Appendix A

Value of Solar Study

I. Introduction

The “Order Establishing Special Contemporary Resource Planning Issues” issued on November 4, 2020 in EO-2021-0067 and EO-2021-0068 directed jurisdictional utilities to:

“Conduct a Value of Solar study to inform efforts relating to integrated resource planning. A Value of Solar study is a comprehensive analysis of the cost avoided and benefits created for the grid, electricity customers, and society as result of the generation of solar energy. Because solar energy is often interconnected at the distribution level of the grid, such a study, done correctly, will capture distribution level benefits and costs that cannot be captured by wholesale level avoided cost estimates. The immediate benefit of such a study is to understand the contributions and costs related to distributed solar generation beyond simplistic and subjective allegations of cross subsidies. The utility’s Value of Solar study should consider the National Association of Regulatory Utility Commission’s Distributed Energy Resources Rate Design and Compensation manual, National Renewable Energy Laboratory’s Value of Solar: Program Design and Implementation Considerations, and the National Energy Screening Project’s National Standard Practice Manual for Distributed Energy Resources among any other industry guidance on value of solar study development and implementation.”

The Value of Solar ("VOS") study was designed to support the Commission's express goals of informing integrated resource planning and developing objective measures of costs and benefits. The remainder of the VOS study is organized into the following sections. In section II, the industry literature cited by the Commission is reviewed. In section III, the potential costs and benefit categories are outlined and discussed. In section IV, the measureable cost and benefits are evaluated. Section V summarizes the evaluation and provides concluding remarks.

II. Review of the Industry Literature

A. *National Association of Regulatory Utility Commission's Distributed Energy Resources Rate Design and Compensation (NARUC DER Manual)*

The NARUC DER Manual was created "to assist commissions in considering appropriate rate design and compensation policies for distributed energy resources (DER)" and is designed "to provide regulators with a comprehensive understanding of the question of how does DER affect regulation."[1]

The NARUC DER Manual characterizes the principles and purpose of utility rate design in the context of DER. Specifically, "DER may impose onto the utility new costs, which need to be recovered to ensure the utility's financial health and to allow the utility to recover necessary investments in the distribution grid to maintain reliability and quality of service. Of course, over the long term, DER may reduce utility costs. Identifying the appropriate principles, goals, and objectives for rate design can assist a regulator in determining an appropriate rate (or compensation methodology) that collects the authorized utility costs or authorized revenue requirement."[2]

This characterization highlights at least two important points. First, DER may impose new costs on utilities, presumably in the short and long term, and that benefits (cost reductions) are likely a long-term proposition. Second, rate (or compensation) design is primarily predicated on a utility's recovery of cost.

The NARUC DER Manual provides a general overview of the rate design process consistent with the standard industry knowledge and practice. The overview includes an outline of rate design principles, basic types of rate design, and some specific policy considerations.

The NARUC DER Manual discusses the definition of DER and cites example definitions established across various jurisdictions or employed by various research and industry institutions.[3] A relatively exhaustive list of potential DER and enabling technologies is also discussed.[4]

The NARUC DER Manual lists practical considerations, challenges, and questions concerning DER. The list includes both financial and technical issues. Two specific financial issues include revenue erosion and cost shifting.[5] Physical or technical issues related to DER include operational visibility, intermittency, coordination, and locational heterogeneity, as well as the integration of distribution system and integrated resource planning. [6] This list provides useful context for a broad discussion of DER policy.

[1] NARUC DER Manual: Executive Summary page 5.
[2] NARUC DER Manual: What is the Rate Design Process? Section A page 19.
[3] NARUC DER Manual: What is DER? Section A page 41.
[4] NARUC DER Manual: What is DER? Section B and C pages 45-56.

The NARUC DER Manual's discussion of DER benefits is general and short, but includes the specific list of benefits included in the VOS tariffs ordered by the Minnesota Public Utility Commission. The list includes environmental costs, distribution capacity costs, transmission capacity costs, reserve capacity costs, generation capacity costs, variable utility plant operations and maintenance costs, fixed utility plant operations and maintenance costs, and fuel costs.[7] All of the benefit categories include utility costs that could be avoided.

The NARUC DER Manual also outlines issues related to the impact of DER on non-DER owning customers. The following issues are some that are considered:

1. Does DER avoid utility infrastructure costs?
2. Revenue shifting due to fixed cost recovery through volumetric rates.
3. DER customer reliance on the grid at peak times.

Although the discussions are brief, these issues are at the core of the VOS and worthy of broad consideration.[8]

Finally, the NARUC DER Manual discusses mechanisms and methodologies for DER rate design and compensation. The distinction between DER rate design and compensation design highlights the possibility for independent DER rate (charge) and compensation mechanics. Most other discussions of the benefits of DER focus only on potential compensation mechanisms. It is possible that independent DER charges and compensation mechanisms would produce better results in terms of the principle purpose of rate design.

