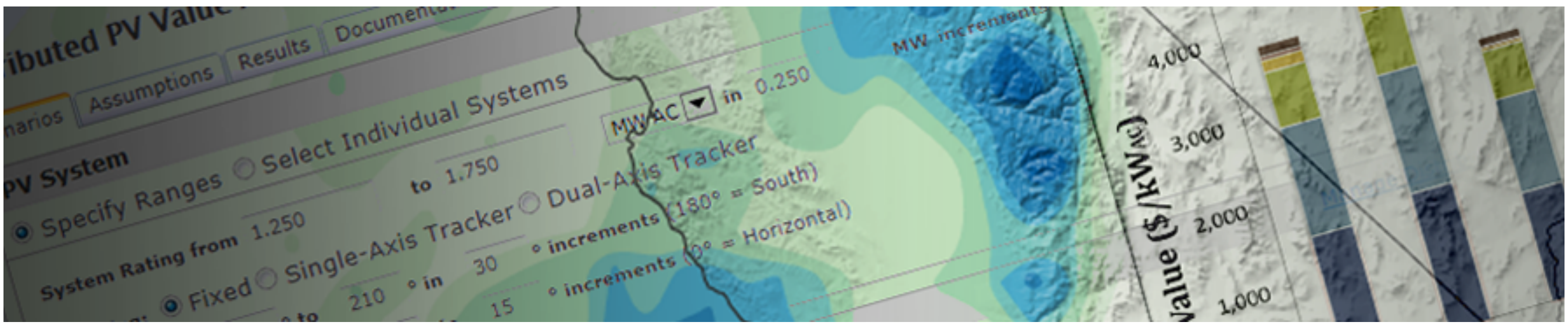
PV Valuation Methodology:

Cooperatively-Owned and Municipal Utilities

with Specific Examples for an Iowa Municipal Utility



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Executive Summary

The Midwest Renewable Energy Association (MREA) was incorporated in 1990 in the state of Wisconsin to promote renewable energy, energy efficiency and sustainable living through education and demonstration. It is in this context that Clean Power Research was selected to develop a detailed and prescriptive valuation methodology for use by Cooperatively-Owned Utilities (COU) and municipal utilities to determine appropriate bill credit values for both member-owned PV systems and shared solar systems (total value of generation, not per customer.)

The present document provides the methodology to inform value of solar (VOS) rate design for use by COUs. It is based on stakeholder input and includes a sample VOS calculation for Bloomfield, Iowa based on simulated PV generation, wholesale rates and electrical demand timeseries representative of the solar resource and demand characteristics of Bloomfield. It includes a detailed example calculation for each step of the calculation.

Key aspects of the methodology include:

- A standard PV rating convention
- Methods for creating an hourly PV production time-series, representing the aggregate output of all PV systems in the service territory per unit capacity corresponding to the output of a PV resource on the margin
- Methods for calculating the value of avoided energy and capacity supply and associated avoided losses.
- Economic methods for levelizing the unlevelized values based on the common warrantied lifetime of PV systems (25 years), expected capacity degradation and expected wholesale cost escalation
- Methods for summarizing input data and final parameters in order to facilitate internal or external review

Application of the methodology results in the creation of three tables: Two tables summarizing input data; one highlighting the time-series data used and another highlighting the fixed technical and economic parameters used, and the VOS calculation table where individual value components are combined to generate the gross unlevelized VOS. Together these tables ensure transparency and facilitate understanding among all pertinent stakeholders.

The simplified VOS Calculation Table is illustrated in Figure ES-1. The table shows each value component and how the gross economic value of each component is converted into a gross distributed solar value "Total". The process calculates the *overt* cost avoidance per unit of PV-generated electricity both in terms of avoided energy purchases displaced by PV generated electricity (E_1) and in terms of the demand charges avoided by peak demand displaced by coincident PV generation at the peak (D_1). It also calculates the cost avoidance from losses that would otherwise have been incurred across the distribution grid because PV is in place, both in terms of energy (E_2) and in terms of capacity (D_2) (loss of effective capacity across the distribution grid at the peak.) Each the avoided energy supply costs ($E = E_1 + E_2$) and avoided capacity supply costs ($D = D_1 + D_2$) are summed simply added together to generate the total unlevelized VOS.

Figure ES-1. Simplified VOS Calculation Table:

		Overt Cost Avoidance A ($/kWh)	+	Distribution Loss Avoidance B ($/kWh)	=	Distributed PV value C ($/kWh)
Energy Supply	Avoided Energy Purchases	E_1		E_2		E
Capacity Supply	Avoided Demand Charges	D_1		D_2		D
						Total

As a final step, the methodology calls for the conversion of this total VOS to a 25-year levelized value, accounting for a fixed cost escalator applied to both energy supply and demand charge, expected PV capacity degradation, and based on a discount rate agreed upon by stakeholders.

In our example application case for the city of Bloomfield, using a series of baseline assumptions[1] we calculate the 25-year levelized VOS to be 8.13 ¢/kWh, a value which is ~25% lower than the most recent (2013) commercial light and power rate of 10.8 ¢/kWh we could obtain for the City of Bloomfield. While this avoided cost is certainly lower than retail, it is important to note that this rate does not include other value components such as avoided distribution capacity and a whole host of societal and environmental benefits that the community gains per kWh of PV-generated electricity.

In our case example for Bloomfield, we show the effect on VOS of altering the discount rate within the range of 3-7% and in the appendix, discuss how to calculate the value of deferred distribution capacity upgrades in the case of a forecasted increase in demand.

[1] 9.62 $/kW demand charge, 36.2 $/MWh energy charge, 1 %/yr PV degradation, 3% variable distribution losses, 1 % fixed distribution losses, 2.5 %/yr annual price escalation, 3 % discount rate.

Contents

Introduction

Background

The Midwest Renewable Energy Association (MREA) engaged Clean Power Research (CPR) to develop a detailed solar valuation methodology for use by Cooperatively-Owned Utilities (COUs) and municipal utilities. The methodology could be used to determine the value of all non-utility solar generation, from both customer-owned PV systems and shared solar resources irrespective of customer class. Such a methodology may share certain features of prior value of solar (VOS) methods in other jurisdictions, but would address the unique aspects of these smaller utilities since they are assumed here to own none of their own generation or transmission assets, cost components typically included in prior studies.

The VOS methods could be used by the Iowa utilities to develop new value-based compensation mechanisms as alternatives to existing net energy metering (NEM) structures. The VOS would ideally provide an attractive rate of return for prospective solar customers while at the same time ensure that the utility is able to recover critical infrastructure costs associated with distribution.

In order to evaluate whether VOS would meet these objectives, it is necessary to define a candidate method for calculating value, such as by defining the benefit categories, the treatment of loss savings, the calculation of economic parameters, and so on. These details are proposed in the current document, along with a sample calculation for one municipal utility, the City of Bloomfield, which provided relevant cost and load data in support of this work.

