data that can arise from a sudden increase in either plant investment or peak load. This method also has the added benefit of being straightforward, transparent, easy to understand, and easy to replicate.

For purposes of this study, the years 2008 through 2017 was chosen as an appropriate time-frame for analysis of the relationship between changes in system costs and system load. However, examination of additions to deferrable plant, and indeed most calculations of marginal system costs, is premised on utilities experiencing positive system growth. As shown in Figure 20 below, both EML and MPC have experienced flat to declining peak loads in recent years. This creates a problem to the estimation of avoided T&D costs since the data suggests little to no T&D capacity in this time period has been deferred. The dataset used in this analysis, was modified to include only time periods for positive peak load growth which for EML was 1994 to 2011, while for MPC this time period ranged from 1994 to 2010.

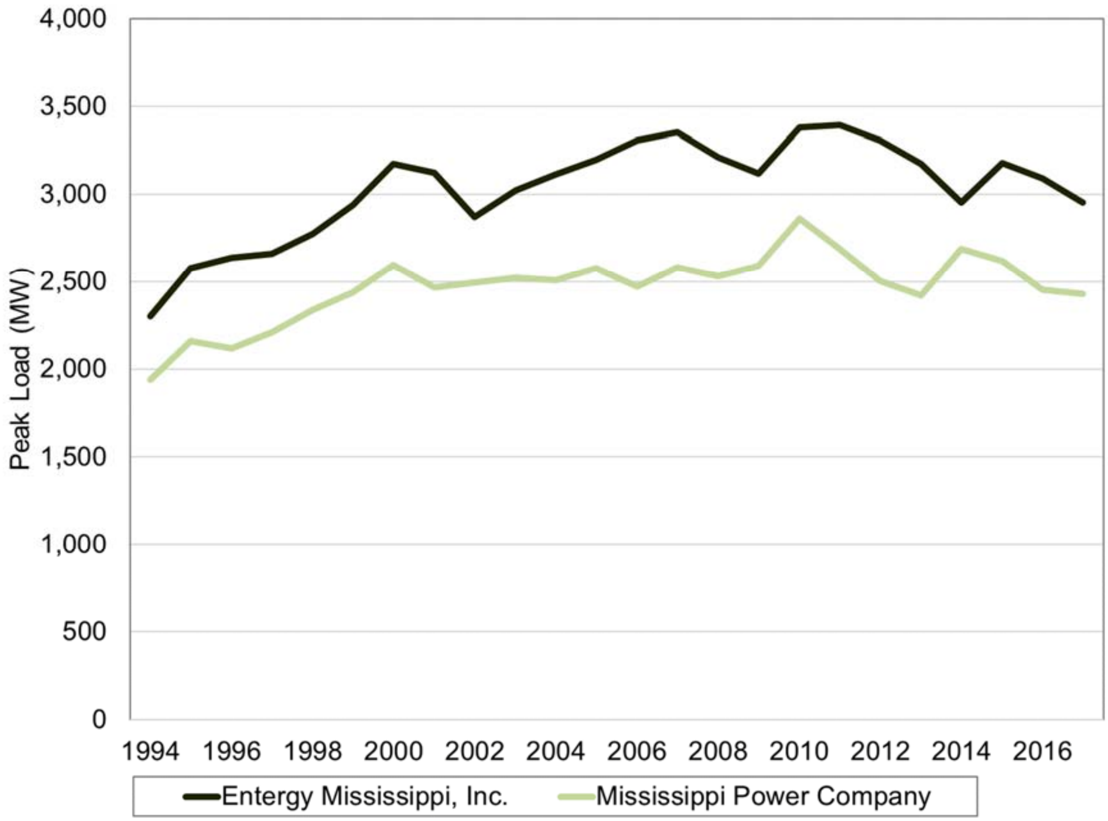

Figure 20: Annual Peak Load for Mississippi Utilities, 1994-2017
Source: Utility Annual Reports, FERC Form 1

Examining additions to deferrable distribution plant results in avoided distribution plant benefits that are reasonably similar between utilities, $16.00 per kW-year for EML and $12.35 per kW-year for MPC. Results for avoided transmission plant benefits vary slightly between utilities: $16.39 per kW-year for EML; and $9.19 per kW-year for MPC. On a combined basis, the avoided cost for T&D is $32.39 per kW-year for EML, and $21.53 per kW-year for MPC.

4.3.2. Hypothetical Revenue Requirement – Total Plant: Arguably, the drawback of the deferrable plant method discussed earlier is that it works well for utilities experiencing steady and consistent load growth. As noted earlier, EML and MPC both experienced noticeable growth in system demands through the 1990s, which continued at a slower pace through the first decade of the millennium. Since 2010, however, both Mississippi IOUs have experienced flat to declining system load growth. The previous method essentially ignores this recent negative trend and assumes that this declining peak load growth trend will reverse in the future.

However, a method used by the MidAmerican Energy Company ("MidAmerican") to price benefits associated with avoided transmission and distribution costs in energy efficiency filing before the Iowa Utilities Board does not rely on an established load growth trend.[108] Specifically, this method establishes a hypothetical revenue requirement-type analysis based on a utility's current depreciated T&D plant in service to estimate annual financing costs and expenses. Therefore, instead of examining changes in utility plant, this method examines the entirety of the utility's current applicable T&D-related rate base, and prices the remaining lifetime cost of these assets against the utility's system peak demand requirement, in order to develop an avoidable, per unit T&D cost.

FERC Form 1 data was used to determine the current book value of the Mississippi IOU's T&D investments. From this data, an annual revenue requirement associated with the carrying costs associated with the non-depreciated T&D investments was developed. Examining the revenue requirement associated with the transmission system investment results in a first-year levelized cost of $37.40 per kW-year for EML, and $28.59 per kW-year for MPC. Likewise, the total benefit from avoided distribution system investments for EML is $86.66 per kW-year, with similar total benefits from avoided transmission system investments for MPC being $44.85 per kW-year. On a total transmission and distribution basis, EML has a total avoided cost benefit of $124.06 per kW-year and MPC

[108] MidAmerican Energy Company Energy Efficiency Plan. Iowa Utilities Board Docket No. EEP-2012-0002. Direct Testimony of O. Dale Stevens, II.

has a total avoided cost benefit of $73.45 per kW-year. Arguably, this method, will circumventing the peak load growth requirements and challenges discussed earlier, suffers from potentially being overstated since the method include all T&D plant investment, not the deferrable portion of the plant. The following subsection estimates the deferrable component of this T&D investment.

4.3.3. Hypothetical Revenue Requirement – Deferred Plant: An alternative avoided T&D cost estimate, using the revenue requirement-type method discussed earlier, can be developed that focusses exclusively on a utility's deferrable, not total, T&D plant investment. Like before, this revenue requirement-based approach estimates a fixed revenue requirement associated with deferrable (not total T&D) plant, keeping all other assumptions constant.

The total benefit from avoidable distribution system investments for EML is estimated to be $20.05 per kW-year and the avoidable transmission system investments for EML being $20.47 per kW-year. Likewise, the total benefit from avoidable distribution system investments for MPC is $14.90 per kW-year, and avoidable transmission system investments for MPC being $15.28 per kW-year. On a total T&D basis, EML has a total avoided T&D cost benefit of $40.52 per kW-year and MPC has a total avoided T&D cost benefit of $30.18 per kW-year.

4.4. Recommendations: Table 25, which highlights the results of the survey previously referenced as the Mendota Survey,[109] shows that other studies that have assessed benefits from avoided transmission and distribution costs as ranging anywhere from $0.00 per kW-year to slightly more than $200 per kW-year depending on the utility.

[109] Mendota Group, LLC (September 16, 2014). *Estimates of Transmission and Distribution Costs Avoided by Energy Efficiency Investments*, pp. 26-27.

On a median basis across all studies, assessed benefits from avoided transmission investments have on average been $19.19 per kW-year, with assessed benefits from avoided distribution investments being on average $37.93. On a combined basis, the studies assessed by the Mendota Survey have had a median benefit from avoided transmission and distribution investments of $53.17 per kW-year.

Table 25: Mendota Survey of Avoided T&D Capacity Benefits

Source: Mendota Group, LLC (2014). *Estimates of Transmission and Distribution Costs Avoided by Energy Efficiency Investments*. September 16. p. 42.

State	Utility	Date of Estimation	Benefit from Avoided Cost: Transmission	Distribution	O&M	Total T&D
			---------- ($/kW-Year) ----------			
AZ	TEP	2013	N/A	N/A		$100.00
AZ	APS	2013	$0.00	$0.00		$0.00
CA	PG&E-Com	2011	$19.60	$55.97		$75.57
CA	PG&E-Res	2011	$18.77	$55.85		$74.62
CA	SCE-Com	2011	$23.39	$30.10		$53.49
CA	SCE-Res	2011	$23.39	$30.10		$53.49
CA	SDG&E-Com	2011	$21.08	$52.24		$73.32
CA	SDG&E-Res	2011	$21.08	$52.24		$73.32
CA	Weighted Average	2011	$21.20	$44.38		$65.59
CO	Xcel	2014	$14.31	$38.85		$53.17
CT	CL&P	2013	$1.30	$30.94		$32.24
CT	United Illuminating	2013	$2.64	$47.82		$50.46
IA	Interstate Power & Light	2014	$81.00	$26.00		$107.00
IA	MidAmerican	2013	$14.85	$37.01		$51.86
IL	Commonwealth Edison	2014	N/A	N/A		$42.00
MA	National Grid	2013	$88.64	$111.37		$200.01
MA	NSTAR	2011	$21.00	$68.79		$89.79
MA	WMeco	2011	$22.27	$76.08		$98.35
MA	Unitil	2013	$0.00	$171.15		$171.15
MI	Consumer's Energy	2012	$0.00	$0.00		$0.00
MN	Xcel	2014	$14.31	$38.85		$53.17
MO	Ameren	2014	$22.00	$10.00		$32.00
NH	PSNH	2013	$16.70	$53.35		$70.05
NW	NW Conservation and Electric Power Plan utilities	2010	$0.00	$23.00		$66.59
NV	Sierra Pacific Power dba Nevada Energy	2013	N/A	N/A		$12.23
NY	Consolidated Edison (Network)	2013	$0.00	$120.52		$120.52
NY	Consolidated Edison (Non-Network)	2013	$0.00	$42.63		$42.63
OR	PacifiCorp	2011	$36.89	$15.75		$52.64
OR	PGE	2011	$10.80	$22.40		$33.20
RI	National Grid	2013	$20.62	$20.62		$41.24
SD	MidAmerican	2012	$13.79	$34.37		$48.16
UT	PacifiCorp	2011	$36.89	$15.75		$52.64
VT	Burlington Electric Department (Prescriptive Programs)	2013	N/A	N/A		$158.00
VT	Burlington Electric Department (Custom Programs)	2013	N/A	N/A		$48.00
VT	Efficiency Vermont	2013	$34.25	$93.25	$50.00	$158.15
WA	PacifiCorp	2011	$36.89	$15.75		$52.64
WI	Focus on Energy		$0.00	$0.00		$0.00
	Median		$19.19	$37.93	-	$53.17

Table 26 shows the results of ACG's analyses under all three methods discussed above for EML and MPC.

Table 26: Summary of Avoided T&D Capacity Benefits

	Avoided Transmission Capacity Value	Avoided Distribution Capacity Value	Combined Capacity Value	Hourly Capacity Value	Estimated Load Carrying Capacity	Effective Hourly Capacity Value	
	---------- ($/kW-Year) ----------			($/MWh)	(%)	($/MWh)	(cents/kWh)
Average Annual Additions to Deferrable Plant							
Entergy Mississippi, LLC.	$ 16.39	$ 16.00	$ 32.39	$ 3.70	28.7%	$ 1.06	0.1061
Mississippi Power Company	$ 9.19	$ 12.35	$ 21.53	$ 2.46	26.1%	$ 0.64	0.0641
Hypothetical Revenue Requirement -- Total Plant							
Entergy Mississippi, LLC.	$ 37.40	$ 86.66	$ 124.06	$ 14.16	28.7%	$ 4.06	0.4063
Mississippi Power Company	$ 28.59	$ 44.85	$ 73.45	$ 8.38	26.1%	$ 2.19	0.2187
Hypothetical Revenue Requirement -- Deferrable Plant							
Entergy Mississippi, LLC.	$ 20.47	$ 20.05	$ 40.52	$ 4.63	28.7%	$ 1.33	0.1327
Mississippi Power Company	$ 15.28	$ 14.90	$ 30.18	$ 3.45	26.1%	$ 0.90	0.0899

Under most of these methods, the median estimate of avoided transmission capacity values for EML and MPC are $20.47 and $15.28 per kW-year, respectively. This is reasonably consistent with the median value from the Mendota Survey of $19.19 per kW-year for such benefits. On a distribution perspective, all three methods generally result in avoided cost benefits that are noticeably less than the median value from the Mendota Survey, with the exception of a hypothetical revenue requirement analysis based on total distribution plant. From a combined perspective, most methods resulted in avoided cost benefits that were lower than the median value from the Mendota Survey. Importantly, none of the estimated combined transmission and distribution avoided cost benefits, while being lower than the median surveyed estimates, are lower than what has previously been estimated for surveyed utilities. Furthermore, three studies of various states and utilities have found no discernible benefit associated with avoided cost of transmission and distribution development.

5. Other Avoided Costs

5.1. Overview: In addition to providing avoided capacity benefits, DER is viewed as providing some other benefits to utility systems. For example, a benefit provided by DER not include in the prior analysis relates to utility line losses. As a fundamental principle of electric power transmission, the amount of power required to be produced by a utility electric generator is more than the ultimate electric power that will be utilized by consumers due to the effect of impedance on transmission and distribution lines. This loss is correlated with the distance that electricity is required to flow over a line and is inversely related to the voltage of the electric line. DG, being located at the site of an end-use customer, effectively takes this principle in reverse, and any avoided capacity needs at the end-use customer should include an adder to reflect avoided line losses which would normally be considered in utility planning.

Additionally, reductions in demand at the meter result in additional value from the associated reduction in required procurement of ancillary services such as the need for regulation service and operating reserves. MISO currently operates a day-ahead and real-time ancillary services market for both regulation services and contingency reserves. Like avoided system losses, avoided regulation services and contingency reserves can be looked at as an adder to avoided generation capacity benefits to appropriately reflect the full value of the benefit.

DER also potentially provides a market price suppression effect. To the extent DER has a noticeable impact on customer demand and an increase on the available utility electric generation supply, DER is anticipated to lower wholesale electricity prices. Likewise, DER also potentially has the ability to provide benefits to customers from avoided outages. Specifically, DER systems, if configured appropriately, have the ability to provide limited power to the participating customer even during period of service interruptions. Finally, DER will assist utilities in meeting future environmental regulations by reducing the need for carbon-intensive traditional fossil fuel generation resources.

5.2. Prior Studies: The prior Synapse Report listed a number of potential benefits associated with DER.[110] These included avoided system losses, avoided RPS compliance, avoided environmental compliance costs, market price suppression effects, avoided risk or price volatility, avoided ancillary service costs, avoided costs associated with utility outages, and finally non-energy related benefits. While the report listed these benefits, most were not quantitatively assessed in the analysis, with the exception of avoided system losses, avoided environmental compliance costs, and avoided risks.[111]

Synapse's reason for omitting the other identified benefits were many. Synapse did not quantify avoided ancillary service costs because most prior studies had focused on the benefit of DER to operating reserve requirements, which was embedded in that analysis' calculation of avoided generation capacity costs.[112] Likewise, Synapse did not quantify as a benefit avoided outage costs as it noted that prior value of lost load ("VOLL") analyses had demonstrated inconsistent and variable monetary values associated with reduced disruption of electrical service, and that there was little evidence to indicate that solar DER would improve reliability in Mississippi.[113]

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[110] Stanton, Elizabeth A, *et. al.* (September 19, 2014). *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations*. Synapse Energy Economics, Inc. September 19, 2014. P. 4.
[111] *Id.*, pp. 29-30.
[112] *Id.*, p. 34.
[113] *Id.*, pp. 34-35.