The NARUC DER Manual explicitly analyzes four rate design elements and two primary compensation designs. The four rate design elements include:

1. Demand charges
2. Fixed Charges and Minimum Bills
3. Standby and Backup Charges
4. Interconnection and Metering Fees

The majority of the consideration is given to Demand Charges.[9] The two primary compensation methodologies include:

1. Net Energy Metering
2. Valuation methodologies

[5] NARUC DER Manual: DER Considerations, Questions and Challenges Section B page 63-67.
[6] NARUC DER Manual: What is DER? Section B and C pages 52-58 and DER Considerations, Questions and Challenges Section B page 68-69.
[7] NARUC DER Manual: DER Considerations, Questions and Challenges Section C page 70-73.
[8] NARUC DER Manual: Impacts on other Customers Section F page 70-73.
[9] NARUC DER Manual: Rate Design and Compensation: Mechanisms and Methodologies page 97-126, where pages 98-117 are dedicated to demand charges.

Two distinct valuation methodologies are presented:

1. Value of Resource
2. Value of Service

The first method, value of resource, defines compensation for a specific DER technology or resource, while the second, value of service, defines compensation by specific services that a DER provides.[10] The former is most consistent with the value of solar approach. The latter is similar conceptually to the pricing of capacity, energy, and ancillary services in organized wholesale markets.

B. *National Renewable Energy Laboratory's Value of Solar: Program Design and Implementation Considerations (NREL VOS Manual)*

The NREL VOS Manual defines VOS as a mechanism for the purchase of distributed solar generation, and explains how a VOS tariff is intended to compensate distributed generation photovoltaic ("DGPV") for the real value it provides to the electric system, independent of retail electricity rates. This idea of independence from retail electricity rates is perhaps the most meaningful concept included in the NREL VOS Manual.

The NREL VOS Manual is designed for utilities, regulators, and stakeholders interested in VOS program design and implementation, and discusses VOS program design options, but does not critically analyze the calculation of a VOS rate. The NREL VOS Manual does explain that a VOS rate is a bottom-up calculation of the benefits and costs DGPV provides to and imposes on an electric system. The values are generally associated with the avoided utility costs (benefits) and the costs of incorporating solar into the utility system.[11]

A "buy-all, sell-all" VOS program design is explicitly identified. Under a "buy-all, sell-all" program design, DGPV customers purchase all of the electrical energy they consume at applicable retail rates and sell all of their solar production to the utility at the VOS rate. This is the way in which a VOS tariff rate is independent of retail electricity rates, and distinct from net energy metering (NEM) compensation mechanisms.

The NREL VOS Manual highlights how the "buy-all, sell-all" program design separates the compensation for DGPV production from the customer's purchase of retail electricity, and can allow for full recovery of utility fixed costs.[12] However, a buy-all, sell-all VOS program will only allow for full recovery of utility costs if the VOS tariff rate only incorporates costs that the utility actually avoids. If there are other non-utility avoided cost benefits of DGPV that accrue to society at large, and public policy supports the attainment of these benefits, then the costs associated with attainment should be allocated to society through a mechanism outside of the utility rate making process. If

[10] NARUC DER Manual: Rate Design and Compensation: Mechanisms and Methodologies pages 126-139.
[11] NREL VOS Manual: Executive Summary page v.
[12] NREL VOS Manual: Executive Summary page v-vi.

those benefits are included in a VOS tariff rate and paid to customer generators, then utilities would not be allowed full recovery of their costs, or it would be necessary to shift those costs to non-generating customers.

The NREL VOS Manual defines three states of the DGPV market, and explains how the state of the market could impact VOS policy. The three market states are defined by the relationship between DGPV's levelized cost of energy ("LCOE") and the VOS tariff rate. The three market states are as follows:[13]

1. Price Support Market: LCOE > VOS rate
2. Transitional Market: LCOE ≈ VOS rate
3. Price Competitive Market: LCOE < VOS rate

The NREL VOS Manual's discussion of these three market states starts from the assumption that the decision has been made to support the development of DGPV, and performs an analysis of the state of the market.[14] The NREL VOS Manual avoids analyzing whether it is appropriate to transition away from NEM policies, but rather assumes the VOS tariff replaces NEM policies for the purpose of the analysis.[15] While this analysis might be interesting, it does not directly contribute to the objective of this study, to inform efforts related to integrated resource planning, or to the calculation of a VOS.