VOS Overview

The proposed VOS method and any tariff that may follow from it defines value as the utility savings that results from solar electricity exported to the grid. Such savings may, for example, derive from the reduced amount of wholesale electrical purchases from the utility's supplier. By defining value in this way, the utility should be economically indifferent to compensating solar at the calculated VOS rate on the one hand, and compensating suppliers in the "business as usual" scenario on the other.

The VOS should not be viewed as an incentivized rate. Its purpose is not to incent solar installations or promote any particular public policy. Nonetheless, incentives could be applied to systems compensated under the VOS rates. If it were determined to be in the interest of public policy, incentives could be in the form of capital buy-down programs or in performance based format. Regardless of the decision on such incentive programs, the VOS described here is determined and applied independently.

This report provides a brief overview of categories of "societal benefits" that could be adopted by the utility as a justification of incentive amounts or simply as separate benefit components that could be paid by all ratepayers. CPR does not take any position on whether these should be adopted, and leaves them to the utilities themselves.

It should be further noted that the VOS could be designed either to allow behind-the-meter (BTM) consumption (“self-consumption”) or not. If BTM consumption were allowed, it would imply that any electricity produced and consumed directly, without passing through the meter, would not be measured and would not be credited. From the customer perspective, it would effectively be valued at the retail rate, similar to self-consumption provided for the NEM. From the utility perspective, it would represent load reduction, similar to energy efficiency.

If self-consumption were allowed under the tariff terms, PV energy would be exported to the grid whenever generation exceeded customer load. In this case, the VOS rate could be used to credit only the export energy. If self-consumption were not allowed, then PV energy would be separately metered and credited. Consumption would be charged based on existing tariffs.

The proposed methodology would be valid under both of these tariff designs. However, the calculated value depends on this selection of separate metering versus export-only metering. This is because the hourly profile of “net” export energy would deviate from that of “gross” PV production. The two approaches would result in two different VOS rates because the capacity-related benefits and loss savings benefits depend upon utility loads in any given hour.

The presently described methodology is a simplified VOS calculation that only includes overt cost avoidance from displaced electricity, peak demand reduction and associated avoided losses across the distribution grid. It is to be noted that there are many other value components that PV offers, including but not limited to: avoided fuel costs, avoided fixed and variable plant O&M, avoided generation and reserve capacity, avoided transmission capacity and avoided environmental costs (both direct and lifecycle emissions). Such components are not included here because they are either effectively included in the wholesale rates (e.g., fuel costs are embedded in wholesale energy rates) or because the policy related to compensation of societal benefits are not established.

VOS Calculation Table Overview

The simplified VOS outlined here is the sum of several distinct value components, each calculated separately using procedures defined in this methodology. As illustrated in Table 1, the calculation includes two overt cost avoidance values (Column A), and two associated distribution loss avoidance values (Column B). The cost avoidance values and distribution loss avoidance values are separated into those linked to energy supply and those linked to capacity supply (i.e. linked to avoided demand charges.) These are summed in the total distributed PV component values (Column C), and summed for a total rate.

The value elements shown are based on a single year of load and simulated regional PV data in dollars per kWh. The ‘Total Unlevelized VOS’ represents the summed value of distributed PV values (C) related to both energy and capacity supply in the first year. Based on these first-year results, the methodology later discusses how to levelize these costs over a 25-year period, the assumed useful service life of the PV system. This allows the VOS to take into account energy and demand cost escalation, PV capacity degradation and discount rate.

Table 1. Illustration of the simplified unlevelized VOS Calculation Table

			Overt Cost Avoidance A ($/kWh)	+	Distribution Loss Avoidance B ($/kWh)	=	Distributed PV value C ($/kWh)
Energy Supply		Avoided Energy Purchases	E_1		E_2		V_1
Capacity Supply		Avoided Demand Charges	D_1		D_2		V_2

Total Unlevelized VOS

VOS Components

Table 2 presents the VOS avoided cost components that are included in this methodology and a description for each component. The table is divided into two avoided cost categories; those reflective of avoided energy supply and those reflective of avoided capacity supply (i.e. demand charges). Each of these two categories are further separated into overt cost avoidance and costs related to avoided losses across the distribution grid. Each parameter within the table is defined in units of $/kWh.

Table 2. VOS components included in methodology.

	Value Component	Detail	Parameter Name
Energy Supply	Avoided Energy Purchases	Energy supply costs avoided per kWh of PV-generated electricity.	E_1
	Energy Loss Avoidance	Avoided effective energy supply losses per kWh of PV-generated electricity that would otherwise have been incurred across the distribution grid.	E_2
Capacity Supply	Avoided Demand Charges	Avoided demand charges per kWh of PV-generated electricity that result from PV generation at the system load peak	D_1
	Capacity Loss Avoidance	Avoided costs from avoiding distribution-grid losses that would otherwise have been incurred at the demand peak.	D_2

Economic Analysis Period

In evaluating the value of a distributed PV resource, the economic analysis period is set at 25 years, the assumed useful service life of the PV system[2]. The methodology includes PV degradation effects when levelizing costs, as described later.

The goal is to calculate the avoided costs over this defined economic analysis period, including the impact of predicted cost escalation and PV performance degradation. Cost escalation will increase the value delivered over time per kWh of PV generation, while PV degradation will decrease the value.

[2] NREL: Solar Resource Analysis and High-Penetration PV Potential (April 2010). http://www.nrel.gov/docs/fy10osti/47956.pdf

As an alternative to this approach, it would be possible to apply, say, rates re-calculated each year rather than fixing the valuation over the long term. Such an approach would benefit from reducing the uncertainty in future costs. However, the long term approach is used to provide financial stability to solar customer-investors.

Methodology: Inputs and Assumptions

There are two specific categories of inputs required to perform the analysis. The first category contains timeseries data regarding the production of PV and the load across the service territory and the second category contains a series of fixed technical and economic parameters that help simulate distribution system losses and model current and future cost savings. In the following subsections, we describe some terminology and important assumptions as well as methods to obtain some of the critical inputs.

Load Analysis Period

The VOS methodology requires that the analysis be performed over a fixed and temporally-consistent period of time in order to account for day-to-day variations and seasonal effects, such as changes in solar radiation. System-wide timeseries of PV production (whether simulated or metered) and system-wide timeseries of load must reflect the identical time resolution and identical time period of at least one year.

The data may start on any day of the year, and multiple years may be included, as long as all included years are contiguous and each included year is a complete one-year period. For example, valid load analysis periods may be 1/1/2012 0:00 to 12/31/2012 23:00 or 11/1/2010 0:00 to 10/31/2013 23:00.

Two types of timeseries data are required to perform the technical analysis:

Table 3. Time-series parameters required for technical analysis.