The most recent E3 analysis for California also included assessments of DER's potential benefit to ancillary services, environmental compliance, and avoided renewable energy purchases.[114] Finally, while not assessing these benefits independently, the analysis included a discussion of generation loss factors that were not included in its assessment of avoided generation capacity costs.[115] E3 explained that CAISO markets included four types of ancillary services: regulation up and down, spinning reserves, and non-spinning reserves.[116] E3 furthermore explained that regulation services are generally procured independent of load reductions or distributed generation exports, and therefore were assumed to not benefit from DER.[117] However, spinning and non-spinning reserves vary directly with load changes, and the California IOS is required to maintain 5 percent reserves for generation served by hydro-electric power, and 7 percent for generation served by traditional thermal generators.[118] E3 used values from CAISO's 2015 markets which found that ancillary service costs averaged 0.7 percent of wholesale energy costs as a proxy for hourly avoided ancillary service costs.[119]

E3 also included an avoided CO2 emission compliance cost based on a forecast of CO2 prices that steadily increased from approximately $18 per ton in 2016, to $50 per ton by 2030.[120] Likewise, E3 includes an estimate of avoided renewable purchases based on California RPS goals requiring IOUs to purchase 33 percent of all generation from renewable generation technologies by 2020, increasing to 50 percent by 2030.[121]

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[114] Horii, Brian, *et. al.* (August 1, 2016). *Avoided Costs: 2016 Interim Update*. E3 Consulting, pp. 25, 33-40.
[115] *Id.*, p. 39.
[116] *Id.*, p. 25.
[117] *Id.*
[118] *Id.*, p. 26.
[119] *Id.*
[120] *Id.*, pp. 33-34.
[121] *Id.*, p. 36.

5.3. Avoided Line Losses: Mississippi rules supporting NEM require that the utility's calculation of the avoided costs of wholesale power include an adjustment to account for appropriate average line losses.[122] As such, lines losses associated with wholesale power are outside of the Commission's defined 'Actual Benefits of Distributed Generation' covered by this report. However, avoiding generation capacity needs adds an additional benefit to utility customers associated with avoided line losses associated with the reduced peak demand needs, which should be accounted for.

In response to discovery issued to each IOU, EML and MPC have provided line loss estimates that are used in system planning. Line losses in Mississippi are noticeably less than those seen nationally. For example, EML reports that total line losses to secondary distribution customers is only 7.05 percent.[123] MPC, likewise, estimates that total losses on its system is even lower, at only 5.35 percent of generation.[124]

Table 27 below presents estimated avoided line losses associated with generation capacity for EML. These calculations assume that all DER generation is associated with customers taking secondary distribution service, arguably providing a conservative estimate of avoided line losses. As can be seen in Table 27 benefits associated with avoided line losses range from $0.06 per MWh to $0.67 per MWh for EML.

[122] *In re: Order Establishing Docket to Investigate the Development and Implementation of Net Metering Programs and Standards*, Mississippi Public Service Commission Docket No. 2011-AD-2. Order Adopting Net Metering Rule (December 03, 2015). Exhibit A, p. 1.

[123] Entergy Mississippi, Inc. Response to Data Request ACA 2-5.

[124] Mississippi Power Company Response to Data Request ACG 2-6, Confidential Attachment A.

Table 27: Avoided Line Losses (EML)

	CCGT Hourly Capacity Value ($/MWh)	Annual Line Loss (%)	Hourly Avoided Line Losses ($/MWh)
Net Cost of New Entry ("CONE")	$ 9.45	7.05%	$ 0.67
Southeast Generation Costs	$ 5.42	7.05%	$ 0.38
Implied Capacity Premium - EMI	$ 7.23	7.05%	$ 0.51
MISO RPA - Zone 10	$ 0.79	7.05%	$ 0.06

Table 28 below presents estimated avoided line losses associated with generation capacity for MPC. Like the prior calculations for EML, these calculations assume that all DER generation is associated with customers taking secondary distribution service, arguably providing a conservative estimate of avoided line losses. As can be seen in Table 28, benefits associated with avoided line losses range from $0.13 per MWh to $0.32 per MWh for MPC.

Table 28: Avoided Line Losses (MPC)

	NGCC Hourly Capacity Value ($/MWh)	Annual Line Loss (%)	Hourly Avoided Line Losses ($/MWh)
Net Cost of New Entry ("CONE")	$ 5.93	5.35%	$ 0.32
Southeast Generation Costs	$ 2.50	5.35%	$ 0.13
Implied Capacity Premium - MPC	$ 5.34	5.35%	$ 0.29

5.4. Avoided Ancillary Services: ACG evaluated the benefit DGS will have on avoided generation reserve margins. EML stated in response to a data request that it utilizes a 12 percent capacity reserve margin on an annual and projected basis.[125] While MISO does maintain rules for planning reserve margin requirements, they are based on

[125] Entergy Mississippi, Inc. Response to Data Request ACA 2-4.

probabilistic resource adequacy requirements rather than minimum reserve requirements. However, EML's use of a 12 percent capacity reserve margin for planning purposes is consistent with that used in other regional transmission organizations, specifically Southwest Power Pool ("SPP"), which requires all member utilities to maintain a minimum 12 percent capacity reserve.[126]

Table 29 presents the hourly avoided ancillary costs associated with avoided capacity reserve margins for EML. As can be seen in Table 29, benefits associated with avoided ancillary service costs range from $0.10 per MWh to $1.13 per MWh for EML.

Table 29: Avoided Capacity Reserve Margins (EML)

	CCGT Hourly Capacity Value ($/MWh)		Target Capacity Reserve (%)	Hourly Avoided Reserve Cost ($/MWh)	
Net Cost of New Entry ("CONE")	$	9.45	12.00%	$	1.13
Southeast Generation Costs	$	5.42	12.00%	$	0.65
Implied Capacity Premium - EMI	$	7.23	12.00%	$	0.87
MISO RPA - Zone 10	$	0.79	12.00%	$	0.10

MPC recently filed a reserve margin plan with the Commission as an element of its settlement in Docket 2017-AD-112.[127] Every three years, MPC in coordination with its Southern affiliates conducts a formal Reserve Margin Study to determine the appropriate target reserve margin for planning purposes.[128] The most recent study conducted in early 2018 validated the company's existing summer long-term target reserve margin of 16.25

[126] *See*, Mark Watson (2018). *FERC approves SPP Resource Adequacy Requirement tariff revision effective July 1.* S&P Global – Platts. August 8, 2018.
[127] In Re: Mississippi Power Company Reserve Margin Plan Filing, Docket No. 2018-AD-145, Mississippi Power Company's Reserve Margin Plan (August 6, 2018).
[128] *Id.*, Attachment A at 11.

percent, but also established a 26 percent winter long-term target reserve margin.[129] In its filing, MPC noted that its system had experienced its annual system peak during the winter season in six of the last nine years. However, MPC also argued that this was a relatively recent trend, and that it furthermore currently projected future annual system peaks to occur during summer months.[130]

As noted earlier, the duel-peaking nature of MPC's system creates unique challenges when evaluating the capacity benefits created by DER for MPC's system. DER effectively partially imparts avoided capacity benefits for MPC's system at two separate parts of the year, if at different rates. To maintain consistency with the calculated benefit associated with avoided generation capacity, ACG averages MPC's target reserve margin used for planning purposes in both its winter season and summer season. This results in an average target reserve margin of 21.125 percent.

Table 30 presents the hourly avoided ancillary costs associated with avoided capacity reserve margins for MPC. As can be seen in Table 30, benefits associated with avoided ancillary service costs range from $0.53 per MWh to $1.25 per MWh for MPC.

Table 30: Avoided Capacity Reserve Margins (MPC)

	NGCC Hourly Capacity Value ($/MWh)	Target Capacity Reserve (%)	Hourly Avoided Reserve Cost ($/MWh)
Net Cost of New Entry ("CONE")	$ 5.93	21.13%	$ 1.25
Southeast Generation Costs	$ 2.50	21.13%	$ 0.53
Implied Capacity Premium - MPC	$ 5.34	21.13%	$ 1.13

[129] *Id.*
[130] *Id.*, Attachment A at 9.

5.5. Market Price Suppression: In the 2014 Synapse study, it was noted that DER has the potential to put downward pressure on wholesale electric prices by introducing new supply of energy and capacity in the market.[131] Other studies have likewise argued for the existence of such benefits in both the realm of DER and related items such as energy efficiency. The Synapse study, however, chose not to quantify the potential future benefits associated with future market price suppression.

DER adoption in Mississippi is currently in a nascent state, as has been noted by stakeholders to this analysis. The limited nature of DER in the State renders a calculation of wholesale market price suppression benefits difficult. Furthermore, even if it was possible to calculate such benefits, these benefits would almost certainly be insignificant due to the small amount of energy and capacity being imparted. For these reasons, ACG has decided not to quantify any benefits associated with wholesale market price suppression effects.

5.6. Benefit from Avoided Electrical Outages: In the 2014 Synapse study, it was noted that DER has the potential to reduce the costs associated with power interruptions by allowing customers to self-generate during service interruptions.[132] The study noted that the benefits of grid reliability are estimated through "value of lost load" analyses.[133] As noted earlier, however, the Synapse study ultimately did not quantify the benefit associated with avoided electrical outage costs, arguing that existing literature on the subject have arrived at inconsistent determinations of the value of lost load.[134]

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[131] Stanton, Elizabeth A, *et. al.* (September 19, 2014). *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations*. Synapse Energy Economics, Inc, p. 4.
[132] *Id.*, p. 5.
[133] *Id.*, p. 5.
[134] *Id.*, pp. 34-35.

Furthermore, Synapse argued that there was insufficient evidence that solar DER would improve reliability.[135]

ACG agrees with Synapse's earlier assessments regarding the wisdom of quantifying benefits for DER associated with avoided outage costs. In June 2009, Lawrence Berkeley National Laboratory ("LBNL") published the results of a meta-study, i.e. study of studies, estimating the value of electric service reliability.[136] The results of the LBNL meta-study demonstrate that the value of lost load is dependent on a multitude of independent variables – the customer class in question, the duration of interruption avoided, time of interruption occurrence, and the industry in question for commercial and industrial customers.[137] A residential customer may only see limited inconvenience and costs associated with momentary outages occurring during a weekday afternoon, while the same customer will see significantly large costs during extended electrical outages as refrigerated foods spoil. Likewise, an information technology server farm will experience significant costs even during a momentary service disruption from loss of client data. There is simply no recognized, universal, value of lost load.

Furthermore, it should be recognized that the purpose of this study is to provide appropriate information to the Commission to assist it in establishing a new compensation rate for Mississippi DER investments. In this regard, only benefits occurring to the public should be included, such as benefits associated with the avoided cost of new electric generation which would have been recovered from ratepayers through traditional ratemaking. A DER system that is able to provide power to the customer who installed it

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[135] *Id.*, pp. 34-35.

[136] Sullivan, Michael J. (June, 2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States.* Ernest Orlando Lawrence Berkley National Laboratory.

[137] *Id.*, p. xxi.

is providing a private benefit, outside of limited circumstances involving the provision of power to designated critical infrastructures customers such as first responder stations and water treatment facilitates during emergency circumstances,[138] regardless of whether that customer is also able to receive grid-supplied electric power at the time. DER systems only provide a public benefit during electric service interruptions if the system is able to provide local power to nearby customers in a micro-grid setting. Such a circumstance would require a DER system that has been designed and sized to serve loads in excess of the net metered customer and furthermore is able to export to the electric grid during emergency circumstances. It is unclear if Mississippi DER systems or utility distribution systems are designed to permit operations such as this.

5.7. Avoided Environmental Compliance: In the 2014 Synapse study, Synapse developed a hypothetical cost of carbon that began at $15 per ton in 2020, and increased steadily to $60 per ton in 2040.[139] However, subsequent the publishing of the Synapse report, it has become increasingly unlikely that a national carbon tax, cap-and-trade regime, or other environmental compliance policy associated with carbon dioxide emissions will be implemented in the foreseeable future. It is even less clear at this time the form these regulations would take. For this reason alone, ACG has decided not to include benefits associated with avoided future carbon compliance costs. Future analyses can revisit this benefit if it becomes clear that such a policy will be adopted.

[138] See Critical Infrastructure Sectors, Cybersecurity and Infrastructure Security Agency ("CISA"), Department of Homeland Security, available online at: "https://www.dhs.gov/cisa/critical-infrastructure-sectors."

[139] Stanton, Elizabeth A, *et. al.* (September 19, 2014). *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations*. Synapse Energy Economics, Inc, p. 26.

5.8. Recommendations: Table 31 presents the total monetary hourly avoided cost benefits of both avoided line losses and ancillary service costs for EML. Table 31 presents these results for each of the avoided generation capacity cost valuation methods presented in section 3 and also includes the allowance for the ELCC of solar generation. In EMI's service territory, total benefit from DER associated with hourly avoided line losses and capacity reserves on an effective basis range from $0.04 per MWh to $0.52 per MWh for solar DER.

Table 31: Total Avoided Other Costs (EML)

	Hourly Avoided Line Losses	Hourly Avoided Reserve Cost	Hourly Total Avoided Other Costs	Effective Load Carrying Capabilities	Effective Hourly Capacity Value	
	-------------- ($/MWh) --------------			(%)	($/MWh)	(cents/kWh)
Net Cost of New Entry ("CONE")	$ 0.67	$ 1.13	$ 1.80	28.7%	$ 0.52	0.0517
Southeast Generation Costs	$ 0.38	$ 0.65	$ 1.03	28.7%	$ 0.30	0.0296
Implied Capacity Premium - EMI	$ 0.51	$ 0.87	$ 1.38	28.7%	$ 0.40	0.0395
MISO RPA - Zone 10	$ 0.06	$ 0.10	$ 0.15	28.7%	$ 0.04	0.0043

Table 32 presents the total monetary hourly avoided cost benefits of both avoided line losses and ancillary service costs for MPC. Table 32 presents these results for each of the avoided generation capacity cost valuation methods presented in section 3 and also include the allowance for the ELCC for solar generation. In MPC's service territory, total benefit from DER associated with hourly avoided line losses and capacity reserves range from $0.17 per MWh to $0.37 per MWh for solar DER.

Table 32: Total Avoided Other Costs (MPC)

	Hourly Avoided Line Losses	Hourly Avoided Reserve Cost	Hourly Total Avoided Other Costs	Effective Load Carrying Capabilities	Effective Hourly Capacity Value	
	-------------- ($/MWh) --------------			(%)	($/MWh)	(cents/kWh)
Net Cost of New Entry ("CONE")	$ 0.32	$ 1.25	$ 1.57	26.1%	$ 0.41	0.0409
Southeast Generation Costs	$ 0.13	$ 0.53	$ 0.66	26.1%	$ 0.17	0.0172
Implied Capacity Premium - MPC	$ 0.29	$ 1.13	$ 1.41	26.1%	$ 0.37	0.0369

For purposes of this analysis, the median value of other avoided cost estimates was used for each utility. This has the benefit of recognizing the range of reasonable possible estimates for each component, while leaving the final estimate of the total benefit of DER not dependent on outlining estimates. On an effective basis, the median estimate for avoided generation capacity benefits from DER is $0.35 per MWh (0.03 cents/kWh) for EML, and $0.37 per MWh (0.04 cents/kWh) for MPC.

6. Conclusions

The purpose of this Report has been to provide the Commission with the direct and quantifiable benefits arising from the implementation of Mississippi-based DER. The recommendations of this report have been developed as a proposed replacement of the currently-active 2.5 cent per kWh adder being used by the Mississippi IOUs per the Commission's DER Rule. The estimates provided in this Report are based upon what is reasonably known and measurable, consistent with traditional ratemaking standards as they are used around the country as well as Mississippi. No non-measurable or difficult-to-measure benefits are included in the recommendation of this Report since these benefits can often be speculative, wide-ranging, and difficult to support from an empirical perspective.

The primary known and measurable benefit associated with Mississippi DER arises from the displaced capacity that occurs when behind-the-meter generation is developed in the state. This DER capacity offsets capacity that otherwise would have been developed by the IOUs and includes avoided generation, transmission, and distribution capacity investments. The estimates provided in this Report also include some smaller, additional benefits associated with avoided line losses. There are three fundamental challenges, however, that limit the economic benefits that DER provides in Mississippi.

First, solar is the predominant renewable DER technology used in Mississippi and the capacity offset that solar provides can be limited because of its intermittency. Solar energy is only generated while the sun is shining and when the sun does not shine, other capacity resources have to be utilized by utilities in order to meet their load and reliability obligations. Further, and more importantly, even when the sun is shining, solar generation does not usually peak at the same time that utility systems peak in Mississippi. As noted in this Report from data and evidence provided by the IOUs, Mississippi system peaks typically occur much later in the day, several hours after solar installations provide their optimal generating potential. Thus, the ability of Mississippi solar DER to contribute to offsetting peak loads, and thereby deferring capacity, is limited.

Second, Mississippi is a slow growing state in terms of its electricity demand. Average electricity demand growth in the state over the past five years averages a negative 0.25 percent. Further, both IOUs report negative peak load growth over the past five years: negative 2.14 percent and negative 0.93 percent for EML and MPC, respectively. This is much lower than the U.S. average. This Report has used generous assumptions about peak load growth in order to develop avoided capacity estimates, particularly for avoided T&D capacity. A result indicating zero T&D capacity benefits could equally be justified given the evidence provided by the IOUs which found little to no offsetting capacity benefit.

Third, all generation markets throughout the U.S. are long on capacity. This outcome is particularly true in the southeast and in Mississippi which still carries a considerable amount of excess capacity developed during the merchant build out of the last decade, as well as the recent construction of a large natural gas plant (i.e., Kemper). Further, as noted earlier, load growth in the southeast, and much of the U.S., has been limited further drawing out excess reserve margins for longer periods of time from existing capacity. In total, the average value of any DER capacity offset is going to be very limited, now and into the foreseeable future. While the Commission is currently assessing the role of older legacy generation in the state, and the possibility of seeing some legacy generation capacity retirements exists, there is no evidence that these capacity retirements will be allowed to proceed in a fashion that creates considerable capacity shortfalls that could change the valuation outlook estimated in this report.

Thus, this Report concludes and recommends a “realized and quantified” DER benefit adder of 0.35 cents per kWh for EML, and a similar DER benefit adder of 0.27 cents per kWh for MPC. A decomposition and summary of this estimate is provided for EML below in Table 33, while a similar decomposition and summary is provided for MPC in Table 34. These calculations utilize the median values of each component presented earlier in this study. These are the recommended values the Commission should use as adders to avoided energy cost for DER “puts” to the distribution grid for the two Mississippi IOUs. These recommended values should remain in place until either (a) the Commission conducts its five year review of its DER rules and their impact on DER development or (b) a three year period, whichever comes first.

Table 33: Total Avoided Costs (EML)

	Hourly Avoided Cost ($/MWh)	Effective Load Carrying Capacity (%)	Effective Hourly Avoided Cost ($/MWh)	Effective Hourly Avoided Cost (cents/kWh)
Avoided Generation Capacity				
Net Cost of New Entry ("CONE")	$ 9.45	28.7%	$ 2.71	0.2712
Southeast Generation Costs	$ 5.42	28.7%	$ 1.55	0.1555
Implied Capacity Premium	$ 7.23	28.7%	$ 2.07	0.2074
MISO RPA - Zone 10	$ 0.79	28.7%	$ 0.23	0.0228
Median Value	$ 6.32	28.7%	$ 1.81	0.1815
Avoided T&D Capacity				
Average Annual Deferrable Additions	$ 3.70	28.7%	$ 1.06	0.1061
Hypothetical Revenue Requirement – Total Plant	$ 14.16	28.7%	$ 4.06	0.4063
Hypothetical Revenue Requirement – Deferrable Plant	$ 4.63	28.7%	$ 1.33	0.1327
Median Value	$ 4.63	28.7%	$ 1.33	0.1327
Avoided Other Costs				
Net Cost of New Entry ("CONE")	$ 1.80	28.7%	$ 0.52	0.0517
Southeast Generation Costs	$ 1.03	28.7%	$ 0.30	0.0296
Implied Capacity Premium	$ 1.38	28.7%	$ 0.40	0.0395
MISO RPA - Zone 10	$ 0.15	28.7%	$ 0.04	0.0043
Median Value	$ 1.20	28.7%	$ 0.35	0.0346
Total Avoided Cost Benefits				
Avoided Generation Capacity	$ 6.32	28.7%	$ 1.81	0.1815
Avoided T&D Capacity	$ 4.63	28.7%	$ 1.33	0.1327
Avoided Other Costs	$ 1.20	28.7%	$ 0.35	0.0346
Total Avoided Cost Benefits	**$ 12.16**		**$ 3.49**	**0.3488**

Table 34: Total Avoided Costs (MPC)

	Hourly Avoided Cost ($/MWh)	Effective Load Carrying Capacity (%)	Effective Hourly Avoided Cost ($/MWh)	Effective Hourly Avoided Cost (cents/kWh)
Avoided Generation Capacity				
Net Cost of New Entry ("CONE")	$ 5.93	26.1%	$ 1.55	0.1546
Southeast Generation Costs	$ 2.50	26.1%	$ 0.65	0.0651
Implied Capacity Premium	$ 5.34	26.1%	$ 1.39	0.1392
Median Value	$ 5.34	26.1%	$ 1.39	0.1392
Avoided T&D Capacity				
Average Annual Deferrable Additions	$ 2.46	26.1%	$ 0.64	0.0641
Hypothetical Revenue Requirement – Total Plant	$ 8.38	26.1%	$ 2.19	0.2187
Hypothetical Revenue Requirement – Deferrable Plant	$ 3.45	26.1%	$ 0.90	0.0899
Median Value	$ 3.45	26.1%	$ 0.90	0.0899
Avoided Other Costs				
Net Cost of New Entry ("CONE")	$ 1.57	26.1%	$ 0.41	0.0409
Southeast Generation Costs	$ 0.66	26.1%	$ 0.17	0.0172
Implied Capacity Premium	$ 1.41	26.1%	$ 0.37	0.0369
Median Value	$ 1.41	26.1%	$ 0.37	0.0369
Total Avoided Cost Benefits				
Avoided Generation Capacity	$ 5.34	26.1%	$ 1.39	0.1392
Avoided T&D Capacity	$ 3.45	26.1%	$ 0.90	0.0899
Avoided Other Costs	$ 1.41	26.1%	$ 0.37	0.0369
Total Avoided Cost Benefits	**$ 10.20**		**$ 2.66**	**0.2659**

Appendix A:
August 2, 2018 ACG Presentation

Commission Consultant Overview: Study Methodologies and Procedural Matters

Public Meeting, Docket No. 2011-AD-2. Distributed Generation Benefits Study. Jackson, MS, August 2, 2018.

David E. Dismukes, Ph.D.
Acadian Consulting Group
Baton Rouge, Louisiana

www.acadianconsulting.com

Acadian Consulting Group

Presentation outline

- Introduction
- Current Commission net metering rules
- Mississippi DER trends
- Proposed stakeholder topics
- Proposed stakeholder procedural issues

Introduction

Acadian Consulting Group, LLC: Overview.

Acadian Consulting Group (ACG) is a research and consulting firm specializing in the analysis of economic, statistical, financial and accounting issues that arise in the **regulation and public policy of energy and regulated industries**.

We provide expert witness testimony, research, and reports to state and federal regulatory agencies and private industries. **Since 1995**, ACG team members have participated in more than **400 regulatory proceedings in over 25 states** including the District of Columbia and the Federal Energy Regulatory Commission.

ACG clients.

ACG works **primarily for commission staffs, consumer counsels and attorney generals** across the U.S. Current and more recent clients include:

- Louisiana Public Service Commission
- North Dakota Public Service Commission
- New Jersey Division of Rate Counsel
- District of Columbia People's Counsel
- Arkansas Attorney General
- Florida Office of Public Counsel
- Massachusetts Attorney General
- AARP-Vermont

ACG: prior DER experience.

ACG has long history in working on distributed generation topics that date back to the 1990s:

- Preparation of comments for Capstone, Honeywell and other DG manufacturing companies in the **CA DER proceedings in 1990s**.
- **Extensive market design and policy work** in New Jersey that includes the development of long term SREC contracting mechanisms, solar loan programs, utility solar development proposals, solar RPS standards, SCAP pricing, and community solar rules.
- Examination and negotiation of **clean energy contributions for various mergers** in New Jersey and the District of Columbia.
- Multiple engagements **examining alternative rate designs and their implications for efficiency and DER** (DC, NJ, ND, ME, AR)
- **Extensive academic/independent research**, publication, and instruction on the nexus of regulatory policy, rate design and DER development.

Contacts during course of study process:

Primary Project Director:

David E. Dismukes, Consulting Economist

daviddismukes@acadianconsulting.com

Project Manager:

Michael Deupree, Research Associate

michaeldeupree@acadianconsulting.com

Phone:

225-769-2603

ACADIAN CONSULTING GROUP

Introduction

- Study participants are **welcome to reach out and contact the project team at any time**. We will attempt to respond to inquires at a timely fashion.
- Study participants wishing to **provide information for consideration in this proceeding are welcome** to submit directly to the study team.
- Study participants wishing to provide detailed information can request to have that **protected under confidentiality provisions as defined by Commission rule**.
- Project team **welcomes all relevant information** in this process and open communication.

Current Net Metering Rules

Mississippi Renewable Energy Net Metering Rule - Overview

Mississippi Renewable Energy Net Metering Rule (“MRENMR” or “net metering rule”)

- Requires **utilities to provide net metering** to all customers using a renewable energy resource.
- Residential systems limited to **20 kW.**
- Non-residential systems up to **2 MWs.**
- **System caps** are imposed if **RE capacity exceeds 3 percent of system peak** for the prior calendar year.
- All net metered customers **must also satisfy** the requirements of the **Commission’s interconnection rule**.

Current Net Metering Rules

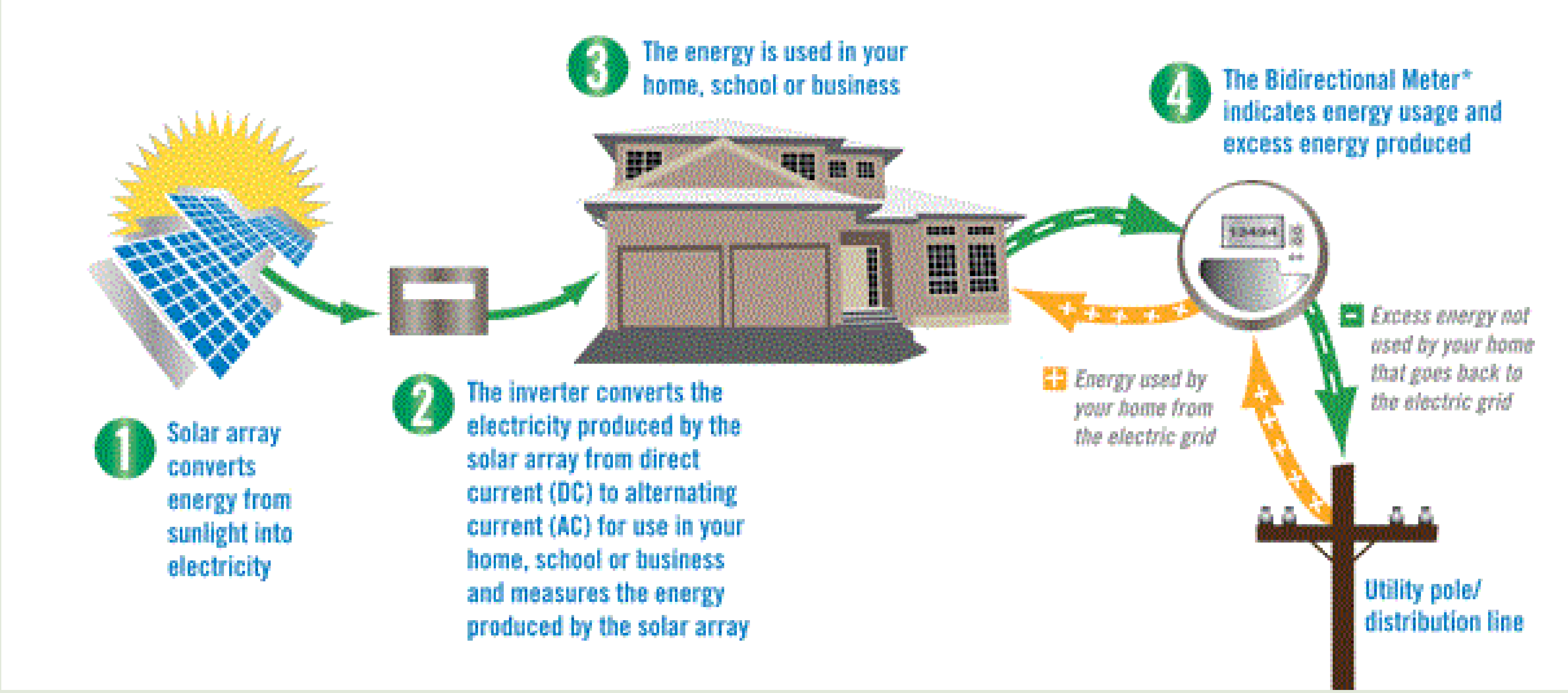
Net metering rule billing methodology.

- Net metering rule requires utilities to provide net metering service at **non-discriminatory rates** that are **identical**, with respect to rate structure and level, retail rate components, and any monthly fixed charges, to the rates that the net metered customer would have been charged absent the presence of a net metered renewable generation system.
- Mississippi uses **bi-directional metering** and assesses DER energy flows on what can be referred to as **"two channel billing"** or **"net billing"** basis:
  - **Energy used** by the net metered customer is charged in a manner consistent with Commission-approved **retail rates**.
  - Energy **exported** by the net metered customer is valued at a determined "Total Benefits of Distributed Generation" rate.
- Effectively, all electricity used by the net metered customer behind the meter is credited at full retail rates; while excess generation exported by the net metered customer is valued at a differing rate that, to date, has been administratively set.

Current Net Metering Rules

Two channel or net billing methodology: example.

Prices for two streams of energy to be priced separately. Shown below as a thick green line, and a thick yellow line.



Net Metering Rule: Current DER valuation

Total Benefits of Distributed Generation:

- Defined as Avoided Cost of Wholesale Power plus Non-Quantifiable Expected Benefits.

Non-Quantifiable Expected Benefits:

- Temporary set at 2.5 cents/kWh.
- To be replaced and subsumed by actual benefits 3 years from 2016 effective date of Commission's Rule.

Low-Income Benefits Adder:

- Additional 2 cent per kWh adder for the first 1,000 qualifying customers whose household incomes are at or below 200% of the federal poverty level.

Current Net Metering Rules

Rule provisions regarding future changes in DER valuation

Commission's net metering rule explicitly recognizes that the inclusion of **"non-quantifiable expected benefits"** is a **<u>temporary provision</u>**.

Rule clearly notes that this additional benefit (adder to the avoided cost reimbursement rate) will **last no longer than three years** after the effective date of the rule.

Intent of the temporary adder is to serve as **"proxy" for "actual benefits of distributed generation."**

Goal was to also help facilitate early-adoption DER.

The timing constraint on the low-income adder is much longer (**15 years).**

Section 107 study process

Commission rule notes (section 107) that "Commission shall cause a study to be performed by an independent consultant beginning no earlier than one year after the effective date of this rule …."