Under those assumptions, the NREL VOS Manual analyzes the state of the market under three VOS rate values, five different incentive policy scenarios, and modeled LCOE of DGPV for 49 states and the District of Columbia. The results provide the range of market states across the country without specific attention to any one location. The conclusion of the analysis is that most states are in the price support market condition. It is worth noting that the NREL VOS Manual does not support implementing policies that inflate the VOS rate in order to change the state of the market, but rather explains that additional, independent incentives would be needed to support the growth of a DGPV market, if such growth was the object of a broader policy.[16]

Finally, the NREL VOS Manual outlines a VOS program design framework. It begins by reiterating that VOS is not an incentive program, but a utility rate, highlighting the intention of a VOS tariff to reflect "real value DGPV provides to the electric system". It acknowledges that the framework is not a guide to best practices due to the nascent nature of VOS programs, but instead provides a range of options and directional impacts of choices. [17] The framework for VOS program design is divided into five sections:

[13] NREL VOS Manual: Introduction page 4.
[14] NREL VOS Manual: Introduction page 2.
[15] NREL VOS Manual: Introduction page 2 and Executive Summary page vii.
[16] NREL VOS Manual: Solar Market Characterization: Comparing the VOS to the Cost of Solar page 19-32.
[17] NREL VOS Manual: VOS Program Design Framework page 33.

1. Balancing Design Decisions
2. Installation Details
3. Rate and Contract Treatment
4. Price Support
5. Administrative Issues

Balancing Design Decisions focuses on the tradeoff between the accuracy of program design and the benefits of increased accuracy. For instance, the VOS rate would be more accurate if it was location specific and therefore beneficial in terms of economic and technical efficiency, but there is cost associated with the development of location specific VOS rates.[18]

The Installation Details section goes beyond technical specifications of a DGPV installation (size and configuration) to include consideration of eligible customers by class, participation of third parties, and limits on total participation. The VOS Rate and Contract Treatment section includes a comparison of the buy-all, sell-all model with a buy-net, sell-net model. The truth of the buy-net, sell-net model is that it is effectively a NEM policy. The remainder of the section discusses the potential for variation in VOS rates across classes, time, location, and a few other variables.[19]

The Price Support section outlines potential incentives that can be laid on top of the VOS rate in order to support DGPV in markets that are not yet in the transitional or competitive states.[20] Additional incentives are already available in Missouri, including legislatively authorized solar rebates.[21] The Administrative Issues section raises several transition to VOS issues including program contract (tariffs and applications) development, general timing, and stakeholder communications. An analysis of different stakeholder issues resulted in four high level themes:

1. Pay the utility sufficient revenues for grid services provided to support solar growth
2. Recognize the VOS benefits and costs, and compensate the project owner appropriately
3. Limit cost to customers, both those with solar and those without
4. Create a transparent VOS rate calculation methodology

[18] NREL VOS Manual: VOS Program Design Framework page 35.
[19] NREL VOS Manual: VOS Program Design Framework pages 43-48.
[20] NREL VOS Manual: VOS Program Design Framework pages 48-52.
[21] Ameren Missouri's current solar rebate expires at the end of 2023, Rider SR – RSMo 393.1670.

C. *National Energy Screening Project's National Standard Practice Manual for Distributed Energy Resources (NESP DER Manual)*

The NESP DER Manual was developed to provide guidance to jurisdictions developing benefit-cost analysis for DERs and extends the guidance the NESP developed for energy efficiency.[22]

> "In this evolving landscape, applying a comprehensive and consistent benefit-cost analysis framework to analyze investments in DERs can help jurisdictions implement optimal levels of DERs and avoid uneconomic decisions that can lead to unintended increased costs for customers."[23]

The quotation above illustrates the perspective of the NESP DER Manual. The NESP DER Manual outlines a framework for benefit cost analysis. Typically, when a benefit cost analysis is conducted, the one conducting the analysis is also the investment decision maker. Also in a benefit cost analysis situation, the investment is typically made if the benefits are greater than the cost. This is not the case in the context of integrated resource planning.

First, integrated resource planning is not simply a matter of benefit cost analysis. Resources are not selected because their benefits are greater than their costs, but rather a multitude of resources are considered to meet a specific objective. That objective is to reliably serve load, and to do so at the lowest cost.[24] Second, the one tasked with measuring benefits and costs here is not the investment decision maker. In the present context, the utility is tasked with evaluating the costs and benefits of a specific type of DER, i.e. DGPV. It is individual customers who will ultimately make private investment decisions based on their private benefit cost evaluations. These distinctions are important to understand when deciding which benefit cost categories should be included in a VOS, especially because a VOS calculation is typically developed as a rate of compensation.

Nonetheless, the NESP DER Manual highlights the disconnection between the private benefit cost analysis that drives DGPV investment and utility resource planning and operations. This highlight provides useful insights that can be used to avoid potential pitfalls in the evaluation of DGPV. The NESP DER Manual is broken into four major parts plus appendices. The four major parts include:

1. Benefit-Cost Analysis Framework
2. Potential DER Benefits and Costs

[22] The NESP DER Manual extends the 2017 NSPM for Assessing Cost-Effectiveness of Energy Efficiency Resources. Summary page i

[23] NESP DER Manual: Introduction page 1-1.

[24] Additional considerations are given weight in the selection of resources during the resource planning process. A simplified comparison of benefit cost analysis and least cost planning is offered here to highlight the salient difference between the two analytical methods.