Timeseries Variable	Timeseries Name	Description	Units
L_t	Hourly Distribution Load	The hourly distribution load over the Load Analysis Period. The distribution load is the power entering the distribution system from the transmission system (i.e., generation load minus transmission losses).	kWh
P_t	Nominal Hourly PV Fleet Production	The hourly PV Fleet production over the Load Analysis Period. The PV fleet production is the aggregate generation of all of the PV systems in the PV fleet divided by the total rated capacity of all systems.	$\frac{kWh}{kW_{AC}}$

Both types of data must be provided as temporally-synchronized, time-stamped hourly values of average power over the same period, and corresponding to the same hourly intervals. Data must be available for every hour of the Load Analysis Period. PV data using Typical Meteorological Year data is not time synchronized with time series production data, so it should not be used as the basis for PV production.

Data that is not in one-hour intervals must be converted to hourly data (for example, 15-minute meter data would have to be combined to obtain 1-hour data). Also, data values that represent energy must be converted to average power.

If data is missing or deemed erroneous for any time period less than or equal to 24 hours, the values corresponding to that period may be replaced with an equal number of values from the same time interval on the previous or next day if it contains valid data. This data replacement method may be used provided that it does not materially affect the results.

Nominal Hourly PV Fleet Production (P_t)

PV System Rating Convention

The methodology uses a rating convention for PV capacity based on AC delivered energy (not DC), taking into account losses internal to the PV system. A PV system rated output is calculated by multiplying the number of modules by module PTC rating[3] [as listed by the California Energy Commission (CEC)[4]] to account for *module* de-rate effects by the CEC-listed inverter efficiency rating[5] and the derate factor. This derate factor is calculated by multiplying the inverter efficiency and any other common internal PV array losses (wiring losses, module mismatch and other losses).

If no CEC module PTC rating is available, the module PTC rating should be calculated as 0.90 times the module STC rating[6]. If no CEC inverter efficiency rating is available, an inverter efficiency of 0.95 should be used. If no measured or design loss factor is available, 0.85 should be used.

To summarize: [7]

Derate factor = [Inverter Efficiency Rating] x [Additional Loss Factor]

Rating (kW-AC) = [Module Quantity] x [Module PTC rating (kW)] x [Derate factor]

Hourly PV Fleet Production

Hourly PV Fleet Production can be obtained using any one of the following three options:

1. Utility Fleet - Metered Production. Fleet production data can be created by combining actual metered production data for every PV system in the utility service territory, provided that there are a sufficient number of systems[8] installed to accurately derive a correct representation of aggregate PV production across the distribution service territory. Such metered data is to be

[3] PTC refers to PVUSA Test Conditions, which were developed to test and compare PV systems as part of the PVUSA (Photovoltaics for Utility Scale Applications) project. PTC are 1,000 Watts per square meter solar irradiance, 20 degrees C air temperature, and wind speed of 1 meter per second at 10 meters above ground level. PV manufacturers use Standard Test Conditions, or STC, to rate their PV products.
[4] CEC module PTC ratings for most modules can be found at: http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php
[5] CEC inverter efficiency ratings for most inverters can be found at: http://www.gosolarcalifornia.ca.gov/equipment/inverters.php
[6] PV manufacturers use Standard Test Conditions, or STC, to rate their PV products. STC are 1,000 Watts per square meter solar irradiance, 25 degrees C cell temperature, air mass equal to 1.5, and ASTM G173-03 standard spectrum.
[7] In some cases, this equation will have to be adapted to account for multiple module types and/or inverters. In such cases, the rating of each subsystem can be calculated independently and then added.
[8] A sufficient number of systems has been achieved when adding a single system of random orientation, tilt, tracking characteristics, and capacity (within reason) does not materially change the observed hourly PV Fleet Shape (see next subsection of PV Fleet Shape definition).

gross PV output on the AC side of the system, but before local customer loads are subtracted (i.e., PV must be separately metered from load). Metered data from individual systems is then aggregated by summing the measured output for all systems for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.

2. Utility Fleet, Simulated Production. If metered data is not available, the aggregate output of all distributed PV systems in the utility service territory can be modeled using PV system technical specifications and hourly irradiance and temperature data. These systems must be deployed in sufficient numbers to accurately derive a correct representation of aggregate PV production. Modeling must take into account the system's location and each array's tracking capability (fixed, single-axis or dual-axis tracking), orientation (tilt and azimuth), module PTC ratings, inverter efficiency and power ratings, other loss factors and the effect of temperature on module output. Technical specifications for each system must be available to enable such modeling. Modeling must also make use of location-specific, time-correlated, measured or satellite-derived plane of array irradiance data. Ideally, the software will also support modeling of solar obstructions.

   - To make use of this option, detailed system specifications for every PV system in the utility's service territory must be obtained. At a minimum, system specifications must include the following parameters:
     - Location (latitude and longitude)
     - System derate factor (derived from component ratings and/or estimation)
     - Tilt and azimuth angles if fixed-tilt.
     - Tracking type (if applicable)
   - After simulating the power production for each system for each hour in the Load Analysis Period, power production must be aggregated by summing the power values for all systems for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.

3. Expected Fleet, Simulated Production. If neither metered production data nor detailed PV system specifications are available, a diverse set of PV resources can be estimated by simulating groups of systems at major load centers in the utility's service territory with some assumed fleet configuration. To use this method, one or more of the largest load centers in the utility service territory may be used. If a single load center accounts for a high percentage of the utility's total load, a single location will suffice. If there are several large load centers in the territory, groups of systems can be created at each location with capacities proportional to the load in that area.

- For each location, simulate multiple systems, each rated in proportion to the expected capacity, with azimuth and tilt angles such as the list of systems presented in Table 3. Note that the list of system configurations should represent the expected fleet composition. No method is explicitly provided to determine the expected fleet composition; however, a utility could analyze the fleet composition of PV fleets outside of its territory.

Table 3. (Illustrative) Azimuth and tilt angles

System	Azimuth	Tilt	% Capacity
1	90	20	3.5
2	135	15	3.0
3	135	30	6.5
4	180	0	6.0
5	180	15	16.0
6	180	25	22.5
7	180	35	18.0
8	235	15	8.5
9	235	30	9.0
10	270	20	7.0

- Simulate each of the PV systems for each hour in the Load Analysis Period. Aggregate power production for the systems is obtained by summing the power values for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.
- If the utility elects to perform a location-specific analysis for the Avoided Distribution Capacity Costs, then it should also take into account what the geographical distribution of the expected PV fleet would be. Again, this could be done by analyzing a PV fleet composition outside of the utility's territory. An alternative method that would be acceptable is to distribute the expected PV fleet across major load centers. Thereby assuming that PV capacity is likely to be added where significant load (and customer density) already exists.
- Regardless of location count and location weighting, the total fleet rating is taken as the sum of the individual system ratings.