"Said independent consultant will work **collaboratively with the utilities** and gather information from **other stakeholders** to provide the Commission with **guidance in developing a calculation of benefits that can be demonstrated to have been realized and quantified** as a result of the adoption of distributed generation in Mississippi." (emphasis added)

Current Net Metering Rules

Section 103: "Actual benefits of distributed generation"

The purpose of this study is to estimate the "actual benefits of distributed generation" as defined by the Commission's rule, which is defined as:

"…**actual, quantifiable benefits** realized by installed distributed generation **over and above** the Avoided Cost of Wholesale Power, which shall be calculated based upon information derived from the report of a third party consultant chosen by the Commission and the **experience of the utilities** since implementation of the rule, as well as any **additional information that may be available in the industry** at that time." (emphasis added)

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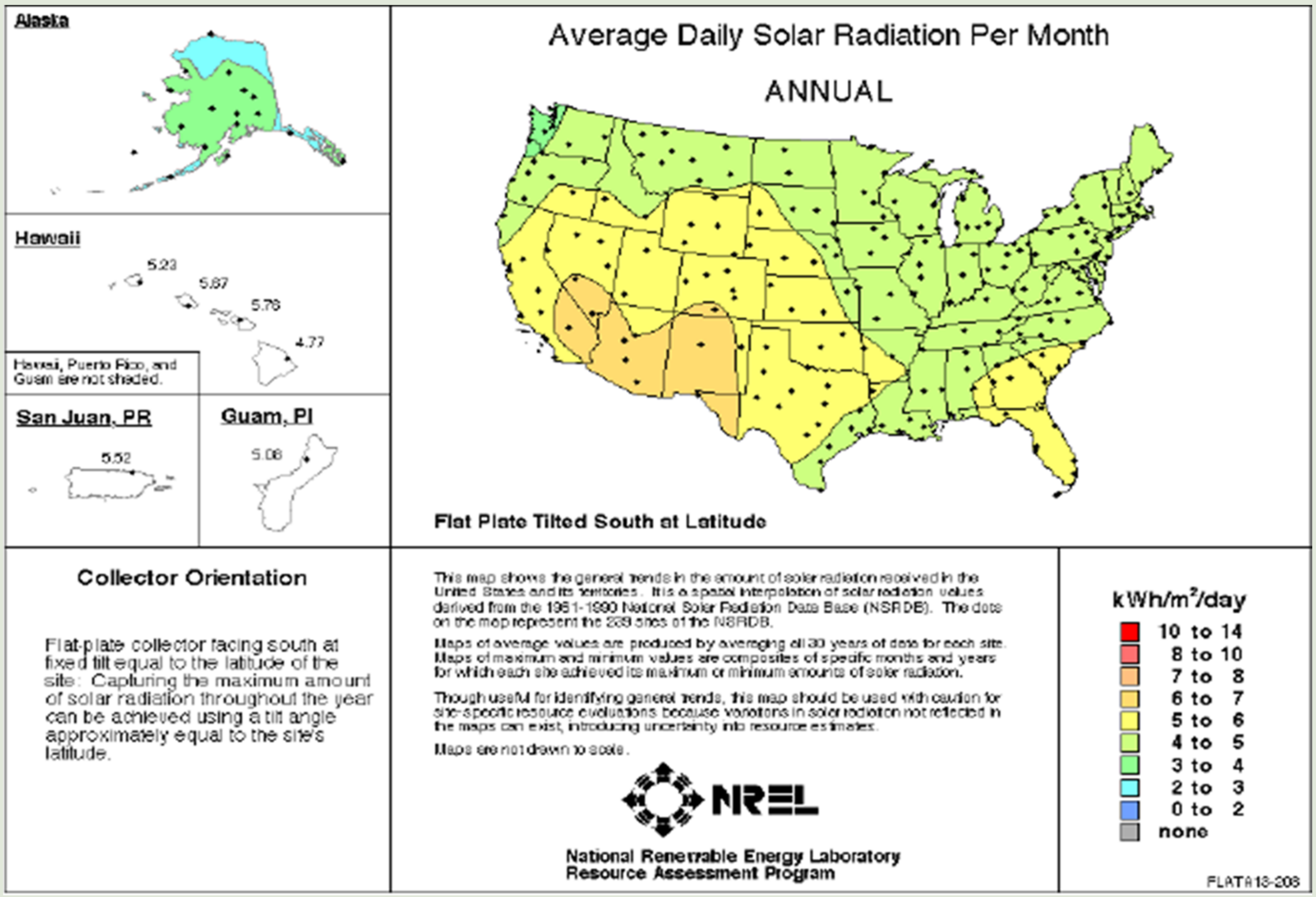
Current State of Distributed Solar In Mississippi and Nationwide

Technical Capabilities -- Solar

Mississippi sits in a region of the country that has reasonable, but not exceptional, solar generation technical capabilities.



Source: NREL Energy Analysis Office

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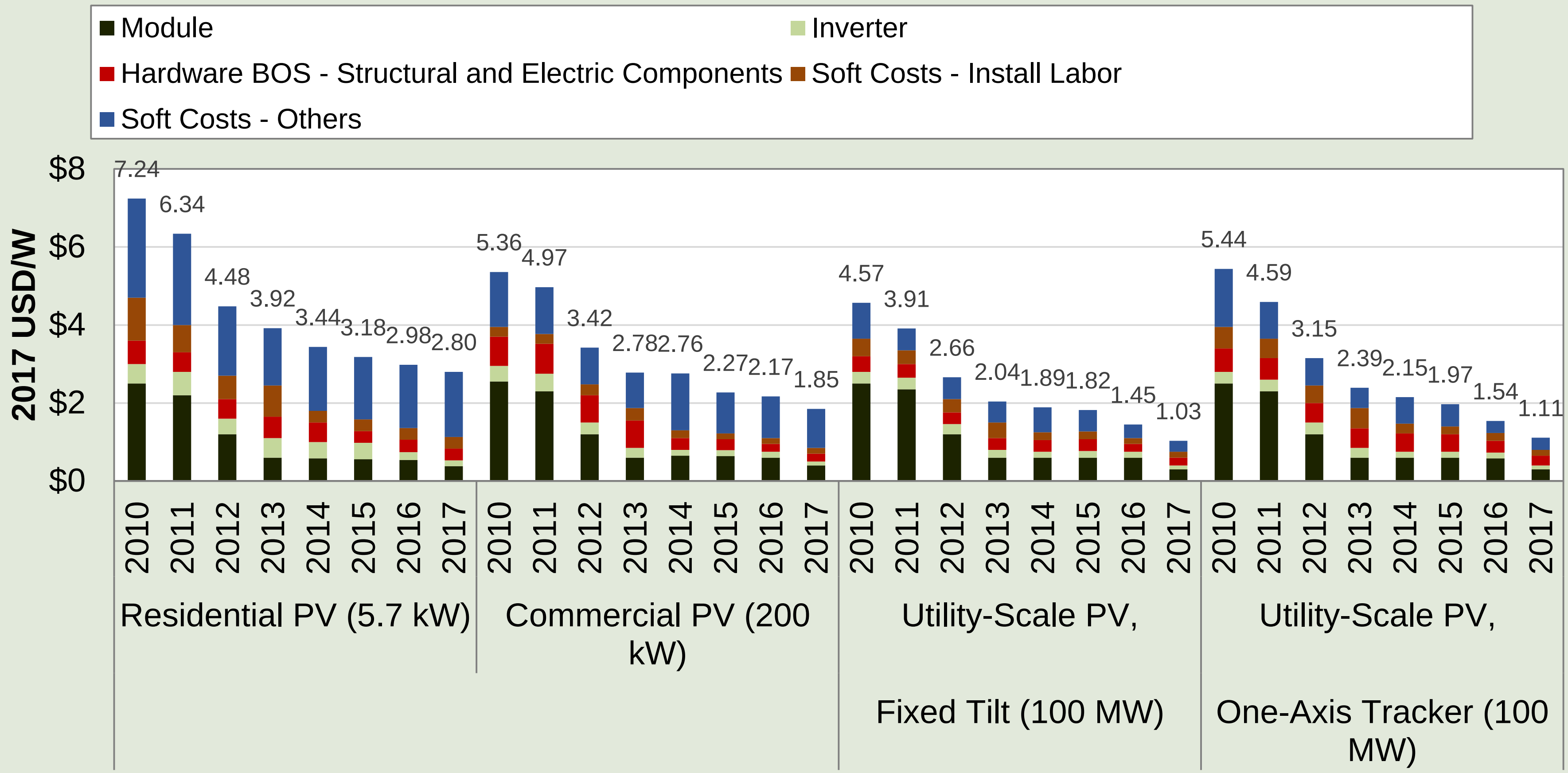
Mississippi

Trends in Installed Solar Generation Costs ($/Watt)

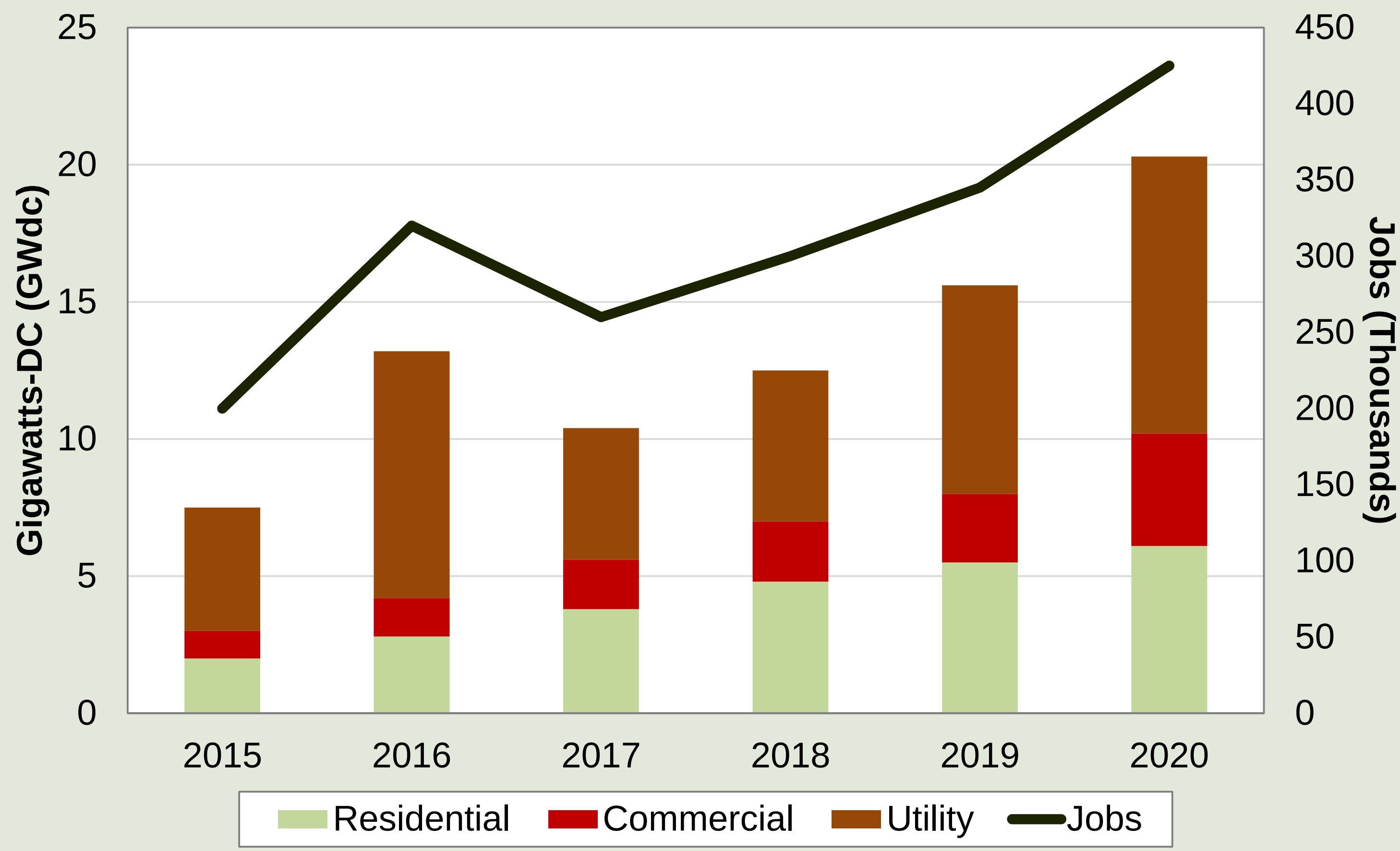
Solar development costs have seen considerable cost decreases over the past several years in most all market segments.



Source: Fu, Ran et. Al. (September 2017), U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017, U.S. Department of Energy National Renewable Energy Laboratory, Figure ES-1.

Forecast U.S. Solar Capacity by Market Segment (GW)

Solar market outlook is relatively strong to 2020, although industry forecasts anticipate larger growth in utility/grid scale projects than residential.

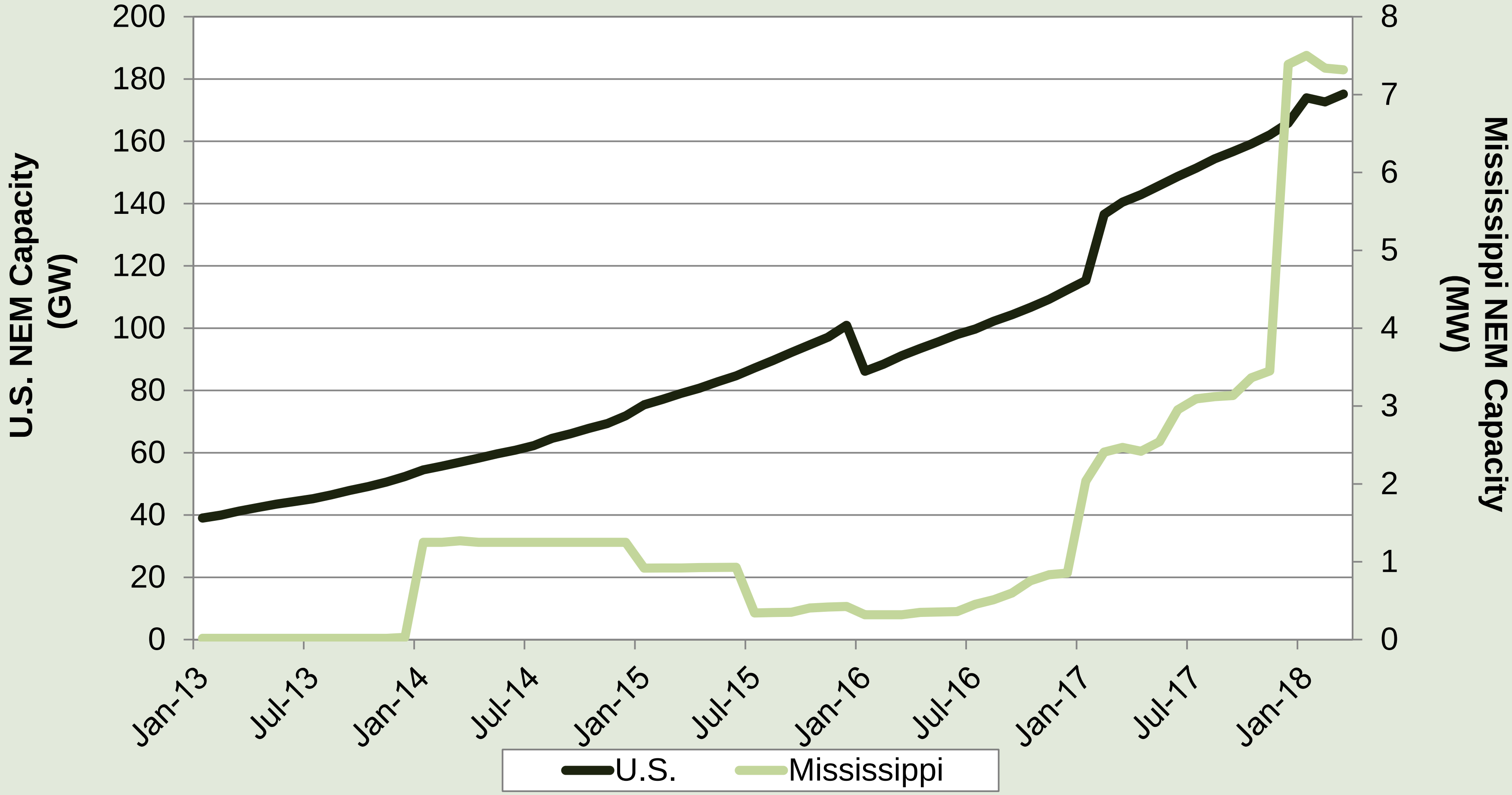


Source: Solar Energy Industries Association.