3. Guidance on Single DER Benefit-Cost Analysis by DER Type[25]
4. Guidance on Multiple DER Benefit-Cost Analysis and Dynamic System Planning

Part 1 on the Benefit-Cost Analysis Framework lists eight principles for assessing the benefits and costs of DER.[26] Two principles are general high-level advice consistent with good practice in the regulated utility setting generally.

1. Align DER evaluation with policy goals.
2. Ensure transparency in DER evaluation.

Three principles reflect an integrated resource planning perspective. It is helpful to think of the integrated resource planning problem primarily as a cost minimization problem subject to some load or reliability constraint.[27]

1. Treat DER as a utility system resource, i.e. the same as any other resource.
2. Ensure symmetry among resources as well as costs and benefits.
3. Conduct forward looking, long term, incremental analysis.

And the remaining three arise from a more specific and independent benefit-cost analysis perspective, which is not necessarily consistent with cost minimization.

1. Account for the relevant, material impacts of DER.
2. Avoid double-counting impacts of DER benefits and costs.
3. Conduct benefit-cost analysis separate from rate impact analysis.[28]

The eight principles are followed by the outline of a five step process for developing a benefit-cost test for DERs:

1. Articulate Applicable Policy Goals
2. Include All Utility System Impacts
3. Decide Which Non-Utility System Impacts to Include
4. Ensure Costs and Benefits are Properly Addressed
5. Establish Comprehensive, Transparent Documentation

Steps two, three, and four of that process highlight the distinction between integrated resource planning and benefit-cost analysis. In step two of the NESP DER Manual's process, all utility system benefits of a DER are identified for inclusion. In step three, a decision is made about which non-utility system benefits to include. Step four ensures

[25] NESP DER Manual specifically names the following DER Types: energy efficiency, demand response, distributed generation, distributed storage, electric vehicles, and building electrification.
[26] NESP DER Manual: Summary page iv.
[27] The reliability constraint might be better understood as the need to serve some forecasted peak load.
[28] Under 20 CSR 4240-22.010 2 B, the primary criterion for selection of the preferred resource plan is minimization of long-run utility cost. Long-run utility cost is a direct determinant of utility rates. The contrast between the NESP DER Manual and the resource planning process highlights the inconsistency between the NESP DER Manual and the integrated resource planning process.

that costs and benefits are treated symmetrically and that DER types are considered consistently. Despite the principle to treat DER as a utility resource, ensuring DER resources are treated consistently with other utility system resources is not an explicit concern of the NESP DER Manual's benefit-cost analysis. The concern for symmetric treatment appears only to extend to the treatment across benefits and costs among DERs, without explicit consideration for the manner in which costs and benefits are used to evaluate non-DER resources in the integrated resource planning process.

Part 2 presents a range of potential benefits and costs associated with DER. Those benefits are grouped into three broad categories:[29]

1. Electric Utility System
2. Host Customer
3. Societal

These categories of benefits and costs help to flesh out the differences between the type of benefit-cost analysis outlined in the NESP DER Manual, a VOS rate calculation, and evaluation of DER through an integrated resource planning process. For instance, host customer costs, including the cost of DGPV modules and installation are part of the private benefit-cost calculation a customer makes to inform their decision to install DGPV or not. Those costs do not influence an electric utility's resource planning decisions. Furthermore, those installation costs would not be part of an electric utility's calculation of a VOS tariff rate.

A slightly more complicated example would be other environmental benefits or costs. The minimization of the present value of the revenue requirement is the primary selection criterion for the preferred resource portfolio. As part of the minimization algorithm, electric utilities do not assign positive benefits to renewable or emission free generating technologies, but rather assign probable environmental costs to emitting generation technologies. The attribution of positive costs to emitting generation technologies increases the relative probability that emission free technologies are selected over emitting technologies, but the selection is made not by assigning positive benefits to emission free technologies, but rather by assigning the emission cost to emitting technologies. Furthermore, insofar as emissions impose real costs on current generating facilities, the value of those costs would be reflected in the incremental cost of energy production and therefore be captured in an avoided cost of energy calculation.

In order to put a finer point on the matter, assume there are real and quantifiable environmental costs associated with emitting technologies that are not reflected in the cost of energy generation. If those costs were considered a benefit of DGPV and assigned a value that was included in a VOS rate, but not symmetrically attributed to utility scale

[29] NESP DER Manual: Summary page viii and ix.

solar PV or wind generation, then the VOS rate would not ensure symmetry in the treatment of utility system resources. These specific examples are intended to highlight the distinction, which should be made, between benefit-cost analysis and a VOS rate that is consistent with integrated resource planning. Benefit-cost analyses are designed to identify if a specific investment is net beneficial, independent of other similar investments, while integrated resource planning seeks to identify investments which meet a specific need at the least cost relative to many other possible investments.[30]

Chapter 8 of Part 3 provides a detailed consideration of benefit-cost analysis for distributed generation technologies, including DGPV. Several important key points are included in the summary of Chapter 8:

1. DGPV may reduce or increase transmission and distribution costs.
2. DGPV may increase costs due to the electricity they inject into the system.
3. DGPV can lead to lost revenues that increase rates.