Nominal Hourly PV Fleet Production

Regardless of which of the three methods is selected for obtaining the Hourly PV Fleet production, the next step is divide each hour's value by the PV Fleet's aggregate AC rating to obtain the *Nominal* Hourly PV Fleet Production. This nominal timeseries has nominal units of kWh/kW and reflects the ratio of PV production across the utility service territory relative to its aggregate rated capacity on the AC-side.

Hourly Distribution Load (L_t)

The hourly distribution load, should be a timeseries of system-wide load temporally coincident with the timeseries of nominal hourly PV Fleet Production. This timeseries should reflect the load at the substation level across the entire utility service territory in kW.

Fixed Technical and Economic Parameters

Next, in Table 4 below, a series of utility-specific physical and economic parameters are required.

Table 4. Fixed Technical and Economic Parameters

	Parameter	Detail	Unit	Type	Parameter Name
Physical Parameters	Variable Distribution Losses	The average annual variable losses through the distribution grid. i.e. those losses which vary according to current (I^2R), not the fixed losses which result from system architecture (leakage current).	%/yr	Fixed parameter	λ
	PV degradation	The expected annual degradation in AC-rated capacity compared to the time of installation.	%/yr	Fixed parameter	ψ
Economic Parameters	Energy Charge	The price of wholesale electricity within the REC's service territory.	$/kWh	Fixed parameter	E
	Demand Charge	The demand charge within the REC's service territory. Assuming demand charge is calculated based on monthly peak load.	$\$/kW_p$	Fixed parameter	D
	Annual Price Escalator	The expected increase in demand and energy charge rates on an annual basis.	%/yr	Fixed parameter	e

	Discount rate	A rate by which to discount future cash flows and determine a levelized VOS rate.	%/yr	Fixed parameter	d

It is to be noted that if peak load across the distribution service territory is forecasted to grow, there could exist some additional value in deferring distribution capacity investment given the peak-load reduction value brought by PV. When we perform an example calculation for Bloomfield, peak load was not forecasted to grow and hence we have not included it in the simplified input table above. If this is to be included, the peak load growth rate and the capacity-related distribution capital cost are also required.

An example of the *Fixed Technical and Economic Parameters* table complete with sample values reflecting the City of Bloomfield can be found below.

Table 5. Fixed Technical and Economic Parameters (Assumed for Bloomfield)

	Parameter	Parameter Name	Example Value	Unit
Physical Grid Parameters	Variable Distribution Losses	Λ	3%	%/yr
	PV degradation	Ψ	1%/yr	%/yr
Economic Parameters	Energy Charge	E	$0.0362	$/kWh
	Demand Charge	D	$9.62	$/kW$_p$
	Annual Price Escalator	E	2.5%	%/yr
	Discount rate	D	3%	%

Methodology: Economic Analysis

First Year Energy Value

Calculation of the value of Avoided Energy Purchases (E_1)

The avoided energy purchases do not require a calculation; this parameter (E) simply represents the energy supply costs avoided per kWh of PV-generated electricity. As the wholesale rate—referenced as the *energy charge* with symbol (E)—represents the value of wholesale electricity which the PV-generated electricity is displacing, the value of avoided energy purchases is simply equivalent to it:

$$E1 = E$$

In our example for Bloomfield, E_1 is therefore equal to its corresponding energy charge of 3.62 ¢/kWh.

Calculation of the Energy Loss Avoidance value (E_2)

In order to calculate the value of the avoided effective energy supply losses per kWh of PV-generated electricity that would otherwise have been incurred across the distribution grid, we follow the follow the following procedure.

1) First, calculate an intermediary loss parameter μ as described in the appendix.

   In our example for Bloomfield, μ is equal to 8.63986 x 10^{-6}. As can be seen in the equation above, μ is the ratio between the sum of the hourly loads across the load analysis period and the sum of the squared loads across the load analysis period. The *t* subscripts denote time, which should be hourly for both timeseries.

2) Next, calculate the hourly timeseries of Load at the customer level ($L_{customer,t}$), which is simply the hourly distribution Load (L_t) minus the variable distribution losses ($L_{loss,t}$)

$$L_{customer,t} = L_t - L_{loss,t} = L_t - {L_t}^2\mu$$

3) Next, calculate a timeseries reflecting PV production's impact at the substation ($P_{susbstation,t}$), i.e. the PV generation at the retail level plus the corresponding reduction of losses across the distribution grid. This can be calculated by multiplying the hourly timeseries of PV generation at the retail level (P_t) by the ratio between the load at the distribution level (L_t), and the load at the retail customer level ($L_{customer,t}$):

$$P_{substation,t} = P_t \cdot \frac{L_t}{L_{customer,t}} = \frac{P_t \cdot L_t}{L_t - {L_t}^2\mu}$$

This timeseries represents the full avoided energy impact at the substation, for each kWh of PV generation, inclusive of distribution-system losses.

4) In any hour, the avoided losses corresponding to PV production is the difference between the PV impact at the substation ($P_{substtation,t}$) and the metered or simulated PV generation at the retail customer level (P_t). These avoided losses losses are then summed over all hours of the Load Analysis Period. The avoided losses are then divided by the total PV generation at the customer level (P_t) over the same period to give the avoided losses per unit of PV production. This is applied to the wholesale rate (E) to determine the value of these avoided losses, the *Energy Loss Avoidance Value* (E_2):

$$Avoided\ Losses = \sum_t P_{substation,t} - \sum_t P_t$$

$$Relative\ Avoided\ Losses = \frac{Avoided\ Losses}{PV\ Production} = \frac{\sum_t P_{substation,t} - \sum_t P_t}{\sum_t P_t}$$

$$\boxed{E_2 = E \times Relative\ Avoided\ Losses}$$

E_2 represents the energy supply costs avoided due to displacement of these distribution-grid losses per kWh of PV generation. In our example for Bloomfield, relative avoided losses are equal to 3.3% and therefore, when we multiply by the wholesale rate of E = \$0.0362 per kWh, our energy loss avoidance value (E_2) is equal to \$0.00121per kWh.

First Year Capacity Value

The first year capacity value of solar is reflected in the reduction of generation capacity that otherwise would have been required to meet load at the distribution system peak and the corresponding avoided distribution system losses from having distributed solar.

Calculation of the value of Avoided Demand Charges (D_1)

The value of avoided demand charges is determined by calculating how much distributed PV generation reduces the total system-wide demand charge paid by the utility. Demand charges are assessed by applying the demand charge rate, D (\$/kW) to the peak distribution load within each month. PV fleet production across the service territory at each of these monthly demand peaks essentially reduces the distribution system peak load and therefore reduces the demand charge that otherwise would have been incurred. By applying the demand charge rate to this instantaneous PV fleet production at each of the monthly distribution system peaks and summing up across the year, we calculate the nominal annual distribution peak reduction value. A step-by-step strategy to do so is summarized below:

1) Identify the date and time (day and hour) of each monthly distribution load (L_t) peak.

Example: In June 2015, the distribution load peaked on the 10^{th} of the month at 2pm in Bloomfield.

2) Identify the corresponding nominal hourly PV fleet production (P_t) at each of these peak hours.

Example: On June 10^{th} at 2pm, the nominal hourly PV fleet production (P_t) at the peak ($P_{\text{at the peak}}$) was 0.6086 kW per kW of installed PV capacity.

3) Calculate the Monthly Avoided Demand Charges by multiplying the demand charge rate (D) by the nominal hourly PV fleet production at each monthly demand peak.

$$\textit{Monthly Avoided Demand Charges} = P_{peak} \times D$$

Example: Bloomfield's demand charge rate is assumed to be \$9.62/kW. Therefore, at this same monthly peak, 06/10/2015 2pm, the nominal avoided demand charges are \$5.85 per kW of rated PV capacity.

4) Calculate the annual value of these monthly Avoided Demand Charges (D_1) by dividing the sum of these nominal charges over the course of the load analysis period by the sum of the nominal hourly PV fleet production (P_t) over the same timeframe.

$$\boxed{D_1 = \frac{\sum_{year} Monthly\ Avoided\ Demand\ Charges}{\sum_{year} P_t}}$$

Example: The sum of Bloomfield's monthly avoided demand charges across 2015 (the load analysis period) is \$30.39 per kW of solar. The sum of the hourly nominal PV fleet production for 2015 was 1266.83 kWh per kW of solar. Therefore, the value of the avoided demand charges (D_1) is equal to \$0.02399 per kWh.

Calculating the Value of Capacity Loss Avoidance (D_2)

Next, calculate the value of the capacity that otherwise would have been lost to variable distribution grid inefficiencies were distributed PV not present. The following procedure is used:

1) Identify the date and time (day and hour) of each monthly distribution load (L_t) peak. Note that this identification should already have been performed in step 1 of calculating (D_1)

Example: In June 2015, the distribution load peaked on the 10^{th} of the month at 2pm in Bloomfield.

2) Identify the corresponding nominal hourly PV fleet production (P_t) at each of these peak hours.

Example: On June 10^{th} at 2pm, the nominal hourly PV fleet production (P_t) was 0.6086 kW per kW of rated PV capacity.

3) Identify the corresponding nominal hourly PV fleet production impact at the substation ($P_{substation,t}$). This timeseries should have been calculated previously in step 3 of calculating the Energy Loss Avoidance value (E_2)

Example: On June 8th at 8am, the nominal hourly PV fleet production at the substation ($P_{substation,t}$) was 0.6421 kW per kW of rated PV capacity.

4) Calculate the difference between the instantaneous PV generation impact at the substation ($P_{substtation, peak}$) and the metered or simulated PV generation at the customer level (P_{peak}) at the peak hour for each month, we obtain the nominal amount of avoided capacity losses that otherwise would have been incurred at this peak hour (units in kW). If we then multiply this nominal avoided capacity loss for each month by the demand charge rate (D, in $/kW), we obtain the monthly nominal avoided capacity charges resulting from avoided distribution losses per kW of PV generation (*Nominal Avoided Capacity Loss Charges)*. Summing up these monthly nominal avoided capacity loss charges over the course of the load analysis period and dividing this sum by the total amount of PV generation at the retail customer level (P_t) over the same period, we obtain an indication as to the total demand charges saved because we are avoiding losses over the distribution grid *per unit of PV electricity produced.* This is the Capacity Loss Avoidance Value (D_2):

$$Nominal\ Avoided\ Capacity\ Losses = P_{substation,peak} - P_{t,peak}$$

$$Nominal\ Avoided\ Capacity\ Loss\ \boldsymbol{Charges} = Nominal\ Avoided\ Capacity\ Losses \times D$$

$$\boxed{D_2 = \frac{\sum_{year} Nominal\ Avoided\ Capacity\ Loss\ Charges}{\sum_{year} P_t}}$$

Example:

- At the peak for June 2015 (June 8th at 8am), the nominal avoided capacity losses in Bloomfield were 0.03349 kW per rated kW of solar (0.6421-0.6086)
- The nominal avoided capacity loss charge for this peak was therefore $0.32 ($9.62 x 0.03349)
- The sum of all the nominal avoided capacity loss charges—for each month of 2015—is $1.50. As each nominal kW of our PV fleet in Bloomfield produces 1266.83 kWh annually, our Capacity Loss Avoidance Value (D_2) is therefore $0.00119 per kWh.

Total First Year Value of Solar (VOS)

Now that we have all four simplified components; two reflecting capacity savings (D_1, D_2) and two reflecting energy savings (E_1, E_2), we simply sum them up to calculate the total VOS:

$$VOS_{unlevelized} = \sum E_1, E_2, D_1, D_2$$

Example: In the calculation table below all of the required individual parameters are shown. In the case of Bloomfield, we calculate a value of avoided energy purchases of 3.74 ¢/kWh and a value of avoided demand charges of 2.52 ¢/kWh, including the effect of avoided distribution system losses. Therefore, the total first year unlevelized VOS is 6.26 ¢/kWh.

Table 6. (EXAMPLE for Bloomfield) Calculating the first year unlevelized VOS

		Overt Cost Avoidance A (¢/kWh)	+	Distribution Loss Avoidance B (¢/kWh)	=	Distributed PV value C (¢/kWh)
Energy Supply	Avoided Energy Purchases	3.62 ¢/kWh		0.12 ¢/kWh		3.74 ¢/kWh
Capacity Supply	Avoided Demand Charges	2.40 ¢/kWh		0.12 ¢/kWh		2.52 ¢/kWh
				Total Unlevelized VOS		**6.26 ¢/kWh**

Levelized VOS

The following provides a methodology for extrapolating the first year values over the full Economic Analysis Period, and for levelizing the VOS in a fixed, long term rate. In considering the long term avoided costs, the wholesale rates are assumed to increase by an estimated escalation rate (the same rate is used for both energy and demand prices). The methodology ensures that the net present value of the avoided costs is equal to the net present value of the VOS compensation.

By setting a compensation rate at the 25-year levelized value of solar, PV generators are being credited for the value they are forecasted to provide in the future. Of course, this levelized rate is still subject to the correlation between load and PV generation remaining roughly the same as it includes capacity value. We therefore recommend re-assessing the calculation on a periodic basis in order to reflect the true relationship between PV and the load.

Calculation of Nominal Annual PV Fleet Production

We first simulate the amount of electricity (in kWh) a nominal kW of our PV fleet is expected to produce for all 25 years of simulation. The amount produced in year *i* is *a* function of the degradation rate (ψ) and the total amount produced in year zero (the sum of the hourly timeseries P_t) as follows:

$$Nominal\ Annual\ PV\ Fleet\ Production \rightarrow \sum_{year} P_t \times (1-\psi)^i$$

Example:

In Bloomfield, nominal annual PV fleet production in year 10, assuming a 1% per year degradation rate is expected to be:

$$Nominal\ Annual\ PV\ Fleet\ Production_{10} = 1267\ kWh \times (1-1\%)^{10} = 1145\ kWh$$

Calculation of Nominal Annual Savings

We next calculate the nominal annual savings to the utility for each of the 25 years of simulation. This is an indication of the expected gross value delivered per kW of PV in the fleet and is therefore a function of both the escalated wholesale rate (escalation factor e) and the degraded PV generation. Nominal Annual Savings ($) is given by:

$$Nominal\ Annual\ Savings_i \rightarrow VOS_0 \times (1+\mathrm{e})^i \times Nominal\ Annual\ PV\ Fleet\ Production_{\,i}$$

Example:

In Bloomfield, the Nominal Annual Savings in year 10 is expected to be:

$$Nominal\ Annual\ Savings_{10} = \$0.0626/kWh \times (1+2.5\%)^{10} \times 1145\ kWh = \$91.78$$

Discounting Nominal Annual Savings and Nominal Annual PV Production

Next, we calculate the levelized value of solar by dividing the sum of the discounted nominal annual savings over the levelizing period of 25 years by the sum of the discounted nominal annual PV fleet production over the same period.

1) Discounting the Nominal Annual Savings in year *i* is calculated as such, where d is the discount rate:

$$Discounted\ Nominal\ Annual\ Savings_i = Nominal\ Annual\ Savings_i \times \frac{1}{(1+\mathrm{d})^i}$$

Example: In Bloomfield, the discounted nominal annual savings in year 10 would be:

$$Discounted\ Nominal\ Annual\ Savings_{10} = \$91.78 \times \frac{1}{(1+3\%)^{10}} = \$68.3$$

2) Discounting the nominal annual PV fleet production in year *i* is calculated in a very similar fashion:

$$Discounted\ Nominal\ Annual\ PV\ Fleet\ Production_i = Nominal\ Annual\ PV\ Fleet\ Production_i \times \frac{1}{(1+\mathrm{d})^i}$$

Example: In Bloomfield, the discounted nominal annual savings in year 10 would be:

$$Discounted\ Nominal\ Annual\ PV\ Fleet\ Production_{10} = 1145.7kWh \times \frac{1}{(1+3\%)^{10}} = 853\ kWh$$

3) Finally, we can calculate the 25-year levelized Value of Solar by dividing the sum of the discounted nominal annual savings by the sum of the discounted nominal annual PV fleet production across that time period:

$$VOS_{levelized} = \frac{\sum_i Discounted\ Nominal\ Annual\ Savings_i}{\sum_i Discounted\ Nominal\ Annual\ PV\ Fleet\ Production_i}$$

Example: In Bloomfield, the sum of the discounted nominal annual savings across 25 years is \$1666.8 and the sum of the discounted nominal annual PV Fleet production across the same period is 20503 kWh. Therefore, the discounted VOS ($VOS_{levelized}$) would be:

$$VOS_{levelized} = \frac{\$1{,}666.8}{20{,}503\ kWh} = \$0.0813\ per\ kWh$$

In

Table 7, an example for Bloomfield is shown where the individual parameters discussed in the steps above are shown for each year of calculation.

Table 7. (EXAMPLE for Bloomfield) Levelizing the VOS

yr	Nominal Annual PV Fleet Production (kWh)	Nominal Annual Savings $	Discounted Annual PV Fleet Production (kWh)	Discounted Annual Savings $
0	1266.83	$ 79.28	1267	$ 79.3
1	1254.17	$ 80.45	1218	$ 78.1
2	1241.62	$ 81.64	1170	$ 76.9
3	1229.21	$ 82.84	1125	$ 75.8
4	1216.92	$ 84.06	1081	$ 74.7
5	1204.75	$ 85.30	1039	$ 73.6
6	1192.70	$ 86.56	999	$ 72.5
7	1180.77	$ 87.84	960	$ 71.4
8	1168.96	$ 89.13	923	$ 70.4
9	1157.27	$ 90.45	887	$ 69.3
10	1145.70	$ 91.78	853	$ 68.3
11	1134.24	$ 93.13	819	$ 67.3
12	1122.90	$ 94.51	788	$ 66.3
13	1111.67	$ 95.90	757	$ 65.3
14	1100.56	$ 97.32	728	$ 64.3
15	1089.55	$ 98.75	699	$ 63.4
16	1078.66	$ 100.21	672	$ 62.4
17	1067.87	$ 101.69	646	$ 61.5
18	1057.19	$ 103.19	621	$ 60.6
19	1046.62	$ 104.71	597	$ 59.7
20	1036.15	$ 106.25	574	$ 58.8
21	1025.79	$ 107.82	551	$ 58.0
22	1015.53	$ 109.41	530	$ 57.1
23	1005.38	$ 111.02	509	$ 56.3
24	995.32	$ 112.66	490	$ 55.4
		Σ	20503	$ 1,666.8
			$VOS_{levelized}$	8.13 ¢/kWh

Sensitivity Analyses

While our example calculation for the City of Bloomfield represents reasonable parametric assumptions, changes in these assumptions can alter the calculation and therefore the VoS. In the series of tables below, we show how altering individual variables affects the resultant VoS. In each table, the first row indicates the value of the variable being modified[9] while the second row indicates the levelized VOS corresponding to this value. For instance, in the first table, the VOS corresponding to 1% variable distribution losses is 7.92 ¢/kWh while the VOS corresponding to 5% variable distribution losses is 8.35 ¢/kWh.

Table 8 VOS sensitivity to variable distribution loss rate

Variable Distribution Losses	1.0%	1.5%	2.0%	2.5%	3.0%	3.5%	4.0%	4.5%	5.0%
VOS$_{levelized}$	7.92 ¢/kWh	7.97 ¢/kWh	8.02 ¢/kWh	8.08 ¢/kWh	8.13 ¢/kWh	8.18 ¢/kWh	8.24 ¢/kWh	8.30 ¢/kWh	8.35 ¢/kWh

Table 9 VOS sensitivity to annual PV capacity degradation rate

PV degradation/yr	0.0%	1.0%	2.0%	3.0%	4.0%	5.0%	6.0%	7.0%	8.0%
VOS$_{levelized}$	8.23 ¢/kWh	8.13 ¢/kWh	8.03 ¢/kWh	7.93 ¢/kWh	7.83 ¢/kWh	7.74 ¢/kWh	7.65 ¢/kWh	7.57 ¢/kWh	7.49 ¢/kWh

Table 10 VOS sensitivity to energy charge.

Energy Charge ($/MWh)	28.2	30.2	32.2	34.2	36.2	38.2	40.2	42.2	44.2
VOS$_{levelized}$	7.06 ¢/kWh	7.32 ¢/kWh	7.59 ¢/kWh	7.86 ¢/kWh	8.13 ¢/kWh	8.40 ¢/kWh	8.67 ¢/kWh	8.93 ¢/kWh	9.20 ¢/kWh

Table 11 VOS sensitivity to demand charge rate

Demand Charge ($/kW)	5.62	6.62	7.62	8.62	9.62	10.62	11.62	12.62	13.62
VOS$_{levelized}$	6.77 ¢/kWh	7.11 ¢/kWh	7.45 ¢/kWh	7.79 ¢/kWh	8.13 ¢/kWh	8.47 ¢/kWh	8.81 ¢/kWh	9.15 ¢/kWh	9.49 ¢/kWh

[9] The baseline assumption value is highlighted in yellow for clarity.

Table 12 VOS sensitivity to rate of annual price escalation

Annual Price Escalator (%/yr)	0.50%	1%	1.50%	2%	2.50%	3%	3.50%	4%	4.50%
$VOS_{levelized}$	6.58 ¢/kWh	6.93 ¢/kWh	7.30 ¢/kWh	7.70 ¢/kWh	8.13 ¢/kWh	8.59 ¢/kWh	9.09 ¢/kWh	9.62 ¢/kWh	10.20 ¢/kWh

Table 13 VOS sensitivity to discount rate

Discount Rate	1%	2%	3%	4%	5%	6%	7%	8%	9%
$VOS_{levelized}$	8.33 ¢/kWh	8.23 ¢/kWh	8.13 ¢/kWh	8.03 ¢/kWh	7.94 ¢/kWh	7.85 ¢/kWh	7.77 ¢/kWh	7.69 ¢/kWh	7.61 ¢/kWh

By examining these tables, we can get a clearer picture regarding the influence each of these variables has on the VOS. If each of these variables is taken in concert to the VOS-maximizing top of its range[10] , we obtain a VOS of 14.57 ¢/kWh. Conversely, if we take each of these variables to their VOS-minimizing value, we obtain 4.37 ¢/kWh[11].

[10] 1% discount rate, 4.5%/yr annual price escalation, 13.62 $/kW demand charge, 44.2 $/MWh energy charge, 0%/yr PV degradation, 5% variable distribution losses

[11] 9% discount rate, 0.5%/yr annual price escalation, 5.62 $/kW demand charge, 28.2 $/MWh energy charge, 8%/yr PV degradation, 1% variable distribution losses

Other Considerations

Avoided Distribution Capacity Cost

In addition to the avoided capacity and energy charges, avoided distribution capacity costs may also be calculated. They are only important when distribution load is projected to grow and solar potentially avoids the cost of future capacity additions. They can be calculated in either of two ways:

- **System-wide Avoided Costs**. These are calculated using utility-wide costs and lead to a VOS rate that is "averaged" and applicable to all solar customers. This method is described below in the methodology.

- **Location-specific Avoided Costs**. These are calculated using location-specific costs, growth rates, etc., and lead to location-specific VOS rates. This method provides the utility with a means for offering a higher-value VOS rate in areas where capacity is most needed (areas of highest value). The details of this method are site specific and not included in the methodology, however they are to be implemented in accordance with the requirements set for the below.

System-wide Avoided Costs

System wide costs are determined using actual data from each of the last 10 years and peak growth rates are based on the utility's estimated future growth over the next 15 years. The costs and growth rate must be taken over the same time period because the historical investments must be tied to the growth associated with those investments.

All costs for each year for FERC accounts 360, 361, 362, 365, 366, and 367 should be included. These costs, however, should be adjusted to consider only capacity-related amounts. As such, the capacity-related percentages shown in Table 8 will be utility specific.

Table 8. (EXAMPLE) Determination of deferrable costs.

Account	Account Name	Additions ($) [A]	Retirements ($) [R]	Net Additions ($) = [A] + [R]	Capacity Related?	Deferrable ($)
	DISTRIBUTION PLANT					
360	Land and Land Rights	13,931,928	233,588	14,165,516	**100%**	14,165,516
361	Structures and Improvements	35,910,551	279,744	36,190,295	**100%**	36,190,295
362	Station Equipment	478,389,052	20,808,913	499,197,965	**100%**	499,197,965
363	Storage Battery Equipment					
364	Poles, Towers, and Fixtures	310,476,864	9,489,470	319,966,334		
365	Overhead Conductors and Devices	349,818,997	22,090,380	371,909,377	**25%**	92,977,344
366	Underground Conduit	210,115,953	10,512,018	220,627,971	**25%**	55,156,993
367	Underground Conductors and Devices	902,527,963	32,232,966	934,760,929	**25%**	233,690,232
368	Line Transformers	389,984,149	19,941,075	409,925,224		
369	Services	267,451,206	5,014,559	272,465,765		
370	Meters	118,461,196	4,371,827	122,833,023		
371	Installations on Customer Premises	22,705,193		22,705,193		
372	Leased Property on Customer Premises					
373	Street Lighting and Signal Systems	53,413,993	3,022,447	56,436,440		
374	Asset Retirement Costs for Distribution Plant	15,474,098	2,432,400	17,906,498		
TOTAL		3,168,661,143	130,429,387	3,299,090,530		**$931,378,345**

Cost per unit growth ($ per kW) is calculated by taking all of the total deferrable cost for each year, adjusting for inflation, and dividing by the kW increase in peak annual load over the 10 years.

Future growth in peak load is based on the utility's estimated future growth over the next 15 years. It is calculated using the ratio of peak loads of the fifteenth year (year 15) and the peak load from the first year (year 1):

$$GrowthRate = \left(\frac{P_{15}}{P_1}\right)^{1/14} - 1 \tag{18}$$

If the resulting growth rate is zero or negative (before adding solar PV), set the avoided distribution capacity to zero.

A sample economic value calculation is presented in Table 9. The distribution cost for the first year ($200 per kW in the example) is taken from the analysis of historical cost and estimated growth as described above. This cost is escalated each year using the rate in the VOS Data Table.

For each future year, the amount of new distribution capacity is calculated based on the growth rate, and this is multiplied by the cost per kW to get the cost for the year. The total discounted cost is calculated ($149M) and amortized over the 25 years.

PV is assumed to be installed in sufficient capacity to allow this investment stream to be deferred for one year. The total discounted cost of the deferred time series is calculated ($140M) and amortized.

Utility costs are calculated using the difference between the amortized costs of the conventional plan and the amortized cost of the deferred plan. For example, the utility cost for 2022 is ($14M - $13M)/54MW x 1000 W/kW = $14 per effective kW of PV. As before, utility prices are back-calculated using PV production, and the VOS component rate is calculated such that the total discounted amount equals the discounted utility cost.

Location-specific Avoided Costs

As an alternative to system-wide costs for distribution, location-specific costs may be used. When calculating location-specific costs, the calculation should follow the same method of the system-wide avoided cost method, but use local technical and cost data. The calculation should satisfy the following requirements:

- The distribution cost VOS should be calculated for each distribution planning area, defined as the minimum area in which capacity needs cannot be met by transferring loads internally from one circuit to another.
- Distribution loads (the sum of all relevant feeders), peak load growth rates and capital costs should be based on the distribution planning area.

- Local Fleet Production Shapes may be used, if desired. Alternatively, the system-level Fleet Production Shape may be used.
- Anticipated capital costs should be evaluated based on capacity related investments only (as above) using budgetary engineering cost estimates. All anticipated capital investments in the planning area should be included. Planned capital investments should be assumed to meet capacity requirements for the number of years defined by the amount of new capacity added (in MW) divided by the local growth rate (MW per year). Beyond this time period, which is beyond the planning horizon, new capacity investments should be assumed each year using the system-wide method.
- Planning areas for which engineering cost estimates are not available may be combined, and the VOS calculated using the system-wide method.

Table 9. (EXAMPLE) Economic value of avoided distribution capacity cost, system-wide.

		Conventional Distribution Planning				Deferred Distribution Planning			
Year	Distribution Cost	New Dist. Capacity	Capital Cost	Disc. Capital Cost	Amortized	Def. Dist. Capacity	Def. Capital Cost	Disc. Capital Cost	Amortized
	($/kW)	(MW)	($M)	($M)	$M/yr	(MW)	($M)	($M)	$M/yr
2014	$200	50	$10	$10	$14				$13
2015	$204	50	$10	$9	$14	50	$10	$9	$13
2016	$208	51	$11	$9	$14	50	$10	$9	$13
2017	$212	51	$11	$9	$14	51	$11	$9	$13
2018	$216	52	$11	$8	$14	51	$11	$8	$13
2019	$221	52	$11	$8	$14	52	$11	$8	$13
2020	$225	53	$12	$7	$14	52	$12	$7	$13
2021	$230	53	$12	$7	$14	53	$12	$7	$13
2022	$234	54	$13	$7	$14	53	$12	$7	$13
2023	$239	54	$13	$6	$14	54	$13	$6	$13
2024	$244	55	$13	$6	$14	54	$13	$6	$13
2025	$249	55	$14	$6	$14	55	$14	$6	$13
2026	$254	56	$14	$6	$14	55	$14	$6	$13
2027	$259	56	$15	$5	$14	56	$14	$5	$13
2028	$264	57	$15	$5	$14	56	$15	$5	$13
2029	$269	57	$15	$5	$14	57	$15	$5	$13
2030	$275	58	$16	$5	$14	57	$16	$5	$13
2031	$280	59	$16	$4	$14	58	$16	$4	$13
2032	$286	59	$17	$4	$14	59	$17	$4	$13
2033	$291	60	$17	$4	$14	59	$17	$4	$13
2034	$297	60	$18	$4	$14	60	$18	$4	$13
2035	$303	61	$18	$4	$14	60	$18	$4	$13
2036	$309	62	$19	$4	$14	61	$19	$3	$13
2037	$315	62	$20	$3	$14	62	$19	$3	$13
2038	$322	63	$20	$3	$14	62	$20	$3	$13
2039	$328					63	$21	$3	
				$149				$140	

CONTINUED Table 9. (EXAMPLE) Economic value of avoided distribution capacity cost, system-wide.

Year	p.u. PV Production (kWh)	Costs Utility ($)	Costs VOS ($)	Discount Factor	Disc. Costs Utility ($)	Disc. Costs VOS ($)	Prices Utility ($/kWh)	Prices VOS ($/kWh)
2014	1800	$16	$15	1.000	$16	$15	$0.009	$0.008
2015	1791	$15	$15	0.926	$14	$14	$0.009	$0.008
2016	1782	$15	$15	0.857	$13	$13	$0.009	$0.008
2017	1773	$15	$15	0.794	$12	$12	$0.009	$0.008
2018	1764	$15	$15	0.735	$11	$11	$0.009	$0.008
2019	1755	$15	$15	0.681	$10	$10	$0.008	$0.008
2020	1747	$15	$15	0.630	$9	$9	$0.008	$0.008
2021	1738	$15	$15	0.583	$9	$8	$0.008	$0.008
2022	1729	$14	$14	0.540	$8	$8	$0.008	$0.008
2023	1721	$14	$14	0.500	$7	$7	$0.008	$0.008
2024	1712	$14	$14	0.463	$7	$7	$0.008	$0.008
2025	1703	$14	$14	0.429	$6	$6	$0.008	$0.008
2026	1695	$14	$14	0.397	$6	$6	$0.008	$0.008
2027	1686	$14	$14	0.368	$5	$5	$0.008	$0.008
2028	1678	$14	$14	0.340	$5	$5	$0.008	$0.008
2029	1670	$13	$14	0.315	$4	$4	$0.008	$0.008
2030	1661	$13	$14	0.292	$4	$4	$0.008	$0.008
2031	1653	$13	$14	0.270	$4	$4	$0.008	$0.008
2032	1645	$13	$14	0.250	$3	$3	$0.008	$0.008
2033	1636	$13	$14	0.232	$3	$3	$0.008	$0.008
2034	1628	$13	$14	0.215	$3	$3	$0.008	$0.008
2035	1620	$13	$14	0.199	$3	$3	$0.008	$0.008
2036	1612	$13	$13	0.184	$2	$2	$0.008	$0.008
2037	1604	$12	$13	0.170	$2	$2	$0.008	$0.008
2038	1596	$12	$13	0.158	$2	$2	$0.008	$0.008
2039								

Validation: Present Value	**$166**	**$166**

While the avoided distribution capacity costs are likely the most directly pertinent to COUs, there do exist a number of other societal benefits delivered per kWh by PV which can be calculated and could be considered. Some of these societal benefits are summarized in table 10 below.

Table 10. Societal Benefits

Value Component	Detail
Credit for Local Manufacturing/ Assembly	Local tax revenue tied to net solar jobs
Market Price Reduction	Cost of wholesale power reduced in response to reduction in demand
Disaster Recovery	Cost to restore local economy (requires energy storage and islanding inverters)
Avoided Environmental Cost	Externality costs

Appendix

Derivation of the intermediary parameter, μ

The method assumes that variable distribution Losses ($L_{loss,t}$) are proportional to the square of the instantaneous distribution load (L_t^2) times a factor μ. Note that both $L_{loss,t}$ and L_t^2 are hourly timeseries and μ is a fixed parameter.

$$L_{loss,t} = {L_t}^2 \mu$$

Percent variable annual energy loss across the distribution grid, λ, is taken from the utility loss studies. By definition:

$$\lambda = \frac{\sum_{year} L_{loss,t}}{\sum_{year} L_t}$$

Substituting and solving, we get the following:

$$\mu = \lambda \frac{\sum_{year} L_t}{\sum_{year} {L_t}^2}$$

This equation enables the calculation of μ by using hourly load data. Once known, losses for any hour may be calculated using the first equation above.