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A Review of Value of Solar Studies In Theory and In Practice

Authors
Forrester, Sydney
O'Shaughnessy, Eric

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Sydney P. Forrester and Eric O'Shaughnessy

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A Review of Value of Solar Studies In Theory and In Practice

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Principal Authors
Sydney Forrester
Eric O'Shaughnessy

Ernest Orlando Lawrence Berkeley National Laboratory
1 Cyclotron Road, MS 90R4000
Berkeley CA 94720-8136

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Table of Contents

List of Figures

List of Tables

Acronyms and Abbreviations

CO_2	carbon dioxide
DER	distributed energy resource
DPV	distributed photovoltaic solar
DRIPE	demand-reduction-induced price effects
ISO	independent system operator
kWh	kilowatt-hour
MW	megawatt-hour
NEM	net energy metering
NO_x	nitrogen oxides
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
PV	photovoltaic
RGGI	Regional Greenhouse Gas Initiative
RPS	renewable portfolio standard
RTO	regional transmission organization
SCC	social cost of carbon
SO_2	sulfur dioxide
T&D	transmission and distribution
VoS	value of solar

Executive Summary

This brief summarizes a collection of state- and utility-commissioned value-of-solar (VoS) studies and related literature, with a focus on who commissioned the study, which value and cost categories were discussed and/or quantified, and the methods used. Our objective is to compile information on prior VoS studies to inform state regulators and other stakeholders that may pursue related studies or integrate findings into rate design. The brief is organized into three parts: 1) an introduction to distributed solar photovoltaic (DPV) compensation; 2) a review of theoretical research on VoS; and 3) a review of VoS studies.

The vast majority of VoS studies have served an informational role of quantifying the net benefits of PV. Three studies were commissioned in states or utility service territories that subsequently implemented VoS tariffs in California, New York, and Austin, Texas. When applied as a tariff, VoS aims to compensate PV output as efficiently as possible by doing so at rates that reflect the marginal benefits and costs of PV through value and cost categories that may vary temporally and/or geographically. This could lead to higher compensation in locations and times where more PV output is more valuable and consequently drive adoption in those locations to provide more societal benefits.

Value and cost factors can be broadly grouped into five categories: generation, transmission, distribution, other utility, and other social categories. Those conducting VoS studies must weigh various tradeoffs when deciding which categories to include and quantify. Tradeoffs include prioritizing values based on their magnitude of value or cost impact, as well as taking into account the feasibility of data collection and accurate quantification. Values of higher magnitude and estimation feasibility are quantified in the majority of studies, including the earliest of studies conducted in the 2000s and 2010s. Additionally, some values of higher magnitude but low feasibility in the earliest of studies have become quantifiable in recent years. There are some values with low average system-wide levels but very high magnitude in specific locations or hours. The value magnitude in some cases can be tied to DPV penetration with low value in areas with little congestion and/or low penetration and vice versa. In these cases, values that are easier to quantify are often incorporated, while those that are more difficult are often addressed via a placeholder value. The placeholder value is paired with a discussion around data needs and methods to improve future estimates, as well as a conversation about when these value categories may increase in magnitude and necessitate more rigorous quantification.

This brief summarizes findings from two meta-analyses of VoS studies that took place between 2005 and 2018, as well as findings from four additional studies published from 2018 to 2023. Table ES-1 summarizes the various value and cost categories included in each respective study and whether they were quantified, discussed, or omitted. Values such as avoided energy, capacity, transmission capacity, line losses, and avoided environmental costs are quantified in every study. Some categories were deemed harder to quantify and less impactful at the time of the study, so they were discussed but not quantified (e.g., ancillary services). Other categories, including many at the distribution level, were very locationally and/or temporally specific and dependent on high DPV penetration. These were sometimes quantified and at other times discussed. Notably, when it came to utility costs, integration costs were discussed in all cases, though they were deemed to have a small impact. Other utility costs were omitted for the most part; however, the utility-commissioned study (by NorthWestern Energy in Montana) included both lost utility revenue and programmatic/administrative cost categories. While there are some similarities across studies, each had fairly unique methods that are detailed in the body of this brief.

Table ES-1: Regions in which value of solar studies were conducted between 2018 and 2023 that are analyzed in this brief and whether each value and cost category were either quantified, discussed, or omitted

		Montana* (Navigant 2018)	Maryland (Daymark 2018)	Connecticut (CT DEEP and PURA 2020)	New Hampshire (Dunsky 2022)
Generation	Avoided Energy	Quantified	Quantified	Quantified	Quantified
	Avoided Capacity	Quantified	Quantified	Quantified	Quantified
	Avoided Renewable Portfolio Standard	Quantified	Quantified	Quantified	Quantified
	Fuel Hedging	Discussed	Discussed	Omitted	Quantified
	Market Price Response	Discussed	Quantified	Quantified	Quantified
	Ancillary Services	Discussed	Discussed	Discussed	Quantified
Transmission & Distribution	Avoided Transmission Capacity	Quantified	Quantified	Quantified	Quantified
	Avoided Line Loss	Quantified	Quantified	Quantified	Quantified
	Avoided Distribution Capacity	Quantified	Discussed	Quantified	Quantified
	Resilience & Reliability	Discussed	Discussed	Discussed	Discussed
	Distribution Operations & Maintenance	Discussed	Discussed	Discussed	Quantified
	Voltage and Power Quality	Omitted	Discussed	Discussed	Discussed
Costs	Integration	Discussed	Discussed	Discussed	Discussed
	Lost Utility Revenue	Quantified	Omitted	Omitted	Omitted
	Program Admin	Quantified	Omitted	Omitted	Quantified
Social	Avoided Cost of Carbon	Quantified	Quantified	Quantified	Quantified
	Other Avoided Environmental Costs	Quantified	Quantified	Quantified	Quantified
	Local Economic Benefit	Discussed	Quantified	Quantified	Omitted
	Other	Discussed	Discussed	Discussed	Discussed
* Of the four studies, the one in Montana was the only one commissioned by a utility (NorthWestern Energy) whereas the other three were commissioned by the state.					

This brief is intended to contextualize and summarize the value and cost categories that have been included in past VoS studies and research, as well as the methodologies used to quantify these values. This can provide context to states that may want to do the same to understand or quantify the net benefits of solar or integrate findings into new or updated solar incentives or tariffs.

1 Introduction

Distributed PV (DPV) refers to relatively small-scale PV systems (typically less than 1 megawatt [MW]) installed "behind the meter," i.e., on distribution grids serving specific customers. As of the end of 2023, 31 states in the United States required certain electric utilities to compensate all DPV output at the full retail electricity rate, a rate structure commonly known as net energy metering (NEM) (Apadula et al. 2024). Nevertheless, in 2023 many states took policy action to address distributed generation compensation and valuation (Apadula et al. 2024). States have explored and implemented various approaches, among which are tariffs designed to compensate PV output based on the value of that output to the grid or to society. These structures are commonly known as value of solar (VoS) tariffs, the focus of this brief.

This brief's focus on VoS should not be construed as an evaluation of VoS against other PV compensation tariffs such as NEM. All PV compensation schemes — including NEM and VoS — have strengths and weaknesses that vary across different state contexts. The purpose of this brief is to conduct a review of state- and utility-commissioned studies of the value of solar (VoS) and related literature, reflecting the output of a technical assistance effort. Our objective is to compile information on prior VoS studies to inform state regulators and other stakeholders that may pursue related studies or integrate findings into ratemaking proceedings. The brief is organized into three parts: 1) an introduction to DPV compensation; 2) a review of theoretical research on VoS; and 3) a review of research on VoS in practice.

2 VoS In Theory

VoS tariffs refer to rate structures that aim to credit PV compensation at a rate reflective of the net benefits provided by PV output. The objective is to design a rate that approximates VoS while also being practical. Achieving that objective requires a firm understanding of the theory underlying VoS, which is the focus of this section.

2.1 Theoretical Benefits of VoS as an Efficient Rate Design

In theory, VoS tariffs can be an efficient rate design for PV compensation under electricity rate design principles (National Academies of Sciences Engineering and Medicine 2023; Revesz and Unel 2017; Shenot et al. 2022). To understand this claim and the theoretical arguments for VoS, we must briefly provide more context on electricity rate design.

Ratemaking is a process where utilities and regulators collectively translate utility costs into customer charges (Rábago and Valova 2018). There is no single standard for ratemaking. Rather, rate design is guided by a series of ratemaking principles, especially principles first enunciated in Bonbright (1961). Ratemaking principles are often grouped into three key principles (Rábago and Valova 2018):

- Revenue requirement: Rates must ensure that utilities earn enough revenues to recoup all costs of service
- Fair cost allocation: Rates should fairly allocate utility costs in the form of fair charges on distinct customer classes
- Efficiency: Rates should incentivize the efficient generation and use of electricity, generally meaning that rates accurately convey the marginal costs of electricity service.

These same principles apply to PV compensation. PV compensation rates should: 1) ensure that utilities recoup their costs; 2) fairly allocate costs among PV adopters and non-adopters; and 3) reflect the incremental benefits or costs of PV output.

In practice, all rates reflect attempts to balance multiple competing principles, and no electricity rate perfectly achieves all ratemaking principles. VoS tariff design aims to compensate PV output as efficiently as possible by compensating PV output at rates that reflect the marginal benefits and costs of PV. VoS rate design has at least four theoretical benefits:

- Efficient investment: By compensating PV output based on its estimated value, VoS can incentivize socially optimal levels of investment in PV.
- Efficient siting: VoS rate design can be locational, meaning that rates vary at different points on the grid based on locational VoS. Locational VoS rate design can incentivize more PV at grid points where PV has greater value, thus maximizing the overall value of PV to the grid.
- Efficient operation: VoS rate design can also be temporal, meaning that PV compensation rates can vary over the course of a day or over weeks or months. Temporal VoS can incentivize more efficient operation of PV systems, such as by incentivizing more or less PV export to the grid depending on grid conditions.
- Mitigation of rate impacts: By definition, VoS rate design aims to equate PV compensation rates to the net utility costs of serving PV customers (though not necessarily in cases where VoS rates include social or environmental values). By minimizing any potential mismatches between PV compensation and utility costs, VoS tariffs could reduce the risk of over- or under-compensation of PV output.

2.2 Estimating VoS

The key challenge of VoS tariff design is the estimation of the benefits and costs of PV output (Blackburn et al. 2014; Hansen et al. 2013; Keyes and Rábago 2013; Woolf et al. 2014). There are two dimensions to VoS estimation. The first dimension is defining the scope of the VoS, i.e., which benefits and costs should be included in the VoS rate and which can be excluded. The benefits and costs included in the VoS tariff are often referred to as the value "stack." The second dimension is estimating the quantitative magnitude of the components of the value stack, which is a key element of the practical considerations discussed in Section 3.

Table 1 summarizes six factors that are most frequently identified in VoS value stacks in the literature, though many other factors have been included, as discussed in Section 3. The table breaks the components down into two types: cost-of-service components and societal components. The cost-of-service components reflect only how PV affects utility costs and revenues. As a result, a VoS based on the cost-of-service components is theoretically efficient in the sense of compensating PV at a rate that reflects the marginal benefits of that PV to the grid. A value stack that adds the societal components goes beyond utility costs of service to reflect the full "social" value of solar. A VoS based on the full social value is theoretically efficient in the sense of compensating PV at a rate that reflects the full social marginal benefits of PV.