Chapter 8 also includes a detailed table of the potential benefit and cost categories and an assessment of the likelihood that DGPV will result in benefits or costs in each category. The categories where DGPV is likely to result in benefits include energy generation, generation capacity, and transmission and distribution system losses. The categories where DGPV may result in benefits or costs include distribution system capacity, operations, and maintenance, transmission capacity, and ancillary services. In addition to these general categories, the NESP DER Manual specifically identifies the costs associated with the cumulative effect of DGPV investment commonly referred to as the Duck Curve, and the potential increased cost associated with increased need for load following resources.

Chapter 8 also includes common challenges associated with DGPV policy. Those challenges include:

1. Tariff Design
2. Lost Revenue and Utility System Cost Identification
3. Transmission and Distribution Cost Impact Accounting
4. DGPV Customer Service Cost Accounting

[30] Additional resource planning objectives, beyond revenue requirement minimization, are considered in the selection of a preferred resource plan. The analysis outline in these preceding two paragraphs is intended to highlight potential inconsistencies that can arise from combining distinct evaluation methodologies, e.g. cost minimization and benefit cost analysis.

III. Potential Costs and Benefits Categories

The NARUC DER Manual and NREL VOS Manual provide cursory overviews of the cost and benefit categories that a public utility commission should consider.[31] The NESP DER Manual provides the broadest perspective on potential categories of benefits and costs.[32]

In order to inform integrated resource planning, the resources considered in a VOS should be evaluated using the same benefit and cost categories as the other resources considered in the planning process. This equivalent treatment is required by 20 CSR 4240-22.010(2)(B), which states that "the fundamental objective requires that the utility shall consider and analyze demand-side resources, renewable energy, and supply-side resources on an equivalent basis."[33] While the NESP DER Manual considers a wide variety of potential benefits and costs, the NESP DER Manual also promotes the principle of treating DER like a utility resource.

In addition, 20 CSR 4240-22.010(2)(A) states that "the utility shall use minimization of the present worth of long-term utility costs as the primary selection criterion in choosing the preferred resource plan."[34] The aforementioned principles and resource planning policy objectives provide a clear direction for determining the benefit and cost categories that should be included in a VOS study.

There is one important difference between resources covered by a VOS study and resources traditionally considered in a utility resource plan that is worth noting at this point in the study. The resources under consideration in the VOS literature are not resources chosen by the utility. Instead, these resources are chosen by customers. This difference has the potential to convolute the perspective from which benefits and costs are identified. The only benefits and costs of DGPV that are consistent with the resource planning policy objectives are avoided utility costs. Therefore, the reasonably quantifiable benefit and costs categories which are appropriate to include in a VOS study are as follows:

A. Generation Capacity Benefits – Avoided Fixed Generation Costs[35]

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[31] NARUC DER Manual: DER Considerations, Questions and Challenges Section C page 72.

[32] Another resource which has not been fully evaluated, but a preliminary evaluation indicates might be a good resource for developing a robust value of solar study is NREL's *Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System*.

[33] 20 CSR 4240-22.010 Policy Objectives

[34] 20 CSR 4240-22.010 Policy Objectives

[35] In so far as there are fixed cost associated with generation pollution mitigation technology investments, the those costs are internalized in the fixed cost of generation, and therefore, the avoided capacity cost implicitly credits DGPV resources with environmental benefits.

B. Generation Energy Benefits – Avoided Variable Generation Costs[36,37]
C. Transmission System Benefits – Avoided Transmission Costs
D. Distribution System Benefits – Avoided Distribution Costs

The benefits and costs that accrue to the DGPV customer generator influence that private individual's decision, are beyond the utility's control, and only impact the utility as a result of the customer's decision. It is paramount that a VOS provides an economic signal that only reflects the value of the customer's decision to the electric utility system. Any other private value associated with the investment will be internalized by the individual customer and will result in efficient private investment in DGPV only if the economic signal provided by the utility reflects real avoided cost.

Societal costs that do not result in actual utility costs should not be included in the VOS. Similarly, societal benefits, the avoidance of societal costs or otherwise, should not be included in the VOS. The evaluation of the societal benefits and costs associated with DGPV is perhaps better suited for broader public policy consideration, and not necessarily appropriate for evaluation within the integrated resource planning process.

There is at least one broad category of costs that should also be considered in the future discussions of the VOS, but are not reasonably quantifiable at this time, and those are DGPV integration costs. Those costs could include generation capacity and energy costs associated with the increased need to build, operate, and maintain dispatchable generation resources that can flexibly follow intermittent solar resource generation to ensure system reliability. Those costs could also include distribution system infrastructure, operations, and maintenance costs necessary to interconnect and delivery DGPV generation. It is reasonable to expect that these costs will become an issue of increasing importance as DGPV penetration increases.

