ENVIRONMENTAL LAW & POLICY CENTER
Protecting the Midwest's Environment and Natural Heritage

August 27, 2020

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Highway
P.O. Box 30221
Lansing, MI 48909

Re: MPSC Case No. U-20697

Dear Ms. Felice:

The following is attached for paperless electronic filing:

> *Initial Brief of the Ecology Center, the Environmental Law & Policy Center, the Great Lakes Renewable Energy Association, the Solar Energy Industries Association, and Vote Solar (collectively Joint Clean Energy Organizations, or JCEO)*

Sincerely,

Margrethe Kearney

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Environmental Law & Policy Center
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cc: Service List, Case No. U-20697

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	)))))	Case No. U-20697

INITIAL BRIEF OF

THE ECOLOGY CENTER
THE ENVIRONMENTAL LAW & POLICY CENTER
THE GREAT LAKES RENEWABLE ENERGY ASSOCIATION
THE SOLAR ENERGY INDUSTRIES ASSOCIATION
AND VOTE SOLAR

August 27, 2020

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I. INTRODUCTION

In this case, Consumers Energy Company proposes to end its net energy metering (NEM) Program, which it has used to bill and credit its distributed generation customers for more than a decade. The Company proposes to replace NEM with a Distributed Generation (DG) Tariff, which assigns customers a charge for the energy they consume from the grid (Inflow), and a separate credit for the energy they deliver to the grid (Outflow). Michigan law gives the Commission broad authority and discretion to approve a DG Tariff, so long as the rates in that Tariff reflect "equitable cost of service."

As the Joint Clean Energy Organizations[1] (JCEO) demonstrate in Section II of this brief, the Company's application lacks any evidence, data, analysis, or other quantitative justification showing that its Tariff is based on "equitable cost of service." Instead, the Company simply assumes that its proposed DG Tariff will "reduce intra-class subsidies" relative to the current NEM Program, without providing any evidentiary support demonstrating the existence, magnitude or direction of those subsidies. And the Company turns a blind eye to the value of the energy flowing from its DG customers to its grid.

The record in this proceeding in fact reflects that, contrary to the Company's unsupported assumption, DG customers cost *less* to serve than non-DG customers. The record also reflects that energy flowing from DG customers to the grid provides value to the electric system that exceeds not only the Company's proposed compensation to those customers, but even exceeds the **full retail rate** for electric service**.** The Company's failure to determine the cost to serve DG customers and the value those customers provide does not meet the evidentiary standard under Michigan law. The Commission must therefore reject Consumers' proposed DG Tariff. In order

[1] The Joint Clean Energy Organizations are Ecology Center, Environmental Law & Policy Center, Great Lakes Renewable Energy Association, Solar Energy Industries Association and Vote Solar.

to ensure that the Company develops a tariff that fairly compensates DG customers, the Commission should direct Staff to convene stakeholders in developing a comprehensive "Value of Solar" framework that accounts for the full range for costs and benefits associated with DG. While that framework is being developed, the Commission should direct the Company to compensate DG customers for the excess energy they provide to the grid at the full retail rate, even though this will likely continue the subsidization of non-DG customers by DG customers.

In Section III of this brief, JCEO explain that the Company's pattern of ignoring the value of customer-owned DG bleeds into, and hamstrings, its distribution system planning and investment process. JCEO recommend that the Company implement an "Integrated Distribution Planning" process in order to strengthen its consideration of customer- and third-party owned resources as alternatives and complements to traditional utility distribution infrastructure. JCEO specifically examine the Company's battery storage, conservation voltage reduction, and Distributed Energy Resource Management System (DERMS) investment proposals, and recommend that the Commission:

- Direct the Company to clearly articulate a pathway to translate battery storage pilots into system-wide deployments;
- Direct the Company to report regularly on the performance of its conservation voltage reduction program;
- Reject the Company's proposed investment in a DERMS, and;
- Direct the Company to investigate Integrated Distribution Planning.

II. DISTRIBUTED GENERATION PROGRAM

A. Background on Michigan's Distributed Generation Program

Consumers Energy, like Michigan's other rate-regulated electric utilities, has billed distributed generation (DG) customers[2] through the "net energy metering" (NEM) mechanism since the implementation of Public Act 295 in 2009. M.P.S.C. No. 14 Original Sheet No. C-58.00 C11 Net Metering Program. Under NEM, utilities "net" the excess energy that customers' DG systems produce (Outflow) against the energy the customer draws from the grid (Inflow) over the course of a monthly billing period. MCL 460.1177 (4). As a result, DG customers pay retail rates only for the "net" energy they consume from the grid and are effectively credited the full retail rate for the excess energy they inject back into the grid. *Id*.

On December 21, 2016, Governor Snyder signed Public Acts 341 and 342 (Acts 341 and 342) into law. Acts 341 and 342 set in motion the wheels of the state's transition from NEM to a "Distributed Generation Program." As a foundation for that Distributed Generation Program, Section 6a (14) of Act 341 directs the Commission to "conduct a study on an appropriate tariff reflecting equitable cost of service for utility revenue requirements" and to approve such a tariff in rate cases filed after June 1, 2018. MCL 460.6a (14).

To implement Section 6a(14) of Act 341, the Commission opened Case No. U-18383. As a part of that proceeding, the Commission directed Staff to convene a Distributed Generation Workgroup ("DG Workgroup") that held several meetings between March and December of 2017. Those meetings culminated in Staff's February 2018 Report recommending a transition from NEM to an "Inflow/Outflow" billing framework, and the Commission's April 18, 2018

[2] For the purposes of this brief, JCEO use the term "DG customers" to refer to customers with DG systems interconnected to the Company's distribution grid, and billed either through NEM or, if the Company's tariff is approved, through Consumers' DG Tariff in the future.

Order adopting Staff's recommendation and directing utilities to file an Inflow/Outflow tariff in any rate case filed after June 1, 2018. Case No. U-18383, Order at 17-18 (Apr. 18, 2018).

The Inflow/Outflow framework does not prescribe a specific *numerical value* or *rate* corresponding to customers' Inflow or Outflow. Case No. U-18383, Order at 11. Rather, as the Commission noted in its Order in Case No. U-18383, Inflow/Outflow is a is a billing *framework* that accommodates separate rates for Inflow and Outflow by leveraging advanced metering infrastructure, which can track customer generation and consumption on a near-instantaneous basis. *Id.* Importantly, the Commission explained that the Inflow/Outflow framework "allow[s] the Commission to collect the data and information necessary to accurately capture the costs and benefits attributable to DG customers in a way that could not be done under traditional net metering." *Id.* As such, the Inflow/Outflow framework is adaptable—by assigning separate rates to Inflow and Outflow that reflect actual costs and benefits, it can "ensure conformance with COS principles even as conditions change." *Id*. In fact, the Commission expressly acknowledged that as more load and generation data from DG customers becomes available over time, it will "better be able to assess the cost and benefit impacts" of distributed generation, and armed with that assessment, "conduct rate design consistent with [cost of service] principles." *Id*. at 17. The Commission's Order in Case No. U-18383, therefore, contemplated the Inflow/Outflow framework as a starting point. It anticipated setting specific Inflow and Outflow rates in subsequent rate cases, informed by improving data on the costs and benefits of distributed generation as the state's DG Program grows. *Id*. at 17-18.

Since the Commission's Order in Case No. U-18383, DTE Electric Company, Indiana Michigan Power Company (I&M) and Upper Peninsula Power Company (UPPCo) have each proposed DG tariffs that replace net metering. In both the UPPCo and I&M rate cases, the

Commission approved settlement agreements that included DG tariffs crediting Outflow at the total power supply rate (including transmission). The Commission did not analyze those tariffs in either Order. *See* Case No. U-20276, Order (May 23, 2019); Case No. U-20359, Order (Jan. 23, 2020). In Case No. U-20162, DTE proposed an Inflow/Outflow tariff, including a monthly charge on DG customers (System Access Contribution charge) simply for connecting to the grid, and including rates for Outflow that did not compensate customers for the value of the capacity their systems provide. The Commission rejected the proposed System Access Contribution charge, finding it neither cost-based nor equitable per the requirements of Michigan law and basic cost-of-service ratemaking principles. Case No. U-20162, Order at 198 (May 2, 2019). The Commission also rejected the Company's proposed Outflow credit, and noted that while it "would be premature to direct the company to undertake a power-outflow study at this time" it would "continue to monitor implementation and adoption of DG tariffs in other upcoming electric rate cases . . . and may reconsider the necessity of a power-outflow study at a later date." *Id*. at 180. Based on the record available to the Commission in that case, it found that compensating Outflow using the power supply component of the rate schedule, excluding transmission, was reasonable and prudent. *Id.* at 182.

B. Standards Relevant to the Commission's Determination

1. Relevant Legal Standard under Michigan Public Utility Law

Like all rates, rates for DG customers—including rates charged for Inflow and credits provided for Outflow—must be just and reasonable. MCL 460.6g(2). Moreover, those rates must reflect the equitable cost of providing service to the customer paying the rate and must ensure that the customer is assessed for her "fair and equitable use of the grid." MCL 460.6a (14); 460.11 (1).

Consumers Energy has the burden of proof to establish that its DG Tariff satisfies the legal standard—that is, that the Tariff is just and reasonable and reflects equitable cost of service. *See Consumers Energy*, Case No. U-18322, Order at 6 (Mar. 29, 2018). MCL 460.6a requires a utility seeking to alter, change or amend any rate or rate schedules to place into evidence facts it relies on to support the justness and reasonableness of the proposals in its application. MCL 460.6a. That evidence must be "thorough, detailed, and meaningful" in order for the Commission to approve Consumers' proposals. *See Consumers Energy*, Case No. U-16794, Order at 13 (June 7, 2014) ("in the absence of thorough, detailed, and meaningful evidence, the Commission's hands are tied."). Michigan courts have long held that unproven allegations do not substitute for evidence, and that courts cannot base judgment on conjecture. *Van Auken v.* Monroe, 38 Mich. 725 (1878); *Holgate v. Chrysler Corp.*, 279 Mich. 24 (1937).

Moreover, the Commission's authority is not limited to approving or rejecting Consumers' application and its proposed DG Tariff. While the Commission does not have the authority to make management decisions for utilities, *Union Carbide Corp. v. Pub. Serv. Comm'n*, 431 Mich. 135, 148-150 (1988), the Commission has broad authority to regulate rates under chapter 460 of the Michigan Compiled Laws. *In re Consumers Energy Co.*, 913 N.W.2d 406, 413 (Mich. Ct. App., Dec. 28, 2017). The Commission has exercised that authority to, for example, require the amendment of a tariff provision (*see DTE Electric Co.*, Case No. U-20162, Order at 105-106 (May 2, 2019)); require the applicant utility to work with stakeholders to carry out an investigation or study (*see Ind. Mich. Power Co.*, Case No. U-18404, 2019 WL 2448491 at *7, Order (June 7, 2019)); and direct the applicant utility to provide the Commission with reports, information or analysis (MCL 460.55; *see DTE Electric Co.*, Case No. U-18014, Order at 40 (Jan. 31, 2017)).

2. Relevant Public Utility Ratemaking Principles

In addition to the "equitable cost of service" standard, the Commission also regularly looks to the principles of public utility rate making that James Bonbright articulated in 1961. 8 Tr. 4330 (Rábago Dir.) As JCEO witness Rábago describes, the Bonbright principles focus on the utility's revenue requirement, fair apportionment of costs among customer classes, and optimal efficiency in electricity consumption. *Id* ."In addition, Bonbright instructed that rates must be simple, understandable, free from controversy in interpretation, stable, and non-discriminatory." *Id.*

In order to demonstrate that the Company's proposed DG Tariff not only complies with Michigan law but also comports with widely accepted public utility ratemaking principles, the Company must demonstrate that:

- It has incurred costs that support the revenue recovered under the DG Tariff; that is, that DG customers are responsible for the revenue requirements imposed on them by the DG Tariff;
- The costs the Company seeks to apportion to customers under the DG Tariff are fair, just and reasonable;
- The proposed rate is economically efficient and accounts for all the costs and benefits associated with DG customers' use of distributed generation.

8 Tr. 4331 (Rábago Dir.) Mr. Rábago also recommends several modern adaptations to the Bonbright principles to account for changes to the electric system brought on by increasing numbers of DG customers:

- DG Tariffs should fully reflect the resource value of DG;
- Rates should account for the relative market positions of the various market actors, and especially for the information asymmetries among customers, utilities, and other parties;
- Rates must be grounded in a careful assessment of the practical economic impacts of DG rates on all market participants;

- DG rates, like utility rates in general, must support capital attraction for beneficial investments;
- Regulation must account for the incentive effects of DG rates, and;
- Rates for DG require accurate accounting for utility costs and careful differentiation between cost causation and the potential for cost shifting.

8 Tr. 4332 (Rábago Dir.).

3. Relevant Legal Standard Under Michigan Environmental Protection Act

Section 1705 (1) of the Michigan Environmental Protection Act (MEPA) provides that any person may intervene in an administrative proceeding by filing a pleading asserting that the proceeding "has, or is likely to have, the effect of polluting, impairing, or destroying the air, water, or other natural resources." MCL 324.1705 (1). The Commission has found that in a proceeding where an intervenor makes such an allegation, "the alleged pollution, impairment, or destruction of the air, water, or other natural resources . . . shall be determined, and conduct shall not be authorized or approved that has or is likely to have such an effect if there is a feasible and prudent alternative consistent with the reasonable requirements of the public health, safety, and welfare." *DTE Electric Co.*, Case No. U-20471, Order at 42 (Feb. 20, 2020) (citing MCL 324.1705(2)). Specifically, the Commission has found that where an intervenor makes an allegation of impairment, it is appropriate to determine: (1) whether the proposal made in the proceeding would impair the environment; (2) whether there was a feasible and prudent alternative to the impairment; and, (3) whether the impairment is consistent with the promotion of the public health, safety and welfare in light of the state's paramount concern for the protection of its natural resources from pollution, impairment or destruction. *DTE Electric Co.*, Case No. U-20471, Order at 43 (Feb. 20, 2020) (citing MCL 324.1705(2)); *see also DTE Electric Co.*, Case No. U-18419, Order at 124 (Apr. 27, 2018).

C. Overview of Consumers' Proposed Distributed Generation Program

In this proceeding—Consumers' first rate case filed since June 1, 2018—the Company proposes to replace traditional net metering with an Inflow/Outflow framework to bill its DG customers. Company Exhibit A-16 (RLB-2) Revised Schedule F-15 (New Rule C11.3 Distributed Generation). That billing framework eliminates netting of customer generation and consumption over the billing period. 8 Tr. 4347 (Rábago Dir.). Instead, it uses a two-channel billing approach, setting a charge—based on the consumption rate otherwise applicable to the customer's class—for Inflow, and a credit—based on energy production costs—for Outflow. 8 Tr. 4347 (Rábago Dir.) (see Table 1 below for a comparison of Outflow credits under NEM, which credits excess energy at the full retail rate, versus the Company's proposed DG Tariff).

Table 1: Comparing Outflow Credits for Residential Customers

Residential Rate			Summer On-Peak RSP	Smart Hours RSH	Night Time Savers RPM
Summer	Peak	Full Retail Rate	$0.215553	$0.215553	$0.215553
		Proposed by Company (DG Tariff)	$0.125355	$0.125355	$0.125355
	Off Peak	Full Retail Rate	$0.164685	$0.164685	$0.179125
		Proposed by Company (DG Tariff)	$0.084319	$0.084319	$0.097334
	Super Off Peak	Full Retail Rate	$0.164685	$0.164685	$0.135767
		Proposed by Company (DG Tariff)	$0.084319	$0.084319	$0.062420
Winter	Peak	Full Retail Rate	$0.164783	$0.173051	$0.173051
		Proposed by Company (DG Tariff)	$0.088869	$0.095128	$0.095128
	Off Peak	Full Retail Rate	$0.164783	$0.162304	$0.170519
		Proposed by Company (DG Tariff)	$0.088869	$0.086523	$0.094440
	Super Off Peak	Full Retail Rate	$0.164783	$0.162304	$0.141914
		Proposed by Company (DG Tariff)	$0.088869	$0.086523	$0.070323

8 Tr. 4240 (Lucas Dir.); Company Exhibit A-16 (RLB-2) Revised Schedule F-5.

If approved, the Company's DG Program would make it substantially more difficult for its customers to access and benefit from DG going forward—an outcome that is at odds with the state's clean energy goals embedded in Acts 341 and 342 and in the Commission's more recently-launched MI Power Grid Initiative. *See* Case No. U-20645, Order at 1 (Oct. 17, 2019)

("MI Power Grid is a focused, multi-year stakeholder initiative to maximize the benefits of the transition to clean, distributed energy resources for Michigan residents and businesses."). JCEO witness Kenworthy demonstrates that the typical DG customer would pay $390 more per year under the Company's DG Tariff proposal than under NEM and lose over $4,500 in net present value (see Table 2, below).