Table 1. Typical solar value stack

Component	Description
Cost-of-service components	
Ancillary services	PV equipped with advanced inverters can provide certain ancillary services such as frequency regulation and voltage control. However, DPV can impose a net demand for, rather than a supply of, ancillary services (Hansen et al. 2013), in which case ancillary services may be reflected as a net cost in the value stack.
Capacity	PV provides additional capacity (MW) to reliably meet demand during daylight hours.
Energy	PV generates electricity (megawatt-hours) that can power end-use loads.
Transmission and distribution	DPV is collocated with end-use loads, meaning that DPV can reduce transmission costs relative to centralized forms of generation. However, DPV can also impose burdens on distribution systems that may result in net costs.
Societal components	
Environmental	By displacing fossil fuel-based forms of generation, PV output reduces grid emissions and the associated environmental damages.
Social	PV deployment can provide various social benefits, such as health benefits (from reduced emissions from displaced fossil fuel generation), economic development, and resiliency (e.g., islanding capabilities during grid outages).

Table adapted from: Burger et al. 2019; Hansen et al. 2013; Hayibo and Pearce 2021; Keyes and Rábago 2013; O'Shaughnessy & Ardani 2020; Orrell et al. 2018a; Taylor et al. 2015. In some cases, the environmental component is also a cost-of-service component, insofar as DPV output reduces utility costs to comply with state renewable portfolio standards.

2.3 Criticisms of VoS

Notwithstanding the theoretical benefits of VoS as an efficient rate design, there are several limitations and critiques of VoS that are worth bearing in mind.

VoS tariffs are relatively complex and challenging to implement relative to NEM (Blackburn et al. 2014; Brown and Bunyan 2014). Whereas NEM relies on existing retail rates, VoS requires the estimation of the various values of the value stack to be applied toward VoS tariffs. In theory, the full value of the value stack would reflect the full value of solar. In practice, pragmatic compromises must be made in the process of rate design that substantially erode the theoretical benefits of VoS (O'Shaughnessy and Ardani 2020).

The fact that VoS entails practical challenges does not imply that tackling such challenges is not worth the effort. Still, many stakeholders have questioned whether a transition from NEM to alternatives like VoS are worth such efforts (Revesz and Unel 2017). NEM is a simple and broadly accepted rate design (National Academies of Sciences Engineering and Medicine 2023). NEM is broadly regarded as a relatively inefficient rate design, but the practical implications of that inefficiency are likely trivial at relatively low rates of PV adoption (e.g., <3% of households) (Barbose 2017). Even as PV adoption increases, the relatively small inefficiencies of NEM may be justified to achieve state clean energy goals (National Academies of Sciences Engineering and Medicine 2023). Many states have weighed the practical benefits of NEM against alternatives and decided to maintain NEM (Apadula et al. 2024).

A criticism of VoS based on social valuation (i.e., including the societal components in Table 1), is that such valuation may be arbitrary and inefficient. Brown and Bunyan (2014) make this case by arguing that efficient prices or rates are typically controlled by an "external discipline." Competition provides that discipline for most market goods. In the case of monopoly utilities, rate designers replicate that discipline in the form of cost-based regulation (Rábago and Valova 2018). In either case, the discipline yields rates that reflect costs while preventing excess profits. VoS breaks from that tradition by asking that rates reflect societal values rather than utility costs. Without the "external discipline" of cost-based regulation, VoS design creates the risks of arbitrary distortions in electricity rates. As a clear example of this issue, New York regulators included the benefit of reduced carbon emissions in the state's VoS value stack. The state estimated that value from the social cost of carbon (SCC), a metric that estimates the social damages associated with each additional unit of carbon dioxide emitted. The SCC is, however, highly uncertain. Rennert et al. (2022), for instance, estimate that the true SCC could range somewhere between \$44 and \$413 per ton of carbon dioxide (based on 5th and 95th percentiles of estimates). A VoS based on the low-end SCC would look substantially different from a VoS based on the high-end SCC. Thus, a regulator's subjective choice of an SCC — or updates in SCC estimates in the literature — could result in potentially substantial and arbitrary swings in VoS rates.

3 VoS In Practice

VoS studies have been conducted in various states over the last few decades (see Appendix A for a full table of studies), and several meta-analyses have reviewed a large number of these studies. RMI published a study in 2013 that reviews 16 DPV benefit/cost studies that were completed between 2005 and 2013 (Hansen et al. 2013). Maintaining continuity, an ICF study published in 2018 considered 40 total studies between 2014 and 2017, focusing on a representative sample of 15 studies and ensuring no overlap with the RMI study (Fine et al. 2018). We summarize the findings of these meta-analyses in Section 3.1. In Section 3.2, we review four new studies conducted from 2018 through 2023 and discuss methods, data, common criteria, limitations, and important considerations among them. Additionally, we summarize the similarities and differences in studies over time, incorporating the findings from the previous two meta-analyses. These studies focus on the VoS and the value of other distributed energy resources (DERs) to various stakeholders such as the utility, ratepayer (average, non-adopter, and/or adopter), and/or society at large.

We show that, over time, the categories of value have remained fairly consistent. The foundational tradeoffs have also remained the same: When conducting these studies and considering which value categories to include, authors weigh the magnitude of the value category, giving more weight to values that have a higher magnitude of net costs or benefits, and feasibility, giving more weight to metrics that are quantifiable and easier to collect (Figure 1). Values of high magnitude and feasibility are quantified from the earliest of studies (upper-right quadrant). Some values of high magnitude but low feasibility in the earliest of studies have become quantifiable via new hardware, models, data collection, and analysis in later studies, showing a shift from the upper-left quadrant to the upper-right over time. Finally, there are some values with low average system-wide levels but very high magnitude in specific locations or hours. The value magnitude in some cases can be tied to DER penetration with low value in areas with little congestion and/or low penetration and vice versa. In these cases, values that are easier to quantify are often incorporated, while those that are more difficult are often addressed via a placeholder value. The placeholder value is paired with a discussion around data needs and methods to improve future estimates, as well as a conversation about when these value categories may increase in magnitude and necessitate more rigorous quantification. Indeed, with increasing levels of DER adoption, authors acknowledge that some value categories will shift upward in magnitude and will have a large impact on overall value, necessitating inclusion in the value stack. As time progresses, value categories will likely shift in magnitude (upward or downward) and increase in feasibility as DER penetration increases and as regions enhance quantification methods, models, data collection, and evaluation techniques.

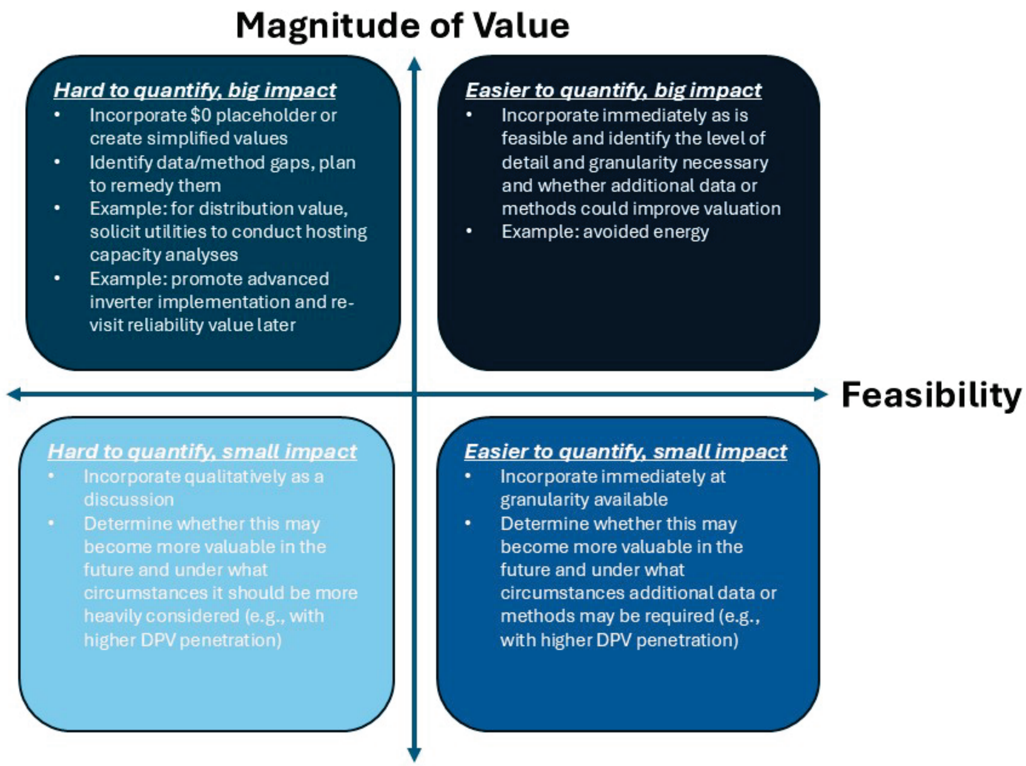

Figure 1. Hierarchy for assessing VoS components

3.1 VoS Studies 2005–2017: Summary of Existing Meta-Analyses

Through two meta-analyses, RMI and ICF collectively summarize VoS studies conducted from 2005 to 2017 (Fine et al. 2018; Hansen et al. 2013). We organize insights from these meta-analyses into three discussions around value category selection (Section 3.1.1), VoS estimation (Section 3.1.2), and VoS study results (Section 3.1.3).

3.1.1 Value Category Selection

The RMI and ICF meta-analyses show that VoS design is driven by practical considerations about the quantification of different value categories and the magnitude of those values at different DPV penetration levels. The RMI meta-analysis highlights that readily quantifiable values were associated with existing prices such as energy, capacity (where markets exist), and avoided renewable portfolio standard (RPS) (Hansen et al. 2013). Certain other value categories were largely omitted for two practical reasons: 1) difficulty with value quantification or projection and/or 2) anticipated negligible value due to low PV penetration. Those difficult to quantify included highly temporal values such as generation capacity, highly locational values such as transmission and distribution (T&D) capacity, and values that required additional modeling or data such as employment and tax benefits, water value, land value, reliability, and resilience. Those that were omitted due to low anticipated impacts included ancillary services and financial risk. Low-impact categories were also often deemed difficult to quantify.

Many studies acknowledged that these values may be dynamic, with some values decreasing in magnitude (e.g., energy and generation capacity) while others increase (e.g., T&D capacity, ancillary services, reliability).

Like RMI, ICF found that the most commonly included value categories were those that impacted the bulk system (i.e., less geographically specific and valued in wholesale markets), those categories with large impacts, and/or those that were easier to quantify (Fine et al. 2018). Those less often quantified were those that were highly locational (distribution-specific values) or situational. As such, all studies included energy, generation capacity, and transmission capacity value. Calculated in some studies were avoided and/or incurred costs in environmental, avoided line losses, distribution capacity, and integration categories. Those least common were resilience and reliability values, as well as avoided distribution operation and maintenance (O&M) costs (see Figure 2).

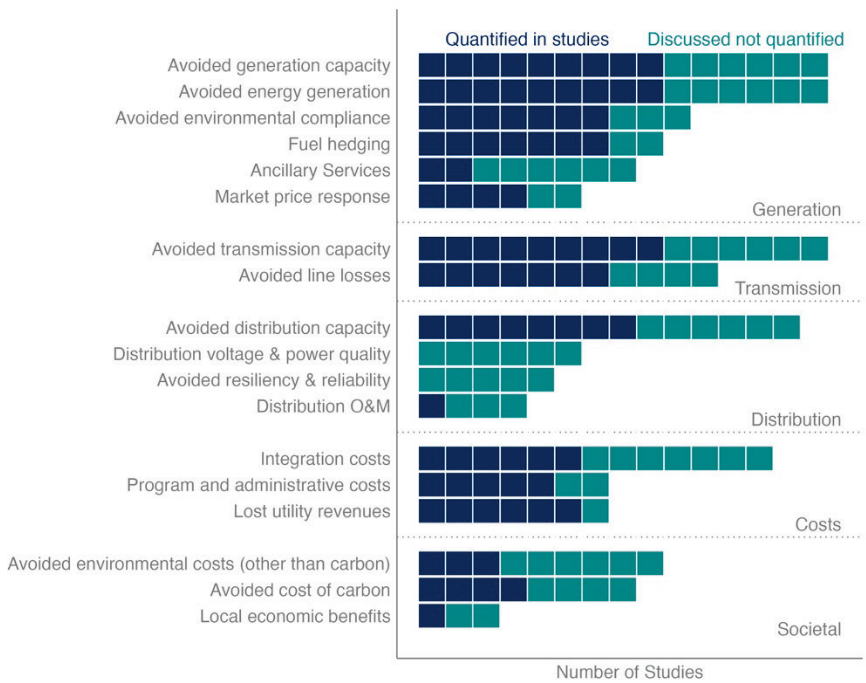

Figure 2 . Value stack components in VoS studies

Figure adapted from ICF study (Fine et al. 2018)

The main progress made between the periods of the RMI and ICF meta-analyses was in the development of metrics for hard-to-quantify values. For example, most studies reviewed by ICF accounted for fuel hedging and a third quantified market price response (i.e., impact of DPV on retail rates) (Fine et al. 2018). In addition, half of studies included ancillary services, either using historical prices or an assumption that such values were a certain percentage of avoided energy value (1% in the case of an E3 analysis in South Carolina [Patel et al. 2015]). A few studies quantified economic development, including job creation, local tax revenue, and other indirect benefits, but this value largely remained unquantified, along with other social/environmental values such as water or land use.

Values that remained difficult to quantify in this group of studies included hyper-locational values such as avoided reliability, resilience, voltage and power quality services, and avoided distribution O&M. The ability to provide many of these benefits and subsequent accurate valuation requires the implementation and use of advanced inverters. While the potential values may be high in areas of concentrated DER adoption, there is high variation both spatially and temporally. Some states had made progress in estimating avoided distribution capacity value through utility data access and hosting capacity analyses. For example, New York's Value of DER tariff includes a utility-specific distribution value based on utility marginal cost of service studies, in addition to a locational value based on feeder-level conditions (New York PSC 2017). The study indicates that future versions of the utilities' benefit cost handbooks will have greater locational and temporal granularity to better quantify distribution values. Minnesota's proposed tariff also showed that credit to systems installed at high-value locations on the distribution grid would be impactful and highly situational (Norris et al. 2014).

In addition to values, new costs were introduced during the study period of the ICF review, including integration costs, program administration costs, and lost utility revenue (Fine et al. 2018). Half of the studies reviewed included lost utility revenue and a potential cost shift, while others argued that the shift was not present or negligible. Half of the studies also included program and administrative costs. The majority discussed integration costs; however, studies did not unify around which specific investments are assumed or attributed to DPV or whether they are applied to the distribution or transmission level. Some potential investments could include voltage regulation; transformer or other equipment upgrades; increased fault protection; scheduling, forecasting, and controlling DERs; or procuring additional ancillary services.

3.1.2 VoS Estimation

RMI found that VoS estimation methodologies varied based on input assumptions, granularity and availability of data, which stakeholder perspectives were considered, and the categories of costs and benefits (Hansen et al. 2013). These earlier studies had similarities in theoretical costs and benefit categories and had similar data availability issues pertaining to particular categories. Some values were relatively easily quantifiable through readily available metrics, such as locational marginal prices or RPS compliance costs. Still, challenges arose with projecting those values forward in cases where future costs and benefits were considered and levelized. In these cases, many studies used a combination of empirical historic data and literature review to project values forward. Many studies also made simplifying assumptions that often corresponded with low DPV penetration, such as zeroing out ancillary services and variable O&M costs. Studies also assumed that the natural gas generators on the margin would remain so into the future. These studies simplified assumptions around categories that were difficult to quantify and/or categories that presented little, if any, cost or benefits due to low PV penetration. In these cases, some studies left placeholders or mentioned that some values and costs would become relevant in the future as adoption levels increased and as relevant data collection and evaluation became feasible. Table 2 summarizes VoS estimation methodologies that were considered in these studies conducted between 2005 and 2013.

Table 2. Summary of VoS estimation methodologies

Category	Quantified in Studies	Notes and Commonalities Across Studies
Energy	Yes	• Uses independent system operator/regional transmission organization (ISO/RTO) locational marginal prices • Natural gas on the margin (heat rate, system losses, carbon intensity) • Negligible variable O&M costs • Value degrades with increased PV penetration
System Losses	Yes	• Simplifications may be made to average system losses over space or time • Vary between studies: Some are empirical, while others are theoretical/modeled
Capacity (Generation)	Yes	• Most use effective load-carrying capacity and assume natural gas on the margin • Heavily dependent on electricity market structure • Value degrades with increased PV penetration • Zero value off-peak and/or in locations that do not need additional capacity
Capacity (T&D)	No	• Heavily locational (especially for distribution system)
Ancillary Services	No	• Heavily dependent on electricity market structure • At low PV penetration, this is assumed to be low and increase with adoption
Financial risk (fuel price hedge, market price suppression)	Some	• Small impacts with low PV adoption, increasing risk with higher adoption • Uses future natural gas price projections
Reliability and Resilience	No	• Value in reducing transmission congestion, which could be embodied in locational marginal prices • Valuable in context of microgrids but out of scope and hard to quantify • Small impacts with low PV adoption, increasing impacts with higher adoption
Avoided RPS	Yes	• Value is zero if there are no requirements, or if existing or planned utility-scale resources are projected to meet requirements • Value proxied by prices for renewable energy certificates used for RPS compliance
Environment (CO_2, NO_x, SO_2, water, land)	Some	• Benefits of abated CO_2 emissions were frequently quantified along with abated criteria pollutants • Water and land benefits were acknowledged but not comprehensively addressed • Depends heavily on price of carbon and heat rate of marginal resources (some assumed a future price on carbon based on social cost of carbon or existing markets, e.g., Regional Greenhouse Gas Initiative)
Social (jobs, tax)	No	• Acknowledged but not generally quantified

The ICF meta-analysis reiterated some of the key points around VoS estimation found in the RMI analysis, while making several additional observations for the time period from 2013 to 2017 (Fine et al. 2018):

- **More detailed estimation:** ICF noted a trend toward more comprehensive and detailed approaches. While this may be somewhat due to increased DPV adoption levels, it was not necessarily the case that detailed analyses were taking place only in high-adoption areas.
- **Expanded scope of technologies:** ICF noted an expansion of studies to value DERs more broadly. ICF grouped studies into three categories: **(1) NEM cost/benefit analyses** that focused

on the question of value shifting and whether NEM was over- or under-valuing DPV; **(2) VoS/NEM successor studies** that focused on the value stack of solar; and **(3) DER value frameworks** that applied beyond DPV alone. Hawaii included requirements to incorporate storage, and the two "Value of DER" studies in California and New York took a more technology-neutral approach by assigning value to each hour, as opposed to fixing value to a solar production curve.

- **Use of placeholder values:** Many studies introduced more comprehensive and detailed approaches without estimating values. Instead, studies included placeholders for values that either would be *possible* to quantify in the future with additional data collection and analysis or would be *necessary* to quantify at higher DPV penetration levels. This deferred quantification method provides a practical approach to allow states to adapt VoS methodologies to changing needs as DPV penetration levels increase. For example, a cited Maine study included placeholder values and conditions under which these placeholder (i.e., $0/kilowatt-hour [kWh]) values would be re-analyzed. For instance, avoided distribution capacity may become positive in the case of distribution load growth, and voltage regulation could be realized with smart inverter deployment. Minnesota similarly included voltage control and solar integration costs as placeholders. South Carolina took a different approach in which analysts compared three different stacks with "low," "base," and "high" DER value, where each level incorporated incremental value categories.
- **Recurring studies:** The ICF meta-analysis included recurring VoS studies. For example, a Nevada study was a follow-up to a study using the same methods two years prior. A D.C. analysis also recommended a continuous update, especially once solar reaches 10% of peak load, which may lead to changes in value and cost magnitude. Additionally, Minnesota proposed in their study that, if made into a tariff, the tariff could be updated annually for enrolling customers based on new DPV penetration data.
- **Context and perspective:** ICF introduced a few new considerations around context. ICF found that studies included multiple perspectives through the use of traditional utility energy efficiency evaluation methods (i.e., utility cost, total resource cost, societal cost, participant cost, and rate impact measure tests). ICF noted that it mattered to understand who commissioned the study and what the objectives and questions were. ICF also included context around legislative, regulatory, and rate design discussions occurring at respective state levels, where available.
- **Uncertainty:** Studies accounted for uncertainty by including several sensitivity analyses such as varying the generation mix or which generator may be on the margin, the cost of carbon, natural gas prices, and more.

3.1.3 VoS Study Results

RMI highlights the high level of variation across VoS estimates (Hansen et al. 2013). RMI attributes that variation to several factors, including the local electric grid conditions, differences in demand and DER projections, and differences in electricity market structures, among other factors. RMI notes that VoS estimates even vary considerably across studies within the same region. For example, RMI reviewed several studies in California that used many of the same data but reached different values. One found negative VoS because the study included private adoption costs, illustrating how perspective matters—whether from the adopter, the utility, other ratepayers, or society. Ignoring private adoption costs and moving to a societal view, the study estimated a VoS of $0.12/kWh. A separate study used similar methods but included the value of avoided RPS compliance and found a VoS of $0.20/kWh (Hansen et al. 2013). This illustrates the importance of carefully selecting the stakeholder perspective, the categories of value, and other considerations.

ICF found that avoided energy and avoided capacity were often the largest categories, but that (consistent with the RMI meta-analysis) value erodes over time as lower cost resources remove higher cost resources on the margin and the net load curve shifts and reduces DPV coincidence with peak periods. The study highlights a finding that capacity can be very valuable but begins to erode at roughly 10% penetration, at which point energy value dominates (Fine et al. 2018). General trends may indicate which values may exceed others; however, due to heterogeneity among regulatory structures and methods to quantify values, it is difficult to directly compare one study's results to another. While this report focuses primarily on methodology, Figure 3 reproduces an illustration that shows value levels across different cost categories in addition to each region's comparative retail rate level (Mims Frick et al. 2021).

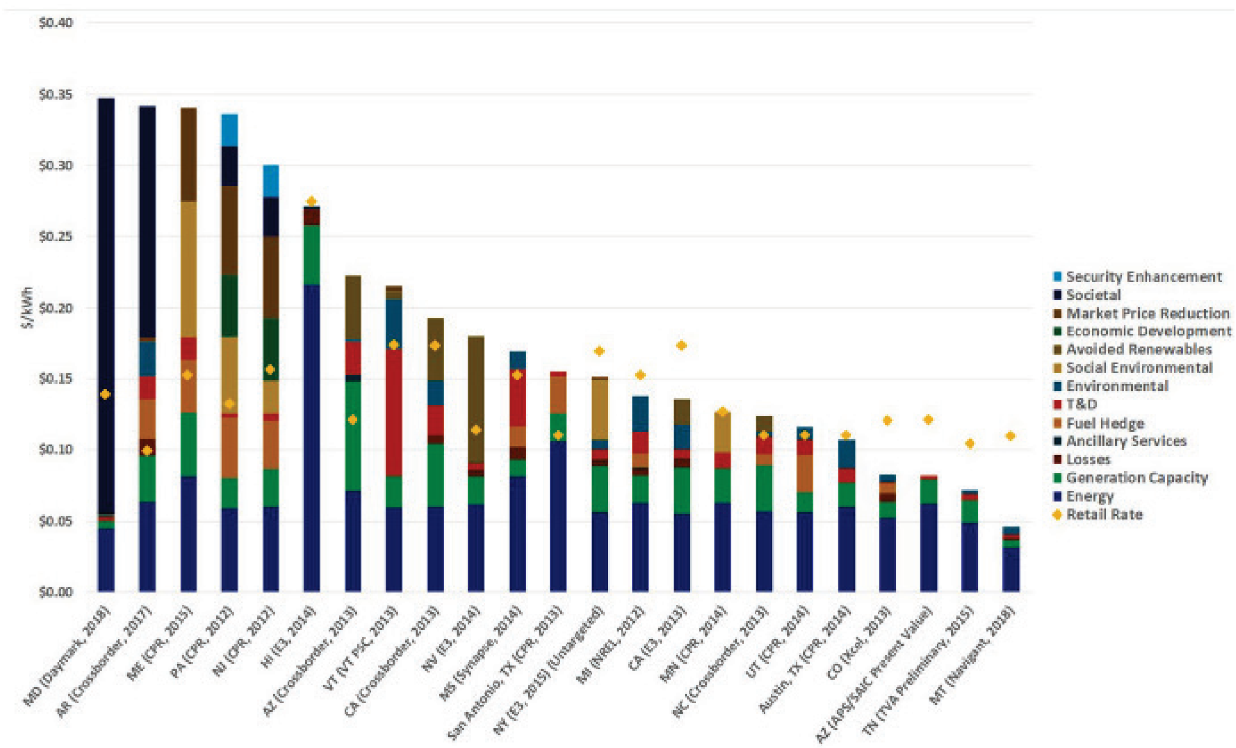

Figure 3. Estimated VoS levels across studies, reproduced from Mims Frick et al. 2021

3.2 VoS Studies 2018–2023: Summary of New Analyses

Across the four studies that were conducted between 2018 and 2023, it is notable that the cost categories were more or less the same as in previous years' analyses. For values that had been quantified for some time, such as avoided generation energy and capacity costs, many of the methods also remained fairly consistent with past efforts. Different from previous meta-analyses, it is notable that avoided cost of carbon, avoided RPS, and other avoided environmental costs were quantified in each of these studies. Workforce development and economic benefit were also discussed at longer length with efforts and literature review that quantified these benefits in terms of jobs created and tax benefits accrued. Further, while deemed "difficult to quantify" in the previous two meta-analyses, distribution capacity was quantified in three of the four studies, though these values remained at the system-wide level. Though there was often differentiation in value by the hour of the year due to the peaky nature of capacity value, the system-wide approach averaged out distribution values that were exceptionally high across a small number of feeders but zero across most of the territory. This resulted in low values that may not accurately represent DER value in constrained areas. This set of four analyses also illustrated a move from exclusive consideration of solar to more technology-agnostic approaches and provided a higher level of sophistication and transparency into methods and data used. This section outlines each study and how they differ from one another before going into a description of each value category and the methods used by each set of authors. Table 3 summarizes each category and whether it was included and quantified, whether it was included as a discussion and/or literature review, or whether it was omitted. The categories roughly mimic that of ICF's meta-analysis, for comparison (Fine et al. 2018).

Table 3. VoS components in four reviewed studies

		Montana* (Navigant 2018)	Maryland (Daymark 2018)	Connecticut (CT DEEP and PURA 2020)	New Hampshire (Dunsky 2022)
Generation	Avoided Energy	Quantified	Quantified	Quantified	Quantified
	Avoided Capacity	Quantified	Quantified	Quantified	Quantified
	Avoided RPS	Quantified	Quantified	Quantified	Quantified
	Fuel Hedging	Discussed	Discussed	Omitted	Quantified
	Market Price Response	Discussed	Quantified	Quantified	Quantified
	Ancillary Services	Discussed	Discussed	Discussed	Quantified
T&D	Avoided Transmission Capacity	Quantified	Quantified	Quantified	Quantified
	Avoided Line Loss	Quantified	Quantified	Quantified	Quantified
	Avoided Distribution Capacity	Quantified	Discussed	Quantified	Quantified
	Resilience & Reliability	Discussed	Discussed	Discussed	Discussed
	Distribution O&M	Discussed	Discussed	Discussed	Quantified
	Voltage and Power Quality	Omitted	Discussed	Discussed	Discussed
Costs	Integration	Discussed	Discussed	Discussed	Discussed
	Lost Utility Revenue	Quantified	Omitted	Omitted	Omitted
	Program Admin	Quantified	Omitted	Omitted	Quantified
Social	Avoided Cost of Carbon	Quantified	Quantified	Quantified	Quantified
	Other Avoided Environmental Costs	Quantified	Quantified	Quantified	Quantified
	Local Economic Benefit	Discussed	Quantified	Quantified	Omitted
	Other	Discussed	Discussed	Discussed	Discussed

* Of the four studies, the one in Montana was the only one commissioned by a utility (NorthWestern Energy) whereas the other three were commissioned by the state.

3.2.1 Overview

Connecticut (CT DEEP and PURA 2020)
Connecticut's DER value study was prepared jointly by the Department of Energy and Environmental Protection and the Public Utilities Regulatory Authority in 2020 in response to the governor's *Act Concerning a Green Economy and Environmental Protection* and subsequent opening of Docket 19-06-29. This study is somewhat unique in several ways. First, it was developed by state agencies themselves, as opposed to consultants. Perhaps as a result, it focused more specifically on quantifying value categories that are most aligned with state policy, which is to conserve energy, develop and utilize renewables to the greatest extent possible, diversify the energy supply mix, assist citizens and businesses in energy consumption and cost reduction, and prioritize conservation and load management for capacity additions. Across calculations, the authors determined that an incremental value of $0.0106/kWh should be used to approximate the net macroeconomic benefit of increased DER deployment, specifically. Second, this study falls under the "value of DER" category, as it is not limited to DPV and considers multiple technologies such as DPV, utility scale solar, DPV + storage, utility scale storage, fuel cells, and energy efficiency. Third, this study quantified the energy market response separate from the capacity market response as opposed to combining the impacts into one category. Finally, this study quantified economic development value within the stack. Ultimately, the full value

stack was estimated at roughly \$0.18/kWh for DPV alone in 2024, decreasing to roughly \$0.14/kWh. After adding storage, this estimate increased to greater than \$0.34/kWh and \$0.20/kWh for the same years. Interestingly, while capacity value eroded quickly from 2024 (the largest value category) to zero six years later, the energy value increased over time, which varies from other study results. It is also important to note that avoided CO_2 emissions represented a sizeable level of value in the stack for DPV with or without storage.

Maryland (Daymark 2018)
Maryland's benefit-cost study of utility-scale and behind-the-meter solar was conducted by Daymark for the Public Service Commission in 2018 as part of a review initiated by the Commission. The study focuses on the impact to (1) the bulk power system, (2) the local distribution system, and (3) economy/society, even though DPV penetration remains relatively low. This study quantified most values within generation, transmission, and social benefit categories and discussed potential distribution benefits. The study focused on each of the four investor-owned utility territories and did not quantify benefits that accrue at a smaller geographic level such as distribution system benefits. Nevertheless, the authors offered a literature review and noted that these services could add significant value. As an illustrative example, they mentioned that 2 MW in solar that avoids a \$2 million distribution investment could add \$0.11/kWh or more in benefits. Though utilities did not provide locational data, they quantified their existing hosting capacity territory-wide prior to this analysis to constrain solar technical potential and assume consequent minimal/zero integration costs across all scenarios. Of note, the Methods section in this study is very thorough and has a lot of background information, calculations, and literature review, including for the values only discussed but not quantified. They also include a list of "fundamental enabling requirements" necessary to support increased hosting capacity and list nine different algorithms used to determine electrical hosting capacity in Table 57 within the text. This may be a helpful resource for Wisconsin or any state that is interested in initiating a discussion with utilities surrounding hosting capacity and data transparency.

Montana (Navigant 2018)
Montana's NEM benefit-cost study was conducted by Navigant and commissioned by NorthWestern Energy (a Montana utility) in response to 2017 legislature and focuses on a utility cost test of DPV, as well as a ratepayer impact measure test to identify any cost shift of NEM. The study uses "low," "medium," and "high" solar adoption scenarios derived from a National Renewable Energy Laboratory (NREL) study to compare each portfolio and quantify various benefits in addition to lost utility revenue and program administration costs. Ultimately, the analysts find a net utility cost value of \$0.036–\$0.046/kWh (after costs of roughly \$0.15/kWh are netted out), indicating net value to the utility. The ratepayer impact was valued at -\$0.10/kWh, indicating an effect of increased rates across the rate base due to the lost utility revenues from DPV. Additional values are discussed but not quantified. Some of the discussed values were assumed to be zero due to minimal (current) anticipated impact such as fuel hedging, market price response, resilience and reliability, and integration. Others were not able to be quantified, such as avoided grid ancillary services, distribution O&M, and other social benefits. They mention the need to identify additional systems and/or processes that may be required when NEM resources reach a certain threshold, which may also unlock both the ability to provide additional

services and the tools to quantify them. This study is unique compared to the others analyzed in that it was commissioned by a utility and takes a strong utility perspective.

New Hampshire (Dunsky 2022)
New Hampshire's Value of DER study was prepared by Dunsky Energy + Climate Advisors for the state's Department of Energy in 2022, along with a Microsoft Excel tool (available online for public download [Dunsky 2022]) where users can input values and quantify value. The summary here focuses on the full 2022 study, since that is where methods and data were summarized, though it is important to note that there was a 2023 update (including to the Excel tool) due to a surge in natural gas prices that increased the estimated value of DER. For example, the estimated full value stack of DPV increased roughly $0.02/kWh compared to what was determined in the 2022 study.

To determine the hourly avoided cost value of DER, the analysts focused on net value to both the utility system and to ratepayers (adopters and non-adopters). The study looked at the current NEM structure next to an alternative value stack to test how this net value would change by rate structure with sensitivities around (1) whether environmental externalities were considered in the value stack, (2) whether system-wide load increased as a result of building and transportation electrification, and (3) whether DERs were actively participating in wholesale markets, making them a supply-side resource as opposed to a load-modifying resource. To do this, the study created a technology-neutral value stack and separately developed hourly DER production profiles to create DER-specific avoided cost values at the hourly level. This methodology produced a highly temporally specific analysis, which showed some values varying greatly between their annual average and maximum value. Any value that was derived from peak period coincidence (whether it was market-level or utility-level) often had low average values and either a singular hour (in the case of capacity value) or 100 hours (for distribution capacity, line losses) of very high value.

Though the Excel tool allows anybody to estimate value of a custom DER, this study considered multiple DERs to illustrate their methods including south-facing DPV with and without storage (residential and commercial), west-facing DPV with and without storage, large commercial solar, and micro hydro. Results showed that residential solar had a net value of $0.17/kWh in 2021 ($0.22/kWh with environmental externalities considered) that decreases to $0.13/kWh ($0.18/kWh) in 2035, in large part due to declining avoided energy value. Storage attachment did not change the 2021 value, though it increases in 2035 to $0.23/kWh ($0.27/kWh), in large part due to T&D avoided costs, consistent with the Connecticut findings. Additional findings show that environmental externalities add considerable value to DERs, depending on the technology.

In terms of methods, the analysts attempted to maintain consistency with energy efficiency cost effectiveness evaluation as much as possible. As such, they leveraged standard benefit/cost criteria, tools, and used methodologies from the regional Avoided Energy Supply Costs 2021 study (AESC study) wherever possible (Synapse Energy Economics 2021). For value categories not covered by the AESC study, the analysts attempted to quantify those values with other methodologies or, if impossible to quantify, discussed them qualitatively, informed by interviews. Locational values were not considered, but the authors acknowledge, similar to other studies, that this could be sizable. The authors also cite an additional limitation in using historical data to project future value, which may not be valid in cases of high future DER penetration or load growth.

Rate and bill impacts showed that DPV under NEM caused rates to increase slightly for non-adopters at the scale of 1%–1.5%, whereas the alternative value stack led to slightly smaller value of 0.9%–1.4%, demonstrating a small cost shift under both tariff structures. Adopters' bills fell by 87%–92% under NEM, but this was reduced to 72%–75% under the value stack. The average customer (both non-adopters and adopters) benefited from both NEM and the alternative value stack at very similar, small levels with a rate decrease of 0%–1% under either tariff.

This study stood out in a few different ways when compared to the others reviewed. First, it was unique in its transparency, through the methodology reporting in its appendices and the publicly available Excel-based tool. This allows users to create unique hourly DER profiles and estimate value with this alternative tariff structure. Taking this additional step in detail and transparency could allow for easier transition into a future tariff. This study was also unique in that it conducted interviews to supplement a literature review for the value categories that were more difficult to quantify. This led to additional insights and allowed for the collection of both qualitative and quantitative utility data to progress understanding of these value categories. This study, along with its tool and appendices, would be a helpful resource to any state interested specifically in developing an alternative tariff and comparing various outcomes to the incumbent (e.g., NEM).

3.2.2 Valuation Methods for Generation

Similar to previous meta-analyses, avoided energy, capacity and RPS values were readily quantified across studies (Table 4). Notable in these recent analyses, market price response was quantified in three of four studies, and fuel hedging and ancillary services were quantified in one but discussed in almost all.

Table 4. Valuation methods for generation in four reviewed studies

		Montana* (Navigant 2018)	Maryland (Daymark 2018)	Connecticut (CT DEEP and PURA 2020)	New Hampshire (Dunsky 2022)
Generation	Avoided Energy	Quantified	Quantified	Quantified	Quantified
	Avoided Capacity	Quantified	Quantified	Quantified	Quantified
	Avoided RPS	Quantified	Quantified	Quantified	Quantified
	Fuel Hedging	Discussed	Discussed	Omitted	Quantified
	Market Price Response	Discussed	Quantified	Quantified	Quantified
	Ancillary Services	Discussed	Discussed	Discussed	Quantified

* Of the four studies, the one in Montana was the only one commissioned by a utility (NorthWestern Energy) whereas the other three were commissioned by the state.

3.2.2.1 Energy

The utilities or states within existing wholesale markets often use these data to quantify avoided energy value. Projections are often readily available, making it easy to simply take those values with the assumption that the DER is acting as a price taker. To increase complexity and accuracy in future high-adoption scenarios, the potential impacts of DERs on market prices could be taken into account, such as through scenario-based capacity expansion modeling. For this value category, another important consideration is avoiding double counting with other value categories. It is important to clearly understand which services are embedded in the avoided energy value and whether any overlap may exist. In some cases, there may be additional embedded costs in volumetric energy prices, such as avoided compliance costs for RPS, carbon, or criteria pollutants; transmission line losses; and congestion. If this is the case, those values must only be accounted for in one value category. In the case of avoided compliance costs around carbon (e.g., Regional Greenhouse Gas Initiative [RGGI]), many studies included the compliance cost embedded into avoided energy costs and separately considered the net carbon value (i.e., SCC minus RGGI) elsewhere.

Connecticut quantified projected annual retail sales revenues under different cases (base case and DER case) and took the difference in annual retail sales divided by the difference in DER generation to arrive at a $/kWh energy value (CT DEEP and PURA 2020). The authors considered the price impacts of demand reduction in their forecasted values, described further in the Market Price Response sub-section.

Maryland notes that PJM Interconnection's locational marginal prices comprise energy, transmission congestion, and marginal line losses (Daymark 2018). As such, it is important to ensure no double counting elsewhere by either omitting those values in other categories where comprehensive (e.g., marginal line losses) or quantifying the value attributed to those subcategories and netting them out in other categories. Analysts consider PV generation as a reduction in the utility's purchase requirement along with the market price response (i.e., as a "price taker").

For **Montana**, Navigant and NorthWestern Energy calculated avoided energy costs by comparing the difference in total production (generation) costs for scenarios with different solar adoption forecasts to the business-as-usual case. They then divided the difference in cost by the difference in solar output and levelized the value over 25 years to $/kWh (Navigant 2018).

New Hampshire's energy value was calculated to be consistent with existing energy efficiency evaluation. As such, they used hourly locational marginal prices in the New Hampshire zone to determine value (Dunsky 2022). DERs in this study, similar to others, were considered as load reduction "price takers." To project value, researchers used their AESC study (Synapse Energy Economics 2021) and natural gas prices from NYMEX Henry Hub futures. The energy value included embedded environmental compliance costs including RGGI cap and trade, in addition to sulfur dioxide (SO_2) values. Line losses and hedging were considered outside of this category.

3.2.2.2 Capacity

The majority of utilities or states within existing capacity markets often use ISO/RTO data to quantify avoided capacity value. Even for those in wholesale markets without capacity products, ISOs and RTOs may have data that could be leveraged for these calculations. Similar to the avoided energy category, it is important to identify any embedded values so as not to double count. Of note, in Connecticut's study, they perform a literature review and point out that many of these value studies were conducted before state policy and goals were created that could lead to early fossil plant closures and a need for more generation capacity and other services (CT DEEP and PURA 2020). It is important to consider this as a scenario in which value levels may change considerably in the future for states with similar goals under development or discussion.

Connecticut quantified generation capacity value as the value placed on total generation, as opposed to peak generation (CT DEEP and PURA 2020). They quantify the peak capacity value within their market price response using ISO New England parameters, as described in a following subsection. Since this value is quantified over all generation as opposed to solely the peak, the value does not decay over time with increased DPV adoption as does the peak value, which shifts with increased DPV adoption to other times in the day that may not be coincident with solar production. Connecticut derived this value first by multiplying the full cumulative capacity [MW] of incremental DERs by the annual ISO New England clearing price [$/MW] to get a dollar value for the incremental DER capacity [$]. Then, they determine the production of those incremental DERs and divide the total value by this value to get a $/kWh value.

Maryland analysts took PJM capacity auctions, capacity demand and supply curves, and calculations to determine capacity credit (Daymark 2018). They note that avoided generation capacity in PJM considers transmission constraints between zones, and they account for this so as not to double count value. They also assume that, while utility-scale solar participates on the supply side, DPV is assumed to only be able to reduce load.

Montana is not within a capacity market. Even so, the authors derived an effective load-carrying capacity estimate with the Southwest Power Pool's net planning capability calculation tool based on 10 years of qualifying facility solar and the utility's Montana retail load data (Navigant 2018). They determined a 9.1% capacity contribution factor and line loss factor to convert solar nameplate to firm capacity at the bulk system level to determine value. The authors outline future improvements to this method that would use probabilistic methods to develop loss of load expectations and predict firm capacity of NEM resources, more accurately estimating effective load-carrying capacity.

New Hampshire, in keeping with energy efficiency evaluation methods, based capacity values on ISO New England's forward capacity market, similar to Connecticut (Dunsky 2022). The analysts then adjusted the prices to account for the variation between the auction clearing prices, established three years prior, and the actual cost of capacity procured in the market. They started with the AESC study (Synapse 2021), which has forecasted capacity and reserve margins, and multiplied forecast prices by

(1+ [reserve margin]). They then adjusted the cleared capacity prices using the most recent difference between the net clearing price and effective charge-rate. This offers prices from 2021 to 2035, which are distributed over the ISO New England annual system peak hour to generate hourly avoided cost values.

3.2.2.3 Renewable Portfolio Standard Compliance

For states with an RPS, this value was included as an avoided cost of a renewable energy credit (avoided compliance cost). Some states used historical data, while others looked to future projections. The magnitude of this value will vary, as some states may not have this requirement or may have a requirement low enough to be met by existing resources (e.g., NorthWestern in Montana [Navigant 2018]). Maryland included sensitivities that increased the base value of $0.001–$0.002/kWh to $0.01/kWh if the supply were constrained (Daymark 2018). This allows an understanding of the full range of potential value. New Hampshire only applied this value to the portion of energy consumed behind the meter and excluded the value for exported energy (Dunsky 2022). They used the AESC study (Synapse 2021) and accounted for the step changes in RPS levels over time.

3.2.2.4 Fuel Hedging

Fuel hedging is a value that one state of the four quantified but all four discussed.

The **Maryland** study mentioned that fuel hedging is a widely accepted value, but there is no standard method for calculation (Daymark 2018). Even though the authors did not include this value, the discussion was very thorough, and they reviewed three potential methods that increase in difficulty. The first proposed method was to assess the change in mean and standard deviation of relevant energy prices, which they carried out by modeling total spot energy supply portfolio costs in the state with and without additional solar. They performed a Monte Carlo analysis to simulate locational marginal price and load variability. This was done using average daily locational marginal prices and loads modeled as distributions fit to historic values. They reported the change in mean and standard deviation of the portfolio cost in the study.

New Hampshire conducted a literature review to determine appropriate assumptions and starting values (Dunsky 2022). The authors used this to apply a risk premium to wholesale energy prices including line losses, multiplied wholesale hourly capacity prices by the wholesale risk premium, and summed the values. The analysts made some additional simplifications and assumed a uniform wholesale risk premium across both wholesale energy and capacity prices.

3.2.2.5 Market Price Response

Market price response refers to the potential impact of DPV deployment on wholesale market prices (e.g., reduced cost of capacity, of energy, etc.). Market price response is a value that the ICF meta-analysis considered difficult to quantify prior to 2018 (four of 15 studies quantified it, and only an additional two discussed it at the time [Fine et al. 2018]). However, three of the four states in this review of studies conducted since then were able to quantify market price response, and all discussed it. The one study that did not quantify it (NorthWestern in Montana [Navigant 2018]) assumed that the value would be negligible due to the relatively low levels of DPV adoption and consequent low levels of impact. Estimating the market price response is not necessary if the study simply is taking a snapshot or historic look at value (e.g., for a retrospective NEM benefit/cost analysis) or if the study assumes persistent low DER adoption levels. However, for broader value of DER studies and most recent studies, estimating future value is considered within the context of, and in support of, state goals such as those that encourage DER adoption. This highlights the importance of policy, context, and establishing study goals early on when deciding which value categories may be most impactful. For future scenarios that have encouraged DER growth, these resources will begin to impact market prices, and it may be important to develop methodology for quantifying this impact.

Connecticut calculated the market price response for energy separate from capacity via demand-reduction-induced price effects (DRIPE) (CT DEEP and PURA 2020). For energy DRIPE, the Connecticut study used annual statewide net cost-to-load forecasts and divided by annual DER generation to derive the value.

For capacity DRIPE, the Connecticut study assumed that the current Forward Capacity Market rules in ISO New England would persist. Using the ISO New England's market rule and training materials, the analysts quantified expected peak load contribution. Since solar adoption levels impact this peak timing and magnitude, this value was calculated annually. As to be expected, with more solar deployment unattached to storage, the peak contribution erodes over time from 38% in 2021 to 20% in 2045. This study uses an auction demand curve to help trace the capacity price impacts of adding annual increments of DERs, described in the market price response subsection, and finds decay factors of capacity value that start at 1 in Year 1 and decay to 0 in year 7.

New Hampshire, like Connecticut, calculated energy DRIPE separate from capacity (Dunsky 2022). For net energy DRIPE, the authors used gross energy DRIPE wholesale values from the AESC study (Synapse 2021), which exist for four periods: summer on-peak and off-peak, and winter on-peak and off-peak. The analysts then multiplied the gross energy DRIPE wholesale values by the percentage of unhedged energy supply in the state (i.e., the portion purchased on the spot market) and then multiplied these by a decay schedule that depends on the year of installation. These values were then levelized to the year of installation to then convert it to hourly values, transforming the four periods to each hour of the year. This is repeated for each study year. The study assumes that annual DRIPE persists and decays through 2031. Intrazonal DRIPE values are proportional to the percentage of zonal load with respect to ISO New England system load.

To determine capacity DRIPE, New Hampshire multiplied the state's zonal unhedged demand with a reserve margin by a benefit decay (also assumed to persist and decay for 11 years, as with energy DRIPE). This is similarly levelized to the year of installation and converted to hourly values by distributing the value over a set of peak hours based on the effective load-carrying capacity.

3.2.2.6 Ancillary Services

Most studies found that ancillary services both were difficult to quantify and had a likely small impact on value due to low penetration. There are different methods to determine ancillary service value, depending on the market, so it is also important to understand regulatory context. For example, the New Hampshire study notes that resources providing energy services may be excluded from providing ancillary services, and since energy value is so high in the near term, the ancillary service value could be assumed to be zero (Dunsky 2022). This may also complicate projections, as it is unclear how the value of ancillary services may change as avoided energy cost values decrease. At high solar penetration levels, short-term variation in net load could increase, which would, in turn, increase the reserve requirement. Advanced inverters could alleviate this need or even provide larger grid benefit if deployed and used. Additionally, other hardware and software such as storage attachment, sensors, controls, and communications can unlock the ability for DERs more generally to provide ancillary services and increase dispatchability.

New Hampshire was the one study that quantified ancillary services (Dunsky 2022). Following energy efficiency evaluation methods, the authors assumed that any reduction in load reduces the need for ancillary services and load obligation charges to the utility, resulting in avoided costs. In order to quantify this, they assume that ancillary service prices are proportionally pegged to wholesale energy prices due to the difficulty in projecting costs (this is an assumption that has precedent in a study summarized in the ICF meta-analysis). To do this, the authors used ISO New England wholesale monthly zonal reports to calculate the historic hourly ancillary service prices as a percentage of hourly energy costs to develop hourly ancillary service prices as a percent for each type of service and load obligation charge across three years to create an hourly avoided cost template. This percentage is used to calculate ancillary service avoided costs based on projected energy costs.

3.2.3 Valuation Methods for Transmission and Distribution

Avoided costs for T&D were quantified along similar trends as those shown in previous meta-analyses, with quantification available for avoided T&D capacity, as well as line losses (Table 5). Somewhat different than previous analyses, some line loss methods separated out distribution from transmission losses and had unique quantification methods or discussions around future work to increase precision. These more recent analyses also were not able to value many of these highly locational or hard-to-quantify distribution values. However, there was more acknowledgement that DERs in higher concentrations would have an important impact on these values—either in a positive or negative direction. Discussions surrounding methods were more involved than in previous analyses and could assist in future quantification.

Table 5. Valuation methods for transmission and distribution in four reviewed studies

		Montana* (Navigant 2018)	Maryland (Daymark 2018)	Connecticut (CT DEEP and PURA 2020)	New Hampshire (Dunsky 2022)
T&D	Avoided Transmission Capacity	Quantified	Quantified	Quantified	Quantified
	Avoided Line Loss	Quantified	Quantified	Quantified	Quantified
	Avoided Distribution Capacity	Quantified	Discussed	Quantified	Quantified
	Resilience and Reliability	Discussed	Discussed	Discussed	Discussed
	Distribution O&M	Discussed	Discussed	Discussed	Quantified
	Voltage and Power Quality	Omitted	Discussed	Discussed	Discussed
* Of the four studies, the one in Montana was the only one commissioned by a utility (NorthWestern Energy) whereas the other three were commissioned by the state.					

3.2.3.1 Transmission Capacity

Some studies combined avoided T&D capacity costs, while others kept them separate. For avoided transmission capacity, value could be near zero if transmission capacity is not needed in that particular region or if DER penetration is anticipated to be too low to avoid or defer these large projects. Utilities or states within organized wholesale market footprints may be able to leverage those data to quantify value. While this review is focused mostly on DPV alone, it is important to note that storage attachment in the value of DER studies introduces the ability to capture this value, especially for future scenarios with high penetration of both grid-scale and distributed renewable energy generators.

Connecticut identified some constraints and transmission congestion in forecasts, but the study notes that there is limited value for avoided capacity and the congestion is already embodied within energy prices (CT DEEP and PURA 2020). To quantify avoided transmission capacity value, they used Aurora, which is a zonal model. This presented some limitations, as the model was unable to identify any intra-zonal issues. The authors acknowledge that DERs do provide some inter-zonal value, but it remains difficult to quantify and relatively small. They provide a literature review, citing methods used in other states like Arkansas (Beach and McGuire 2017), Maryland (Daymark 2018), and Mississippi (Stanton et al. 2014). Ultimately, they used a simplified version of the Mississippi and Arkansas method, where they approximated the transmission marginal avoided cost [$/kW-year] in 2021 by adjusting the Arkansas value in 2017 for inflation (Beach and McGuire 2017; Stanton et al. 2014). They then used total study period's cumulative avoided generation capacity, divided by 10 years, to calculate the avoided generation capacity and subsequently arrived at the avoided transmission value. Final values of $0.0091/kWh were in line with the RMI meta-analysis summarized in this document and slightly above the Maryland study results, also summarized here in the next paragraph (Daymark 2018; Hansen et al. 2013).

Maryland leveraged PJM's Transmission Cost Information Center forecasts that include planned investment for each zone and an estimate of transmission rates (Daymark 2018). The value can be broken down to (1) avoiding or deferring new infrastructure, and (2) load reduction impact on PJM charges. While utility-scale solar can only do (1), DPV can do both. The value can be estimated by looking up the top 5 hours of transmission peak from the previous year and determining the coincidence of solar, quantifying the average and maximum coincidence across those peak hours over the course of time. In this case, due to small/negative growth and recent investments to alleviate congestion issues, value is near zero, and for DPV, this translates to $0.002–0.007/kWh.

Montana developed marginal cost information from the utility's resource plans and budgets for capacity-based investments (Navigant 2018). The analysts argue, however, that the value is near zero for DER deferral due to the large amount of DER capacity needed in order to provide deferral value, the lack of deferral value more generally, and coincidence mismatch.

New Hampshire used ISO New England's Regional Network Service and Local Network Service charges to estimate the costs of upgrading and maintaining regional bulk system infrastructure (Dunsky 2022). These values are assessed monthly and are based on the coincidence of utility system monthly peaks with ISO New England's monthly peak. The authors projected these forward by using short-term Regional Network Service forecasts published by the ISO for near-term study years, and assumptions that Local Network Service charges are a fixed percentage of Regional Network Service charges based on historic trends. The analysts converted monthly values to hourly based on utility peak contributions during ISO New England's specified monthly peak load hours. This method was repeated for each year of the study period to account for changes over time.

3.2.3.2 Avoided Line Losses

Avoided line losses take various shapes in these studies. Sometimes, they are combined T&D losses, while other times, they are separated into two categories. Additionally, line losses vary by grid level as well as by location, and some studies note that line losses are usually an avoided cost, though they can be an incurred cost in locations with high levels of backflow to the grid. Many studies develop utility territory-wide line loss estimates, whereas others may lack the data and rely on statewide averages or literature review. None currently report line losses on a more granular level than utility-territory-wide. Incorporating one additional level of complexity, New Hampshire's method (described below) incorporated some temporal specificity by applying a marginal loss factor to peak hours and an average loss factor to the remaining hours in the year (Dunsky 2022).

Connecticut (CT DEEP and PURA 2020) used Maryland's numbers (Daymark 2018) and took total line losses to be 15%. The authors note that locational power flow studies are required to accurately determine these values and that they did not have these data at the time.

Maryland used their regulated utility's model in CYME software with some modifications (Daymark 2018). Instead of finding the average loss rate, they ran the model with pre- and post-solar portfolios and then quantified the annual losses and divided by the kWh difference in portfolios.

Montana's study was commissioned by NorthWestern Energy (a utility with access to their own data), and was able to use their data and models to estimate 4.05% distribution system loss (using the CYME-DIST model) and an additional 4.03% (based on a NorthWestern-specific 1998 study) (Navigant 2018).

The authors mentioned the desire to update the transmission loss factor using load flow simulations in the future.

New Hampshire used utility data, the AESC study (Synapse 2021), and a literature review to derive both marginal and average line loss factors. The authors then applied the marginal line loss factor to the top 100 state system peak hours in each year and the average line loss values to the rest of the hours. DER coincidence with these hours impacted the costs avoided (Dunsky 2022). The study treated transmission and distribution losses separately but methods were similar. The same steps were taken for distribution losses using distribution system data and peaks. The two differences were (1) that line loss factors were sector-specific for and (2) derate factors applied only to energy consumed behind the meter.

3.2.3.3 Distribution Capacity

Some studies combined avoided transmission and distribution capacity costs, while others kept them separate. For avoided distribution capacity, value is often near zero system-wide in locations where projections show decreasing load or in areas with high levels of hosting capacity or low DER adoption rates. However, where there is value, it is usually highly locational and can be very large in magnitude.[1] Due to this highly locational nature, quantifying this value is heavily dependent on data availability and utility cooperation. This value often fell into the category of hard to quantify, important to include. As such, studies included this value but with many simplifying assumptions. Future efforts in utility data transparency, hosting capacity analyses, and other state-level policy goals will be necessary to quantify this more specifically and especially to target high-value locations as opposed to just high-value times. This value is set to increase in the future and become more important to the value of DPV and other DERs.

Connecticut conducted an extensive literature review, focusing on Washington, D.C. (Whited et al. 2017) and Arkansas (Beach and McGuire 2017) studies that derived values of $0.167/kWh and $0.094/kWh, respectively, for avoided distribution capacity costs. They were the two locations that separated out distribution from transmission capacity value within their literature review, however, both conducted a system-wide analysis and did not take into account locational or temporal differences. For locational value, the authors reviewed studies in California (Cohen et al. 2015), New York (Fine et al. 2018), Maryland (Daymark 2018), and New Hampshire (Dunsky 2022). The summary focused on different findings. For example, the authors highlighted that the California study found that, across the entire distribution system, capacity deferrals were a small fraction of value due to a general lack of capacity need, but that roughly 10% of feeders required capacity projects within the following decade. The value across these 10% of feeders was $0.025–$0.035/kWh in comparison to $0.0005–$0.007/kWh system wide, showing that locational value was roughly five times as high as average

[1] For more information: A report from Pacific Northwest National Laboratory created for Illinois goes in further depth on the locational distribution value of distributed generation to right-size a rebate. The report addresses (1) avoided distribution capacity cost, (2) reduction in distribution losses, (3) distribution voltage support, and (4) operating reserves. Discussions include a literature review and data requirements for various methods (Orrell et al. 2018b)

system value (Cohen et al. 2015). The California study noted that DPV adoption levels were low at the time and assumes diminishing returns as grid issues are addressed via incremental DER deployment. Connecticut's review also highlighted New York's two-fold approach to finding a system-wide value using the utilities' Marginal Cost of Service studies, as well as a secondary locational value determined by utilities to identify high-value locations and apply specific value incentives (Fine et al. 2018).

Specific to their state, Connecticut referenced a demonstration project rate rider that was developed to locationally target DER deployment for one substation that required 4.9 MW of peak relief to avoid $635,000 of investment. This ultimately amounted to $127.55/kW or $0.053/kWh during the summer peak period (2–6 p.m.) during the relevant five-year planning period (CT DEEP and PURA 2020). The authors applied this methodology to other known, discrete capacity additions that are set to occur in the next years with the value of $127.55/kW value applied (a simplification) to get an average value of $0.0055/kWh system wide (CT DEEP and PURA 2020). They noted a series of assumptions and simplifications including zero DER degradation over the five years, uniform capacity credit, no locational differentiation, and homogenous deferred capacity value. They noted that locational dependencies include several factors such as load growth rate, peak day load profiles, the type and location of DERs, age and capacity of feeders and transformers, etc. The state agency authors noted that locational and temporal factors must be better understood and that they did not have these data.

Maryland's study did not quantify distribution system benefits and costs, but it did have a literature review and lengthy discussion. The authors mention that reduced distribution system losses could add a value up to $0.006/kWh but that deferred lines or substations may lead to values from a few cents to tens of cents per kWh in value, which would make a huge difference in overall value of DPV, adding a potential incremental value of up to $0.13/kWh, depending on the circuit and characteristics (Daymark 2018). The authors mention that to quantify this in the future, policymakers would have to investigate changes to utility distribution planning processes to increase transparency and data. Figure 37 in the study provides a helpful illustration of how the locational value of avoided distribution capacity could be analyzed as a function of added capacity.

Montana's study was commissioned by NorthWestern Energy (a utility with access to their own data), so avoided distribution capacity was derived from the projected amount of "firm" solar capacity by substation and whether this amount was sufficient to defer planned capacity investments over the next 25 years (Navigant 2018). This study made several assumptions. For example, DER adoption was assumed to be proportional to the number of customers on each substation. Additionally, NorthWestern assumed uniform coincidence with distribution peaks, assigning 52% coincidence in the summer and no value in other seasons. Using this logic, the study found six deferrals but then averaged this out over all of the solar portfolio to reach a level of $0.002/kWh. In reality, the value is $0 in most cases, which brings the average down. However, the study valued deferral at $0.5 million if less than or equal to 1 MW of deferral, $1.75 million for 1–5 MW of deferral, $8 million for 5–20 MW of deferral, and $20 million for more than 20 MW of deferral, which would lead to very high value for those DERs served by those six substations (Navigant 2018). The study did not report the levelized value of solar in those regions alone. They also note that future steps would include hosting capacity studies to better inform this.

New Hampshire conducted a separate study, *Locational Value of Distributed Generation*, which preceded the Dunsky (2022) analysis (Guidehouse 2020). The Guidehouse study (2020) covered distribution capacity investments but did not address reliability investments. In the Dunsky study (2022), the authors supplemented these data with capital expenditure levels gathered from utility data and interviews and system load profiles gathered from utilities as well. Similar to other studies, the authors note that this value category is highly locational and the locational value is much higher than the value represented in this system-wide study. In order to quantify this value, analysts found actual and planned capital expenditures by utility and determined which were deferrable by DERs (i.e., which were load-related) and which components were included. These data were compared to the previous locational study results to develop an annual per-unit, system-wide proxy [$/kW] estimate of annual system-wide avoided distribution costs. Escalating for inflation, analysts created an hourly profile with AESC load profile projections for 2021–2035 (Synapse 2021) and established coincidence with the top 100 peak distribution hours and used the system-wide proxy to find the system-wide $/kWh value.

3.2.3.4 Resilience and Reliability

This category remains difficult to quantify. For resilience, studies found this value both difficult and often out of scope because these benefits accrue privately to the DPV solar host, as opposed to larger society. Microgrid cases, which provide societal value, are beyond the scope of analyses. In addition, the studies that focus solely on DPV may find hybrids with battery attachment or demand response out of scope as well.

Connecticut described a general (potential) future methodology to quantify how DERs could impact system resilience, though the study mentioned that nobody has done this (including Connecticut) due to the reasons mentioned in the prior paragraph (CT DEEP and PURA 2020). The potential methodology steps include: (1) Characterize potential sources of disruptions; (2) Specify metrics and corresponding uncertainty for resilience that are measurable according to source of disruption; (3) Quantify baseline system resilience; (4) Characterize how DERs modify system resilience from the baseline condition; (5) Compare the benefits and costs of DERs in terms of resilience.

New Hampshire’s literature review focused more on studies that attempted to define or value resilience (Dunsky 2022). They note that value is highly context-specific and very difficult to quantify.

For reliability, many studies acknowledge that this value could be high in the future, but capturing it is dependent on better understanding the location, magnitude, and timing of need, as well as smart inverter deployment. At present, smart inverters are either not yet deployed or are deployed but underutilized. As such, this value is often considered to be a $0 placeholder but one that could have non-negligible value in the future as DER and smart inverter utilization increases.

3.2.3.5 Distribution Operations and Maintenance

Studies mention that distribution O&M could be an avoided cost or an incurred cost. At low levels, the impacts will likely be negligible and can even reduce wear and tear if DPV reduces distribution peak magnitude. However, at high levels, uncontrolled power flow will likely become problematic and increase costs. Battery storage attachment, smart inverters, or other controls and communication can alleviate this and promote net value.

New Hampshire is the only study that quantified distribution operating expenses (Dunsky 2022). The authors interpreted this as reduction or deferrals as a result of equipment life extensions, lower maintenance costs, lower labor costs, and other expense reductions. The authors identified which operating expense budget items could be reduced through DERs or load from each utility and normalized these by the expected load increases over the same time period. Assuming that these costs are driven by the top 100 distribution peak hours, annual $/kW were distributed across these hours and coincidence of DER determined value. Federal Energy Regulatory Commission Form 1 data, utility data, and interviews were necessary to gather these data.

3.2.3.6 Voltage and Power Quality

This value is currently a placeholder and point of discussion in studies, but it will remain zero until smart inverters are deployed and utilized.

New Hampshire's discussion addressed this with a bit more detail than others (Dunsky 2022). The authors interviewed utilities about some of these qualitatively addressed incurred and avoided costs. On the topic of voltage, power factor correction, and power quality support, utilities noted that they have not needed to invest in additional grid support services as a result of DER installations to date, nor have they tested the full functionality of smart inverters. They mention that the potential value would depend on how smart inverters are used. If they are used to simply correct issues of the collocated DER, they would not incur costs, nor would they avoid them from a system perspective. However, if they were used to provide incremental system value, this could be an avoided cost. At least one utility interviewed is planning a pilot that will test advanced inverter support functionality as a part of their grid modernization efforts, so additional relevant data could be available in the future. This may be relevant for regions that have high levels of collocated DERs with deployed smart inverters that are not currently being leveraged. Understanding value and how to extract it would be helpful to alleviate reliability concerns of utilities under a high-DER adoption scenario and could provide additional value to the grid and DER hosts once valued in a tariff, incentive, or program.

3.2.4 Valuation Methods for Increased Utility Costs

Utility costs analyzed include only those that are additional due to incremental solar addition (Table 6) Integration was discussed across all studies; however, it was widely acknowledged that the cost of interconnection is borne by the developer if the local grid cannot handle the increase of distributed generation. As such, this is not an incremental cost to the utility. Lost utility revenue was included solely within the Montana study, which was commissioned by NorthWestern Energy, a utility that earns revenue on generation. Finally, program administration data is a very small cost category and requires utility data to accurately quantify.

Table 6. Valuation methods for utility costs in four reviewed studies

		Montana (Navigant 2018)	Maryland (Daymark 2018)	Connecticut (CT DEEP and PURA 2020)	New Hampshire (Dunsky 2022)
Costs	Integration	Discussed	Discussed	Discussed	Discussed
	Lost Utility Revenue	Quantified	Omitted	Omitted	Omitted
	Program Admin	Quantified	Omitted	Omitted	Quantified
* Of the four studies, the one in Montana was the only one commissioned by a utility (NorthWestern Energy) whereas the other three were commissioned by the state.					

3.2.4.1 Integration

Many studies assumed that integration costs are zero, especially at low levels of DPV penetration. This is largely due to the fact that adopters or developers incur the cost of integration in order to interconnect. While there may be additional integration costs associated with a large fleet of DPV resources concentrated in one area, this is not yet considered to be a large problem and may fall under other categories listed here.

Connecticut's study noted that the average annual incurred cost of interconnection per kW is $66/kW (CT DEEP and PURA 2020). Similar to other studies, the authors noted that this cost is typically paid for by developers and added that this could actually be seen as a net benefit if it replaces the need for a planned upgrade and increases hosting capacity. Since this is a private cost, it is considered out of scope.

Maryland's study assumed this cost to be $0, but the authors mentioned that integration costs may be required at higher levels of DPV adoption to invest in hardware such as grounding banks, voltage regulators, capacitors, reclosers, fault detectors, or control system changes, which can cost up to $300,000 (Daymark 2018). Substation expansions or distribution line rebuild costs could be $1 million or larger, usually associated with larger projects. These costs typically fall to the developer and can have a negative impact of $0.017–$0.023/kWh, depending on the upgrade required.

3.2.4.2 Lost Utility Revenue

Lost utility revenue for vertically integrated utilities is the largest cost category, where included. For example, Navigant and Montana's NorthWestern Energy calculated the entire production of the modeled DPV portfolio would reduce their respective utility revenue by a levelized cost of $0.144–$0.146 per kWh over 5 years (Navigant 2018). Notably, the Navigant Montana study is the only study of the four that was commissioned by a utility and is the only study that considers lost utility revenue.

3.2.4.3 Program Administration

Program administration fees are expected to make up a small portion of costs. Only two of the four studies included and quantified this value, one of which was the utility-funded study.

Montana's study from Navigant and NorthWestern Energy described each task and quantified the labor category, rate, and hours associated to reach a cost of $194 per NEM application in their territory (Navigant 2018). Levelizing this over 25 years resulted in a cost of $0.003/kWh.

New Hampshire's AESC study (Synapse 2021) did not quantify these costs, so the authors developed their own quantification method for this study for program administration, metering, billing, collections, evaluations, un-reimbursed interconnection assessment efforts, labor, and materials outside of non-NEM-related work (Dunsky 2022). They took all of these NEM costs by utility, calculated a per-unit cost, and levelized it over the study period, similar to NorthWestern (Navigant 2018).

3.2.5 Valuation Methods for Other Avoided Social Costs

Similar to previous studies, avoided cost of carbon and other avoided environmental costs were quantified. More recent studies differed from previous ones in that local economic benefits were quantified in two of four studies, focusing on job creation and tax revenue generated. Studies went into a fair amount of depth in terms of literature review and exploration of different methods. Finally, studies discussed a fair number of other, miscellaneous, hard-to-quantify avoided costs and explored various values and methods via literature review, though they did not provide specific recommendations for quantification.

Table 7. Valuation methods for social costs in four reviewed studies

		Montana (Navigant 2018)	Maryland (Daymark 2018)	Connecticut (CT DEEP and PURA 2020)	New Hampshire (Dunsky 2022)
Social	Avoided Cost of Carbon	Quantified	Quantified	Quantified	Quantified
	Other Avoided Environmental Costs	Quantified	Quantified	Quantified	Quantified
	Local Economic Benefit	Discussed	Quantified	Quantified	Omitted
	Other	Discussed	Discussed	Discussed	Discussed
* Of the four studies, the one in Montana was the only one commissioned by a utility (NorthWestern Energy) whereas the other three were commissioned by the state.					

3.2.5.1 Avoided Cost of Carbon and Other Avoided Environmental Costs

Carbon value methods varied across studies. Some were considered within proprietary models, others were defined and embedded in compliance costs (e.g., RGGI), and the rest primarily used the U.S. Interagency Working Group's SCC definition — though the level selected and how it was projected into the future were often slightly different. Additionally, the level of carbon avoided was often determined via different methods.

Connecticut used the SCC value netted with RGGI so as not to double count. Table 23 in their study summarizes the values used in other states, for reference, which range from $0.021/kWh in Maine to $0.102/kWh in Vermont (CT DEEP and PURA 2020). To quantify value, authors followed methods from a New York study: (1) Identify generation displaced by DER, (2) Calculate emissions rate [kg/kWh] of displaced resources, (3) Calculate damage per unit of avoided emissions [$/kg], (4) Monetize value from displaced generation [$/kWh], and (5) Subtract any damages from the DER itself to calculate net avoided damages. To do this, they used air pollution emission experiments and policy analysis models, BenMAP, COBRA, and a regression to estimate air pollution's social impact. Criteria pollutant reduction was quantified via the difference in the reference case with each use case (using Aurora's capacity expansion model) and then monetized using the U.S. Environmental Protection Agency's "Estimating the Benefit per Ton of Reducing PM2.5 Precursors from 17 Sectors" (EPA 2013). Values were converted to nominal dollars and extended to the study period using linear extrapolation.

Maryland used the COBRA model for carbon dioxide and criteria pollutants such as particulate matter, SO_2, and nitrogen oxides (NO_x) (Daymark 2018). They then used RGGI for avoided CO_2 value and the EPA's Cross-State Air Pollution Rule and Acid Rain Program for NO_x and SO_2. Beyond RGGI, they considered the net value of the Interagency Working Group's SCC definition as a nonmonetized benefit of carbon reduction.

Montana's NorthWestern Energy study used Navigant's proprietary model (Navigant 2018). They took into account natural gas prices and capacity additions/retirements to quantify this value. These data relied upon their Mid-Year 2017 Energy Market Outlook. The authors used the Northwest Power Pool region to select the proper data. They then assumed a cap-and-trade policy targeting 28% reductions from 2005 levels in 2028, ramping up 1% each year to 50% in 2050. In 2016 $, this resulted in a level of $4.50/ton in 2028 and $25.23/ton in 2050, for comparison.

New Hampshire. Similar to other states within RGGI, New Hampshire's avoided carbon costs included SCC less RGGI, which was accounted for in avoided energy value (Dunsky 2022). This value decreases over time based on the assumption that the state phases out all coal by 2025. SO_2 was also included in the avoided energy value. NO_x and particulates were separately considered, and authors used the AESC social cost of NO_x (Synapse 2021). For particulates, the assumption of zero coal by 2025 led to the assumption that there was minimal value and was thus not included. Unique to New Hampshire, the study discussed methane but determined that it was hard to develop forecasts, since much of the loss occurs upstream and was therefore not included.

3.2.5.2 Local Economic Development

Studies found this difficult to quantify, though some did so through literature review or other analysis.

Connecticut did an extensive review of other states' determination of economic development and other macroeconomic benefits of DERs. In their discussion, they highlighted Arkansas and the Sierra Club's assumption that 22% of DPV costs are spent in the local economy ($0.0336/kWh) (Beach and McGuire 2017). They also highlighted Mississippi with Synapse (Stanton et al. 2014), which used the same method as described in Maryland's example two paragraphs below (Daymark 2018). The authors went on to acknowledge that state tax credits and other incentives can increase the cost to taxpayers but can lead to direct jobs. The Connecticut study also discussed property tax. The meta-analysis leveraged two studies that quantified the premium on housing prices that resulted from rooftop solar, translating that to an increase of local tax revenue.

For their specific calculation, the Connecticut authors quantified both costs and value. State incentives have averaged $0.53/W since the inception of the state's program in 2012, and this led to 936 direct and 312 indirect and induced job-years to deploy 60 MW of DPV. They were able to use direct data from an incentive program to quantify the number of jobs created for a specific level of DPV deployment, which is somewhat unique. On the value side, they mimicked Arkansas and the Sierra Club's method (Beach and McGuire 2017) that used a 2013 NREL study that categorized employment levels for each soft cost category (Friedman et al. 2013). The authors noted that NREL's 2018 updated study did not have a breakdown for each soft cost category (Fu et al. 2018), so they took the distribution of the 2013 study and applied it to the average system cost per watt as calculated empirically by the Connecticut Green Bank for the state incentive program. They then made some adjustments to calibrate the numbers to Connecticut, noting that their incentive program saw an average price of $3.57/W and that labor costs in the state are higher than elsewhere. Using the distributions from the 2013 NREL study, Connecticut quantified $0.03/kWh of macroeconomic benefits, but also taking into account the incentive costs of $0.0194/kWh, this led to a net benefit of $0.0106/kWh. This method was incredibly comprehensive and took into account both costs and value.

Maryland used the IMPLAN input/output model to combine economic factors, multipliers, and demographics to measure the economic impact for the state (Daymark 2018). The authors then calibrated this value for each utility. The metrics reported in the study include job-years [#], labor income [$], value added [$], and output [$]. They also reported the tax revenue generated [$].

3.2.5.3 Other Social Benefits

Connecticut highlighted the Advanced Energy Economy Institute's work in New York, which provided regulators with a series of proxies, benchmarks, regulatory judgment, and multi-attribute decision analysis that could be used (Woolf et al. 2014). This includes multi-attribute decision analysis that is able to take both quantifiable and non-quantifiable factors into a decision matrix that weighs all information to score/prioritize options. Tables 17 and 18 in the Connecticut study demonstrate an example of this (CT DEEP and PURA 2020).

Maryland did not quantify the monetary benefits of water usage or land use (Daymark 2018) but did perform a quantitative analysis to look into the water usage intensity for various generator types, citing a U.S. Department of Energy SunShot study (DOE 2012). The authors also looked into land use, using spatial analysis to identify land use types, coverage, and slope. The results of this analysis showed that both water and land use intensity impacts were small, so they did not attach monetary value or include them in their study. For example, an avoided substation expansion of one transformer and three distribution circuits would be roughly 0.25 acres.

Montana's NorthWestern Energy study by Navigant discussed, though did not quantify, additional benefits that could accrue (Navigant 2018). These include improved health, customer satisfaction, fewer service complaints, land use, and water consumption. They considered these values to be subjective and not yet measurable.

4 Conclusions

Most states require DPV to be compensated via NEM. Many states with net-metering requirements are exploring potential successors such as VoS tariffs. VoS tariffs aim to compensate DPV output based on the estimated net value of that output to the grid. The value can vary temporally and/or spatially and generally fall into several categories including generation, transmission, distribution, and societal avoided costs. Avoided costs vary in terms of their magnitude and overall impact on the final value, as well as how feasible it is to quantify these values.

Studies in more recent years (2018–2023) exhibit some similarities to past studies that span 2005 to 2017, especially in terms of methods surrounding easier-to-quantify values that have a large impact on overall valuation. These include many generation values such as energy, capacity, and avoided RPS, as well as some transmission values. However, recent VoS studies go further in quantifying some values that are higher in magnitude, though more difficult to quantify, than in previous studies. For some, the avoided cost magnitude may be small at present but will likely be high in a future with larger concentrations of DERs. This is the case for various location-specific distribution system values. Further, these more recent studies share literature reviews and deeper discussion about lower magnitude avoided costs along with potential methods to quantify these in a future where the value category's magnitude may increase.

The scope and perspective of individual VoS studies can affect the final VoS estimation. For example, the study in Montana was the only one of the four recent VoS studies that was commissioned by a utility, as opposed to a state government entity. Some value and cost categories that were excluded in state-commissioned studies were included in the utility-commissioned study, such as lost utility revenue. As another example, the Connecticut study that was conducted by a state body, as opposed to a third-party consultant, included value categories that are most aligned with state policy surrounding energy conservation, promoting renewable energy, energy supply diversification, energy affordability, and load management.

With a narrow focus, this brief is intended to contextualize and summarize the value and cost categories that have been included in past VoS studies and research, as well as the methodologies used to quantify these values. This can provide context to states that may want to conduct similar studies to understand or quantify the net benefits of solar or integrate findings into new or updated solar incentives or tariffs.

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APPENDIX A. Table of Value of Solar Studies and Related Resources

Document Title (with link)	Location	Authors/Institution	Year
The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc.	AR	Crossborder Energy	2017
The Benefits and Costs of Solar Distributed Generation for Arizona Public Service	AZ	Crossborder Energy	2013
Docket E-00000J-14-0023: The Alliance for Solar Choice's (TASC) Notice of Filing Direct Testimony of B. Thomas Beach		Crossborder Energy	2016
Avoided Cost Calculator	CA	E3*	2016- Present*
Avoided Cost Calculator		CPUC*	2016-Present*
Docket 13A-0836E: Benefits and Costs of Solar Distributed Generation for the Public Service Company of Colorado	CO	Crossborder Energy	2013
Value of Distributed Energy Resources in Connecticut	CT	CT DEEP, CT PURA†	2020†
Distributed Solar in the District of Columbia	DC	Synapse	2017
A Framework for Determining the Costs and Benefits of Renewable Resources in Georgia	GA	Georgia Power	2019
Evaluation of Hawaii's Renewable Energy Policy and Procurement	HI	E3	2014
Value of Solar + Storage in Hawaii: Methodology		IREC	2015
PV Valuation Methodology: Recommendations for Regulated Utilities in Iowa	IA	Clean Power Research	2016
Distributed Generation Valuation and Compensation Workshops	IL	ICC	2018
Illinois' Distributed Generation Rebate- Preliminary Input and Calculation Considerations		PNNL†	2018†
Value of Distributed Generation – Solar PV in MA	MA	Acadia	2015
Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland	MD	Daymark†	2018†
Maine Distributed Solar Valuation Study	ME	Clean Power Research	2015
PV Valuation Methodology: Recommendations for Regulated Utilities in Michigan	MI	Clean Power Research	2016
Minnesota Value of Solar: Methodology	MN	Clean Power Research	2014
Net Metering in Missouri: The Benefits and the Costs	MO	Missouri Energy Initiative	2015
Net Metering in Mississippi: Costs, Benefits, and Policy Considerations	MS	Synapse	2014
Solar Net Metering Benefit-Cost Analysis	MT	Navigant†	2018†

The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina	NC	Crossborder	2013
The Value of Distributed Energy Resources Study	NH	Dunsky†	2022†
The Value of Distributed Solar Energy Generation to New Jersey and Pennsylvania	NJ/PA	Clean Power Research	2012
Nevada Net Energy Metering Impacts Evaluation	NV	E3	2014
Nevada Net Energy Metering Impacts Evaluation 2016 Update		E3	2016
The Value Stack (& Calculator)	NY	NYSERDA*	2017- Present*
The Benefits and Costs of Net Energy Metering in New York		E3	2015
UM 1716: In the Matter of Public Utility Commission of Oregon, Investigation to Determine the Resource Value of Solar	OR	PUCO	2017
PGE Distributed Solar Valuation Methodology		Clean Power Research	2015
Value of Distributed Generation – Solar PV in RI	RI	Acadia	2015
South Carolina Act 236 Cost Shift and Cost of Service Analysis	SC	E3	2015
The Value of Distributed Solar Electric Generation to San Antonio	TX	Clean Power Research	2013
Value of Solar Rate: Austin Energy's Solar Bill Credits		Austin Energy*	2014- Present*
Value of Solar in Utah	UT	Clean Power Research	2014
Analyzing the Costs and Benefits of Distributed Solar Generation in Virginia	VA	VA Distributed Solar Generation and NEM Stakeholder Group	2014
Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012	VT	VT DPS	2013
Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014		VT DPS	2014
PV Valuation Methodology: Recommendations for Regulated Utilities in Wisconsin	WI	Clean Power Research	2016
A Review of Solar PV Benefit & Cost Studies (2nd ed.)	Multiple	RMI†	2013†
State Strategies for Valuing Distributed Energy Resources in Cost-Effective Locations	Multiple	CESA	2020
Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar	Multiple	ICF†	2018†
* Active tariff			
† Summarized in this report			