[36] The variable generation benefits will result largely from avoided fuel cost, but may also include variable operation and maintenance costs. The variable generation benefits can (should) include the benefits of reduced transmission and distribution line losses, because line losses simply represent lost energy, and therefore avoiding line losses is simply avoiding energy costs. This treatment of line losses is used elsewhere, e.g. MEEIA net margin rate calculations under Rider EEIC.

[37] In so far as there are variable allowance/tax costs associated with the emission of environmental pollutants, local criteria and/or greenhouse gas, then those costs will be internalized in the variable cost of generation, and therefore, the avoided energy cost implicitly credits DGPV resources with environmental benefits.

IV. Evaluation of Benefits and Costs

The evaluation which follows is predicated on the assumption that the value provided by a DGPV resource is considered separately from the value of the consumption by the DGPV owning customer. This evaluation framework is consistent with the buy-all, sell-all model outlined in the NREL VOS Manual.

A. Generation Capacity Benefits – Avoided Fixed Generation Costs: One of the potential benefits of DGPV is a reduction in the cost of utility generation capacity investment. DGPV could avoid fixed generation cost in one of two ways. In the short run, DGPV capacity could free up existing generation capacity that could then be sold to the market. In the long run, it is possible for DGPV capacity to reduce the need to invest in newer additional generation capacity.

One challenge associated with evaluating the avoided fixed generation cost is identifying the capacity value of DGPV. A generation capacity investment is made to generate energy to serve load throughout the year, but ultimately a utility must invest in enough generation capacity to serve load at the time of system peak. The value of any generation resource's capacity is a function of the resource's ability to serve load at the time of system peak. Therefore, the value of DGPV should be assessed based on its ability to operate at the time of system peak.[38]

1. Avoided Fixed Generation Cost Evaluation Method: The ability for DGPV to avoid fixed generation cost depends on the intermittent resource's ability to provide power during system peak periods. The ability of a DGPV system to provide power during system peak periods can be estimated using the DGPV system installed capacity and a peak period availability factor. The peak period availability factor is estimated using the method outlined for determining a solar resource's capacity credit in MISO's resource adequacy business practices manual.[39]

$$Avoided\ Generation\ Capacity = \ Installed\ Capacity\ \times Availabilty\ Factor$$

[38] MISO's February 2021 Renewable Integration Impact Assessment outlines a number of key technical challenges associated with increasing levels of renewable penetration. Several of these challenges are related to the value of renewable generation capacity. In particular, challenges associated with shifting periods of grid stress and shifting periods of energy shortage risk highlight the complex relationship between renewable generation and renewable generation capacity valuation. These complex relationships will be likely drivers of renewable integration costs, and should be considered in any broader, longer-term evaluation of DGPV generation capacity benefits.

[39] MISO Manual No. 011: Business Practice Manual: Resource Adequacy: Appendix V: Solar and Run of River Hydro Capacity Credit. The solar resource output used in the calculation is generated using a simple 1 kW DGPV model and 2019 hourly solar irradiance data for St. Louis from the National Solar Radiation Database.

The value of the DGPV system is a function of the avoided capacity and the per unit cost of generation capacity.

$$Avoided\ Generation\ Capacity\ Value = Avoided\ Generation\ Capacity \times Cost\ of\ Capacity$$

2. Avoided Fixed Generation Cost Evaluation: If we use the availability factor defined using the MISO policy and the 2021 market-based capacity price value from the 2020 Integrated Resource Plan, then the value of a 1 kW installation is as follows.[40]

$$Avoided\ Generation\ Capacity = 1\ kW \times 0.3946 = 0.3946kW$$

$$Avoided\ Generation\ Capacity\ Value = 0.3946\ kW \times \$8/kW/year = \$3.16/year$$

B. Generation Energy Benefits – Avoided Variable Generation Costs: If a DGPV resource generates energy which can be consumed at the point of generation or another nearby point of service, then a DGPV resource will provide generation energy benefits. If DGPV systems generate in periods coincident with an owners consumption or more generally at low levels of DGPV penetration, when other local customers are consuming, then the potential for generation energy benefits is high. However, if DGPV systems generate energy in periods that are not coincident with an owner's consumption or other local customer consumption, then the potential benefits are diminished. Also, the expected value of benefits is likely to decrease as the penetration of DGPV resources increases.