Table 2: Economic Impact of Consumers' Proposed DG Program on Customers

	Net Energy Metering (old program)	Proposed Distributed Generation Program	Difference
Annual Electricity Bill with No Solar	$1,640	$1,640	None
Annual Bill with System (Year 1)	$139	$529	$390
Net Present Value of Investment	$1,903	-$2,789	-$4,692
Simple Payback	9.2 years	12.7 years	Adds 3.5 years

8 Tr. 4160 (Kenworthy Dir.). Mr. Kenworthy also demonstrates that the average current NEM customer would pay an average of $17 more per month (a 62% increase) if they were moved to the Company's proposed DG program. *Id*. at 4161.

The Company defends its DG Program proposal and dismisses concerns that the Program will adversely impact its customers by assuming, without any analysis or support, that the Inflow/Outflow *framework* ensure that *rates* will reflect DG customers' cost of service. *See* 4 Tr. 576, 581 (Miller Rev. Dir.) (stating that the Inflow/Outflow billing framework "appropriately and accurately reflects how a customer uses the electric system."). The Company erroneously elevates form over substance and ignores the relevant legal standard. As the Commission has made clear, the Inflow/Outflow *framework* is distinct from *rates*. In order for the Commission to approve a proposed DG Tariff, the utility must demonstrate that the Inflow and Outflow *rates* embedded in that tariff are themselves just and reasonable and reflect the equitable cost of serving those customers. Consumers has not provided any evidence—let alone thorough, detailed, and meaningful evidence—demonstrating that its proposed Inflow and Outflow rates are just and reasonable and reflect the equitable cost of serving its DG customers. Therefore, the Commission should reject the Company's proposed DG Tariff.

In order to ensure that any DG Tariff the Company implements in the future is consistent with Michigan law, the Commission should direct Staff to facilitate the development of a framework that comprehensively quantifies the costs and benefits associated with DG (a "Value of Solar" framework), and direct the Company to establish Inflow and Outflow rates consistent with that framework. Until such a study is completed—or until the Company otherwise produces actual data to support its proposed DG Tariff—the Commission should direct the Company to compensate DG customers for Outflow at the full retail rate.

D. Argument

1. The Company has not demonstrated that its proposed DG Tariff reflects "equitable cost of service."

i. <u>The Company's proposed Inflow and Outflow rates are not based on actual data regarding the costs and benefits associated with DG.</u>

In concept, an Inflow/Outflow framework provides a reasonable foundation for accounting for the range of costs and benefits—the sum of the economic impacts—of DG. 8 Tr. 4347 (Rábago Dir.). But implementation of the Inflow/Outflow framework alone is insufficient to ensure fairness, adherence to cost of service principles, equity or economic efficiency. *Id*. at 4348 (Rábago Dir.) Those outcomes depend on the Inflow charge and the Outflow credit, and the data used to set each, not the structure of the tariff. *Id*. The data used to set an appropriate Inflow charge and Outflow credit can be produced through a comprehensive analysis of the costs and benefits associated with DG operations (a "Value of Solar" or "VOS" study), which JCEO describe in Section II.D.6, *infra*, of this brief.

The Company proposes to charge DG customers for their Inflow at their otherwise applicable retail rate and credit their Outflow at the power supply rate less transmission. The Company offers no cost of service, empirical data, analysis, or other quantitative justification in support of either its proposed Inflow charge or Outflow credit. The Company fails to analyze available data on DG customers and their energy usage patterns, both before and after installing DG; fails to study DG penetration values at the substation or circuit level; and fails to study even the most basic aspects of grid and revenue impacts from DG customers, such as:

- their impact on marginal line losses;
- distribution system impacts;
- demands on distribution infrastructure;
- analysis of load diversity on the high or low voltage distributions systems;
- how excess power from DG facilities is used on the grid, or;
- the rate impacts of the proposed DG Tariff.

8 Tr. 4373 (Rábago Dir.). Instead of studying these impacts, the Company simply assumes that under net metering, the customer "avoids paying for their use of the system," and that its proposed DG Tariff would—by reducing the rate at which customers are compensated for Outflow—reduce cross-subsidies. 4 Tr. 577 (Miller Rev. Dir.). In fact, as JCEO explain in Section II.D.3, *infra*, of this brief, DG customers cost *less* to serve than non-DG customers, and their Outflow is significantly more valuable than the Company's proposed Outflow credit *as well as the full retail rate*. Importantly, in the absence of a comprehensive measurement of the total impact (costs and benefits) of DG customers on the electric system, the Company's categorical conclusions about DG customers, cross subsidies, and the impacts of its DG Tariff amount to speculation, not evidence. 8 Tr. 4348 (Rábago Dir.).

The Company also asserts that its proposed Inflow charge is reasonable because "[a]lthough some advocates have argued that DG customers benefit the grid, [the Company has] yet to find any compelling research supporting this claim." 4 Tr. 578-579 (Miller Rev. Dir.). And the Company implies that its proposed Outflow credit is reasonable because "[w]hile some stakeholders have argued that utilities should pay DG customers for their excess power at prices above the market because they are less costly to serve than other customers, the Company has not seen any compelling evidence to suggest this is the case." 4 Tr. 580 (Miller Rev. Dir.). But whether the Company has "found" or "seen" any compelling research about the costs and benefits of DG has nothing to do with the Commission's determination in this proceeding. Consumers Energy bears the burden of proof to support its proposed rates with thorough, meaningful and detailed evidence. *See Consumers Energy*, Case No. U-18322, Order at 6 (Mar. 29, 2018). Therefore, the question before the Commission is whether the Company has measured and analyzed the costs to serve its DG customers and proposed an equitable cost of service-based rate based on that analysis. 8 Tr. 4352 (Rábago Dir.). The answer, made plain by the Company's testimony and responses to discovery requests in this proceeding, is that it has not. And indeed, as JCEO witness Rábago points out, there are many studies in the public domain that rigorously analyze costs and benefits of DG and establish that the benefits of DG operation exceed the costs, even under traditional net metering. 8 Tr. 4352 (Rábago Dir.).

Rather than conduct any detailed analysis in support of its proposal or consult publicly available studies on the costs and benefits of DG, the Company provides less than one page of testimony describing its rationale for setting its proposed Inflow charge and Outflow credit. 4 Tr. 578 (Miller Rev. Dir.) That rationale is predicated largely on the language of Section 177 (4) of Public Act 342, which, the Company explains, "allows utilities to compensate customers based on the power supply component of the full retail rate, excluding transmission." 4 Tr. 578 (Miller Rev. Dir.). The Company's reliance on Section 177 (4) is entirely misplaced. As a threshold matter, Mr. Miller's qualifications indicate that he is not an attorney, and therefore is not qualified to testify on the appropriate interpretation of Section 177 (4). 4 Tr. 555-556 (Miller Rev. Dir.). In fact, as the Commission has made clear, Section 177 applies only to modified net metering, and not to Inflow/Outflow tariffs. *DTE Electric Co.*, Case No. U-20162, Order at 180 (May 5, 2019). Section 177 is inapplicable to the Commission's statutory charge to establish a tariff reflecting equitable cost of service for DG customers. *Id.* The Company's threadbare and inapt application of Section 177 to arrive at its proposed Inflow and Outflow rates is far from the sort of thorough, detailed and meaningful evidence required to support the Commission's approval of those rates as reflecting "equitable cost of service."

Mr. Miller also suggests that it is appropriate to exclude transmission from its Outflow credit to customers because "the literature generally suggests that increasing the penetration of solar on the grid increases the intra-day variations in load and may not notably affect the annual load peak of households." 4 Tr. 579 (Miller Rev. Dir.). To support this suggestion, Mr. Miller cites to an underlying study by Fischer, et al.[3] As Mr. Rábago explains, Mr. Miller's citations to that study is misleading. 8 Tr. 4370 (Rábago Dir.). The Fischer study is based on a scenario that is not representative of the Company's system and its DG customers today—it models a dense cluster of homes with high penetrations of several kinds of distributed energy resources, including sub-optimally sized solar PV and battery systems. *Id*. It also identifies heat pumps and electric vehicles as primary drivers of load variability in its model, and concludes, reasonably, that "[i]n a future facing increased electrification of the energy system, careful design of control

[3] Fischer, D., Surmann, A., and Lindberg, K.; Impact of emerging technologies on the electricity load profile of residential areas; Energy and Buildings, 2020; Vol. 208.

strategies is therefore recommended." *Id*. at 4371. Mr. Miller's reliance on the Fischer study to support the Company's exclusion of transmission from the Outflow credit is therefore inapposite and does not substitute for data and analysis of the impact of Consumers Energy's actual DG customers and their Outflow on the Company's system.

The evolution of DG compensation from net metering to a cost-based DG tariff is a very significant step. If handled without care, it can invite controversy and discord, and significantly harm Michigan's nascent solar market and the Company's customers. The Company's approach in this case—particularly its failure to take a data-driven approach—does not reflect the careful scrutiny and attention that the transition from net metering deserves.

ii. <u>The Company itself acknowledges that DG can and does provide value to its distribution grid but does not propose to compensate customers for providing that value.</u>

The Company does not propose to include, in its Outflow credit, any compensation for the benefits that DG provides to the transmission or distribution grid. The Company's reasons for this approach are muddled. Company witness Miller affirmatively suggests that including transmission in the Outflow credit would compensate customers "for a service they are not providing." 4 Tr. 578 (Miller Rev. Dir.). Elsewhere, the Company acknowledges that the Company's approach is based not on any *actual analysis* of the impact of DG on the grid (*See* Exhibit CEO-42), but rather based on the fact that the Company has "yet to find any compelling research" supporting the claim that DG provides benefits to the grid. 4 Tr. 579 (Miller Rev. Dir.). And elsewhere, the Company takes the remarkably strained position that the responsibility of demonstrating that a DG system benefits the grid lies not with the Company but with the DG customer. 6 Tr. 1489-1490 (Blumenstock Cross). Yet the Company acknowledges that its customers have no opportunity to make that demonstration under the Company's current interconnection procedures, and that the Company's interconnection process rules would itself have to be changed to give customers that opportunity. *Id*.

The Company's approach sheds responsibility and attempts to flip the burden in this case from Consumers Energy to its customers. Again, the DG Tariff is the Company's proposal, and it must support it with thorough, detailed and meaningful evidence. The Company could have collected actual data on the impact of DG on its own system before proposing a DG Tariff. And as JCEO have already explained, the Company could have consulted any number of the several publicly available studies regarding the benefits of DG. 8 Tr. 4354 (Rábago Dir.).

In fact, DG can benefit the grid through various value streams, which JCEO witness Sandoval lists in his testimony:

- reduction in peak demand, which can result in the deferral of planned capital investments in the long run and lower energy costs in the short term;
- reduction in energy losses, which reduces the energy that needs to be generated to offset these losses;
- diversification of the energy supply mix, which can increase "energy surety" or uninterrupted service by reducing vulnerabilities associated with the loss of fuels, in addition to enhancing resiliency;
- voltage regulation, which involves maintaining reliable and constant voltage within a transmission or distribution line to ensure electrical equipment is not damaged;
- contingency response, which involves maintaining frequency in response to an unexpected failure or outage of a system component, and;

- regulating reserves, which involves maintaining frequency during normal conditions.

8 Tr. 4418 (Sandoval Dir.). Moreover, some utilities have started exploring more “active” approaches to leveraging DG and other distributed energy resources, working in concert, to provide ancillary services to the grid (which Mr. Sandoval describes as a “virtual power plant”). 8 Tr. 4419 (Sandoval Dir.).

In discovery and through cross examination, the Company acknowledges not only that DG *can* provide several benefits to the grid—including reduced loading on equipment; reduced electrical losses; and voltage support (6 Tr. 1406; *see also* Exhibit A-159 (RTB-35))—but also that DG is providing many of those benefits to its grid today. *See* Exhibit CEO-41. Company witness Blumenstock’s responses during cross examination leave little doubt that while DG customers benefit the Company’s grid, the Company simply hasn’t done the work to quantify and credit DG customers for those benefits.

> Q: Is it fair to say that this data response states that the Company has experienced impacts to the distribution system as a result of DG, including reduced loading on equipment, reduced electrical losses, and voltage support?
>
> A (Mr. Blumenstock): Yep.
>
> Q: And those three items that I just mentioned, those are the same as the theoretical benefits to the grid that you mentioned, correct?
>
> A: Right.
>
> Q: […] Is it fair to say that the Company hasn’t measured those benefits in megawatts or VARs or dollars, correct?
>
> A: Correct.
>
> Q: Has the Company modeled those benefits […] to the grid?
>
> A: Not that I’m aware of.

6 Tr. 1485 (Blumenstock Cross). This means that if the Company's DG Tariff—which includes no compensation for reduced loading on equipment, reduced electrical losses, voltage support and other values that DG provides to the grid—were approved, the Company's customers would be providing the Company grid benefits for free. This would effectively penalize DG customers for the Company's failure to gather the necessary data and carry out a robust analysis of the costs and benefits associated with DG—a fundamentally inequitable result.

iii. <u>Staff has not conducted any analysis in support of its conclusion that the Company's proposed DG Tariff is "cost-based."</u>

Despite the lack of any quantitative analysis of the cost of serving DG customers in the Company's case, Commission Staff concludes that the Company's proposed Inflow and Outflow rates are "cost-based," (8 Tr. 4817 (Mathews Dir.)) and recommends that the Commission approve that tariff (with certain minor changes proposed by Staff witness Cody Mathews). 7 Tr. 2865 (Krause Dir.). Staff does not substantiate its conclusion and therefore Staff's conclusion merits no decisional weight. When asked to explain the assertion that the Company's proposed Inflow and Outflow rates are "cost-based" Staff offered only a citation to its Report in Case No. U-18383 (recommending an Inflow/Outflow framework), a reference to the Commission's decision in DTE's 2018 rate case (Case No. U-20162, in which the Commission approved DTE's Inflow/Outflow tariff), its assumption that the Inflow/Outflow structure produces cost-based rates, and Staff witness Krause's unsubstantiated assertion that the Company's proposed DG Tariff is "a significant improvement over" net metering. Exhibit CEO-39 (KRR-11), Staff response to ELPC-Staff 1-9. Notably, Staff did not point to any *quantitative analysis* of the cost of serving Consumers' DG customers. Indeed, it could not, because neither the Company nor Staff has conducted such analysis.

Staff, like the Company, wrongly elevates form over substance in reaching its conclusion. In stark contrast to its approach in Case No. U-18383, where it recommended a separate proceeding analyzing avoided costs and benefits associated with DG Outflow, Staff here stops at a review of the *form* of the Company's proposed DG Tariff. By doing so, Staff wrongly assumes that the Company's proposed rates reflect equitable cost of service solely on the basis that the Company will apply those rates through an Inflow/Outflow framework, rather than examining the rates themselves. Exhibit CEO-39 (KRR-11), Staff response to ELPC-Staff 1-27. Staff ignores that the Commission's Order in Case No. U-18383 made it explicit that the Inflow/Outflow framework only "*allows* for equitable [cost of service] and *is enabled by* improved data collection." Exhibit CEO-39 (KRR-11), Staff response to ELPC-Staff 1-16 (emphasis added).

As JCEO witness Rábago notes, Staff plays an important role in the review of rates. 8 Tr. 4385 (Rábago Dir.). It must evaluate utility proposals in order to ensure that the Commission has a robust record upon which to make findings, reach conclusions, and issue orders. *Id*. When Staff fails to thoroughly evaluate utility proposals, "the consequences are economic injustice and inefficiency for customers and the state of Michigan, not to mention disservice to the Commission itself." *Id*. at 4386. Here, Staff failed to reasonably evaluate the Company's DG Tariff. Despite finding no Company testimony or exhibits analyzing the relationship between Outflow from DG and cost causation, 7 Tr. 2888 (Krause Cross), Staff did not issue a single discovery request to the Company to determine whether Outflow from DG offsets any distribution- or transmission-related expenses. 7 Tr. 2887 (Krause Cross). Nor did the Staff issue a single discovery request to the Company to determine whether DG provides any grid benefit. 7 Tr. 2894 (Krause Cross). Staff's assertion that the Company's proposed DG Tariff is "cost-based" is not supported by thorough, meaningful, or detailed evidence, and the Commission should afford that unsubstantiated conclusion no weight.

iv. The Commission's previous approvals of Outflow credits for DTE, I&M, and UPPCo's DG customers do not bind the Commission here.