Mississippi

US and Mississippi Installed NEM Capacity (MW)

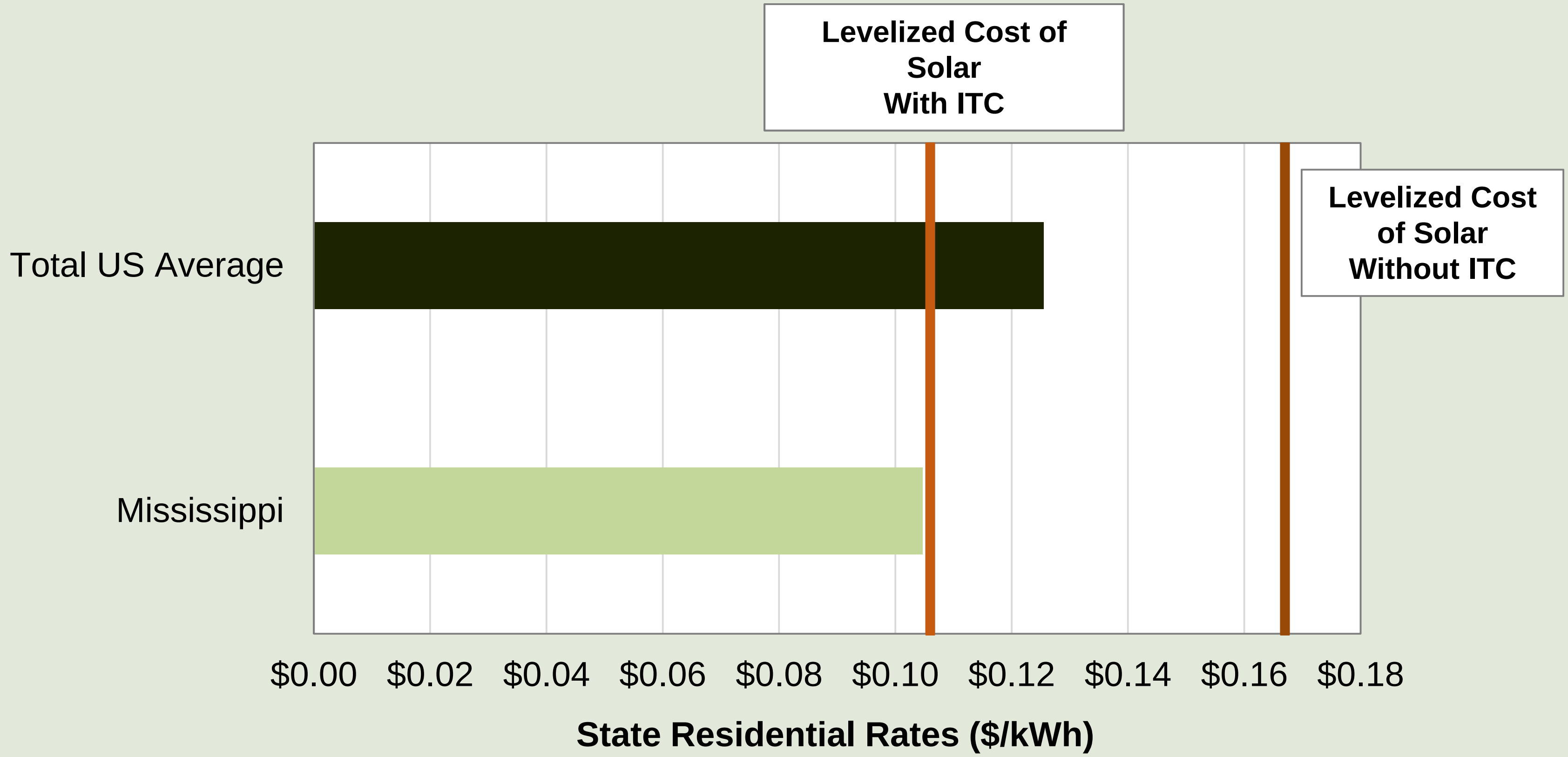
Mississippi development growth lags trends seen in national markets.



Note: January 2017 – Present Data is preliminary. Data includes state-level adjustment to impute values from non-sampled entities.
Source: Energy Information Administration, Form EIA-861.

Retail rate comparison

Relatively low retail electricity rates has a lot to do with low Mississippi solar energy adoption.



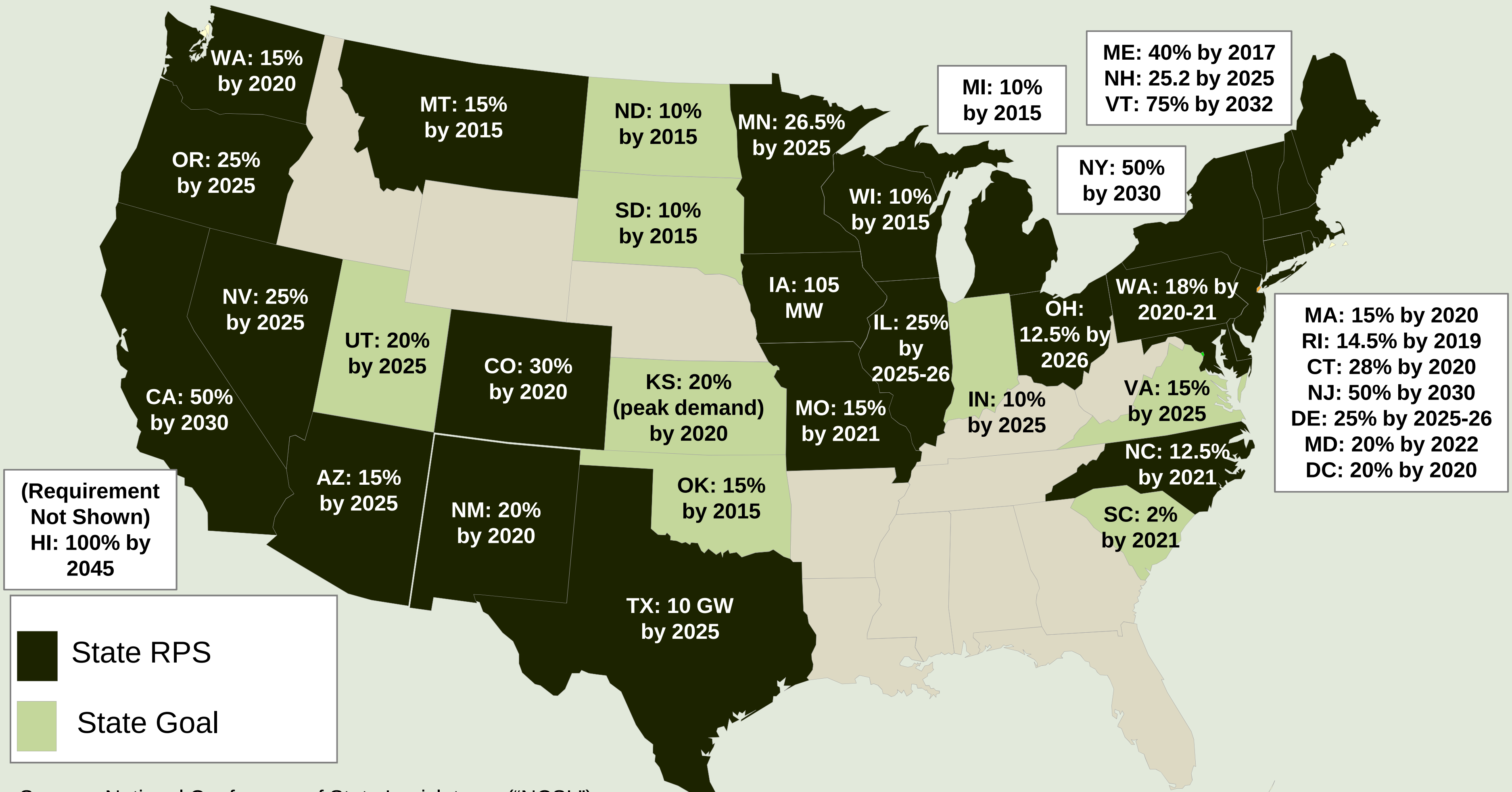
Note: Levelized Cost of Solar based on NREL Q1 2016 finding for Kansas City, Missouri.

Source: Energy Information Administration; and Fu, Ran et. Al. (September 2017), U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017, U.S. Department of Energy National Renewable Energy Laboratory, Figure 18.

Mississippi

Renewable portfolio standards

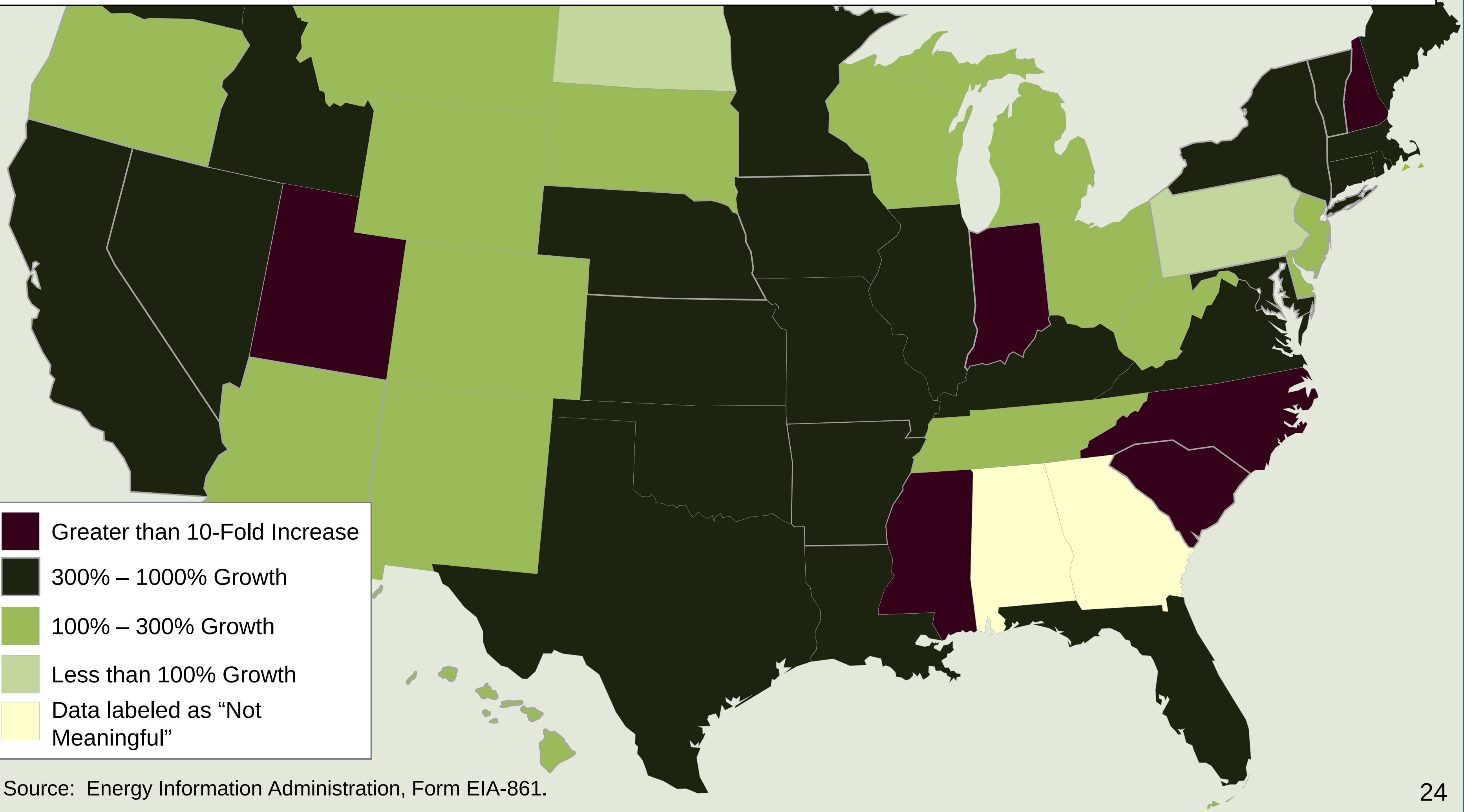
Mississippi does not have mandated renewable market and/or solar set-aside within that mandated RE market.



Source: National Conference of State Legislatures ("NCSL").

Net Metered Capacity Growth (January 2013 through March 2018)

Mississippi has seen considerable growth, on relative and percentage basis. Growth, however, is relative to a zero base.



Source: Energy Information Administration, Form EIA-861.

Stakeholder topical issues

Proposed stakeholder topics

- On July 12, 2018, **three stakeholder participants** to this proceeding (25 x 25, Sierra Club, GSREIA, collectively "solar industry stakeholders") submitted a letter to the Commissioners on collective basis **raising a number of issues** about this proceeding.
- A **subsequent motion** was also filed that follows certain parts of this letter.
- ACG has **no opinion the proposed motion**, but can address the proposed solar industry stakeholder topics **as they relate to the Commission's net metering rules** and the purpose of this proceeding.
- The solar industry stakeholders raise **10 different proposed topics** for this study process/proceeding.

NEM program administration

Stakeholder Proposal	ACG Response
Assessment of the efficacy of utility administration of net metering programs, including comparison of national best practices	ACG will likely be conducting a best practices comparison of net metering policies but will not be doing a performance audit of the utilities' management of their net metering programs. This is beyond the scope of the current investigation.

Disclosure on methods, data, etc.

Stakeholder Proposal	ACG Response
Full disclosure of methodology for modeling energy exports by net metering customers, including load profiles and timing.	ACG will make this information available but certain aspects of this information may require parties seeking the specific information and algorithms to sign non disclosure agreements since (a) some of this information may be confidentially sensitive from a utility perspective and (b) some of the information could incorporate ACG intellectual property.

Costs and benefits

Stakeholder Proposal	ACG Response
Complete detail of the areas of cost and benefits evaluated.	This information will be made available at the time of the first draft. However, the purpose of this study is to examine DER benefits. This is not a comprehensive net benefits analysis.

Rate impacts

Stakeholder Proposal	ACG Response
Complete detail of methodology for calculating induced and indirect rate impacts of NEM customers.	ACG will make data available to parties to the extent this information is examined and compiled. However, this is not a comprehensive net benefits investigation and the Commission's requirements for this investigation are relatively well-defined and limited to "actual benefits of distributed generation" as defined by its rule.

Natural gas and capacity assumptions

Stakeholder Proposal	ACG Response
Reasonableness of gas price and capacity price forecast assumptions.	ACG will provide all data and forecast assumptions, particularly those used in developing energy and capacity forecasts and benefits.

Hedging value

Stakeholder Proposal	ACG Response
Methodology for assessing hedging value.	ACG will provide this information to the extent it is utilized. However, this type of analysis does not appear to fit into the "actual benefits of distributed generation" and, given the currently low levels of DER in MS, it is likely that there is not a very large and significant hedge benefit on utility FAC costs. Further, hedge value is questionable given the fact that reimbursement is tied to avoided costs, not a fixed rate like a feed-in tariff.

Market price impacts

Stakeholder Proposal	ACG Response
Impact of distributed generation on market energy prices.	ACG will provide this information to the extent it is utilized. However, this type of analysis does not appear to fit into the "actual benefits of distributed generation" and, given the currently low levels of DER in MS, it is likely that there is not a very large and significant benefit associated with in-state DER.

Economic impacts (construction)

Stakeholder Proposal	ACG Response
Estimate of distributed generation construction economic activity, including indirect and induced economic impacts.	ACG will not be doing this analysis since it is beyond the scope of the Commission's directives and the scope of this investigation.

DER forecasts

Stakeholder Proposal

Reasonableness of assumptions regarding future distributed generation capacity.

ACG Response

ACG will provide all data and forecast assumptions, particularly those used for developing future DER forecasts. Note there is a chance that this analysis may include commercially-sensitive information (such as utility subscriptions to commercial sources) for which a non-disclosure agreement will need to be signed.

Net metering software costs

Stakeholder Proposal

ACG Response

Amortization period for costs of software upgrades and other one-time utility expenses.

ACG will not be doing this analysis since it is beyond the scope of the Commission's directives and the scope of this investigation.

Stakeholder procedural issues

Stakeholder procedures

Stakeholder procedural proposals

- Solar industry stakeholders also raised a number of proposals for the manner and procedures by which this study should be conducted.
- Solar industry stakeholders make five study process recommendations.

Stakeholder meetings

Stakeholder Proposal	ACG Response
Initial meetings with all stakeholders, including solar industry.	Current workshop has been designed to address this concern. ACG is open to additional workshops as the study process progresses, provided a well-defined agenda can be developed and the workshop can be conducted in a way that does not distract from Commission's timing goals.

Repository (data, information)

Stakeholder Proposal	ACG Response
A central repository for information and data used in the study, including all received by stakeholders. Non-disclosure can be provided.	Commission has docket for this investigation, parties are encouraged to use formal filing procedure. ACG will be maintaining an information and correspondence log during study process. ACG will also be maintaining a bibliography and references file for comparable studies and other relevant information. Parties can provide relevant studies, or can make filing in docket requesting study team to take official notice of study.

Publication/comment: methods, assumptions, etc.

Stakeholder Proposal	ACG Response
Publication of study's proposed data sources, assumptions, methods, including initial round of stakeholder meetings.	ACG will provide this information at the time of the initial draft report release. Parties will be given adequate time to review all assumptions, methods, and data. Note that there could be BOTH confidential information and commercially-sensitive ACG workproduct/intellectual property for which non-disclosure agreements must be signed.

Access/addressing commission, consultants

Stakeholder Proposal	ACG Response
Ability to directly address the Commission regarding study structure, and the Commission should approve the structure.	All parties will have the ability to address the Commission and ACG throughout the course of this investigation. This proceeding is docketed and governed by the Commission's rules which provide for access and input.

Stakeholder procedures

Draft comment period

Stakeholder Proposal	ACG Response
Reasonable notice and comment on draft study prior to release.	ACG envisions allowing all parties to review and comment on study. Likewise, ACG will be responding to parties comments to their respective reviews of the study. NOTE: this is ACG's work product and recommendation to the Commission - it is not a "group" or "collective" report being offered to the Commission. Ultimately, ACG will have to defend ths report and recommendations to the Commission on its own.

Activities to date

ACADIAN CONSULTING GROUP

Current activities

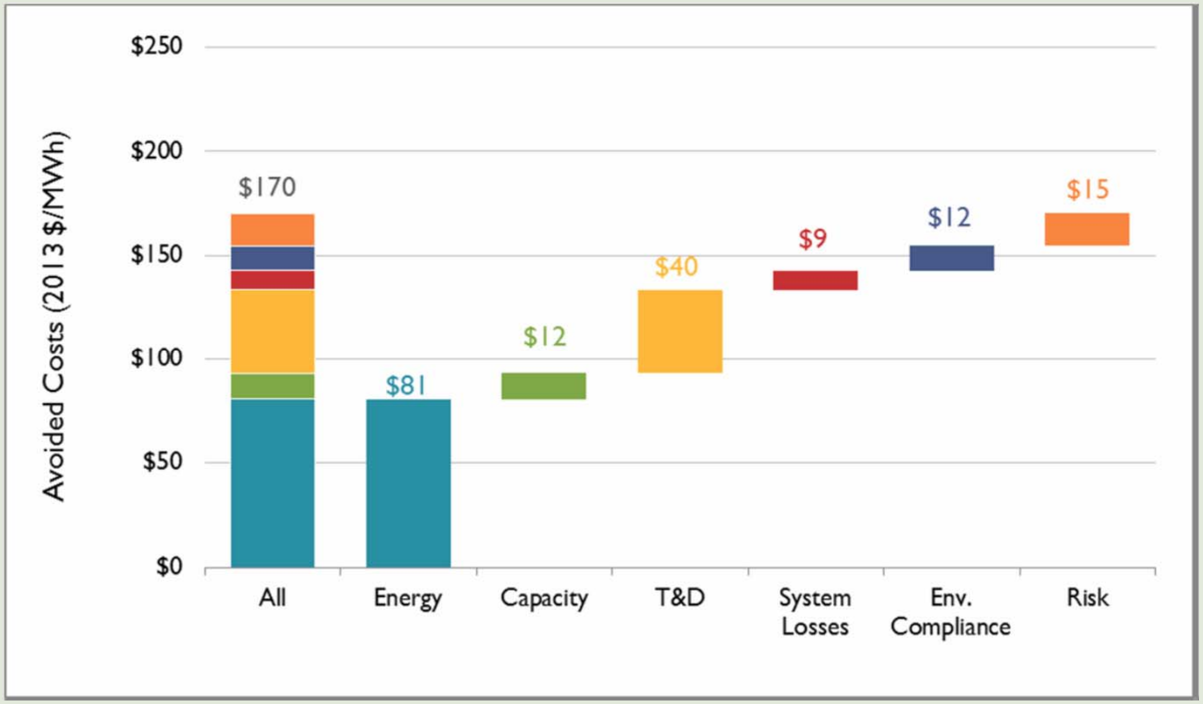
Activities to date

- **Met with Commission counsel and Staff** to discuss plans on moving forward and initiating this public workshop
- **Executed non-disclosure/confidentiality agreements** with MPCo and EMI.
- Have **developed comprehensive informal data request** for utilities. Can provide copy of what was asked, in terms of the questions, to stakeholders but not confidential responses.
- Have **received a good amount of information from MPCo**. **Waiting on EMI responses**. Currently **evaluating this information**.
- **Currently collecting data and information** on fuel prices, capacity prices, energy prices and other inputs that will be needed for the analysis.
- Surveying literature for other **quantitative estimates that are consistent with the methodologies defined in the Commission's net metering rule** recognizing that these can differ by utility, region and other factors.

Methods

- The **methodologies** for examining solar benefits, or the value of solar, are **relatively straightforward**.
- In fact, reasonable people should be able to **agree, in very large part on the individual components** of a study of this nature.
- The challenge is **collecting the data** needed to estimate the individual components of solar value and the **assumptions** used in estimating each component.
- Additional issue for this study will be determining what is a **legitimate "quantifiable" avoided cost (benefit).**

Illustration from Synapse MS Study (2014)



Source: Synapse Mississippi Net Metering Study. Provide for illustrative purposes only and is not an endorsement of method or final estimates.

Current activities

Solar benefits categories

Potential Benefit Category	Description	Study Relevance/Appropriateness
Avoided Energy	All fuel, variable operations and maintenance expenses, emission allowance costs, wheeling charges.	No since these are already established by market-based avoided costs utilized by utilities and defined by Commission rule.
Avoided Capacity	Capacity purchases avoided or improvements to reserve margins created by DER capacity.	Yes.
Avoided Transmission and Distribution Capacity	T&D capacity avoided by DER capacity.	Yes.
Avoided System Losses	Avoided T&D electrical losses from localized electricity generation	Yes.
Avoided RPS Compliance	Reduced payments to comply with RPS requirements.	No.
Avoided Environmental Compliance Costs	Reduced environmental compliance costs not otherwise captured in avoided energy.	No since carbon regulation is not known and measurable regulatory change in foreseeable future.
Market Price Suppression	Price impact caused by introduction of new supply.	Potentially if these can be estimated in known and measurable fashion. Size will be an issue for MS.
Avoided Risk (Hedge)	Reduction in price volatility created by DER resources.	No since DER resources are no supplied on a fixed cost/price basis.
Avoided Grid Support	Ancillary service benefits.	Yes.
Avoided Outage Costs	Avoided interruptions from DER.	Yes, if they can be estimated on reasonable basis. For MS, this will be very small value given current installations.
Non-energy benefits	Wide range of benefits that have dificult to quantify value that can range from economic development, to technological innovation to customer satisfaction and empowerment benefits.	No given Commission rule provisions that clearly require a movement away from non-measurable benefits.

Questions/comments

Appendix B:

Response to Parties' Comments on Draft Report

On November 19th, 2018, the Commission made available a draft version of this report (hereafter "Draft Report") for review by interested parties.[1] The Commission also set a 45-day comment period, which was subsequently extended for an additional 30 days,[2] for parties to submit comments on the Draft Report.

The following five parties submitted comments in response to the Commission's invitation: The 25x'25 Alliance ("25x'25"); Entergy Mississippi, LLC ("Entergy Mississippi," or "EML"); Mississippi Solar Energy Society ("MSES"); Mississippi Power Company ("MPC"); and the Sierra Club. Additionally, the Sierra Club also submitted comments to the Draft Report prepared by Synapse Energy Economics, Inc. ("Synapse") on behalf of the Gulf States Renewable Energy Industries Association ("GSREIA"), the Sierra Club, and 25x'25.

This summary and response has been prepared by the Commission's consultant (Acadian Consulting Group, LLC or "ACG") to respond to Draft Report comments received by the parties in this proceeding. Not all parties have commented upon all the issues discussed below. The discussion and response provided below, however, attempts to address each major area raised by at least one party in their filed comments. A summary of the parties' individual and/or collective positions has been provided on each major topic, followed by a response to those respective opinions.

[1] Order Requesting Comments.
[2] Order Granting Motion to Extend Comment Period.

1. Significant Change in the Estimated Benefits Adder

Comments of Parties

Several intervenors expressed concern with estimated NEM benefits ($0.0035/kWh for EML and $0.0027/kWh for MPC) compared to the existing allowance of 2.5 cent per kWh adder above the utility's avoided cost of energy. These parties, collectively, assert that the estimates included in the Draft Report will undermine distributed generation ("DG") and solar energy development in Mississippi. For instance, 25x'25, states that the estimates provided in the Draft Report would hamper economic development and discourage consumer choice while creating economic harm to those existing net metering customers that have installed DG systems based on expectations of previously determined payback period.[3]

The Sierra Club, likewise, argues that adopting the Draft Report's proposed adders would upset existing economic expectations for customers who have invested significant financial resources in the installation of on-site DG systems. Furthermore, the Sierra Club argues that an eight-fold reduction in the compensation rate for Mississippi NEM customers would violate several rate design principles that include gradualism, public acceptability, and fairness.[4]

Other commenters, primarily the utilities, found the DG benefit estimates, and the methodologies used to calculate these estimates, as being generally acceptable.[5] There are some instances, admittedly, where utility commenters believe ACG's estimates are

[3] Comments of 25x'25 at 2.
[4] Comments of the Sierra Club at 6.
[5] Comments of Entergy Mississippi, LLC on Consultant's Draft Report Dated November 19, 2018, at 3-4; Comments of Mississippi Power Company at 2; and Synapse Energy Economics Comments to MS PSC at 4.

based upon generous assumptions and interpretations of data that, if anything, could result in even lower, not higher avoided capacity costs and other NEM benefits.[6]

Consultant Response

ACG was not tasked by the Commission to support any specific avoided benefit estimate in this engagement. ACG was, in fact, tasked with providing an independent study of the avoided benefits created by DG in Mississippi. The Commission did not direct ACG to conduct a result-driven study, which appears to be what several intervenors, such as Sierra and 25x'25 suggest. Further, ACG's Draft Report is comprised of a number of individual benefit estimates, conducted at a component-level of detail including: avoided generation capacity estimates; avoided transmission capacity estimates; avoided distribution capacity estimates; among several other itemized benefits that; in total, sum to an overall Mississippi-based DG benefit. Each component analysis that was itemized in the Draft Report included not one, but several methodologies, most of which are commonly used throughout the U.S. in comparable types of studies. ACG used a diversity of methods in order to account for the differing approaches that can arise in examining DG benefits. Thus, ACG disagrees with the assertion that, somehow, the Draft Report was biased in any way towards a pre-determined result.

Lastly, ACG was charged with the straightforward task of quantifying and estimating DG benefits. ACG was not tasked with conducting a policy or market analysis estimating the outlook for solar energy in Mississippi. Further, ACG was not tasked with surveying all policy options being adopted by policy makers around the U.S. to promote or encourage solar energy. ACG interprets the plain intent of the Commission's directives

[6] Comments of Entergy Mississippi, LLC on Consultant's Draft Report Dated November 19, 2018, at 4; and Comments of Mississippi Power Company at 3-5.

for this engagement as one that focuses on quantification, not policy analysis. The Commission explicitly noted that the purpose of this engagement is to develop "...a calculation of benefits that can be demonstrated to have been realized and quantified as a result of the adoption of distributed generation in Mississippi."[7]

2. Consistency with Commission Policy

Comments of Parties

The Sierra Club states that ACG misinterpreted prior Commission policies; in particular, taking issue with ACG's use of a "quantifiable and measurable" standard in estimating DG benefits.[8] Sierra states that the Commission's December 3, 2015 Order uses the terms "actual" and "quantifiable" and that somehow these two relatively straightforward terms can also be interpreted to include a set of DG benefits that are not currently measurable, such as avoided environmental compliance costs, avoided environmental risks, and avoided commodity risk costs.[9] Sierra Club goes further by also stating that ACG somehow injected itself into the place of the Commission by making decisions about "what is," and "what is not" quantifiable.[10] Lastly, Sierra states that ACG's analysis starts from a presumption that the currently-in-place 2.5 cent per kWh adder must be changed.[11]

Consultant Response

ACG disagrees with Sierra's assertions that this study should include a wide-range of sweeping benefits, some of which may be difficult if not impossible to accurately

[7] Id. at 4.
[8] Synapse Energy Economics Comments to MS PSC at 3.
[9] Id.
[10] Id. at 4-5.
[11] Comments of the Sierra Club at 2.

quantify. As a point of clarification, ACG's methods, and the use of the "quantifiable and measurable" standard, have been clear since this study process began. ACG gave a detailed presentation to stakeholders early in the study process, and part of this presentation (slides 15 and 16),[12] and a large part of the discussion at that stakeholder meeting, was dedicated to the use of the "quantifiable and measurable" standard that ACG made clear would be used as part of the study's overall methodologies. No party since the time of this stakeholder meeting and presentation has (a) filed a complaint or motion to the Commission seeking clarification on this study methodology issue nor (b) attempted to provide ACG with additional measures or support for broader methodologies. In fact, no stakeholder, in particular the Sierra Club, has attempted to work with ACG or provide ACG with any information throughout the course of this study process, despite early assertions by Sierra that such interaction would be forthcoming.

Further, ACG believes that the plain intent of the Commission's Order, defining the study focus, is clear:

> This temporary adder will be replaced within three (3) years with a calculations of Actual Benefits of Distributed generation using Mississippi-specific data based upon an independent consultant study. This independent consultant will work collaboratively with the utilities and other parties to gather information from all stakeholders and provide the Commission with guidance in developing **a calculation of benefits that can be demonstrated to have been <u>realized and quantified</u>** as a result of the adoption of distributed generation in Mississippi.[13]

Likewise, the Sierra Club is also incorrect in its assertion that the Draft Report is intended to supplement the role of the Commission in any manner. The Commission

[12] Commission Consultant Overview: Study Methodologies and Procedural Matters (August 2, 2018), Public Meeting, Docket No. 2011-AD-2.
[13] Order Adopting Net Metering Rule at 15, emphasis added.

requested a third-party "independent" consultant to calculate the specific DG benefit for Mississippi.[14] ACG believes that if the Commission wanted to define each and every methodological aspect of this study, it could have clearly conducted this study on its own. Instead, the Commission sought outside support to get an "additional set of eyes" in quantifying these benefits. The Commission sought the services of an outside consultant that could bring together, and consider multiple perspectives and methodologies, in the quantification of DG benefits. As noted earlier, ACG's analysis did not focus on one specific methodology, but incorporated several methodologies, into several aspects of its research, to bring together a range of quantified estimates, for the Commission's consideration. The Draft Report reflects the range of methods, each of which are consistent with what ACG believes is the Commission's primary intent which is to focus on quantifiable, not speculative or anecdotal DG benefits.

Lastly, ACG notes that the final decision on this matter of debate with the Sierra Club does, in fact, rest with the Commission. ACG has offered the Commission with a range of options from which to choose. Ultimately, ACG believes the Commission can choose to accept the composite overall recommendation offered in the Draft Report, an individual aspect of those estimates, some modification or those estimates, or the Commission can reject the methods in favor of an approach that is more broadly constructed.

[14] The Mississippi Public Service Commission Requires the Assistance of an Independent Consultant in Docket No. 2011-AD-2 to Perform a Study Calculating the Actual Benefits of Distributed Generation in Mississippi, Mississippi Public Service Commission Request for Proposals at 2.

3. Low NEM Participation Rates

Comments of Parties

Several parties highlight the fact that low NEM/DG penetration in the Mississippi makes it difficult to estimate DG benefits. The Sierra Club, for instance, notes that limiting the estimation of only those benefits currently achieved limits the full scope of potential longer-run DG benefits in Mississippi. [15] For instance, Sierra notes that the Draft Report estimates exclude price suppression and avoided risk benefits that could be more prevalent with higher DG penetration.[16] Likewise, 25x'25 states that the "extremely low penetration" level of DG systems in Mississippi prevents a detailed quantification of actual benefits of DG at the current juncture.[17] Likewise, MSES states that the current penetration of DER in Mississippi is too small to provide adequate data regarding the "true" value of DER benefits.[18]

Both EMI and MPCo also note in their respective comments that DG deployment was likely currently insufficient to support an adequate determination of its actual and quantifiable benefits in Mississippi.[19]

Consultant Response

While ACG admits that DG deployment is small, it disagrees that this, by itself, serves as a basis to (a) not study the impact of DG in Mississippi at the current time and (b) reject using a quantifiable and measurable standard for estimating these DG impacts. In fact, several studies have recently noted that DG benefits rapidly increase at low

[15] Synapse Energy Economics Comments to MS PSC at 10.
[16] Id.
[17] Comments of 25x'25 at 2.
[18] Comments of Mississippi Solar Energy Society at 8.
[19] Comments of Entergy Mississippi, LLC on Consultant's Draft Report Dated November 19, 2018, at 1-2; and Comments of Mississippi Power Company at 1.

penetration rates, but see noticeable declining marginal benefits once DG solar penetration rates hit even modest levels.

The reason for this rapid decline is due to a phenomenon that has been dubbed the “duck curve” due to creating an appearance vaguely resembling the belly and neck of a duck.[20] The duck curve describes a situation where, without storage or other grind-enhancing technologies, DG solar leads to significant drop in mid-day net load on spring and fall days as more and more solar generation is added to the electric grid. This leads to the possibility that solar generation will need to be curtailed to accommodate ramping concerns associated with volatile electric loads. Actively leading to costs to the electric grid, beyond providing declining benefits.

[20] See, “What the Duck Curve Tells us about Managing a Green Grid” (2013), California Independent System Operator.

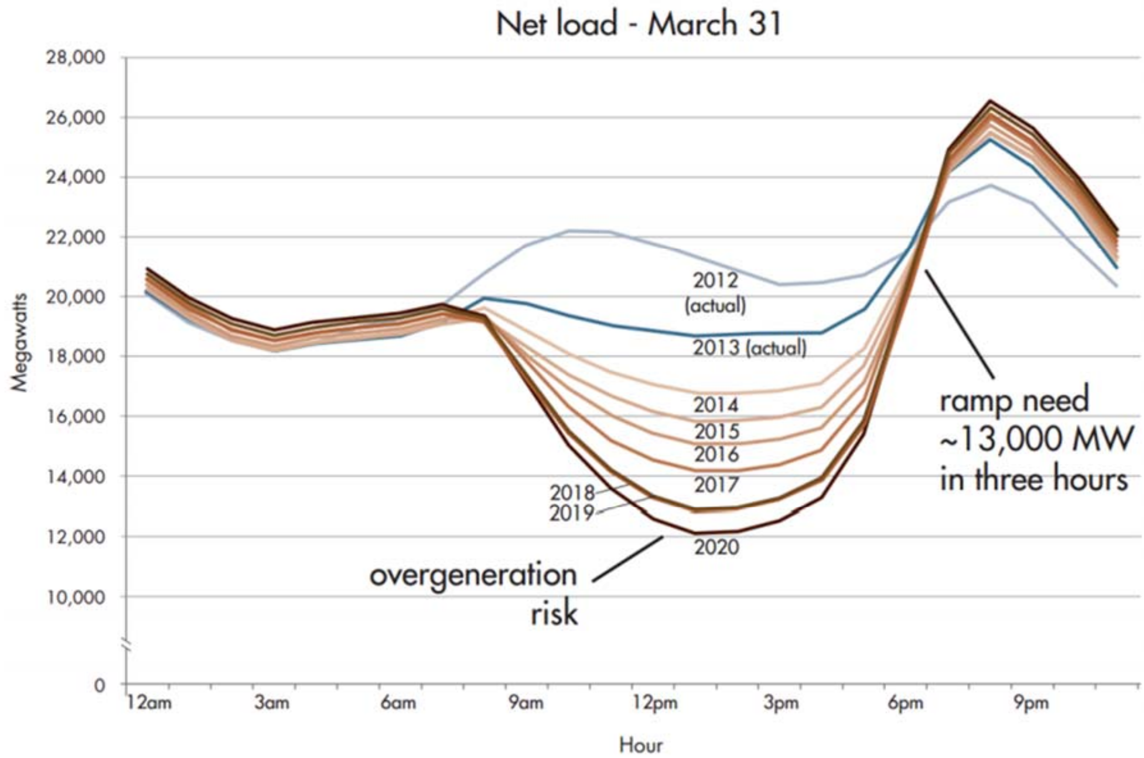


Figure 1: The CAISO Duck Chart for March 31

Source: Denhold, Paul et. al. (November 2015), "Overgeneration from Solar Energy in California: A Field Guide to the Duck Chart," National Renewable Energy Laboratory; citing "What the Duck Curve Tells us about Managing a Green Grid" (2013), California Independent System Operator.

As stated by NREL, the duck curve itself illustrates the challenge of accommodating material solar generation levels, and the potential for overgeneration and even potentially curtailment of solar generation.[21] NREL's analysis of California found that solar penetration rates as low as 11 percent of annual electric generation could lead to some curtailment of solar generation,[22] and that at penetration rates equaling 20 percent of annual electrical generation the marginal curtailment rates could exceed 30 percent.[23]

[21] Denhold, Paul et. al. (November 2015), "Overgeneration from Solar Energy in California: A Field Guide to the Duck Chart," National Renewable Energy Laboratory at 3.
[22] Id. at 20.
[23] Id. at iii.

Likewise, the duck curve phenomenon leads to shifting of utility peaks to later in the day, even during summer peak months, eventually to hours with limited or no solar generation potential with growth in solar penetration rates. A recently released collaborative report by the Center for Energy Studies at Louisiana State University ("LSU") and Southwestern Electric Power Company ("SWEPCO") found that the marginal contribution to utility peak demand rapidly declines after 10 percent of households on a utility's system install solar generation technologies, and all but disappears after 27 percent of households install solar generation technologies due to this peak shifting effect.[24] Likewise, an analysis by the Institute for Energy Research ("IER") on California solar markets find similar results, including the disappearance of any marginal benefit to reduced capacity needs after solar generation reaches rates as low as six percent of annual electricity generation.[25]

Further, ACG disagrees with the Sierra Club's comments suggesting that significantly higher DG penetration would result in greater market price suppression impacts. While this assertion has some anecdotal appeal, it has not been borne out in prior studies around the U.S. The consensus with regards to market price suppression benefits from renewable resources or energy efficiency is that the unitized price reduction caused by decreased demand is usually quite small.[26] The Draft Report's statements about the presence of market price suppression benefits was intended to convey the fact

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[24] Upton, Gregory B. et. al. (February 2019), "The Future of Solar in Louisiana: an Analysis of the Technical and Economic Implications of Solar P.V. Growth on Louisiana's Economy and Electric Grid," at 50.

[25] "The Solar Value Cliff: The Diminishing Value of Solar Power" (August 2017), Institute for Energy Research at 9.

[26] State Approaches to Demand Reduction Induced Price Effects: Examining How Energy Efficiency Can Lower Prices for All (December 2015), Industrial Energy Efficiency & Combined Heat and Power Working Group, State and Local Energy Efficiency Action Network at 6.

that, if such benefits are present, they would be relatively small in the context of the Commission's requested analysis even before one considers the nascent nature of the DER development in Mississippi.

ACG also notes that the Sierra Club's arguments about avoided risk reduction[27] is entirely without merit, and not only lacks an empirical foundation, but fails to grasp basic risk management principles, particularly as they apply to energy commodity markets. Avoided risk mitigation benefits simply do exist given the manner in which the Mississippi Commission, as well as most state regulatory commissions, have set up their net metering tariffs.[28]

Consider that NEM customers are provided some form of financial compensation for the behind-the-meter generation they put to utility's distribution grid. Today, in Mississippi, DG owners are given a financial payment based upon an avoided generation cost measure, plus a 2.5 cent per kWh adder. Avoided generation costs are based upon either (a) in the case of EML, a market based measure or (b) in the case of MPCo, a market-based proxy based upon what is economic for MPCo to dispatch given current generation resources and fuel prices.

The "take-away" in this discussion is that solar is not reimbursed at its own cost of service (which is fixed), but at a cost determined "at the margin" by either the market or a utility's own dispatch, which itself varies based on market conditions. In other words, DG is getting paid like a natural gas-fired generator, these installations are not being reimbursed on a fixed price-basis like a standard renewable energy purchased power agreement ("PPA") often seen in wholesale markets. Thus, there is no "hedge" or "risk

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[27] Synapse Energy Economics Comments to MS PSC at 10.
[28] See, Actual Benefits of Distributed Generation in Mississippi, Draft Report, at 8.

mitigation" benefit to other, non-DG-participating customers since these ratepayers are reimbursing a solar DG installation at a wholesale natural gas-based generation price that is highly variable and dependent upon spot, not longer-term, market conditions. Thus, the Sierra Club's assertions about solar DG creating risk mitigation benefits is entirely without merit.

4. Estimated Load Carrying Capacity Calculations

Comments of Parties

One of the more important estimates included in the Draft Report is the Effective Load Carrying Capabilities ("ELCC") associated with DG (solar) generation. This ELCC measure represents the contribution, in percentage terms, that a DG resource makes to a system's overall capacity during peak hours. An ELCC is used to adjust all capacity measures (generation, transmission, distribution) in the Draft Report. The higher the ELCC, the greater the estimated capacity contribution that is made by a DG resource, and vice versa. Most parties commented upon these estimates given their importance to the overall study results with the solar/DG advocates arguing that ACG had, in effect, improperly understated ELCC benefits and with the utilities suggesting that ACG, if anything, has provided very conservative, or over-estimated ELCC benefits.

MSES recognizes that ACG assesses not one, but several methods of estimating the ELCC contributions (benefits) of DG resources in Mississippi. Yet, despite the variety of methods, MSES still asserts that each of these are inappropriate and incorrect.[29] MSES does not provide an alternative calculation of ELCC using its alleged proper calculations, and instead suggests that the National Renewable Energy Laboratory

[29] Comments of Mississippi Solar Energy Society at 9.

("NREL") or Clean Power Research could calculate such a capability with information provided by the utilities.[30]

Sierra Club also notes that the methods used by ACG to estimate the ELCC benefit does not appear to be consistent with conventional methodology,[31] explicitly stating, but not showing how the Draft Report's chosen method is "*ad hoc*."[32] Sierra, like MSES, simply throws verbal cold water on the estimates without providing any alternative ELCC estimates beyond a passing reference to a MISO ELCC estimate used by EML in a recent IRP filing that is 50 percent.[33]

EML, however, provides comments that suggests ELCC values should not only be below the MISO 50 percent estimate cited by the Sierra Club, but should also likely be lower than the 28.7 percent included in the Draft Report. EML notes that it has estimated a system-specific ELCC that was part of its "Bright Future Solar Projects" proposals that is as low as 17.84 percent.[34]

MPCo states all Southern Company affiliates use an Incremental Capacity Equivalent ("ICE") valuation methodology that is generally consistent with an ELCC, in concept,[35] but differs computationally from the methods presented in the Draft Report.[36] MPCo raises specific issues with what it believes are reliability-related calculations that should be part of an ELCC calculation.[37] These stochastic, reliability-related adjustments effectively discount an ELCC for what Southern Company appears to portray as the

[30] Id.
[31] Synapse Energy Economics Comments to MS PSC at 7.
[32] Id. at 8.
[33] Id. at 7.
[34] Id.
[35] Comments of Mississippi Power Company at 4.
[36] Id.
[37] Id.

suboptimal reliability characteristics of solar energy. This discount is based upon Southern Company's belief that hours of risk and hours of peak demand are not always coincident; especially at greater penetration levels of DER.[38] MPCo importantly notes that its internal analysis finds the Draft Report's ELCC for its system are too high, especially regarding winter system operations. MPCo states that its ICE factors are approximately 21 percent before accounting for intermittency adjustments, and roughly 15 percent after accounting for such adjustments.[39]

Consultant Response

No party in this investigation seems to agree on the appropriate method for estimating ELCCs. The DG-related advocates all suggest methods that considerably over-state ELCC estimates whereas the utilities suggest methods that would greatly discount the already small DG capacity contributions in the Draft Report. ACG disagrees with both sets of comments for a variety of reasons.

First, these comments are all somewhat self-serving and very restrictive in nature. ACG is somewhat frustrated with many of the utilities that were asked, in early data requests, to provide specific ELCC estimates and other corresponding data to help the study process. While MPCo did provide an earlier version of a positon paper on the estimation of its ICE, no specific quantitative estimates, nor data, was provided at that time.

Second, DG-related interests, while disparaging the Draft Report estimates, provide no concrete alternative estimates or calculations, particularly at the degree of sophistication, documentation and empirical rigor that was used in the Draft Report. The

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[38] Id.
[39] Id. at 5.

Commission should disregard their ELCC suggestions out of hand as a very poorly veiled and self-serving attempt to increase overall DG generation reimbursement premiums.

Lastly, ACG feels confident in its results since they are based upon several methods, utilizing differing data, with a high degree of transparency. Further, the estimates correspond with best practices in other regulatory proceedings around the country, are consistent with estimates from methodologies and software provided by the national laboratories, such as NREL and the Lawrence Berkeley National Laboratory ("LBNL"),[40] and consistent with ACG's past research and analyses on this topic.

However, for the sake of argument, alternative adder estimates, using the alternative ELCCs suggested by other parties are presented below. Tables 1-1 and 1-2 present revised Draft Report study results using the 50 percent ELCC that was raised by the DG-related interests in their comments. Tables 2-1 and 2-2 present the results for the same utilities using the utility-suggested ELCC percentages. As see from the tables, the overall change to the proposed premium included in the Draft Report is not considerable.

[40] See, "Greening the Grid: Using Wind and Solar to Reliably Meet Electricity Demand (May 2015)," National Renewable Energy Laboratory; Mills, Andrew and Ryan Wiser (December 2012), "An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes," Ernest Orlando Lawrence Berkeley National Laboratory; and Milligan, Michael and Kevin Porter (March 2006), "The Capacity Value of Wind in the United States: Methods and Implementation," The Electricity Journal, Vol. 19, Issue 2.

Table 1-1: Total Avoided Costs under 50% ELCC (EML)

	Hourly Avoided Cost ($/MWh)	Effective Load Carrying Capacity (%)	Effective Hourly Avoided Cost ($/MWh)	Effective Hourly Avoided Cost (cents/kWh)
Avoided Generation Capacity				
Net Cost of New Entry ("CONE")	$ 9.45	50.0%	$ 4.73	0.4726
Southeast Generation Costs	$ 5.42	50.0%	$ 2.71	0.2710
Implied Capacity Premium	$ 7.23	50.0%	$ 3.61	0.3615
MISO RPA - Zone 10	$ 0.79	50.0%	$ 0.40	0.0397
Median Value	$ 6.32	50.0%	$ 3.16	0.3162
Avoided T&D Capacity				
Average Annual Deferrable Additions	$ 3.70	50.0%	$ 1.85	0.1849
Hypothetical Revenue Requirement -- Total Plant	$ 14.16	50.0%	$ 7.08	0.7081
Hypothetical Revenue Requirement -- Deferrable Plant	$ 4.63	50.0%	$ 2.31	0.2313
Median Value	$ 4.63	50.0%	$ 2.31	0.2313
Avoided Other Costs				
Net Cost of New Entry ("CONE")	$ 1.80	50.0%	$ 0.90	0.0900
Southeast Generation Costs	$ 1.03	50.0%	$ 0.52	0.0516
Implied Capacity Premium	$ 1.38	50.0%	$ 0.69	0.0689
MISO RPA - Zone 10	$ 0.15	50.0%	$ 0.08	0.0076
Median Value	$ 1.20	50.0%	$ 0.60	0.0602
Total Avoided Cost Benefits				
Avoided Generation Capacity	$ 6.32	50.0%	$ 3.16	0.3162
Avoided T&D Capacity	$ 4.63	50.0%	$ 2.31	0.2313
Avoided Other Costs	$ 1.20	50.0%	$ 0.60	0.0602
Total Avoided Cost Benefits	**$ 12.16**		**$ 6.08**	**0.6078**

Table 1-2: Total Avoided Costs under 50% ELCC (MPC)

	Hourly Avoided Cost ($/MWh)		Effective Load Carrying Capacity (%)	Effective Hourly Avoided Cost ($/MWh)		Effective Hourly Avoided Cost (cents/kWh)
Avoided Generation Capacity						
Net Cost of New Entry ("CONE")	$	5.93	50.0%	$	2.96	0.2964
Southeast Generation Costs	$	2.50	50.0%	$	1.25	0.1248
Implied Capacity Premium	$	5.34	50.0%	$	2.67	0.2669
Median Value	$	5.34	50.0%	$	2.67	0.2669
Avoided T&D Capacity						
Average Annual Deferrable Additions	$	2.46	50.0%	$	1.23	0.1229
Hypothetical Revenue Requirement -- Total Plant	$	8.38	50.0%	$	4.19	0.4192
Hypothetical Revenue Requirement -- Deferrable Plant	$	3.45	50.0%	$	1.72	0.1723
Median Value	$	3.45	50.0%	$	1.72	0.1723
Avoided Other Costs						
Net Cost of New Entry ("CONE")	$	1.57	50.0%	$	0.78	0.0785
Southeast Generation Costs	$	0.66	50.0%	$	0.33	0.0330
Implied Capacity Premium	$	1.41	50.0%	$	0.71	0.0707
Median Value	$	1.41	50.0%	$	0.71	0.0707
Total Avoided Cost Benefits						
Avoided Generation Capacity	$	5.34	50.0%	$	2.67	0.2669
Avoided T&D Capacity	$	3.45	50.0%	$	1.72	0.1723
Avoided Other Costs	$	1.41	50.0%	$	0.71	0.0707
Total Avoided Cost Benefits	**$**	**10.20**		**$**	**5.10**	**0.5098**

Table 2-1: Total Avoided Costs under 17.84% ELCC (EML)

	Hourly Avoided Cost ($/MWh)	Effective Load Carrying Capacity (%)	Effective Hourly Avoided Cost ($/MWh)	Effective Hourly Avoided Cost (cents/kWh)
Avoided Generation Capacity				
Net Cost of New Entry ("CONE")	$ 9.45	17.8%	$ 1.69	0.1686
Southeast Generation Costs	$ 5.42	17.8%	$ 0.97	0.0967
Implied Capacity Premium	$ 7.23	17.8%	$ 1.29	0.1290
MISO RPA - Zone 10	$ 0.79	17.8%	$ 0.14	0.0141
Median Value	$ 6.32	17.8%	$ 1.13	0.1128
Avoided T&D Capacity				
Average Annual Deferrable Additions	$ 3.70	17.8%	$ 0.66	0.0660
Hypothetical Revenue Requirement -- Total Plant	$ 14.16	17.8%	$ 2.53	0.2526
Hypothetical Revenue Requirement -- Deferrable Plant	$ 4.63	17.8%	$ 0.83	0.0825
Median Value	$ 4.63	17.8%	$ 0.83	0.0825
Avoided Other Costs				
Net Cost of New Entry ("CONE")	$ 1.80	17.8%	$ 0.32	0.0321
Southeast Generation Costs	$ 1.03	17.8%	$ 0.18	0.0184
Implied Capacity Premium	$ 1.38	17.8%	$ 0.25	0.0246
MISO RPA - Zone 10	$ 0.15	17.8%	$ 0.03	0.0027
Median Value	$ 1.20	17.8%	$ 0.21	0.0215
Total Avoided Cost Benefits				
Avoided Generation Capacity	$ 6.32	17.8%	$ 1.13	0.1128
Avoided T&D Capacity	$ 4.63	17.8%	$ 0.83	0.0825
Avoided Other Costs	$ 1.20	17.8%	$ 0.21	0.0215
Total Avoided Cost Benefits	**$ 12.16**		**$ 2.17**	**0.2169**

Table 2-2: Total Avoided Costs under 15% ELCC (MPC)

	Hourly Avoided Cost ($/MWh)	Effective Load Carrying Capacity (%)	Effective Hourly Avoided Cost ($/MWh)	Effective Hourly Avoided Cost (cents/kWh)
Avoided Generation Capacity				
Net Cost of New Entry ("CONE")	$ 5.93	15.0%	$ 0.89	0.0889
Southeast Generation Costs	$ 2.50	15.0%	$ 0.37	0.0374
Implied Capacity Premium	$ 5.34	15.0%	$ 0.80	0.0801
Median Value	$ 5.34	15.0%	$ 0.80	0.0801
Avoided T&D Capacity				
Average Annual Deferrable Additions	$ 2.46	15.0%	$ 0.37	0.0369
Hypothetical Revenue Requirement -- Total Plant	$ 8.38	15.0%	$ 1.26	0.1258
Hypothetical Revenue Requirement -- Deferrable Plant	$ 3.45	15.0%	$ 0.52	0.0517
Median Value	$ 3.45	15.0%	$ 0.52	0.0517
Avoided Other Costs				
Net Cost of New Entry ("CONE")	$ 1.57	15.0%	$ 0.24	0.0235
Southeast Generation Costs	$ 0.66	15.0%	$ 0.10	0.0099
Implied Capacity Premium	$ 1.41	15.0%	$ 0.21	0.0212
Median Value	$ 1.41	15.0%	$ 0.21	0.0212
Total Avoided Cost Benefits				
Avoided Generation Capacity	$ 5.34	15.0%	$ 0.80	0.0801
Avoided T&D Capacity	$ 3.45	15.0%	$ 0.52	0.0517
Avoided Other Costs	$ 1.41	15.0%	$ 0.21	0.0212
Total Avoided Cost Benefits	**$ 10.20**		**$ 1.53**	**0.1529**

5. Generation Capacity Estimates

Comments of Parties

Synapse notes that the merits of the three alternative valuation approaches utilized by the Draft Report to assess avoided generation capacity are not equal. Specifically, Synapse argues that it is not realistic to assume that substantial generation capacity shortfalls will be addressed through markets or long-term power purchase agreements. Synapse thus recommends that a CONE analysis be used.[41] Synapse furthermore argues that net CONE values will vary regionally and that modeling of net CONE for combustion turbines ("CT") will produce more accurate results. Synapses suggests that

[41] Id.

MISO CT net CONE study would likely be the most reliable source for avoided generation capacity costs for the utilities,[42] but ultimately recommends that the Commission wait for resolutions in the pending IRP processes before assigning prospective values to generation capacity.[43]

EML also takes issue with the Draft Report's consideration of a range of alternative avoided capacity cost estimates presented in the Draft Report.[44] EML argues that a careful review of the Draft Report shows that there is a wide range between the most recent MISO annual capacity auction and the current estimate of Net CONE by MISO.[45] EML suggests that the most appropriate value for avoided capacity would be the result of MISO's annual capacity auction, but ultimately states that it believes that Commission guidance might be beneficial in order to ultimately determine the appropriate inputs.[46]

MPCo argues that it should be allowed to develop its own calculations for its avoided capacity benefit; specifically arguing that the timing of avoided capacity benefits should be consistent with the coordinated planning process conducted by MPC with its Southern Company affiliates.[47] Beyond this, MPC notes that the Draft Report's CONE analysis utilizes EIA data and a survey of other utility's costs to construct rather than its preferred approach which utilizes data provided by Original Equipment Manufacturers ("OEMs").[48] Lastly, MPC states that it believes the Draft Report's valuation method based on the implied prices reported in observed wholesale power markets is potentially

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[42] Id. at 6.
[43] Id.
[44] Comments of Entergy Mississippi, LLC on Consultant's Draft Report Dated November 19, 2018 at 4.
[45] Id.
[46] Id.
[47] Comments of Mississippi Power Company at 6-7.
[48] Id. at 7.

problematic as "there may be times when parties agree to a high capacity price and lower energy price resulting in too high capacity values."[49]

Consultant Response:

Much like the discussion associated with the determination of an appropriate ELCC, the parties demonstrate wide differences on the appropriate methodology for determining benefits associated with avoided generation capacity. It was due to these disparate views on the superiority of different valuation methodologies that the Draft Report sought to utilize multiple estimates, taking the medium result of the resulting estimates. That being said, there appears to be some agreement between parties that issues associated with the appropriate determination of the value of avoided generation capacity are highly intertwined with the current IRP process being undertaken by the Commission. Therefore it is recommended that, if through the IRP process, the Commission establishes a methodology for determining the value of avoided generation capacity that is different for that discussed in this report, this should be utilized in the Commission's next evaluation of the net benefit of NEM in Mississippi.

6. Avoided Transmission and Distribution Capacity Estimates

Comments of Parties

EML argues that it is not reasonable to attempt to estimate avoided transmission and distribution ("T&D") costs arising from NEM DG systems.[50] EML states that customers with DG systems will continue to rely on the utility's system for service, and that there is no meaningful evidence to suggest that a utility will be able to avoid or

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[49] Id. at 8.
[50] Comments of Entergy Mississippi, LLC on Consultant's Draft Report Dated November 19, 2018 at 5.

otherwise defer any T&D investment in T&D facilities due to the current or future development of DG systems.[51]

MPCo, on the other hand, agrees that there may be some avoided transmission investments associated with DG systems. However, MPCo argues that the value of such deferrals is highly dependent on the location and quantity of the DG resource in question.[52] Furthermore, MPCo finds that the evaluation of avoided transmission capacity implicitly presumes that the renewable generation resources will be available long term.[53] MPC argues that the application of avoided transmission capacity costs should only be included when there is a reasonable expectation that the renewable resource will be available "well into the future."[54] MPC underscores this position by explaining that it has no firm contract with DER generators, and that, without such a contract, it has an increased level of uncertainty that the resource will be available when the need occurs. Because of this, MPC recommends that any T&D capacity value be reduced by 90 percent until such time as there are enough non-contracted solar resources to determine a more appropriate reduction factor.[55]

Consultant Response

The comments in this investigation show that the estimation of avoided T&D benefits arising from DG development is contentious and the use of any estimates in a NEM tariff can be even more contentious. ACG is sympathetic with the comments offered by the utilities regarding the questionable nature regarding how DG avoids T&D

[51] Id.
[52] Comments of Mississippi Power Company at 8.
[53] Id. at 10.
[54] Id.
[55] Id.

investments particularly in a very low-load growth environment like Mississippi. However, ACG continues to recommend that the Commission include these estimates for a number of reasons.

First, the approach is quantifiable and measurable, albeit the specific level of these benefits, could, admittedly, be small as seen in the Draft Report estimates. Second, in ACG's experience, most reasonable and objective studies examining NEM and DG benefits includes these avoided T&D investment benefits. Third, the inclusion of these benefits can be more refined and, as suggested by MPCo, can be more refined on a geographic-specific basis. Over time, the recognition of more geographic-specific T&D benefits may prove to send more appropriate and beneficial price signals to DG developers and utilities, alike. This should serve as a basis for their inclusion in the instant investigation.

7. Avoided Line Loss Estimation

Comments of Parties

Sierra Club notes that the Draft Report utilizes line loss figures provided by EML and MPCo that are lower than the national average, though the Draft Report provides no explanation for this discrepancy.[56] Likewise, Sierra Club hypothesizes that the values used are overall averages and likely undershoot the true avoided line loss benefits provided by solar to the utility systems.[57] Lastly, Sierra Club states the Draft Report does account for the interaction between avoided line losses and reduced T&D infrastructure needs.[58]

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[56] Synapse Energy Economics Comments to MS PSC at 9.
[57] Id.
[58] Id.

EML notes that its Schedule NEM-1 includes a fixed line loss adjustment of 10 percent over the avoided cost of wholesale power determined based on EML's approved rate for qualifying facilities ("QF"). Thus, EML argues that the Draft Report double counts line losses in its calculations.[59]

MPC made a similar comment to that of EML, noting that its Renewable Energy Net Metering Rate includes an allowance for avoided line losses.[60] MPC also disputed the inclusion of avoided ancillary costs associated with avoided capacity reserve margins. While MPC agrees that DER may displace generation capacity, the utility does not agree that it displaces the need for the utility to maintain required reserve margins.[61]

Consultant Response

There appears to be a misunderstanding of the Draft Report's calculation of benefits associated with avoided line losses. The avoided line losses referenced in the Draft Report **do not** refer to the benefit associated with avoided losses of energy traveling through a utility's transmission and distribution system. As noted by both EML and MPC, this benefit is incorporated as part of each utility's tariffed compensation based on an adjustment over the Commission-approved avoided cost rate for each utility.

The avoided line losses referred to by the Draft Report are associated with the interrelationship between avoided line losses and reduced generation, transmission, and distribution capacity, as referenced by Sierra Club.[62] Specifically, this benefit recognizes that reduced capacity requirement from the end-use customer will provide an additional capacity benefit at the relevant system level as the utility will not only not have to maintain

[59] Comments of Entergy Mississippi, LLC on Consultant's Draft Report Dated November 19, 2018 at 5.
[60] Comments of Mississippi Power Company at 11.
[61] Id.
[62] Synapse Energy Economics Comments to MS PSC at 9.

system capabilities to satisfy the displaced peak load, but the associated line losses as well. In the Draft Report, the calculated value for the avoided line loss benefit is associated with reduced generation capacity, as the associated benefit to transmission and distribution capacity is included in the calculation of the relevant T&D capacity. The Draft Report has been modified in the final version to clarify this distinction.

Likewise, MPCo is incorrect with regards to its contention that DER would not displace the need for the utility to maintain generation reserves. To the extent DER reduces peak demand requirement, this should also reduce the utility's need to maintain reserves to support fluctuations in this peak demand requirement. It should be remembered that the Draft Report includes an adjustment for ELCC, so the displaced capacity value of DER is only that which can be reasonably relied upon to occur during peak system operation hours.

8. Estimation of "Other Benefits"

<u>Comments of Parties</u>

MSES notes that the Draft Report only assesses three primary benefits: avoided generation capacity costs, avoided T&D capacity costs, and a host of other small elements such as line losses and ancillary services.[63] However, MSES notes that the Draft Report does not address a number of benefits of DER, including; Value of Solar, Renewable Portfolio Standards, uniform Interconnection Standards, avoided carbon, avoided Nitrous Oxides ("NOx"), avoided Sulfur Oxides ("SOx"), avoided Particulate Matter ("PM"), and toxic metal air emissions, ash management, water usage, and other environmental considerations, grid voltage and frequency stabilization, outage benefits,

[63] Comments of Mississippi Solar Energy Society at 8.

standby and surge or peak benefits, load growth, avoided risks, national security benefits due to Russian and Chinese cyberattacks, decentralization of generation sources, resilience and sustainability.[64] MSES states that these aspects can be quantified as demonstrated by the Value of Solar process utilized in Minnesota in a defensible and transparent way.[65] Likewise, Sierra Club reiterates its complaint that the examined time-frame of the Draft Report was too short, and that a longer-term view of the energy sector in Mississippi would likely produce higher estimates for avoided costs.[66]

EML provides extended comments on the Draft Report's calculations of other benefits, noting that it agrees with excluding market price suppression, resiliency, and avoided environmental emissions generally.[67] However, EML disputes the Draft Report's bright line distinction between public and private benefits with regards to resiliency during electrical outages, as first responders, water treatment facilities, grocery stores, or similar type of locations that serve the public would see public benefits from increased electric resiliency during severe weather events.[68] MPC, like EML, agrees with many stated decisions of the Draft Report not to quantify other benefits such as market price suppression, resiliency, and avoided environmental emissions.[69]

<u>Consultant Response</u>

As noted in considerable detail earlier, ACG's methods are premised on the inclusion of "actual, quantifiable" benefits.[70] MSES and Sierra's recommendations are inconsistent with this premise and suggest that a plethora of speculative NEM benefits be

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[64] Id. at 9.
[65] Id.
[66] Synapse Energy Economics Comments to MS PSC at 10.
[67] Comments of Entergy Mississippi, LLC on Consultant's Draft Report Dated November 19, 2018 at 5-6.
[68] Id. at 6.
[69] Comments of Mississippi Power Company at 11-12.
[70] Order Adopting Net Metering Rule, Exhibit A, Mississippi Renewable Energy Net Metering Rule at 1.

included in the study results. ACG recommends that the Commission reject these assertions for the reasons given earlier.

EML's point regarding the distinction between public and private benefits as it applies to the benefit of electric resiliency of designated critical infrastructure, such as first responder stations (i.e. hospitals, police and fire stations), water treatment facilities, and potentially critical retail businesses like grocery stories and retail gasoline stations, is well taken. The final version of this report has been modified to take this point into consideration.