1. Avoided Variable Generation Cost Evaluation Method: The benefits of a kWh of DGPV generated energy could be greater than the avoided cost of a kWh of utility generated energy if that kWh is consumed locally, because there will be zero or limited line losses associated with that kWh. Therefore the value of 1 kWh of DGPV generated energy is a function of the avoided cost of utility generation and utility system lines losses.

$$Avoided\ Generation\ Energy\ Value = Line\ Loss\ Factor \times Avoided\ Cost\ of\ Energy$$

[40] In the Matter of Union Electric Company d/b/a Ameren Missouri's 2020 Utility Resource Filing Pursuant to 20 CSR 4240 – Chapter 22, September 27, 2020, Chapter 2 Planning Environment, page 15. There are two different capacity prices series considered in the 2020 IRP, market-based and hybrid capacity prices. Both series have the same values through 2029, and therefore the choice of the market-based or hybrid capacity price value is inconsequential in this study. However, the choice would be consequential in a study which incorporated forward looking valuations. The nature of the decision, customer and not utility, supports the use of the market-price series.

2. Avoided Variable Generation Cost Evaluation: Using the line loss factor from Rider FAC and the average wholesale price of energy associated with a solar profile, the value of 1 kWh from a DGPV resource installed at secondary voltage is as follows.[41,42]

$$Avoided\ Generation\ Energy\ Value = 1.0570\ \times \$0.02799/kWh = \$0.02958/kWh$$

C. Transmission System Benefits – Avoided Transmission Costs: The ability for DGPV to provide transmission system benefits depends on the ability for DGPV to reduce the load on the bulk power system. The transmission system is designed to reliably serve load or net load in all hours, but the system peak defines a critical reference point for transmission system planning and design.[43,44]

1. Avoided Transmission Cost Evaluation Method: The ability for DGPV to avoid transmission costs is a function of a DGPV resource's generation at the time of system peak. The ability of a DGPV system to provide power during system peak periods can be estimated using the DGPV system installed capacity and a peak period availability factor.

$$Avoided\ Transmission\ Capacity =\ Installed\ Capacity\ \times Availabilty\ Factor$$

The value of the DGPV system is a function of the avoided transmission capacity and the cost of transmission capacity.

$$\begin{aligned} &Avoided\ Transmission\ Capacity\ Value \\ &\qquad =\ Avoided\ Transmission\ Capacity \times Cost\ of\ Transmission\ Capacity \end{aligned}$$

41 The line loss factor for secondary voltage from Rider FAC is used in this calculation. In order to estimate the value of a DGPV kWh of energy generated at primary voltage replace 1.0570 with 1.0224.

42 The avoided cost of energy is calculated using a simple 1 kW DGPV model, 2019 hourly solar irradiance data for St. Louis from the National Solar Radiation Database, and 2019 hourly day ahead MISO LMPs.

43 See section 7.2.4.2 System Planning - Annual Load Analysis and System Planning Process for more specificity concerning the relationship between peak load conditions and system planning.

44 MISO's Renewable Integration Impact Assessment outlines the complex relationship between renewable generation and transmission system planning and operations. MISO defines several types of complexity, e.g. energy adequacy and operating reliability, which relate renewable penetration levels to incremental needs for transmission investment. Similar to the case of generation benefits, these complex relationships will be likely drivers of renewable integration costs, and should be considered in any broader, longer-term evaluation of DGPV transmission system benefits.

2. Avoided Transmission Cost Evaluation: If we use the availability factor defined using the MISO policy and the 2021 avoided transmission cost from the 2020 Integrated Resource Plan, then the value of a 1 kW installation is as follows.[45]

$$Avoided\ Transmission\ Capacity = 1\ kW \times 0.3946 = 0.3946 kW$$

$$Avoided\ Transmission\ Capacity\ Value = 0.3946\ kW \times \$2.14/kW/year = \$0.844/year$$

D. Distribution System Benefits – Avoided Distribution Costs: There are at least three characteristics of DGPV, which complicate the evaluation of distribution system benefits. These three characteristics are the intermittent nature of DGPV generation, the non-coincident nature of DGPV generation, and the decentralized nature of the planning and investment decisions.

The intermittent nature of DGPV and the diverse and unique load characteristics that define the timing and magnitude of local peak loads that drive distribution capacity needs at various points on the system make it difficult to incorporate DGPV generation in the design of distribution circuits. This is because the DGPV generation is not dispatchable and will only be available on a probabilistic basis, and also because different locations on the system experience peak conditions at different times – including some in the winter or later evening hours of the summer, when the DGPV may be less helpful in offsetting peak loads. Generally speaking, DGPV generation is not coincident with load, neither system peak load nor seasonal load patterns. DGPV's lack of coincidence is a contrast to the effect of demand side management measures, which by their nature exhibit coincidence with load.[46] The non-coincident nature of DGPV makes it unlikely that DGPV will reduce load by its installed capacity at the time of system peak. In addition, during some low load periods, e.g. during the day in shoulder months, DGPV can exceed local load. This can result in the back feeding of electrical energy that can result in the need for system upgrades with added cost. Finally, the decentralized planning and investment decisions made by individual customers is not within the control of distribution system planners or the utility more generally, and will not necessarily be known at the time

[45] Avoided transmission cost development is discussed In the Matter of Union Electric Company d/b/a Ameren Missouri's 2020 Utility Resource Filing Pursuant to 20 CSR 4240 – Chapter 22, September 27, 2020, Section 7.1.4 Avoided Transmission Cost.