Staff leans on the Commission's previous approvals of DG Tariffs for DTE, UPPCo, and I&M in support of its position that an Outflow credit equal to the Company's power supply rate less transmission is reasonable. Staff witness Krause explains his agreement with the Company's proposed DG Tariff rate calculation method and Outflow credit as follows:

> The tariff that the Company has proposed is the same design as was approved for DTE Electric in Cases Nos. U-20162 and U-20561, as well as the settlement for Indiana Michigan Power Company in Case No. U-20359. It differs slightly from the settlement for Upper Peninsula Power Company in Case no. U-20276 in that UPPCO's outflow credit is full power supply including transmission.

Mr. Krause gets it wrong—the Commission-approved DG Tariff for I&M customers, like UPPCo customers, includes transmission (full power supply rate inclusive of transmission). Moreover, nowhere does Mr. Krause explain why or how other utilities' tariffs inform his assessment of Consumers' proposed DG Tariff. Those decisions certainly do not bind the Commission's determination here. As Mr. Rábago explains, in the settled I&M and UPPCo cases, the settlement agreement and order provisions relating to the DG Outflow credit are not tied to any calculation or analysis of the costs and benefits of DG Outflows or the cost of serving DG customers. 8 Tr. 4345 (Rábago Dir.). And while the Commission approved an Outflow credit equal to the power supply rate less transmission in the DTE case, it did not rely on any power outflow study, comprehensive Value of Solar analysis, or cost of service study in doing so. 8 Tr. 4346 (Rábago Dir.). The Commission also acknowledged in the DTE Order that it would continue to monitor upcoming DG Tariffs and would reconsider a more detailed study of DG Outflows "at a later date." *DTE Electric Co.*, Case No. U-20162, Order at 182 (May 2, 2019).

Importantly, much has changed since those cases. Now, the two largest utilities in the state—including the applicant in this proceeding, Consumers Energy Company—have made significant investments in fully deploying Advanced Metering Infrastructure (AMI). 8 Tr. 4156 (Kenworthy Dir.). AMI provides granular data on individual customers' use of the system, including DG customers' load and excess generation. At the same time, penetration of DG has rapidly scaled up in Michigan. *Id.* at 4157. Thousands of DG systems are in operation across the state today, and the utilities are approaching statutory "soft caps" [4] on participation in their DG programs. That means multiple years of DG customer load and excess generation data are now available, allowing utilities to conduct a data-informed, robust analysis of the costs and benefits associated with DG and develop tariffs based on that analysis (a "Value of Solar" or "VOS" analysis). *Id.* The Commission has also established a long-term distribution system planning process in Case No. U-20147, which would benefit from a comprehensive VOS analysis. *Id.* And several states across the country considering a transition from net energy metering to a more sophisticated regime for compensating DG have recently commissioned thorough analyses of the full and fair Value of Solar—which gives this Commission several examples to follow. *Id.* at 4157-4158.

It is therefore no longer reasonable for this Commission to defer a thorough analysis of the costs and benefits associated with DG. The Commission has made it clear that the

[4] Section 173 of Act 342 requires each utility to allow *a minimum* of 1% of its average in-state peak load for the preceding five years to participate in the Distributed Generation Program. The 1% minimum participation level is broken down into three sub-groups: 0.5% for customers with DG systems of 20 kilowatts (kW) or less, 0.25% for customers with DG systems of between 20 kW and 150 kW capacity, and 0.25% for customers with a methane digester of greater than 150 kW.

determination of an appropriate Outflow credit is ultimately a fact- or data-based evaluation, requiring an examination of the relevant utility's DG customers. Case No. U-18383, Order at 11. The Commission should ensure that Consumers' Distributed Generation Tariff is based on *actual data* that reflects the equitable cost of serving DG customers. The Commission's prior approval of Outflow credits for other utilities turned on the specific circumstances of those cases, including a different factual record, lower deployment of AMI, and a less-developed DG market. The doctrine of *stare decisis* does not apply to the Commission's ratemaking function, which is legislative and not judicial, and therefore the Commission is not bound by its prior decisions here. *In re Midland Cogeneration Venture Ltd. Partnership et al.*, Mich. Pub. Serv. Comm'n, Case No. U-8871 *et al.*, 1989 WL 418562, Opinion and Interim (Jan. 31, 1989); *In re Ameritech Mich.*, Case No. U-11148, 1996 WL 631232, Order Granting App. for Leave to Appeal, (Oct. 7, 1996). Different circumstances in prior cases cannot and do not substitute for the evidentiary standard here—Consumers must demonstrate that its proposed rates reflect equitable cost of service. It has not done so.

2. The Company has not demonstrated that its proposed DG Tariff comports with widely-accepted public utility ratemaking principles.

Company witness Miller, who describes the proposed DG Tariff, focuses on the impact of the Tariff on the purported "subsidies" that currently flow from non-DG to DG customers. 4 Tr. 577 (Miller Rev. Dir.). JCEO have explained that Mr. Miller does not substantiate his assertions with any analysis or data regarding the Company's cost to serve DG customers, and in Section II.D.3 of this brief, explain that in fact, DG customers cost less to serve than non-DG customers. The Company's failure to substantiate its proposed Tariff with cost of service data not only means that it has not carried its burden of proof, but also means that it has not demonstrated that the Tariff comports with generally-accepted ratemaking principles—such as the Bonbright principles relating to cost causation and fair apportionment.

Nor is the DG Tariff consistent with other ratemaking principles. Mr. Miller does not demonstrate that the Company's proposed DG Tariff would be optimally efficient, simple, understandable, stable, non-discriminatory, or free from controversy in interpretation. Finally, the Company makes no attempt to demonstrate that its Tariff comports with the principles that Mr. Rábago identifies as "modern adaptations" of the Bonbright principles, including comprehension and reflection of resource value; accounting for market positions; accounting for practical economic impacts; supporting capital attraction; or accounting for incentive effects. The Company's superficial presentation of its DG Tariff, lacking any qualitative or quantitative assessment of whether that Tariff comports with widely-accepted utility ratemaking principles, hampers the Commission's ability to determine whether that tariff is reasonable. In the absence of that discussion, the Commission should reject the Company's proposed DG Tariff.

3. Contrary to the Company's assertions in testimony, DG customers cost less to serve than non-DG customers.

i. <u>The Brattle Report is flawed and the Commission should assign the Company's conclusions based on that Report no weight.</u>

While the Company does not provide any quantitative analysis of the costs and benefits associated with DG customers in support of its proposed DG Tariff, Company witness Miller cites to a report produced by the Brattle Group (Brattle Report)[5] to suggest that the cost to serve DG customers is not lower than the cost to serve non-DG customers. 4 Tr. 580 (Miller Rev. Dir.). The Brattle Report used the Company's Class Cost of Service Study (CCOSS) model to calculate the cost of serving DG customers as if they were a separate cost of service class. 8 Tr.

[5] Exhibit CEO-7 (KL-2) CONFIDENTIAL ("Brattle Residential NEM Report").

4190 (Lucas Dir.). Based on its analysis, the Brattle Report concludes that the cost of serving residential DG customers is between 20% and 50% higher than for non-DG customers. 4 Tr. 581 (Miller Rev. Dir.).

The Brattle Report is the Company's only attempt to study the demands that DG customers place on the Company's electric infrastructure, beyond the studies required by Michigan's interconnection procedures for individual installations. 8 Tr. 4365 (Rábago Dir.). The Report is based on some cost of service data, but it is not a cost of service study. 8 Tr 4356 (Rábago Dir.). As JCEO witnesses Lucas, Rábago, and Custodio demonstrate, the Brattle Report is riddled with data, methodology, and data presentation flaws. And despite those flaws, the Brattle Report in fact shows that DG customers are *less costly to serve* than non-DG customers—directly contrary to the conclusion that the Company mistakenly draws from that Report. The Commission should therefore disregard Mr. Miller's conclusions regarding the cost to serve residential DG customers and any use of those conclusions to support the Company's movement away from NEM and its proposed DG Tariff. Below, JCEO detail the flaws in the Brattle Report in turn.

First, the Brattle Report inappropriately models DG customers as their own class in a CCOSS model. As a threshold matter, DG customers represent only 1,654 customers out of the Company's 1,606,159 total residential customers, or a total of 0.1%. 8 Tr. 4193 (Lucas Dir.). Those customers represent only 0.035% of the residential class load, represent 0.08% of the total residential sales, and 0.095% of the class peak. *Id.*; 8 Tr. 4357 (Rábago Dir.). To illustrate the *de minimis* impact of these customers—even if all DG customers were given free service, the impact to non-DG customers would be only $0.10 per year. 8 Tr. 4193 (Lucas Dir.). As such, treatment of DG customers as a separate class is not justified from a practical perspective. Nor is such treatment justified from a grid engineering perspective—DG customers live in the same neighborhoods as non-DG customers and share the same distribution assets. 8 Tr. 4195 (Lucas Dir.). And treatment of DG customers as a separate class is not justified based on load data. As JCEO witness Custodio's analysis demonstrates, there is a wide range of load profiles in the residential class, and the DG customer load is within the range of variability within the residential class. 8 Tr. 4260 (Custodio Dir.). The load characteristics of DG customers do not demonstrate meaningful differences from other residential customers, and therefore do not merit the consideration of DG customers as a group separate from the residential class. 8 Tr. 4272 (Custodio Dir.). To the extent that DG customer use varies from the average residential customer, the timing of DG customers' non-coincident peak (NCP) demand and their hourly profile during the system peak day show that DG customers in fact provide beneficial class diversity (just like many other sub-groupings within the residential class). 8 Tr. 4272-4273 (Custodio Dir.); 8 Tr. 4194 (Lucas Dir.); 8 Tr. 4359 (Rábago Dir.). Moreover, if the Company were to endorse the logic of the Brattle Report, it would follow that any subset of customers that produces statistically significant differences from customers outside that subset warrant treatment as a different rate class within the CCOSS (for example, rural customers, customers with detached houses, customers with electric heat)—an approach that would be neither reasonable nor equitable. 8 Tr. 4195-4201 (Lucas Dir.).

Second, the Brattle Report is plagued by deficiencies in the data on which it is based, and its results are not credible given the updated NEM data that the Company provided in discovery. The Brattle Report relied on 2018 customer load data provided by the Company. That load data represented only a fraction of Consumers' DG customers—it included several customers who had hourly data but were missing data from certain hours or days, as well as several customers that were designated as DG customers but for whom the Company had no hourly data. 8 Tr. 4202 (Lucas Dir.). That data was substantially different than the updated data that the Company provided to the JCEO in discovery—both with respect to customer count as well as underlying load metrics. 8 Tr. 4204 (Lucas Dir.). Brattle however simply assumed that the data the Company provided was statistically representative of customers without data without doing any analysis to determine if this was the case. 8 Tr. 4203 (Lucas Dir.). As Mr. Lucas and Mr. Rábago explain, Brattle's reliance on deficient data creates a concern with respect to the validity of its conclusions, because the CCOSS model uses data from just a handful of hours to allocate many costs, and uses one single hour in the entire year for the "class peak" allocator which is used to allocate nearly all non-customer distribution costs. *Id*.; 8 Tr. 4358 (Rábago Dir.). This means that small changes in the data for these specific hours can have a significant impact on the CCOSS results. *Id*. As such, it is not reasonable to assume that the small subset of DG customers for which Brattle had data was statistically representative of the full set of the Company's DG customers. *Id.*

Beyond the deficiencies in the data on which the Brattle Report relies, the Report also makes a series of questionable assumptions in modifying the Company's CCOSS model. Instead of using a three-year average of load data (per the approach in the Company's original CCOSS model), the Brattle Report only considered 2018 data, and skipped a critical step for the residential class in the inner workings of the CCOSS model: normalizing actual 2018 data for all classes based on the test year data. 8 Tr. 4207 (Lucas Dir.). This omission for the residential class pushed the entire CCOSS model out of balance. *Id*. The Brattle Report ends up treating the residential class differently than other classes: while all other classes' allocators are calculated based on the test year sales, the residential class's allocators are skewed based on nonnormalized 2018 actual data. *Id*. As Mr. Lucas explains, as a result of this mistake, the relative size of all residential class load data was roughly 7.2% higher than appropriate compared to other classes. 8 Tr. 4208 (Lucas Dir.). This matters because the CCOSS allocates costs based on the relative size of a customer class's value compared to the total value of any given allocator. By skewing the data for the residential class by roughly 7.2%, the Brattle Report introduces an error that may percolate through the rest of its analysis and affect results. *Id*.

Despite its several errors, the Brattle Report in fact ultimately shows that DG customers *are slightly less expensive to serve than non-DG customers.* In the appendix to its Report, Brattle shows that on an allocated cost per kWh basis, the total cost to serve DG customers is approximately 7% lower than other residential customers, equal to $0.153/kWh for DG customers compared to $0.164/kWh for non-DG customers. 8 Tr. 4208-4209 (Lucas Dir.) (*See* section marked by a red box in Table 3 below, summing the "totals" for production and distribution costs).

Table 3: Cost Comparison of Non-DG Residential Class and Residential DG Customers using Allocated Cost per kWh Sales

Annual Cost Comparison for Non-NEM Residential and Residential NEM Customers

	Total Allocated Cost ($)		Allocated Cost per kWh Sales	
Cost Type	**Non-NEM Residential**	**Residential NEM**	**Non-NEM Residential**	**Residential NEM**
Production				
Net Capacity Cost	$539,242,902	$252,051	$0.041	$0.022
Capacity-Related Cost Offset	$279,809,565	$201,661	$0.021	$0.018
Non-Capacity-Related Cost	$561,603,008	$472,444	$0.043	$0.042
Total	**$1,380,655,475**	**$926,156**	**$0.105**	**$0.082**
Distribution				
Demand-Related Cost	$633,234,152	$661,939	$0.048	$0.058
Customer-Related Cost	$140,735,282	$144,813	$0.011	$0.013
Total	**$773,969,434**	**$806,752**	**$0.059**	**$0.071**

This contradicts Company witness Miller's conclusion that residential DG customers cost 20% to 50% more to serve than non-DG residential customers. Mr. Miller wrongly bases his conclusion on a Table in the body of the Brattle Report, which shows "Unitized Allocated Costs" in terms of $/kW coincident peak (CP) and $/kW non-coincident peak (NCP) (*See* section marked by a red box in Table 4 below).

Table 4: Cost Comparison for Non-DG Residential Class and Residential DG Customers using Unitized Allocated Costs

Annual Cost Comparison for Non-NEM Residential Class and Residential NEM Customers

	Total Allocated Cost ($)		Unitized Allocated Costs		
Cost Type	Non-NEM Residential	Residential NEM	*Measure*	Non-NEM Residential	Residential NEM
Production					
Net Capacity Cost	$539,242,902	$252,051	*$/kW CP*	$150	$202
Capacity-Related Cost Offset	$279,809,565	$201,661	*$/kW CP*	$78	$162
Non-Capacity-Related Cost	$561,603,008	$472,444	*$/kWh Sales*	$0.043	$0.042
Total	**$1,380,655,475**	**$926,156**			
Distribution					
Demand-Related Cost	$633,234,152	$661,939	*$/kW NCP*	$165	$181
Customer-Related Cost	$140,735,282	$144,813	*$/Customer*	$88	$88
Total	**$773,969,434**	**$806,752**			

Table 4 above (from the body of the Brattle Report) is misleading for three reasons. First, it does not reflect the manner in which costs are actually allocated in the Company's CCOSS. 8 Tr. 4210 (Lucas Dir.). Second, the "Unitized Allocated Costs" suggest that lowering a class's CP would increase costs to serve that class—which defies common sense. 8 Tr. 4211 (Lucas Dir.); 8 Tr. 4364 (Rábago Dir.). Finally, residential customers are not charged based on CP or NCP demand; they are charged a fixed customer charge and a volumetric per kWh rate, and therefore, it is more appropriate to frame the "cost to serve" those customers in terms of $/kWh (per Table 3, above, from the appendix of the Brattle Report). 8 Tr. 4211 (Lucas Dir.).

Given these flaws in data, methodology, and presentation, the Commission should disregard the Brattle Report in its entirety and afford Mr. Miller's conclusions regarding the cost to serve DG customers based on the Brattle Report no weight. 8 Tr. 4212 (Lucas Dir.).

ii. Directly contrary to the Company's conclusions based on the Brattle Report, Mr. Lucas demonstrates that Consumers' DG customers cost *less* to serve than its non-DG customers.

JCEO witness Lucas prepared an analysis of the cost to serve residential DG customers based on updated NEM customer data and a proper modification of the Company's CCOSS. Unlike the Brattle Report, which relied on highly incomplete NEM customer data, Mr. Lucas relied on updated, more complete data that the Company provided in discovery. 8 Tr. 4222 (Lucas Dir.). While the updated data was not perfect, Mr. Lucas accounted for that by limiting his analysis to DG customers meeting a minimum number of hours for which there was data and made adjustments to three stretches of time during which it was clear that the underlying data was invalid. 8 Tr. 4222 (Lucas Dir.). Mr. Lucas then developed several "customer groupings" and corresponding CCOSS metrics. *See* 8 Tr. 4226 (Lucas Dir.). Those groupings and their corresponding load metrics are summarized below in Table 5:

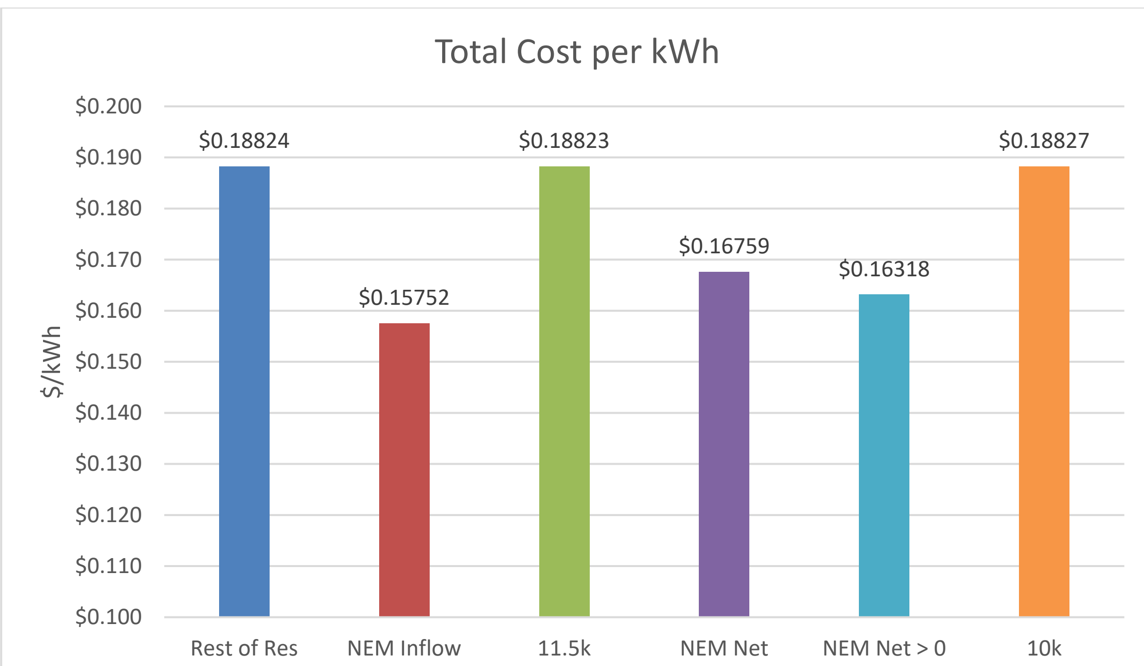
Table 5: Customer Groupings

Grouping	Avg. Usage (kWh)	Classpeak (kW)	Avg 4CP (kW)	Avg 12CP (kW)	Description
NEM Inflow	11,639	3.13	2.15	2.00	NEM customers Inflow data only
11.5k	11,744	3.41	3.04	2.11	Non-NEM customers using between 11k and 12k kWh per year (use roughly same amount of energy as NEM Inflow customers, and have similar average 12CP demand)
NEM Net	9,871	3.11	1.68	1.78	NEM customers with hourly netting of Inflow and Outflow
NEM Net > 0	10,182	3.11	1.68	1.78	NEM customers with hourly netting of Inflow and Outflow. If net < 0, hourly data set to 0.
10k	10,260	3.10	2.76	1.98	Non-NEM customers using between 9.5k and 10.5k kWh per year
Residential	8,084	2.37	2.16	1.56	Average residential customers in 2018
NEM Outflow	1,768	2.31	0.47	0.22	NEM customers Outflow data only

8 Tr. 4226 (Lucas Dir.)

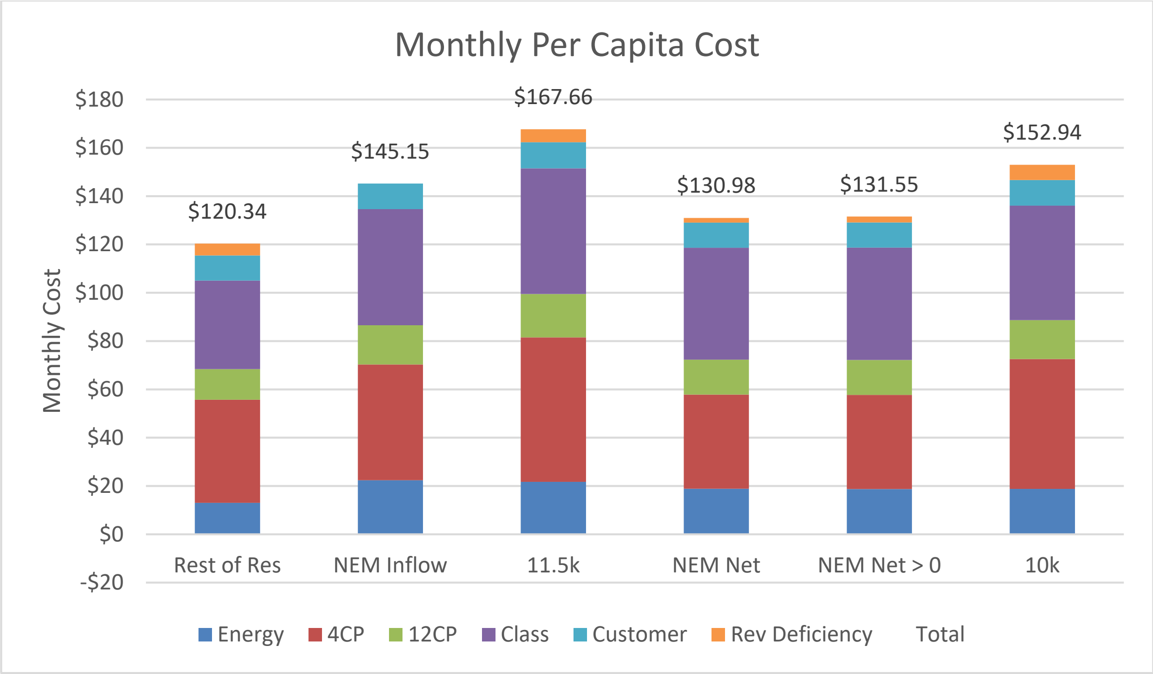
Mr. Lucas incorporated his customer groupings into the Company's CCOSS—and unlike the Brattle Report, retained the normalization of the residential sales to the test year sales to maintain consistency across all classes. *Id*. at 4229. Based on that analysis, Mr. Lucas found that DG customers are substantially less costly to serve than both non-DG customers overall, *and* non-DG customers of a similar energy usage (16.3% less costly than each). 8 Tr. 4230 (Lucas Dir.). Figure 1 below shows the "cost rate" that would collect the Company's proposed revenue from each customer grouping in Mr. Lucas's analysis based on their total allocated costs and total energy usage from the grid (analogous to an "all-in" retail rate that would collect these costs if these customer groups were assigned different retail rates). In Figure 1, the "NEM Inflow" refers to DG customers, while "Rest of Res" refers to non-DG customers overall, and "11.5k" refers to non-DG customers having similar usage to DG customers.

Figure 1: CCOSS Total Cost per kWh



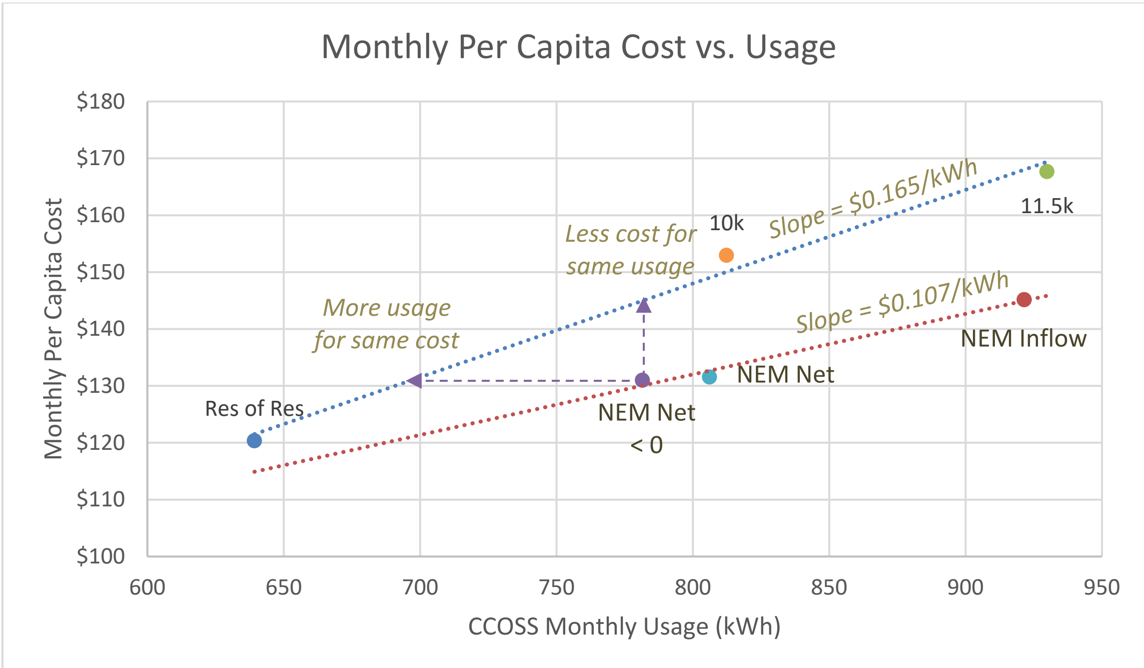
8 Tr. 4231 (Lucas Dir.). Figure 2 below demonstrates that DG customers are also less costly to serve than non-DG customers on a "monthly per capita cost" basis.

Figure 2: Monthly per Capita Cost



8 Tr. 4233 (Lucas Dir.). Figure 3 below aptly illustrates the relationship between monthly per capita cost and usage for DG customers and for non-DG customers. It illustrates that whereas non-DG customers show a relationship between monthly costs to serve and usage that scales roughly at the same rate as the proposed residential rate (approximately $0.165 per kWh of additional usage), DG customers demonstrate a flatter relationship between monthly costs to serve and usage (monthly costs to serve do not increase as quickly with increased usage).

Figure 3: Monthly Per Capita Cost vs. Usage



8 Tr. 4234 (Lucas Dir.). As Mr. Lucas points out, this demonstrates that for a given level of usage, DG customers are less costly to serve than corresponding non-DG customers, *and* that DG customers can use more energy than non-DG customers without increasing the cost to serve them.

Mr. Lucas's conclusions hold even when assuming the Company's proposed "89/0/11" (89%/11% demand to total energy weighting) 4CP allocator. In fact, when Mr. Lucas ran his analysis using the Company's proposed "89/0/11" 4CP allocator, that analysis favored the DG customer group even more strongly, as those customers have substantially lower 4CP demands than non-DG customers. 8 Tr. 4234-4235 (Lucas Dir.). In that analysis, DG customers cost 17.9% less to serve than the rest of the residential class. *Id*.

Overall, Mr. Lucas's analysis, using the Company's own CCOSS model, demonstrates that DG customers cost less to serve than non-DG customers ($0.03073/kWh less under the 75/0/25 4CP allocator, and $0.03415/kWh less under the 89/0/11 4CP allocator). 8 Tr. 4237

(Lucas Dir.). This means that under the Company's current DG Tariff proposal, the average DG customer is overcharged by $378 per year or $31.50 per month over their cost-of-service equivalent rate. Even if the Company were to maintain the 75/0/25 4CP allocator, shift to a more appropriate billing approach (which nets hourly Inflow and Outflow in the CCOSS), and use monthly net billing for its DG customers (none of which the Company has proposed to do in this case), the average DG customers would *still* be overcharged by $194 per year or $16.17 per month over their cost-of-service equivalent rate.

Mr. Lucas expressly points out that while DG customers are less costly to serve than non-DG customers, that does not mean that those customers should be treated as a separate rate class in the COSS (for all the reasons discussed in Section D.3.i, *supra*). 8 Tr. 4195 (Lucas Dir.). However, his analysis shows that the Company's unsubstantiated assumptions about the subsidization of DG customers by non-DG customers under NEM are inaccurate. The Company's proposed DG Tariff would not, therefore, reduce intra-class subsidies as Mr. Miller claims—it would take a rate structure that already fails to adequately compensate DG customers (NEM) and make it even more inequitable.

4. The Company fails to account for DG Outflow in its CCOSS Model, and its Proposed DG Tariff Significantly Undervalues DG Outflow.

i. <u>The Company's cost of service model ignores Outflow from DG Customers and as a result, over-allocates costs to the residential class.</u>

The basic schematic for the Company's development of a class cost of service model is as follows. The Company begins with load study data to derive an hourly load profile by class for the test year. 8 Tr. 4218 (Lucas Dir.). That data is normalized for weather and customer growth. *Id*. Once adjusted, the Company uses a worksheet to produce several characteristics of customer load, otherwise known as load metrics. *Id* at 4216. The Company inputs those load metrics into a Class Cost of Service Study (CCOSS) for each class for the past three years. *Id*. at 4218. Then, it calculates a three-year average for each metric, and normalizes those averages to the test year sales for the class. *Id*. Finally, it uses those normalized values to calculate the several cost allocators, which are used to allocate cost of service by class. *Id*. Importantly, the common unit of time in the CCOSS is one hour—regardless of how often the customer's meter registers load data, the Company aggregates that data at the hour level before calculating load metrics. *Id.* at 4217.

The Company's treatment of DG customers in the CCOSS is fundamentally flawed. because it does not consider Outflow in any of the underlying load metrics—it only considers instantaneous Inflow (as opposed to Inflow netted against Outflow on an hourly basis). 8 Tr. 4218 (Lucas Dir.). Instead of incorporating Outflow as an offset to Inflow in the CCOSS, the Company draws an arbitrary line at the customer's meter, separating the flow of energy from the grid to the customer (Inflow, incorporated in the CCOSS) from the flow of energy to the grid from the customer (Outflow, not incorporated in the CCOSS, compensated through a credit at the power supply rate less transmission). 8 Tr. 4219. This distinction does not comport with the physical reality of the grid. While it is true that even the best cost of service models necessarily deviate from a true physical representation of the electric system, those models "should still strive to be as accurate as possible." 8 Tr. 4215 (Lucas Dir.). In this case, the Company's CCOSS model does not account for the fact that given the low density of residential DG customers in the Consumers service territory, the overwhelming likelihood is that Outflow will travel to the nearest line transformer where it will then flow to the DG customer's neighbor to help meet their Inflow needs. As Mr. Lucas explains, "[t]he Company does not generate or transmit this energy; at best, a tiny fraction of its local distribution assets are used to move the Outflow from one neighbor to another." 8 Tr. 4215 (Lucas Dir.). But the Company's CCOSS treats the Inflow to the DG customer's neighbor as if it had been entirely generated, transmitted, and distributed by the Company, ignoring the contribution of DG customer Outflow. *Id.* By using only Inflow, but excluding DG Outflow, the CCOSS produces load characteristics that are too high, which in turn means that the residential class as a whole is allocated more costs than it should be. This inappropriately increases the revenue that the Company needs to collect from the residential class through rates. 8 Tr. 4220 (Lucas Dir.).

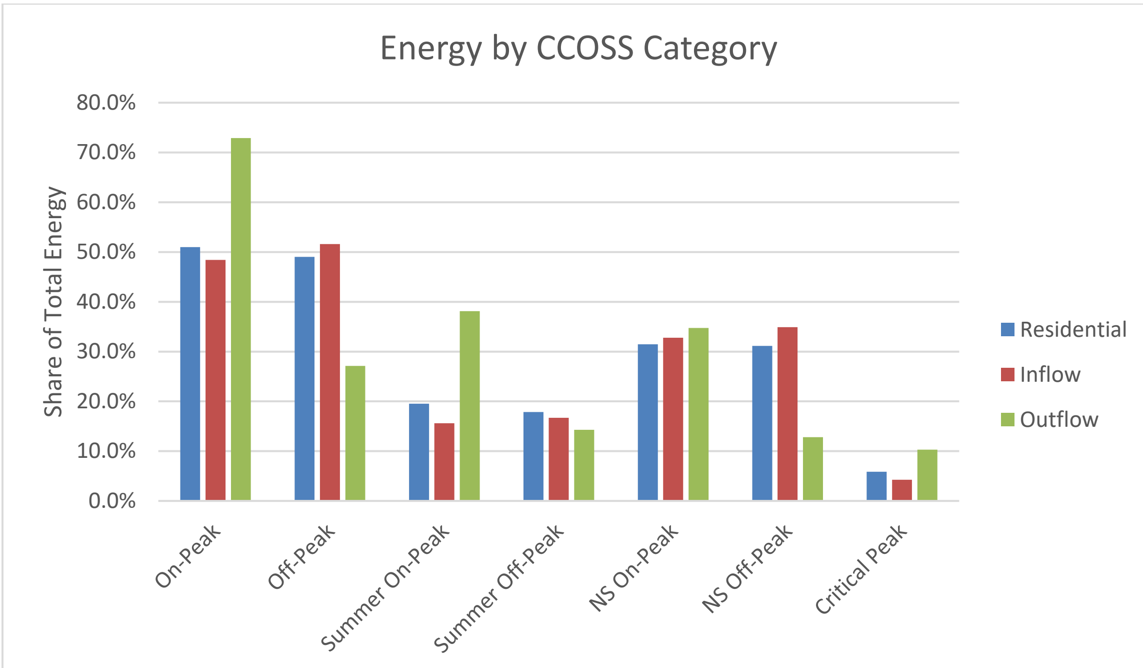
Mr. Lucas analyzed the impact of the Company's exclusion of Outflow in its CCOSS. By appropriately netting Outflow energy from the residential class, Mr. Lucas's analysis produced a rate design target for the residential class that was lower by $55,649 compared to the Company's proposed rate design target for the residential class, representing $41.50 of value that each DG customer's Outflow provides to the residential class. 8 Tr. 4221 (Lucas Dir.). This is equivalent to $0.0235 per kWh of Outflow in savings to the residential class—the result of the mathematical redistribution that occurs in the CCOSS. *Id.* The Company's CCOSS does not capture this value, and by doing so harms *all* residential customers, not just DG customers.

ii. <u>DG provides value that not only exceeds the Company's Outflow credit, but even exceeds the full retail rate.</u>

The Company proposes to credit Outflow energy at the power supply less transmission rate of the DG customer's retail tariff. 4 Tr. 577 (Miller Rev. Dir.). In general, Outflow from DG systems is mostly likely to occur in the months and hours when a DG customer's load is relatively low, and solar output is relatively high. 8 Tr. 4240 (Lucas Dir.). In aggregate, Outflow peaks in the early afternoon of summer days before sloping down in the late afternoon. *Id*. That means that the share of on-peak energy, summer on-peak energy, and critical peak energy is much higher for Outflow than for either the residential class as a whole or for Inflow—making

Outflow energy more "valuable" to the Company and its customers than average energy. 8 Tr. 4242. (See Figure 4 below).

Figure 4: Energy by CCOSS Category



8 Tr. 4242 (Lucas Dir.).

In order to develop a cost-based Outflow credit, it is necessary to look at the underlying costs from the CCOSS model that correspond to the hours when Outflow is produced. As JCEO have detailed, the Company has not proposed a cost-based Outflow credit, conducted any analysis of the impact of Outflow on cost of service, or appropriately accounted for Outflow energy in its CCOSS model. In order to fill that gap in the record, Mr. Lucas applied two alternative methods to calculate a cost-based Outflow credit using the Company's own CCOSS model. Based on either method, Mr. Lucas concludes that the Company's proposed Outflow credit of retail power supply less transmission (which generally falls between $0.084 and $0.125 per kWh) dramatically undervalues Outflow energy. Applying the first method—in which Mr. Lucas modeled Outflow energy as a separate class producing a hypothetical "customer group" that has the same load profile as the Outflow— the equivalent of a cost-based Outflow credit was $0.28125 per kWh. 8 Tr. 4243 (Lucas Dir.). Under the second method—in which Mr. Lucas reallocated the full residential class costs to energy periods by allocator—the Outflow credit was $0.23957 per kWh. 8 Tr. 4246 (Lucas Dir.).

While both methods produce valid cost-based credit rates, Mr. Lucas believes the second method produces more robust results and is consistent with keeping DG and non-DG customers in the same CCOSS class. 8 Tr. 4249 (Lucas Dir.). He explains that "[b]y mapping costs driven by 4CP, 12CP, and class peak demands to the TOU periods in which they tend to fall, the resulting cost rate properly blends the disparate portions of the CCOSS into one comprehensive set of rates. Applying these rates to the outflow energy patterns produces a weighted-average credit that appropriately values outflow energy contributions to reducing demands." 8 Tr. 4249 (Lucas Dir.). Based on Mr. Lucas's analysis, an Outflow credit set at $0.23957 per kWh would reflect DG customers' fair and equitable use of the grid.

iii. <u>An adder to the Outflow credit is appropriate to return DG customers a portion of the savings from the reduction in cost to serve them.</u>

To account for the fact that, based on the Company's own CCOSS, DG customers are being overcharged relative to their usage patterns, Mr. Lucas calculated an Outflow credit adder that transfers a 25% share of the total savings created from DG systems to DG customers, while leaving the remainder in place to reduce costs for all residential customers. 8 Tr. 4247 (Lucas Dir.). Mr. Lucas's proposal to return 25% of savings to DG customers while allowing 75% of the savings to accrue to non-DG customers is eminently reasonable, and essentially donates value from DG customers to the residential class as a whole. That adder, which accounts for the reduced cost to serve DG customers, acts as a layer above the Outflow credit (which reflects cost-based compensation for Outflow). Mr. Lucas explained that such an adder would encourage more DG installations, which would in turn reduce the cost per kWh of the entire residential class. Table 6 below shows the calculated adder based on the various CCOSS scenarios, ranging from $0.0274 per kWh and $0.0534 per kWh.

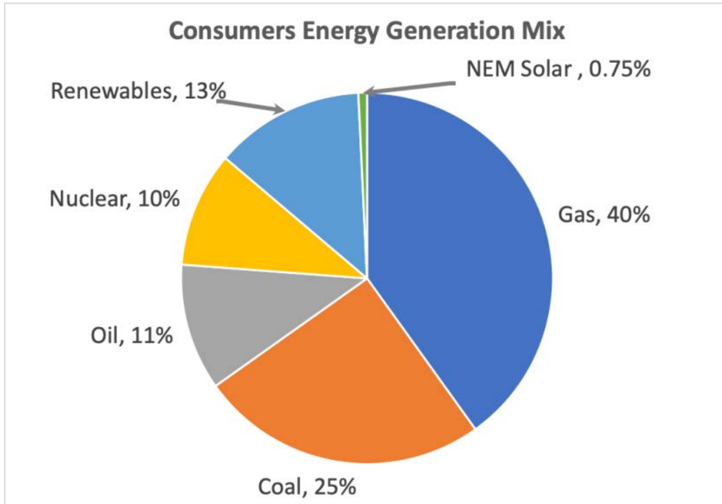
Table 6: DG Customer CCOSS Reduction Outflow Adder

	4CP 75/0/25 CCOSS		**4CP 89/0/11 CCOSS**	
NEM CCOSS Treatment	Inflow	Net	Inflow	Net
Overcharge	$339.79	$193.72	$377.68	$231.41
25% Credit	$84.95	$48.43	$94.42	$57.85
Outflow kWh	1,768	1,768	1,768	1,768
Adder / kWh	**$0.04805**	**$0.02739**	**$0.05341**	**$0.03272**

5. *The Company's proposed DG Tariff would result in environmental impairment.*

JCEO acknowledge that the Commission may not be able to precisely assess the environmental impacts of the Company's proposed DG Tariff due to the lack of evidence in the Company's application. 8 Tr. 4343. All else equal, however, a DG Tariff that is not cost-based, and does not fully value all aspects of DG, will result in suboptimal development of DG projects—which will in turn have a negative impact on the environment. This is because, as Figure 5 below demonstrates, Consumers' generation mix is about three-quarters fossil energy-based, and therefore, reducing the number of potentially cost-effective solar installations would likely result in the Company relying on polluting resources more and for longer than necessary. This will result in more atmospheric and other pollution than would occur without the DG Tariff. *Id.*; *see* Exhibit CEO-24 (KRR-5).

Figure 5: Consumers Energy Generation Mix



The Company has not submitted any evidence about the public health, equity and environmental costs associated with its proposal to transition from NEM to its proposed DG Tariff, let alone analyze the environmental costs of alternative tariffs. JCEO explain below that a Value of Solar analysis would provide, among other data, relevant data regarding the environmental benefits associated with DG. Absent that data, the Commission is not placed to make a determination on the environmental impairment associated with the Company's proposed DG Tariff as is required to do under MEPA—even if environmental impairment is likely as JCEO have explained—or compare the Company's proposed DG Tariff to other feasible and prudent alternatives. The Commission should therefore reject the proposed DG Tariff and require a Value of Solar analysis that provides sufficient data to set cost-based Inflow and Outflow rates (including data regarding environmental costs).

6. The Commission should direct the Company to establish credits for DG Outflow based on a comprehensive Value of Solar (VOS) framework.

As JCEO have explained, Michigan law requires that utilities compensate DG customers based on their "fair and equitable use of the grid." MCL 460.11 (1). In its 2018 report in Case No. U-18383, Staff explained that Inflow/Outflow "provides an independent framework for equitably compensating DG customers for excess power injected into the grid." Case No. U-18383, Order at 3 (Apr. 18, 2018). But the Inflow/Outflow framework does not itself guarantee equitable compensation for DG customers—that outcome depends on the actual rates proposed. Here, as JCEO have demonstrated, the Company's proposed rates would not reflect equitable cost of service. As the Company itself acknowledges, its analysis of DG customers has room for significant improvement in order for it to reflect cost-of-service, stating that "it would be premature to assign costs, or benefits, to DG customers before the Company has had an opportunity to properly gather and evaluate the impacts on the grid." 8 Tr. 4373-4374 (Rábago Dir.). In order to ensure that the Company does indeed "properly gather and evaluate the impacts [of DG customers] on the grid" before saddling DG customers with a Tariff that is not cost-based and would unfairly undercompensate them, JCEO recommend that the Commission reject the Company's proposed DG Tariff and instead direct Staff to facilitate the development of a Value of Solar (VOS) framework[6] in coordination with the Company and stakeholders.

i. <u>A VOS framework reflects equitable cost of service and eliminates cross-subsidies.</u>

A VOS framework allows regulators to account objectively and comprehensively for the sum total of all costs and benefits of DG to all stakeholders, including the customer installing the DG, to all other customers, to the utility, and to all members of the public—including future generations. 8 Tr. 4376 (Rábago Dir.); 8 Tr. 4296 (Chan Dir.). That sum total is commonly referred to as the "social value" of DG. 8 Tr. 4296 (Chan Dir.). Having established the "social value" of DG, the regulator can set prices equal to that value, and leave the decision over whether to adopt DG or not to individual consumers based on whether the VOS exceeds their

[6] This brief uses the term VOS "framework" to mean a methodology that results from a comprehensive VOS study, with specific DG Outflow credits derived from applications of that methodology.

private costs. *Id.* In this manner, administrative oversight can ensure that DG pricing does not harm consumers as a result of the market power of producers or the lack of market power of those impacted by external costs. *Id*. As JCEO witness Dr. Chan explains, in the absence of competitive markets that internalize all externalities, an administrative accounting for the total costs and benefits of DG is required to take the place of market forces such that DG is compensated for its real value to the electric system. *Id*. Importantly, by reflecting the full range of costs and benefits associated with DG Outflow, credits priced based on VOS reflect equitable cost of service and compensate DG Outflow based on DG customers' "fair and equitable use of the grid" (8 Tr. 4298 (Chan Dir.)), consistent with the requirements of Michigan law.

Further, whereas the Company *claims* it wants to reduce the cross-subsidies inherent to DG compensation (*See* 4 Tr. 576, 581 (Miller Dir.) but provides no evidence that its proposed DG Tariff will *actually do so*, a VOS tariff would accomplish the Company's own purported objective for implementing the Inflow/Outflow framework. As Dr. Chan explains, "[v]aluing injected power at exactly the social value, as measured by the VOS, would eliminate all net cross-subsidies." 8 Tr. 4299. In contrast, where pricing is set below social value, DG customers will be unfairly under-compensated for the social benefits of their Outflow, creating a net cross-subsidy from DG customers to society, and result in socially sub-optimal DG deployment.[7]

ii. A VOS framework will produce rates that are consistent with widely-accepted rate design principles.

Among James Bonbright's seminal principles of rate design is the principle that "[r]ates should fairly apportion the utility's cost of service among consumers and should not unduly discriminate against any customer or group of customers." 8 Tr. 4303 (Chan Dir.) The Rocky

[7] Similarly, if compensation for DG Outflow is above social value, the reverse would be true and there would be a net cross-subsidy from society to DG customers. 8 Tr. 4298-4299. As JCEO have demonstrated, however, the Company's proposal would undercompensate DG. *See infra* at II.D.3-4.

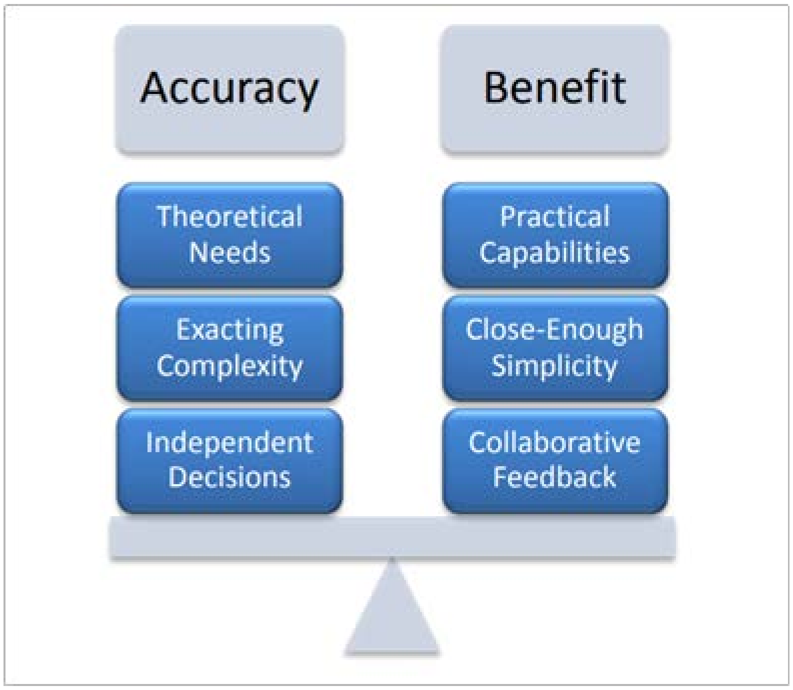
Mountain Institute offers the following re-interpretation of this Bonbright principle to account for distributed generation and other distributed energy resources: "Rate design should be informed by a more complete understanding of the impacts (both positive and negative) of DERs on the cost of service. This will allow rates to become more sophisticated while avoiding undue discrimination." *Id*. Unlike the Company's proposed DG Tariff—which, as JCEO have explained, is inconsistent with well-accepted principles of rate design (*See* Section II.D.2, *supra*)—a VOS framework would enable fair, non-discriminatory rates consistent with Bonbright's principles by producing a more comprehensive understanding of the positive and negative impacts of DERs on the cost of service.

iii. VOS can balance the interests of Michigan utilities, ratepayers and DG customers.

Not only would a VOS framework meet the requirements of Michigan law (a tariff reflecting equitable cost of service) and produce tariffs that comport with the Bonbright principles, the Commission should also view a VOS framework as a vehicle that can balance the interest of utilities, ratepayers and DG customers; as well as other stakeholders including third-party developers, environmental nonprofits, ratepayer advocates and others. In essence, a VOS framework can function as what Dr. Chan calls a "boundary object"—a point of negotiation and a neutral price signal for third-party investment on the grid. 8 Tr. 4318 (Chan Dir.).

The analytic task of establishing a VOS requires compromises that balance the competing goals of accuracy (to minimize cross-subsidization between the utility, ratepayers and DG customers) and practicality (to enable timely implementation, transparency, and collaborative feedback). The following graphic illustrates the balancing inherent to a VOS framework:

Figure 6: Schematic Representation of the Value of Solar Balancing Act (Taylor, et al, 2015).



8 Tr. 4311 (Chan Dir.). That balancing act is compounded by the uncertainty and data constraints related to many of the fundamental drivers of the system-value that DG provides (e.g. long-run avoided costs of volatile natural gas purchases). *Id.* at 4313. Many of the benefits of DG (avoided costs) are analytically difficult to quantify and cannot be directly measured. *Id.* at 4318.

Over time, however, that uncertainty and those data constraints are likely to reduce with increasing information about the electric system as the VOS framework is negotiated and iterated. *Id*. at 4313. As such, the Commission should not view the implementation of a VOS as an "end point," but rather as a "midway point" of a process to integrate new technologies that create varying degrees of private and social benefits. *Id.* With this perspective, it becomes clearer that establishing a VOS framework can be a part of an "adaptive management"[8] process, through

[8] ""Adaptive management" is an approach to governing complex systems that combines management with monitoring, with the goal to iteratively improve decision-making and knowledge about the system over time." 8 Tr. 4314 (Chan Dir.). "Adaptive management provides a helpful framework for decision making amid uncertainty and the potential for learning over time. While adaptive management has been widely applied to manage natural resource systems, adaptive management is also being applied to the regulatory context and administrative law." *Id.*

which Michigan stakeholders can uncover new data, develop new working relationships, grow collective understanding of shared infrastructure systems, and collaborate across sectors to serve the public interest. *Id*. at 4313-4314.

iv. <u>A VOS framework can support the utilities' long-term distribution planning process.</u>

Michigan's utilities are required to file long-term distribution plans in Case No. U-20147. Those plans are intended to, among other things, prepare the distribution grid for increasing levels of distributed generation and other distributed energy resource penetration. JCEO explain in Section III of this brief, however, that the Company's distribution planning process, in its current form, does not thoroughly and systematically leverage customer- and third-party owned DG as potential grid assets. As JCEO witness Sandoval describes, the utilities' long-term distribution planning process must evolve into an "Integrated Distribution Planning" process in order to more comprehensively account for increasing DG penetration. 8 Tr. 4403-4412 (Sandoval Dir.).

A VOS framework can inform Consumers' long-term distribution planning process.[9] Dr. Chan notes that a VOS "can be a very meaningful step toward the more holistic planning for DERs that Integrated Distribution Planning envisions." 8 Tr. 4230 (Chan Dir.) Again, by creating a "boundary object" that supports negotiation over the avoided costs that result from DG, the VOS can support increased learning about the electric distribution system, which in turn can help the Company in its future parallel distribution planning efforts. *Id*. As Dr. Chan explains, "[b]uilding in feedback, points of formal and informal communication, and shared

[9] The relationship between the VOS framework and the Company's distribution planning process works in both directions. As JCEO explain in Section III of this brief, a more robust "Integrated Distribution Planning" process can inform the Company's development of a VOS framework and cost-based DG compensation rates. Unlocking the value of a VOS framework and an Integrated Distribution Planning process requires, however, that the Company make the effort to study, analyze and value customer- and third-party owned DG and other DER on its system.

understanding between utilities and third-party DG developers will be critical for the kind of holistic, collaborative processes that building the grid of the future will require. The VOS is the logical next step towards this future by opening up data, testing cost-allocation frameworks, and building empirically driven platforms for collaboration and negotiation." *Id.* By establishing and iterating a VOS framework, the Commission can help ensure that investment in DG can grow to meet system needs in a way that can be most beneficial to the public in the short- and long-run. *Id*.

v. <u>Establishing a VOS framework can have spillover benefits in other MPSC proceedings beyond long-term distribution planning; and other proceedings can inform the VOS framework.</u>

As Dr. Chan notes, this proceeding "is not the only domain in which the complexity of valuing [distributed energy resources] arises." 8 Tr. 4321 (Chan Dir.). Other proceedings before the MPSC—such as energy waste reduction and resource planning dockets—can help establish a starting point for the VOS. *Id.* But the relationship between a VOS framework and other proceedings before the MPSC also works in reverse: "insights from developing a robust VOS could inform valuation in other key dockets before the MPSC that grapple with the same fundamental issues." *Id*. Indeed, energy waste reduction (EWR) requirements entail procedures for recognizing the system impact of end-use measures. Resource planning seeks to model how DG affects the value of alternative investment strategies (Consumers' IRP, for example, establishes effective load carrying capacities for DGER so that those resources' system-value can be compared to dispatchable centralized generation resources). *Id.* As such, the development of a VOS framework—which will produce valuable data regarding the value of DG—will not only create a foundation for Consumers' or other utilities' DG Tariffs but can also have spillover benefits into other MPSC proceedings.

vi. <u>Minnesota's experience with developing a VOS methodology and implementing a VOS tariff can serve as an example for Michigan.</u>

Minnesota was the first state to adopt legislation directing the establishment of a VOS tariff to compensate DG. 8 Tr. 4281 (Chan Dir.). Article 9 of Minn. H.F. 729 (2013) established an "alternative Tariff" to provide "compensation for resource value" that would replace aspects of the state's existing net metering rules and which would come to be known as the VOS tariff. *Id*. That law was designed to provide a framework for net billing, similar to the Inflow/Outflow framework. *Id*. It contemplated that customers subject to the alternative tariff would receive a credit "for all electricity generated by the solar photovoltaic device at the distributed solar value rate" and a charge for their consumption at the "applicable rate schedule for sales to that class of customer." *Id*. at 4282-4283.

In compliance with the VOS statute, the Minnesota Department of Commerce convened four workshops to develop a VOS methodology from September-November 2013, including over 100 participants representing a diverse set of interested parties including utilities, third-party developers, environmental nonprofits, ratepayer advocates, representatives of the public, and regional and national neutral third-party technical experts. *Id*. at 4285 (Chan Dir.) Later in 2013, the Minnesota Department of Commerce selected a third-party firm to support the Department in its development of a VOS methodology. *Id*. at 4286. Shortly thereafter, in January 2014, the Department submitted a recommended methodology for the VOS, which it described as providing "a rigorous analytical foundation for valuing distributed solar energy that can be updated and adjusted over time . . . to incorporate best available practices." *Id.* at 4286. The Minnesota Public Utilities Commission approved the Department's VOS methodology with a few modifications in early 2014. *See* Exhibit CEO-35 (GC-2). That methodology calculates the total VOS by summing eight separate avoided cost components—categorized in four buckets:

generation, transmission, distribution, and societal. Table 7 below describes those components and their corresponding 2020 values for Xcel Energy—Minnesota's largest utility—which applies a VOS tariff to customers participating in its "community solar garden" program.[10]

[10] By the end of 2019, 20 MW of operational projects in Xcel's service territory received compensation at VOS, and 205 MW of projects in design, construction or study phase were slated to receive compensation at VOS.

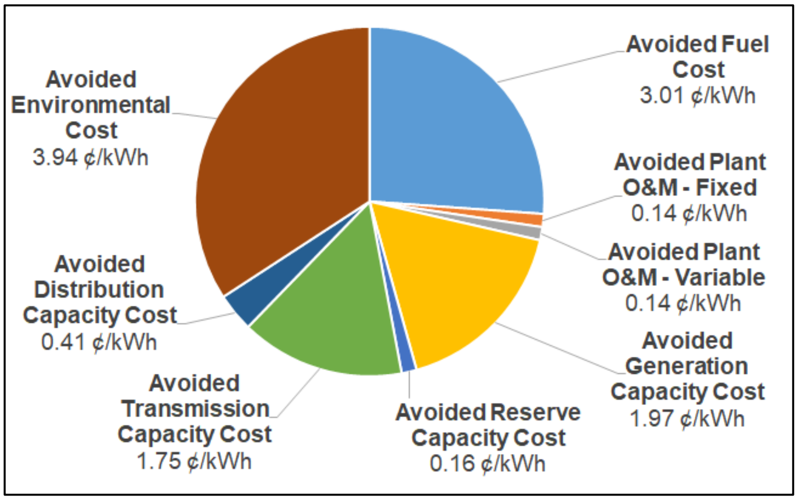
Table 7: Value of Solar Value Categories Used in Minnesota with 2020 VOS Estimates for Xcel Energy.

VOS Component		**2020 Value for Xcel Energy** (cents / kWh)	**Methodology and Additional Considerations** (summary of approved methodology[11])
Generation	Avoided Fuel Cost	3.01	"Avoided fuel costs are based on long-term, risk-free fuel supply contracts. This value implicitly includes both the avoided cost of fuel as well as the avoided cost of price volatility risk that is otherwise passed from the utility to customers through fuel price adjustments." Values are primarily derived from the New York Mercantile Exchange (NYMEX) natural gas futures contract market. However, natural gas futures are closely related to spot prices and contract markets are very thin more than a few years out.[12]
	Avoided Generation Capacity Cost	1.97	"Based on the installed capital cost of a peaking combustion turbine and the installed capital cost of a combined cycle gas turbine, interpolated based on heat rate."
	Avoided Reserve Capacity Cost	0.16	"Identical to the generation capacity cost calculation, except utility costs are multiplied by the reserve capacity margin."
	Avoided Plant O&M – Fixed	0.14	Utility O&M costs that are not dependent on the amount of energy generated
	Avoided Plant O&M – Variable	0.14	Utility O&M costs that are dependent on the amount of energy generated.
Transmission	Avoided Transmission Capacity Cost	1.75	"Based on the utility's 5-year average MISO OATT Schedule 9 charge"
Distribution	Avoided Distribution Capacity Cost	0.41	Can be calculated as a system-wide average value or location-specific value. Current practice has been to calculate this as a system-wide average, which until 2020, was calculated by dividing costs from capacity-related expenditures in FERC accounts 360, 361, 362, 365, 366, and 367 over the last 10 years by estimated future peak growth over the next 15 years. For the 2020 VOS, the methodology for this component was adjusted for one year and a stakeholder group was ordered to discuss methodological improvements to this component.[13]
Societal	Avoided Environmental Cost	3.94	Includes the environmental value of avoided carbon dioxide (CO_2), particulate matter below 2.5 microns (PM 2.5), carbon monoxide (CO), nitrogen oxides (NOx), lead (Pb), and sulfur dioxide (SO_2). Values for CO_2 are derived from a Federal Interagency Working Group on the social cost of carbon[14], and criteria air pollution externality values are based on scientific studies considered in Minnesota dockets E999/CI-93-583 and E999/CI-00-1636. In the 2020 VOS, CO_2 represented over 90% of this component and NOx represented an additional 8%.

8 Tr. 4292 (Chan Dir.).

Since its approval, Xcel Energy—Minnesota's largest utility—has sought and received approval for its implementation of the VOS methodology in four annual rounds from 2017-2020. *Id*. at 4288. In each round, Xcel publicly posts its spreadsheet calculations for the VOS and the Minnesota PUC invites public comments on Xcel's implementation of the methodology. *Id*. Including approved and interim calculations, Xcel has calculated a VOS a total of 11 times. *Id.* Its most recent approved VOS (for 2020) has a 25-year levelized value of 11.52 cents per kWh, broken down as illustrated in Figure 7 below:

Figure 7: The 2020 Minnesota Value of Solar for Xcel Energy.



8 Tr. 4289 (Chan Dir.). Figure 8 below illustrates Xcel's calculation of the VOS—separated by component—since 2015:

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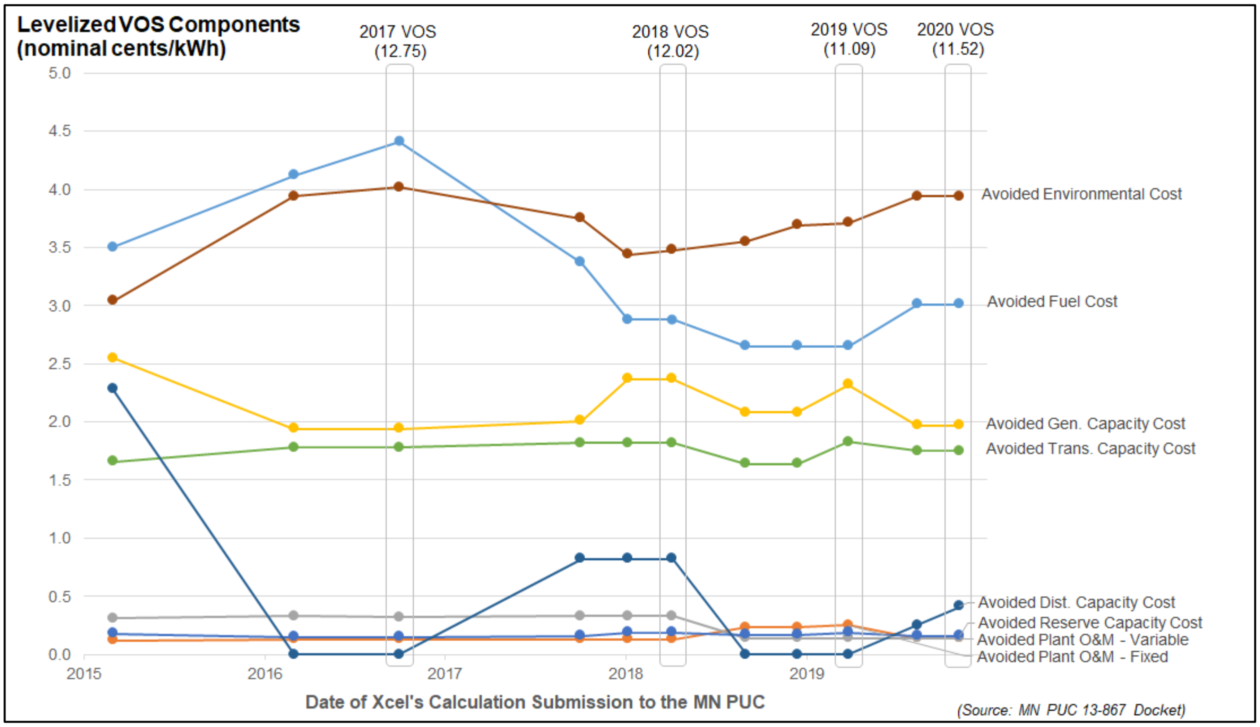
[11] For further detail see MN Department of Commerce VOS Methodology, available at: http://mn.gov/commerce-stat/pdfs/vos-methodology.pdf and Exhibit CEO-36 (GC-3).

[12] See also Chan, Gabriel. November 27, 2018. Comments on Xcel Energy's 2019 VOS Calculation and Proposed 2019 Vintage Year Bill Credit Tariff Sheets in Docket No. E002/M-13-867. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={009A5A67-0000-CC15-BF69-3E12D10B78DD}&documentTitle=201811-148058-01

[13] See Minnesota PUC. December 3, 2019. Order Approving Changes to Distributed Solar Value Methodology as Modified and Requiring Further Filings in Docket E999/M-13-867 and E999/M-14-65. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={30D2CC6E-0000-CA1D-A52B-274566AF32CF}&documentTitle=201912-157987-01

[14] See Interagency Working Group on the Social Cost of Greenhouse Gases. 2016 Revisions. https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf

Figure 8: Xcel Energy's calculation of the value of solar, 2017-2020.



8 Tr. 4290 (Chan Dir.).

Overall, stakeholders view both Minnesota's VOS development process and the approved VOS methodology favorably. 8 Tr. 4286, 4294 (Chan Dir.). Minnesota's VOS methodology itself has remained relatively stable but has also been flexible enough to adapt to changing policy goals and incorporate methodological improvements. *Id.* at 4294 (Chan Dir.). These attributes—in addition to the fact that it produces rates reflecting equitable cost of service consistent with the requirements of Michigan law—make VOS an attractive approach to DG compensation in Michigan.

vii. <u>A VOS framework should account for the complete set of values that DG creates, including the environmental value of DG.</u>

In a review of past applications of cost-benefit analysis to DG in 15 states prepared for the U.S. Department of Energy, the consulting firm ICF found that states have taken varying approaches to the specific categories of costs and benefits included in their respective VOS studies. Those value categories are summarized below in Table 8.

Table 8: VOS Value Categories used in State Cost-Benefit Analyses

Value Category		Benefit (+) or Cost (-)	Number of Studies Addressing this Category (out of 15)
Utility System Impacts			
Generation	Avoided Energy Generation	+	15
	Avoided Generation Capacity	+	15
	Avoided Environmental Compliance	+	10
	Fuel Hedging	+	9
	Market Price Response	+	6
	Ancillary Services	+/-	8
Transmission	Avoided Transmission Capacity	+	15
	Avoided Line Losses	+	11
Distribution	Avoided Distribution Capacity	+	14
	Avoided Resiliency & Reliability	+	5
	Distribution O&M	+/-	4
	Distribution Voltage and Power Quality	+/-	6
Cost	Integration Costs	-	13
	Lost Utility Revenues	-	7
	Program and Administrative Costs	-	7
Societal Impacts			
External Value to Society	Avoided Cost of Carbon	+	8
	Other Avoided Environmental Costs	+	9
	Local Economic Benefit	+	3

8 Tr. 4297 (Chan Dir.); *see also* Exhibit CEO-38 (GC-5). In order to establish a VOS methodology and tariffs that reflect equitable cost of service and square with widely-accepted principles of rate design, the Commission should direct the Company to develop a VOS framework that accounts for the **complete** set of values that DG creates, including all value categories listed in Table 8.

Staff witness Revere suggests that it is inappropriate to compensate for DG for *all* the benefits it creates because by doing so, "it causes those benefits to cease to exist" and that as a result "rates to customers would not go down." 7 Tr. 2928-2929 (Revere Reb.). To illustrate his point, Mr. Revere offers a hypothetical in which DG receives a credit for its positive environmental value, and then subsequently displaces coal generation completely. *Id.* at 2930. Mr. Revere concludes that in this scenario, customers would continue to pay for the positive environmental value that DG creates, and as such remain in the same economic place as they would have been if coal generation still existed. *Id.* Mr. Revere asserts that a more appropriate approach than pricing the "positive externalities" of new resources is to price "negative externalities" of existing resources, as a preferred way to make non-polluting sources cheaper than polluting sources. *Id.* at 2929.

Mr. Revere's argument is riddled with flaws. First, his assertion that DG customers should not be compensated for the full range of benefits associated with their Outflow is out of step with Michigan law, which requires Consumers to compensate DG customers for their "fair and equitable use of the grid" and does not carve out any set of benefits. MCL 460.11 (1). Second, Mr. Revere's assertion that compensating DG customers for the full range of benefits associated with their Outflow would necessarily cause customer rates to stay at the same level is wrong. That is because Mr. Revere's argument improperly assumes an apples-to-apples comparison between DG Outflow credits and the costs that DG Outflow avoids. As Mr. Revere acknowledged during cross examination, whereas the Company earns a return on many of the costs that DG Outflow avoids, the Company does not earn a return on its Outflow credits to DG customers. 7 Tr. 2955 (Revere Cross.). All else equal, therefore, paying for DG Outflow is *cheaper* than the capitalized costs it avoids. Third, and most importantly, Mr. Revere entirely ignores that a VOS framework anticipates a dynamic analysis, in which the VOS is updated based on marginal benefit. 8 Tr. 4284 (Chan Dir.). As such, again in Mr. Revere's hypothetical but this time properly applying a dynamic VOS framework, if highly-polluting coal generation on the system is reduced over time, DG's environmental value within the VOS would *reduce* over time rather than staying the same in perpetuity. When cross-examined on this issue, Mr. Revere acknowledged that in fact, taking into account a dynamic framework, compensating DG customers for their positive environmental value and pricing negative externalities would lead to the same result:

> Q: And if you were able to conduct a dynamic analysis where the externality was consistently being remeasured and the externality was eventually eliminated, the ultimate outcome would be no different for a positive externality versus a negative externality; is that correct?
>
> A (Mr. Revere): I can't say for certain without conducting the analysis, but I think that is likely correct.

7 Tr. 2951 (Revere Cross).

Although JCEO recommend that a VOS framework should account for the full set of values that DG creates, JCEO acknowledge that certain values are difficult to quantify or estimate in a transparent, credible, or reasonably accurate manner. However, as Dr. Chan points out, the fact that estimation challenges exist "does not suggest any principled basis for assuming that any uncertain avoided cost of DG is zero." 8 Tr. 4304 (Chan Dir.). The notion that any class of benefits that are difficult to quantify should be excluded from compensation creates a "bias of omission" and implicitly values the entire class of benefits at zero. *Id.* In fact, the Company's proposed Tariff reflects this bias—Company witness Miller notes that "although some advocates have argued that DG customers benefit the grid, I have yet to find any compelling research supporting this claim." 4 Tr. 579 (Miller Rev. Dir.).

JCEO witness Rábago details multiple studies of the social value of DG which strongly suggest that even though certain categories of benefit may be difficult to quantify, assuming those benefits are "zero" would create a substantial bias. Where calculating a benefit is difficult, a VOS framework can adopt estimation approaches that are transparent and as accurate as feasible. 8 Tr. 4304 (Chan Dir.). Moreover, as Dr. Chan points out, the process of estimating specific avoided costs in a transparent VOS process could *itself* provide meaningful new data and information that can improve future VOS estimation, creating a virtuous feedback loop. *Id*. at 4305.

Importantly, the VOS framework should account for the environmental value of DG (including both the utilities' avoided cost of complying with environmental regulations *as well as* unpriced, external avoided environmental impacts). By incorporating all environmental values, a VOS tariff helps reduce existing cross-subsidies in the energy system that exist due to unpriced external costs. 8 Tr. 4307 (Chan Dir.). Moreover, it is important that the Commission understand the environmental impacts of DG, because those impacts will inform future Commission decisions that implicate DG (for example, resource planning; distribution planning; or DG compensation determination proceedings). Under the Michigan Environmental Protection Act, the Commission is obligated to determine whether the approval of utility actions would impair the environment and whether there is a feasible and prudent alternative—a determination that requires an understanding of the avoided environmental costs associated with DG. MCL 324.1705(2).

It is feasible for a VOS framework to account for the environmental value of DG. Dr. Chan explains that "[e]nvironmental economists have developed a robust set of methodologies for valuing environmental benefits, and environmental valuation is a regular part of state and federal rulemaking." *Id*. at 4306. The U.S. Environmental Protection Agency provides guidelines for assessing environmental benefits, including avoided greenhouse gases and criteria pollutants, within economic analyses. For greenhouse gases in particular, the Federal Interagency Working Group on the Social Cost of Greenhouse Gases produced monetary values for the benefits of reduced greenhouse gas emissions. These values could be directly applied in a VOS framework in Michigan, as they were in Minnesota's VOS framework. *Id.* at 4307.

viii. Undertaking a VOS study as the basis for compensating Consumers' DG customers would be worth the effort required to develop and update it.

JCEO have explained that establishing a VOS framework would help ensure that Consumers' rates reflect DG customers' "fair and equitable use of the grid" and comport with widely-accepted ratemaking principles. Minnesota's experience demonstrates the eminent feasibility of establishing a VOS framework and using that framework to derive cost-based Outflow credits for DG customers. Dr. Chan, who is intimately familiar with the Minnesota process since its inception, notes that "[g]iven its potential impact in shaping a large amount of third-party investment in DERs, and its potential for linking together distinct proceedings, the VOS deserves specific attention." 8 Tr. 4320 (Chan Dir.). He further recommends that Michigan stakeholders spend "significant deliberative energy on establishing and continuously refining the VOS so that investment in DERs can grow to meet system needs in a way that can be most beneficial to the public in the short- and long-run." *Id.* While JCEO recognize that undertaking a VOS study and developing a VOS framework will consume Commission, utility, and stakeholder resources, the value of such an approach in the long-run is clear. The alternative—tariffs that ignore the vast potential of DG, undercompensate DG customers, and choke the state's DG market—is neither lawful nor good policy.

7. Until a comprehensive VOS study is complete, the Commission should direct the Company to credit DG Outflow at the full retail rate.

JCEO witness Lucas's testimony demonstrates that the value of Outflow from DG systems in the Company's service territory is \$0.23957 per kWh, or \$0.28125 per kWh, by applying an alternative method. JCEO witness Lucas also demonstrates it would be appropriate to award DG customers an adder ranging from $0.0274 per kWh and $0.0534 per kWh, above the Outflow credit, to transfer to those customers a portion of the savings that Consumers realizes from the lower cost of serving them.

JCEO witness Lucas's Outflow credit (even before considering his recommended adder) not only significantly exceeds the Company's proposed Outflow credit, but also exceeds the otherwise applicable full retail rate (See Table 9 below).

Table 9: Comparison of Outflow Credit for Residential Customers

Residential Rate			Summer On-Peak RSP	Smart Hours RSH	Night Time Savers RPM
Summer	Peak	Full Retail Rate	$0.215553	$0.215553	$0.215553
		Proposed by Company (DG Tariff)	$0.125355	$0.125355	$0.125355
		Lucas Analysis (based on Company COS)	$0.239570	$0.239570	$0.239570
	Off Peak	Full Retail Rate	$0.164685	$0.164685	$0.179125
		Proposed by Company (DG Tariff)	$0.084319	$0.084319	$0.097334
		Lucas Analysis (based on Company COS)	$0.239570	$0.239570	$0.239570
	Super Off Peak	Full Retail Rate	$0.164685	$0.164685	$0.135767
		Proposed by Company (DG Tariff)	$0.084319	$0.084319	$0.062420
		Lucas Analysis (based on Company COS)	$0.239570	$0.239570	$0.239570
Winter	Peak	Full Retail Rate	$0.164783	$0.173051	$0.173051
		Proposed by Company (DG Tariff)	$0.088869	$0.095128	$0.095128
		Lucas Analysis (based on Company COS)	$0.239570	$0.239570	$0.239570
	Off Peak	Full Retail Rate	$0.164783	$0.162304	$0.170519
		Proposed by Company (DG Tariff)	$0.088869	$0.086523	$0.094440
		Lucas Analysis (based on Company COS)	$0.239570	$0.239570	$0.239570
	Super Off Peak	Full Retail Rate	$0.164783	$0.162304	$0.141914
		Proposed by Company (DG Tariff)	$0.088869	$0.086523	$0.070323
		Lucas Analysis (based on Company COS)	$0.239570	$0.239570	$0.239570

8 Tr. 4240 (Lucas Dir.); Company Exhibit No. A-16 (RLB-2) Schedule F-5.

Mr. Rábago notes that this result is consistent with the majority of VOS studies conducted across the U.S., and likely would be consistent with the result of a VOS study in

Consumers' territory if the Company carried one out. 8 Tr. 4377 (Rábago Dir.). As Mr. Rábago explains, "[t]he lesson of such a [VOS] study is that even under full retail net metering, DG customers *are most likely subsidizing the Company and other customers.*" 8 Tr. 4377 (Rábago Dir.) (emphasis added). The bottom line is, Consumers' DG customers should not be punished for the Company's failure to collect the data and perform the analysis necessary to support an equitable cost of service-based DG Tariff. The Company has the burden of proof in this case, and as the Michigan Supreme Court has held that "[t]he party alleging a fact to be true should suffer the consequences of a failure to provide the truth of that allegation." *Kar v. Hogan*, 399 Mich. 529, 539 (1976). Moreover, it is antithetical to Michigan public policy that DG customers should be economically disadvantaged solely because the rate-regulated utility that has access to and controls system cost data refuses to collect and rely upon that data in a rate proceeding.

Therefore, until a VOS framework is complete, or until the Company undertakes and completes an analysis necessary to support an equitable cost of service-based DG Tariff, it should compensate all DG customers for their Outflow at the **full retail rate**, including all energy (capacity and non-capacity), transmission and distribution charges and fees. This approach would essentially "hold harmless" customers who would, under NEM, receive compensation for their Outflow at the full retail rate.

There is no reasonable likelihood that an Outflow credit set at the full retail rate would overcompensate DG customers. 8 Tr. 4378 (Rábago Dir.). This is because, as Mr. Lucas's testimony establishes, DG customers not only generate Outflow that have value *exceeding* the average retail rate otherwise applicable to consumption, but also *cost less to serve* than non-DG customers. 8 Tr. 4378 (Rábago Dir.). In the unlikely "worst case" that an interim Outflow credit set at the full retail rate overcompensates DG customers, in light of Michigan's small market for

DG today, the total magnitude of Outflow credits in dollar terms (and any cross-subsidy) would likewise be small. And, as Mr. Rábago points out, in that "worst case," Michigan would be home to a few more locally-constructed, non-polluting, renewable energy-generating DG systems while the Commission awaits the development of a VOS framework and cost-of-service-based rates. 8 Tr. 4378 (Rábago Dir.).

8. The Company should voluntarily allow customers to participate in its DG Program after it hits the 1% minimum participation level.

Section 173 of Act 342 requires each utility to allow *a minimum* of 1% of its average in-state peak load for the preceding five years to participate in the Distributed Generation Program. The 1% minimum participation level ("soft cap") is broken down into three sub-groups: 0.5% for customers with DG systems of 20 kilowatts (kW) or less (Category 1), 0.25% for customers with DG systems of between 20 and 150 kW capacity (Category 2), and 0.25% for customers with a methane digester of greater than 150 kW (Category 3). Table 10 below demonstrates that Consumers is very close to reaching its soft cap for Category 1 and Category 2 DG customers.

Table 10: Distributed Generation Program Minimum Capacity

Row Number	Item	Category 1	Category 2	Category 3
1	Currently Applicable Minimum	36,405 kW	18,203 kW	18,203 kW
2	Current Installed Capacity	25,433 kW	11,152 kW	190 kW
3	Capacity Remaining	10,972 kW	7,051 kW	18,013 kW
4	Average applications per month (through February 2020)	1,045 kW	538 kW	0 kW

8 Tr. 4174 (Kenworthy Dir.). Although the COVID-19 pandemic has complicated the Company's forecast, it estimates it could reach its Category 1 soft cap by October 2020, and the Category 2 soft cap by the end of 2021. The Company does not propose to expand its DG

Program beyond the minimum participation levels prescribed by Act 342. Once the Company hits its soft caps, customers choosing to install DG would have the option of selling their excess power to the Company at the standard offer Public Utility Regulatory Policies Act of 1978 (PURPA) rate (PURPA Standard Offer), or at the Midcontinent Independent System Operator's (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (energy only contract), as described in the Company's proposed Rule C11.1 Self-Generation.[15] 4 Tr. 580 (Miller Rev. Dir.). The energy only contract offered under Rule C11.1 Self-Generation does not include any compensation beyond the market value of energy.

JCEO witness Kenworthy explains that customers would more likely choose to participate in the PURPA Standard Offer than the energy only contract offered under Rule C11.1, because they would receive somewhat higher compensation under the Standard Offer contract. 8 Tr. 4176 (Kenworthy Dir.) But the PURPA Standard Offer is designed for interactions between the Company and developers of large "Qualifying Facilities", not residential customers. *Id.* Requiring residential customers to participate in the PURPA Standard Offer would impose an excessive burden on those customers, and moreover, because the PURPA Standard Offer rates are based on Locational Marginal Price (LMP) for energy and monthly payments for capacity based on the PRA, they lack transparency and predictability. 8 Tr. 4176-4177 (Kenworthy Dir.). Requiring residential customers to participate in the PURPA Standard Offer would also be inefficient for the Company. The Company would be required to execute and administer complex qualifying facilities contracts with each individual customer independent of their existing customer relationship with the Company. *Id*. at 4177. The company would also

[15] The Company also notes that if it were to increase the minimum participation level in its DG Program beyond 1%, it would compensate participating customers' Outflow "with a more cost-based price" rather than at the retail power supply rate less transmission. 4 Tr. 580 (Miller Rev. Dir.).

be required to administer monthly invoicing and payments to customers under the Standard Offer contract, separate from their monthly billing of the residential customer. *Id*.

A more reasonable path forward is for the Company to voluntarily offer its DG Program to customers after it passes its soft caps. *Id.* JCEO have explained that if the Company were to develop cost-based DG rates (Inflow charge and Outflow credit) based on a VOS framework, there would be no cross-subsidization between DG and non-DG customers. This *should* make the Company indifferent to the level of DG interconnected to its grid.

Staff witness Matthews endorses this approach, recommending that the Company voluntarily agree to increasing its cap to allow new DG program enrollments to continue after the Company hits its soft caps. 8 Tr. 4817 (Matthews Dir.). Although Mr. Matthews wrongly concludes that the Company's proposed DG Tariff is "cost-based", Mr. Matthews correctly reasons that a cost-based tariff makes limiting DG participation to the soft caps unnecessary. *Id*. The Company should adopt JCEO and Staff's recommendation and extend its DG Program after it reaches its soft caps for each Category of DG customer.

E. Requested Relief with respect to Company's DG Program

The Company has failed to provide thorough, detailed, and meaningful evidence that its proposed DG Tariff is just and reasonable and reflects "equitable cost of service", or that its Tariff comports with widely-accepted ratemaking principles. In fact, the Company itself acknowledges that its analysis of DG customers has room for significant improvement in order for it to reflect cost-of-service, stating that "it would be premature to assign costs, or benefits, to DG customers before the Company has had an opportunity to properly gather and evaluate the impacts on the grid." 8 Tr. 4373-4374 (Rábago Dir.). The Company's DG Tariff will also result in environmental impairment. JCEO therefore request that the Commission:

- Reject the Company's proposed DG Tariff;

- Direct Staff to facilitate a VOS study that establishes a VOS framework in order to ensure the development of a Tariff that complies with Michigan law and ratemaking principles. The VOS study itself should be carried out by an independent third-party consultant, but Staff should coordinate with the Company and stakeholders to lead and inform the VOS framework development process;

- Direct the Company to credit all DG customers for their Outflow at the full retail rate during the interim period while a VOS framework is being developed.

Moreover, JCEO recommend that the Company voluntarily allow customers to participate in its DG Program even after it surpasses the 1% minimum participation level.

III. DISTRIBUTION CAPITAL EXPENDITURES

A. Distribution Planning and Non-Wires Alternatives[16]

Company witness Blumenstock describes Consumers' plan to invest in its distribution system and modernize its grid. *See* 6 Tr. 1023-1314 (Blumenstock Dir.). Mr. Blumenstock's testimony is exhaustive and describes in meticulous detail the Company's guiding principles and long-term objectives, as well as its several distribution and capital O&M programs intended to meet those principles and objectives. *See generally*, 6 Tr. 1023-1314 (Blumenstock Dir.). Notably, the Company has started exploring the use of non-traditional resources such as batteries to meet grid needs (JCEO address the Company's proposed "Grid Storage" sub-program in Section III.B. of this brief, *infra*). But the Company's recognition of the value of non-traditional resources stops at resources that it owns.[17] A significant gap in the Company's approach to planning and investing in its distribution system is its treatment of *customer- and third-party-owned* Distributed Energy Resources (DER), which, like Company-owned resources, can

[16] This section pertains to the Company's proposed Distribution Capital Expenditures generally.
[17] This is a theme in the Company's application—as JCEO explain in Section II of this brief, *supra*, the Company's proposed DG Tariff does not propose to compensate customer-owned DG for any benefits that DG creates for the grid, and the Company suggests that to the extent customer-owned DG creates any grid benefits, its customers are responsible for demonstrating such benefit.

provide valuable services to the grid as alternatives to traditional grid infrastructure ("non-wires alternatives" or NWA).

MEC/NRDC/SC/CUB witness Villarreal emphasizes that the Company's planning process and horizons only allow Consumers' projects and solutions to go forward, while failing to give NWAs a reasonable or fair opportunity to meet the same grid needs. *See* 8 Tr. 3863-3866 (Villarreal Dir.). Mr. Villarreal points to the Company's LVD Substation Reliability program as an example of an area where the Company fails to reasonably consider customer- and third-party owned NWA to meet grid needs. *Id*. at 3864. As Mr. Villarreal explains, the Company unreasonably dismisses the viability of NWA in this program area—if the Company considered *projected* rather than *historic* trends in planning this program, and planned investments further out into the future, then NWAs would have a fairer opportunity to compete with Company-owned infrastructure. In other words, while the Company summarily dismisses NWA as not "mature enough" (6 Tr. 1157), its dismissal ignores the fact that the Company's own distribution planning processes do not create a reasonably level playing field for NWA. This, Mr. Villarreal explains, is "an inequitable result for customers and for markets." *Id*. at 3866.

JCEO Sandoval explains that by implementing an Integrated Distribution Planning process, which expressly leverages customer- and third-party-owned DER to meet grid needs through a robust rather than passively "accommodating" DER that customers add to the grid, the Company can "replace the current paradigm of approaching distribution planning as a process that reacts primarily to system shortfalls, with an approach that provides the Company the tools necessary to proactively pursue the capabilities stakeholders would like to see from their energy system." 8 Tr. 4411 (Sandoval Dir.). Moreover, an IDP can help the Company better assess the value of DG and other DER on the distribution grid, which would be useful considering that the

Company has in this case proposed transitioning from net metering to a cost-based compensation regime for DG.

The Company generally suggests that the transformation of its distribution planning process will take time and will largely occur in the stakeholder process in Case No. U-20147. 6 Tr. 1407 (Blumenstock Reb.). While JCEO agree that Case No. U-20147 (as well as case No. U-20633, which the commission recently opened to consider the alignment of resource, transmission and distribution planning) is an appropriate forum to consider the evolution of the company's distribution planning process, JCEO note that in rate cases, the Company retains the burden of demonstrating that its proposed expenditures are prudent and reasonable. Consideration of potentially economic alternatives to traditional distribution infrastructure, including customer- and third-party owned NWAs, are "an important element in demonstrating whether [a utility's] proposed expenditures are preferable to other options." *DTE Electric Co.*, Case No. U-20561, Order at 112 (May 8, 2020). The Commission should therefore direct the Company to conduct a robust assessment of non-wires alternatives in its next rate case, and work with stakeholders to implement an IDP process that reasonably incorporates NWA analysis prior to its next rate case filing.

Below, JCEO address three of the Company's proposed distribution investments: battery storage pilot project; conservation voltage reduction (CVR); and Distributed Energy Resource Management Systems (DERMS). The Company's troubling pattern of failing to chart a thoughtful approach to integrating and leveraging customer- and third-party owned DER runs through these proposed investments. For the following reasons, JCEO recommend that the Commission:

- Direct the Company to clearly articulate a pathway to translate battery storage pilots into system-wide deployments;

- Direct the Company to report regularly on the performance of its conservation voltage reduction program, and;
- Reject the Company's proposed investment in a DERMS.

B. Grid Storage Sub-Program[18]

Company witness Blumenstock explains that the Company is launching a new "Grid Storage" sub-program within its Reliability Program. 6 Tr. 1218 (Blumenstock Dir.). According to Mr. Blumenstock, the Grid Storage sub-program "will allow the Company to develop its battery strategy" as battery installation capital costs decrease, and as the need for batteries to help smooth out intermittent solar generation of the Company's grid increases. *Id.* While the Company anticipates needed large scale investments in battery storage in the 2025-2032 timeframe, in the short-term, Mr. Blumenstock explains that the Company is investing in smaller deployments of battery storage to "test battery capabilities and develop Company expertise at operating battery systems", which builds off of the Company's experience from implementing its Parkview battery in Kalamazoo and its Circuit West battery in Grand Rapids. *Id.* To that end, the company is proposing three additional battery projects to develop further capabilities: (1) a battery at a solar farm in Cadillac; (2) a portable battery intended to defer a projected substation capacity upgrade, and (3) a battery designed to allow "islanding", which will help mitigate potential outages on a circuit by continuing service to customers while a broader outage is restored. *Id*. at 1219. Generally, Mr. Blumenstock anticipates that the Company's Grid Storage sub-program has "great potential" to reduce customer costs by deferring capital investments, in addition to "the expected contribution of batteries adding to the expected contribution of

[18] This section pertains to line No. 22 on Company Exhibit A-29, the Grid Storage Sub-Program within the Company's Reliability Program.

batteries as an economical supply solution," and their value in providing insights regarding voltage control. *Id*. at 1220.

JCEO witness Sandoval is generally supportive of the Company's proposed Grid Storage sub-program. He notes that the objectives of the Company's proposed pilots—in addition to a separate pilot that will test the installation and use of Company-owned residential behind-the-meter batteries on a circuit near Grand Rapids[19]—align well with the Company's Grid Modernization Strategy. However, the Company's Grid Storage program entirely ignores customer- or third-party-owned storage resources, which can provide the *same* grid services as Company-owned batteries. And while pilots can be useful, Mr. Sandoval recommends that the Company clearly articulate intended outcomes from its pilot proposals, and clearly articulate a path for the pilot to lead to large-scale deployment. 8 Tr. 4425 (Sandoval Dir.). By doing so, Mr. Sandoval explains, the Company can avoid "a cycle where ideas continued to be tested" without a clear path to larger deployments. *Id*.

C. CVR[20]

Conservation Voltage Reduction (CVR) is "the capability to optimize service-point, or customer meter, voltages to reduce energy demand without requiring active participation of behind-the-meter investment by customers." 6 Tr. 1242 (Blumenstock Dir.). CVR includes a set of technologies, including Volt-VAR Optimization (VVO), that reduces the delivery voltage along circuits, which reduces the amount of electric load that must be served on that circuit. The set of technologies works by continuously optimizing control settings both on the substation

[19] While the Company describes this proposed residential behind-the-meter battery pilot in its testimony, *See* 6 Tr. 1063 (Blumenstock Dir.), it does not propose to recover costs associated with this pilot in this case.
[20] This section refers to line 29 on Company Exhibit A-29, the Conservation Voltage Reduction CVR sub-program within the Company's Capacity Program

(upstream) and on voltage regulating equipment (downstream) while making sure that the circuit stays within the "bands" required by regulation. *Id.*

In this case, the Company has proposed a new CVR sub-program within its Capacity program "to complete capital projects necessary for implementing the Company's overall CVR plan that was included in the 2018 IRP." *Id*. at 1243. Those projects include, among other things, conducting circuit conditioning and upgrades to targeted circuits, and installing Distribution Supervisory Control and Data Acquisition (D-SCADA), regulator controllers, and capacitor controllers on those circuits. *Id.* The Company also states that its initial testing of CVR (in 2019) created a baseline, and that once CVR is fully enabled and operational on a circuit, its meter data would provide "sufficient telemetry to ensure continuous measurement and verification of CVR performance." *Id*. at 1243-1244.

JCEO witness Sandoval states that the Company's CVR Plan aligns well with aspects of its broader Grid Modernization strategy but notes that the Company's plan is largely focused on waste reduction, whereas CVR also offers the potential of helping manage dynamic system conditions and help integrate DER. 8 Tr. 4433. Mr. Sandoval explains that regions with significant levels of DERs, like Hawaii, have begun to explore how CVR technologies may be used to safely add more solar to the grid, and lower the cost and increase the speed at which it is added. *Id*.

JCEO witness Sandoval also explains that the Company's proposed approach to the measurement and verification of CVR "appears sound", however, Mr. Sandoval recommends that the Company file periodic reports with the Commission that include metrics detailing:

- The level of voltage reduction achieved;
- The level of loss reduction achieved;

- Service quality issues encountered;
- Energy savings achieved;
- Demand reductions achieved, and;
- Greenhouse Gas emission reductions attributed to performance.

8 Tr. 4432 (Sandoval Dir.). While the company has provided forecasts of some of these potential metrics in its CVR deployment plan, reporting on these performance metrics can help the Commission and stakeholders determine where course correction may be necessary. *Id*.

D. DERMS[21]

A Distributed Energy Resource Management System or DERMS is "an advanced software platform including, but not limited to, specific functions to forecast, monitor, control, and coordinate [distributed energy resources] on the electric grid." 6 Tr. 1176 (Blumenstock Dir.). The Company is planning to deploy a "first phase" of DERMS over the course of 24 to 36 months beginning in 2020 and ending in 2022, and asserts that it will use the solution to control a limited number of Company-owned distributed energy resources to "address potential local operational challenges associated with DER penetration." 6 Tr. 1176 (Blumenstock Dir.). The first phase of DERMS will cost approximately $3 million, and the Company intends to follow the first phase with a larger-scale DERMS deployment. *Id*. at 1176-1177.

The Company's investment in DERMS is not warranted, and the Commission should disallow that investment in its entirety. Company witness Blumenstock acknowledges that it is not currently experiencing *any* operational challenges associated with DER. Exhibit CEO-44.

> Q: […] But those circuits, where you will be installing DERMS in the first phase, aren't experiencing any operational challenges, are they?

[21] This section refers to a specific technology within line 17 on Company Exhibit A-29, the Grid Capabilities: Advanced Technologies sub-program within the Company's Reliability Program.

A: Not that I’m aware of.

6 Tr. 1495 (Blumenstock Cross). In fact, the Company acknowledges that “operational challenges associated with DER begin when DER penetration reaches between 20 and 30 percent at the substation and circuit level (Exhibit CEO-44), whereas the Company’s DER penetration is less than 1% today. 8 Tr. 4174 (Kenworthy Dir.) (citing Exhibits CEO-2 through CEO-4). The Company’s DER penetration is far too low to merit an investment in DERMS—other utilities, such as Pacific Gas and Electric in California, that are exploring DERMS, have over 390,000 DG installations today, and are currently adding over 5,000 solar installations *per month*. 6 Tr. 1505 (Blumenstock Cross).

Notwithstanding the lack of any operational challenges from DER today (which defeats the central use case of the proposed DERMS), the Company takes the position that a DERMS will allow the Company to ensure and rely on the benefits of DG to the grid. 6 Tr. 1501 (Blumenstock Cross). As Mr. Sandoval points out, the Company should pursue a full range of strategies to manage DER interaction with the grid, including voltage optimization and DER self-optimization, before investing capital dollars in a DERMS that creates a large number of controls and unnecessary complexity. Importantly, the risk of a DERMS—as compared to those other approaches to manage DER—is that the technology gives the utility the ability to control and curtail customer-owned resources. 6 Tr. 1490-1491 (Blumenstock Cross); 8 Tr. 4428 (Sandoval Dir.). While the Company does not intend to use its DERMS to control customer-owned resources in its first phase of deployment, the Company acknowledges that its DERMS investments may be used to control customer-owned resources in future phases.

Q: […] I’m trying to understand how these phases relate to each other. Will hardware and software that’s implemented in Phase 1 of DERMS be used in the Enterprise-wide deployment of DERMS? Is there - - In other words, is there

> a commonality in the hardware and software that is actually used […]?
>
> A: That is possible.
>
> Q: O.K. And during the Enterprise-wide deployment of DERMS, does the Company anticipate controlling customer-owned DERs?
>
> A: Yes.

As Mr. Sandoval explains, before implementing a DERMS, the Company should develop a proposal that details whether customer-owned DER control would be voluntary or mandatory, the eligible technologies that the utility would manage, and how these resources would be compensated if the Company reduces their power output. Absent those details, the Company's customers risk paying for a technology that will, at some point in the future, be used to control their DER, without any assurance that Consumers will manage their resources reasonably or compensate them fairly for the services their resource provides to the Company. Until the Commission perceives a real need for DERMS (significant levels of DER penetration presenting near-term operational challenges), and until the Company prepares a plan for its deployment that will protect its DG customers, the Commission should reject the Company's proposed investment in DERMS.

IV. CONCLUSION

Consumers' rate case application, including in particular its proposed Distributed Generation Tariff and proposed distribution system investments, reveals a troubling pattern: the Company consistently ignores the value of customer-owned distributed generation and other distributed energy resources. This should concern the Commission, not only because these resources tend to be non-polluting, promote local economic development, and promote equity, but because they can provide significant benefits to the Company's electrical system and all of its customers.

The Company's approach has adverse implications. Its failure to incorporate customer-owned resources into its distribution planning process puts ratepayers at risk of overpaying for traditional distribution infrastructure. And the Company's Distributed Generation Tariff—which, if approved, would significantly undercompensate distributed generation customers—risks markedly reducing the number of distributed solar systems installed in its service territory.

The Company's approach to customer-owned DG is not only ill-conceived as a matter of policy, it does not meet the requirements of Michigan law. With respect to the Company's DG Tariff, the law requires that the Commission approve rates that reflect "equitable cost of service." The Company, as the party that bears the burden of proof in this proceeding, must provide evidence demonstrating that its proposed rates are cost-based. It has not done so.

Therefore, and for the reasons described in this brief and in the testimony of its witnesses, JCEO request that the Commission grant its requested relief:

- Reject the Company's proposed DG Tariff;
- Direct Staff to facilitate a VOS study that establishes a VOS framework in order to ensure the development of a Tariff that complies with Michigan law and ratemaking principles;
- Direct the Company to credit all DG customers for their Outflow at the full retail rate during the interim period while a VOS framework is being developed;
- Direct the Company to investigate Integrated Distribution Planning;
- Direct the Company to clearly articulate a pathway to translate battery storage pilots into system-wide deployments;
- Direct the Company to report regularly on the performance of its conservation voltage reduction program, and;
- Reject the Company's proposed investment in a DERMS.

Respectfully submitted,

August 27, 2020

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STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-20697

PROOF OF SERVICE

I hereby certify that a true copy of *Initial Brief of The Ecology Center, The Environmental Law & Policy Center, The Great Lakes Renewable Energy Association, The Solar Energy Industries Association, and Vote Solar (collectively Joint Clean Energy Organizations, or JCEO)* was served via electronic mail on August 27, 2020 to the persons listed below.

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