[46] Demand side management is by its nature coincident with load. In the case of energy efficiency, measures are taken which improve the efficiency of end use electrical devices, which can be quantified in terms of a percentage of inefficient device. The energy efficiency savings occur when a device is operating, i.e. coincident with the devices load. Demand response programs on the other hand are trigger decreases in end use load at specific points in real time where the system resources are strained, and absent demand response event's additional resource investments would be required to serve load reliably. In this way, demand response programs are primarily geared towards avoiding new fixed infrastructure costs.

distribution systems investments are made. Therefore, DGPV that is subsequently installed on the distribution system may not result in avoided costs.[47]

1. Avoided Distribution Cost Evaluation Method: The ability of a DGPV system to provide power during system peaks periods can be estimated using the DGPV system installed capacity and a peak period availability factor.

$$Avoided\ Distribution\ Capacity = Installed\ Capacity\ \times Availabilty\ Factor$$

The value of the DGPV system is a function of the avoided distribution capacity and the cost of distribution capacity.

$$Avoided\ Distribution\ Capacity\ Value = Avoided\ Distribution\ Capacity \times Cost\ of\ Distribution\ Capacity$$

2. Avoided Distribution Cost Evaluation: If we use the availability factor defined using the MISO policy and the 2021 avoided distribution cost from the 2020 Integrated Resource Plan, then the value of a 1 kW installation is as follows. [48]

$$Avoided\ Distribution\ Capacity = 1\ kW \times 0.3946 = 0.3946\ kW$$

$$Avoided\ Distribution\ Capacity\ Value = 0.3946\ kW\ \times 18.13/kW/year\ = \$7.15/year$$

[47] Discussions of Distribution System Engineering Analysis and Integrated Distribution Planning are discussed in Section 7.2.4.2 System Planning of the 2020 IRP.

[48] Avoided distribution cost development is discussed In the Matter of Union Electric Company d/b/a Ameren Missouri's 2020 Utility Resource Filing Pursuant to 20 CSR 4240 – Chapter 22, September 27, 2020, Section 7.2.5.3 Avoided Distribution Cost.

V. Conclusion

The literature reviewed provides context for the VOS study and outlines an array of related technical and economic policy issues. The reasonably quantifiable benefits provided by DGPV that were quantified and their sum is provided in the table below. Generally speaking, avoided generation costs can be estimated with greater confidence, because there are markets for both energy and capacity on which those values can be based.[49] Avoided transmission and distribution costs however are a function of integrated system effects and are significantly more difficult to quantify. Nonetheless, the avoided cost values developed in the context of demand side programs were applied to DGPV to develop estimates of VOS. The actual value of any specific DGPV resource will be highly dependent on the local conditions under which it is installed.

2021 Value of Solar Study		
Benefit/Avoided Cost Category	**Avoided Cost kW/year**	**Avoided Cost kWh[50]**
Fixed Generation Cost	$3.16	$0.0018
Variable Generation Cost		$0.0296
Transmission Cost	$0.84	$0.0005
Distribution Cost	$7.15	$0.0041
Total Value of Solar		**$0.0360 kWh**

VOS studies are typically used to develop a rate of compensation that a utility would pay customers for behind the meter solar generation, either as a replacement for or an alternative to net metering compensation rates.[51] In light of this connection to utility rates for compensation, and the broad range of possible policy implications, value of solar studies may be better suited for continued development outside of the integrated resource planning process. The value of solar per kWh quantified above falls below the average rate of compensation credited to net metering customers of $0.0757 per kWh.[52] Missouri law requires the offering of net metering at least until installed capacity reaches 5% of the system peak load, and therefore the value of solar rate identified above is not likely to attract customers that already have access to net metering as a compensation framework that provides greater value. In addition, the implementation of FERC Order 2222 promises

[49] The important aspect of the market in this context is the fungible nature of the product.
[50] Avoided costs per kW-year are transformed into avoided cost per kWh using an assumption of a 20 percent load factor, i.e. that the 1 kW system produces 8,760 × 0.2 = 1,752 kWh a year.
[51] Value of Solar. Program Design and Implementation Considerations, National Renewable Energy Lab, Executive Summary page v.
[52] The rate is a class based behind-the-meter-capacity weighted average of class average energy charges paid by retail customers in the twelve months ending April 2021.

to change the landscape of opportunities available to distributed generation customers. [53]

Ameren Missouri is open to continued discussion about the appropriate compensation rate for behind the meter solar, but ultimately believes those conversations should occur in a public policy forum and not within the integrated resource planning process. A revised policy approach to solar compensation would then feed back into the resource planning process in future years as a variable impacting expected behind the meter solar adoption and therefore energy and capacity needs for the system in future years.

[53] FERC, Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators. Docket No. RM1809-000; Order No. 2222, September 17, 2020. https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf