

# Minnesota Value of Solar: Methodology

Minnesota Department of Commerce,  
Division of Energy Resources



APRIL 1, 2014\*

\*reformatted on April 9, 2014

Prepared by:



Clean Power Research®

Clean Power Research

<http://www.cleanpower.com/>

### Principal Investigators

Benjamin L. Norris  
Morgan C. Putnam  
Thomas E. Hoff

Prepared for:



Minnesota Department of Commerce,  
Division of Energy Resources

Mike Rothman, Commissioner  
Bill Grant, Deputy Commissioner  
Matt Schuerger, Technical Advisor  
Lise Trudeau, Project Manager  
651-539-1861  
[lise.trudeau@state.mn.us](mailto:lise.trudeau@state.mn.us)

### Legal Notice from Clean Power Research

This report was prepared for the Minnesota Department of Commerce by Clean Power Research. This report should not be construed as an invitation or inducement to any party to engage or otherwise participate in any transaction, to provide any financing, or to make any investment.

Any information shared with Minnesota Department of Commerce prior to the release of the report is superseded by the Report. Clean Power Research owes no duty of care to any third party and none is created by this report. Use of this report, or any information contained therein, by a third party shall be at the risk of such party and constitutes a waiver and release of Clean Power Research, its directors, officers, partners, employees and agents by such third party from and against all claims and liability, including, but not limited to, claims for breach of contract, breach of warranty, strict liability, negligence, negligent misrepresentation, and/or otherwise, and liability for special, incidental, indirect, or consequential damages, in connection with such use.

## Executive Summary

Minnesota passed legislation<sup>1</sup> in 2013 that allows Investor-Owned Utilities (IOUs) to apply to the Public Utility Commission (PUC) for a Value of Solar (VOS) tariff as an alternative to net metering, and as a rate identified for community solar gardens. The Department of Commerce (Commerce) was assigned the responsibility of developing and submitting a methodology for calculating the VOS tariff to the PUC by January 31, 2014. Utilities adopting the VOS will be required to follow this methodology when calculating the VOS tariff. Commerce selected Clean Power Research (CPR) to support the process of developing the methodology, and additionally held four public workshops to develop, present, and receive feedback.

The 2013 legislation specifically mandated that the VOS legislation take into account the following values of distributed PV: energy and its delivery; generation capacity; transmission capacity; transmission and distribution line losses; and environmental value. The legislation also mandated a method of implementation, whereby solar customers will be billed for their gross electricity consumption under their applicable tariff, and will receive a VOS credit for their gross solar electricity production.

The present document provides the methodology to be used by participating utilities. It is based on the enabling statute, stakeholder input, and guidance from Commerce. 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
- Requirements for calculating the electricity losses of the transmission and distribution systems
- Methods for performing technical calculations for avoided energy, effective generation capacity and effective distribution capacity
- Economic methods for calculating each value component (e.g., avoided fuel cost, capacity cost, etc.)
- Requirements for summarizing input data and final calculations in order to facilitate PUC and stakeholder review

Application of the methodology results in the creation of two tables: the VOS Data Table (a table of utility-specific input assumptions) and the VOS Calculation Table (a table of utility-specific total value of

---

<sup>1</sup> MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.

solar). Together these two tables ensure transparency and facilitate understanding among stakeholders and regulators.

The 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 distributed solar value. The process uses a component-specific load match factor (where applicable) and a component-specific loss savings factor. The values are then summed to yield the 25-year levelized value.

Figure ES-1. VOS Calculation Table: economic value, load match, loss savings and distributed PV value.

25 Year Levelized Value	Economic Value				Distributed Loss Savings	Distributed PV Value
	(\$/kWh)	X	(No Losses) (%)	X		
Avoided Fuel Cost	E1				DLS-Energy	V1
Avoided Plant O&M - Fixed	E2		ELCC		DLS-ELCC	V2
Avoided Plant O&M - Variable	E3				DLS-Energy	V3
Avoided Gen Capacity Cost	E4		ELCC		DLS-ELCC	V4
Avoided Reserve Capacity Cost	E5		ELCC		DLS-ELCC	V5
Avoided Trans. Capacity Cost	E6		ELCC		DLS-ELCC	V6
Avoided Dist. Capacity Cost	E7		PLR		DLS-PLR	V7
Avoided Environmental Cost	E8				DLS-Energy	V8
Avoided Voltage Control Cost						
Solar Integration Cost						

Lev. VOS

As a final step, the methodology calls for the conversion of the 25-year levelized value to an equivalent inflation-adjusted credit. The utility would then use the first year value as the credit for solar customers, and would adjust each year using the latest Consumer Price Index (CPI) data.

# Contents

- Executive Summary..... ii
- Introduction ..... 1
  - Background ..... 1
  - Purpose ..... 1
  - VOS Calculation Table Overview ..... 1
- VOS Rate Implementation ..... 3
  - Separation of Usage and Production ..... 3
  - VOS Components ..... 3
  - Solar Penetration ..... 5
  - Marginal Fuel ..... 5
  - Economic Analysis Period ..... 6
  - Annual VOS Tariff Update ..... 6
  - Transparency Elements..... 6
  - Glossary..... 6
- Methodology: Assumptions..... 7
  - Fixed Assumptions ..... 7
  - Utility-Specific Assumptions and Calculations ..... 10
- Methodology: Technical Analysis ..... 12
  - Load Analysis Period ..... 12
  - PV Energy Production ..... 13
  - PV System Rating Convention..... 13
  - Hourly PV Fleet Production..... 13
  - PV Fleet Shape ..... 16
  - Marginal PV Resource ..... 16

Annual Avoided Energy ..... 16

Load-Match Factors ..... 16

Effective Load Carrying Capability (ELCC) ..... 17

Peak Load Reduction (PLR) ..... 17

Loss Savings Analysis..... 18

Loss Savings Factors ..... 19

Methodology: Economic Analysis ..... 20

Discount Factors ..... 20

Avoided Fuel Cost ..... 21

Avoided Plant O&M – Fixed ..... 26

Avoided Plant O&M – Variable ..... 28

Avoided Generation Capacity Cost ..... 29

Avoided Reserve Capacity Cost..... 31

Avoided Transmission Capacity Cost ..... 31

Avoided Distribution Capacity Cost ..... 34

System-wide Avoided Costs ..... 34

Location-specific Avoided Costs..... 36

Avoided Environmental Cost ..... 40

Avoided Voltage Control Cost..... 41

Solar Integration Cost ..... 41

VOS Example Calculation ..... 43

Glossary..... 46

## Introduction

### Background

Minnesota passed legislation<sup>2</sup> in 2013 that allows Investor-Owned Utilities (IOUs) to apply to the Public Utility Commission (PUC) for a Value of Solar (VOS) tariff as an alternative to net metering, and as a rate identified for community solar gardens. The Department of Commerce (Commerce) was assigned the responsibility of developing and submitting a methodology for calculating the VOS tariff to the PUC by January 31, 2014. Utilities adopting the VOS will be required to follow this methodology when calculating the VOS rate. Commerce selected Clean Power Research (CPR) to support the process of developing the methodology, and additionally held four public workshops to develop, present, and receive feedback.

The present document provides the VOS methodology to be used by participating utilities. It is based on the enabling statute, stakeholder input and guidance from Commerce.

### Purpose

The State of Minnesota has identified a VOS tariff as a potential replacement for the existing Net Energy Metering (NEM) policy that currently regulates the compensation of home and business owners for electricity production from PV systems. As such, the adopted VOS legislation is not an incentive for distributed PV, nor is it intended to eliminate or prevent current or future incentive programs.

While NEM effectively values PV-generated electricity at the customer retail rate, a VOS tariff seeks to quantify the value of distributed PV electricity. If the VOS is set correctly, it will account for the real value of the PV-generated electricity, and the utility and its ratepayers would be indifferent to whether the electricity is supplied from customer-owned PV or from comparable conventional means. Thus, a VOS tariff eliminates the NEM cross-subsidization concerns. Furthermore, a well-constructed VOS tariff could provide market signals for the adoption of technologies that significantly enhance the value of electricity from PV, such as advanced inverters that can assist the grid with voltage regulation.

### VOS Calculation Table Overview

The VOS is the sum of several distinct value components, each calculated separately using procedures defined in this methodology. As illustrated in Figure 1, the calculation includes a gross component value, a component-dependent load-match factor (as applicable for capacity related values) and a component-dependent Loss Savings Factor.

---

<sup>2</sup> MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.

For example, the avoided fuel cost does not have a load match factor because it is not dependent upon performance at the highest hours (fuel costs are avoided during all PV operating hours). Avoided fuel cost does have a Loss Savings Factor, however, accounting for loss savings in both transmission and distribution systems. On the other hand, the Avoided Distribution Capacity Cost has an important Load Match Factor (shown as Peak Load Reduction, or 'PLR') and a Loss Savings Factor that only accounts for distribution (not transmission) loss savings.

Gross Values, Distributed PV Values, and the summed VOS shown in Figure 1 are all 25-year levelized values denominated in dollars per kWh.

Figure 1. Illustration of the VOS Calculation Table

25 Year Levelized Value	Economic Value	x	Load Match (No Losses)	x	(1 + Distributed Loss Savings)	=	Distributed PV Value
	(\$/kWh)		(%)		(%)		(\$/kWh)
Avoided Fuel Cost	E1				DLS-Energy		V1
Avoided Plant O&M - Fixed	E2		ELCC		DLS-ELCC		V2
Avoided Plant O&M - Variable	E3				DLS-Energy		V3
Avoided Gen Capacity Cost	E4		ELCC		DLS-ELCC		V4
Avoided Reserve Capacity Cost	E5		ELCC		DLS-ELCC		V5
Avoided Trans. Capacity Cost	E6		ELCC		DLS-ELCC		V6
Avoided Dist. Capacity Cost	E7		PLR		DLS-PLR		V7
Avoided Environmental Cost	E8				DLS-Energy		V8
Avoided Voltage Control Cost							
Solar Integration Cost							

Lev. VOS



## VOS Rate Implementation

### Separation of Usage and Production

Minnesota’s VOS legislation mandates that, if a VOS tariff is approved, solar customers will be billed for all usage under their existing applicable tariff, and will receive a VOS credit for their gross solar energy production. Separating usage (charges) from production (credits) simplifies the rate process for several reasons:

- Customers will be billed for all usage. Energy derived from the PV systems will not be used to offset (“net”) usage prior to calculating charges. This will ensure that utility infrastructure costs will be recovered by the utilities as designed in the applicable retail tariff.
- The utility will provide all energy consumed by the customer. Standby charges for customers with on-site PV systems are not permitted under a VOS rate.
- The rates for usage can be adjusted in future ratemaking.

### VOS Components

The definition and selection of VOS components were based on the following considerations:

- Components corresponding to minimum statutory requirements are included. These account for the “value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value.”
- Non-required components were selected only if they were based on known and measurable evidence of the cost or benefit of solar operation to the utility.
- Environmental costs are included as a required component, and are based on existing Minnesota and federal externality costs.
- Avoided fuel costs are based on long-term risk-free fuel supply contracts. This value implicitly includes both the avoided cost of fuel, as well as the avoided cost of price volatility risk that is otherwise passed from the utility to customers through fuel price adjustments.
- Credit for systems installed at high value locations (identified in the legislation as an option) is included as an option for the utility. It is not a separate VOS component but rather is implemented using a location-specific distribution capacity value (the component most affected by location). This is addressed in the Distribution Capacity Cost section.
- Voltage control and solar integration (a cost) are kept as “placeholder” components for future years. Methodologies are not provided, but these components may be developed for the future. Voltage control benefits are anticipated but will first require implementation of recent changes to national interconnection standards. Solar integration costs are expected to be small, but possibly measureable. Further research will be required on this topic.

Table 1 presents the VOS components selected by Commerce and the cost basis for each component. Table 2 presents the VOS components that were considered but not selected by Commerce. Selections were made based on requirements and guidance in the enabling statute, and were informed by stakeholder comments (including those from Minnesota utilities; local and national solar and environmental organizations; local solar manufacturers and installers; and private parties) and workshop discussions. Stakeholders participated in four public workshops and provided comments through workshop panels, workshop Q&A sessions and written comments.

Table 1. VOS components included in methodology.

Value Component	Basis	Legislative Guidance	Notes
<b>Avoided Fuel Cost</b>	Energy market costs (portion attributed to fuel)	Required (energy)	Includes cost of long-term price risk
<b>Avoided Plant O&amp;M Cost</b>	Energy market costs (portion attributed to O&M)	Required (energy)	
<b>Avoided Generation Capacity Cost</b>	Capital cost of generation to meet peak load	Required (capacity)	
<b>Avoided Reserve Capacity Cost</b>	Capital cost of generation to meet planning margins and ensure reliability	Required (capacity)	
<b>Avoided Transmission Capacity Cost</b>	Capital cost of transmission	Required (transmission capacity)	
<b>Avoided Distribution Capacity Cost</b>	Capital cost of distribution	Required (delivery)	
<b>Avoided Environmental Cost</b>	Externality costs	Required (environmental)	
<b>Voltage Control</b>	Cost to regulate distribution (future inverter designs)		Future (TBD)
<b>Integration Cost<sup>3</sup></b>	Added cost to regulate system frequency with variable solar		Future (TBD)

<sup>3</sup> This is not a value, but a cost. It would reduce the VOS rate if included.

Table 2. VOS components not included in methodology.

Value Component	Basis	Legislative Guidance	Notes
<b>Credit for Local Manufacturing/ Assembly</b>	Local tax revenue tied to net solar jobs	Optional (identified in legislation)	
<b>Market Price Reduction</b>	Cost of wholesale power reduced in response to reduction in demand		
<b>Disaster Recovery</b>	Cost to restore local economy (requires energy storage and islanding inverters)		

### Solar Penetration

Solar penetration refers to the total installed capacity of PV on the grid, generally expressed as a percentage of the grid’s total load. The level of solar penetration on the grid is important because it affects the calculation of the Effective Load Carrying Capability (ELCC) and Peak Load Reduction (PLR) load-match factors (described later).

In the methodology, the near-term level of PV penetration is used. This is done so that the capacity-related value components will reflect the near-term level of PV penetration on the grid. However, the change in PV penetration level will be accounted for in the annual adjustment to the VOS. To the extent that PV penetration increases, future VOS rates will reflect higher PV penetration levels.

### Marginal Fuel

This methodology assumes that PV displaces natural gas during PV operating hours. This is consistent with current and projected MISO market experience. During some hours of the year, other fuels (such as coal) may be the fuel on the margin. In these cases, natural gas displacement is a simplifying assumption that is not expected to materially impact the calculated VOS tariff. However, if future analysis indicates that the assumption is not warranted, then the methodology may be modified accordingly. For example, by changing the methodology to include displacement of coal production, avoided fuel costs may decrease and avoided environmental costs may increase.

## 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<sup>4</sup>. The methodology includes PV degradation effects as described later.

## Annual VOS Tariff Update

Each year, a new VOS tariff would be calculated using current data, and the new resulting VOS rate would be applicable to all customers entering the tariff during the year. Changes such as increased or decreased fuel prices and modified hourly utility load profiles due to higher solar penetration will be incorporated into each new annual calculation.

Customers who have already entered into the tariff in a previous year will not be affected by this annual adjustment. However, customers who have entered into a tariff in prior years will see their Value of Solar rates adjusted for the previous year's inflation rate as described later.

Commerce may also update the methodology to use the best available practices, as necessary.

## Transparency Elements

The methodology incorporates two tables that are to be included in a utility's application to the Minnesota PUC for the use of a VOS tariff. These tables are designed to improve transparency and facilitate understanding among stakeholders and regulators.

- **VOS Data Table.** This table provides a utility-specific defined list of the key input assumptions that go into the VOS tariff calculation. This table is described in more detail later.
- **VOS Calculation Table.** This table includes the list of value components and their gross values, their load-match factors, their Loss Savings Factors, and the computation of the total levelized value.

## Glossary

A glossary is provided at the end of this document defining some of the key terms used throughout this document.

---

<sup>4</sup> NREL: Solar Resource Analysis and High-Penetration PV Potential (April 2010).  
<http://www.nrel.gov/docs/fy10osti/47956.pdf>

## Methodology: Assumptions

### Fixed Assumptions

Table 3 and Table 4 present fixed assumptions, common to all utilities and incorporated into this methodology, that are to be applied to the calculation of 2014 VOS tariffs. These may be updated by Commerce in future years as necessary when performing the annual VOS update. Table 4 is described in more detail in the Avoided Environmental Cost subsection. Table terms can be found in the Glossary.

The general escalation rate is calculated as the average annual inflation rate over the last 25 years. The methodology uses the U.S. Bureau of Labor Statistics' Urban Consumer Price Index (CPI) data.

To retrieve Urban CPI data follow these steps:

1. Go to the U.S. Bureau of Labor Statistics's Top Picks for Consumer Price Index – All Urban Consumers<sup>5</sup>
2. Select “ U.S. All items, 1982-84=100 - CUUR0000SA0”. Click the “Retrieve Data” button near the bottom of the page.
3. Across from “Change Output Options”, change the “from” and “to” years to capture the last 25 years of annual average CPI data. For example, a VOS rate calculated in 2014 would enter 1998 (“from” year) and 2013 (“to” year). Click on “go” to generate the data for this time period.
4. Select the annual average CPI numbers for the first and last year of the 25 year period. These numbers are under the “Annual” column. For example, the 1988 annual CPI factor is 118.3, and the 2013 factor is 232.957.
5. Use the annual CPI factors in equation (1) to calculate the 25 year average annual inflation rate.

$$25yrAvgAnnualInflation = \left( \frac{AnnualAvg_{year(-1)} UCPI}{AnnualAvg_{year(-26)} UCPI} \right)^{1/(25)} - 1 \quad (1)$$

$$25yrAvgAnnualInflation = \left( \frac{AnnualAvg_{2013} UCPI}{AnnualAvg_{1998} UCPI} \right)^{1/(25)} - 1 = \left[ \left( \frac{232.957}{118.300} \right)^{1/25} - 1 \right] = 2.75\% \quad (2)$$

<sup>5</sup> CPI data can currently be found at: <http://data.bls.gov/cgi-bin/surveymost?cu>

Table 3. Fixed assumptions used in Methodology’s Example VOS calculations

Guaranteed NG Fuel Prices						
Year				Environmental Externalities		
2014	\$3.93	\$ per MMBtu		Environmental discount rate (nominal)	5.83%	per year
2015	\$4.12	\$ per MMBtu		Environmental costs	(shown in separate table)	
2016	\$4.25	\$ per MMBtu				
2017	\$4.36	\$ per MMBtu		<b>Economic Assumptions</b>		
2018	\$4.50	\$ per MMBtu		General escalation rate	2.75%	per year
2019	\$4.73	\$ per MMBtu				
2020	\$5.01	\$ per MMBtu				
2021	\$5.33	\$ per MMBtu		<b>Treasury Yields</b>		
2022	\$5.67	\$ per MMBtu		1 Year	0.13%	
2023	\$6.02	\$ per MMBtu		2 Year	0.29%	
2024	\$6.39	\$ per MMBtu		3 Year	0.48%	
2025	\$6.77	\$ per MMBtu		5 Year	1.01%	
				7 Year	1.53%	
				10 Year	2.14%	
<b>PV Assumptions</b>						
PV degradation rate	0.50%	per year		20 Year	2.92%	
PV life	25	years		30 Year	3.27%	

Table 4. Environmental externality costs by year.

Year	Analysis Year	CO <sub>2</sub> Cost (\$/MMBtu)	PM10 Cost (\$/MMBtu)	CO Cost (\$/MMBtu)	NO <sub>x</sub> Cost (\$/MMBtu)	Pb Cost (\$/MMBtu)	Total Cost (\$/MMBtu)
2014	0	1.939	0.069	0.000	0.013	0.000	2.022
2015	1	2.046	0.071	0.000	0.013	0.000	2.131
2016	2	2.158	0.073	0.000	0.014	0.000	2.245
2017	3	2.274	0.075	0.000	0.014	0.000	2.363
2018	4	2.395	0.077	0.000	0.015	0.000	2.487
2019	5	2.521	0.079	0.000	0.015	0.000	2.615
2020	6	2.652	0.082	0.000	0.015	0.000	2.749
2021	7	2.788	0.084	0.000	0.016	0.000	2.888
2022	8	2.930	0.086	0.000	0.016	0.000	3.032
2023	9	3.077	0.089	0.000	0.017	0.000	3.182
2024	10	3.230	0.091	0.000	0.017	0.000	3.338
2025	11	3.390	0.093	0.000	0.018	0.000	3.501
2026	12	3.555	0.096	0.000	0.018	0.000	3.669
2027	13	3.653	0.099	0.000	0.019	0.000	3.770
2028	14	3.830	0.101	0.000	0.019	0.000	3.950
2029	15	4.014	0.104	0.000	0.020	0.000	4.138
2030	16	4.205	0.107	0.000	0.020	0.000	4.332
2031	17	4.404	0.110	0.000	0.021	0.000	4.534
2032	18	4.610	0.113	0.000	0.021	0.000	4.744
2033	19	4.824	0.116	0.000	0.022	0.000	4.962
2034	20	5.047	0.119	0.000	0.023	0.000	5.189
2035	21	5.278	0.123	0.000	0.023	0.000	5.424
2036	22	5.518	0.126	0.000	0.024	0.000	5.668
2037	23	5.768	0.129	0.000	0.024	0.000	5.922
2038	24	6.027	0.133	0.000	0.025	0.000	6.185

See explanation in the Avoided Environmental Cost section.

## Utility-Specific Assumptions and Calculations

Some assumptions and calculations are unique to each utility. These include economic assumptions (such as discount rate) and technical calculations (such as ELCC). Utility-specific assumptions and calculations are determined by the utility, and are included in the VOS Data Table, a required transparency element.

The utility-specific calculations (such as capacity-related transmission capital cost) are determined using the methods described in this methodology.

An example VOS Data Table, showing the parameters to be included in the utility filing for the VOS tariff, is shown in Table 5. This table includes values that are given for example only. These example values carry forward in the example calculations.



Table 5. VOS Data Table (EXAMPLE DATA) — required format showing example parameters used in the example calculations.

	Input Data	Units		Input Data	Units
<b>Economic Factors</b>			<b>Power Generation</b>		
Start Year for VOS applicability	2014		Peaking CT, simple cycle		
Discount rate (WACC)	8.00%	per year	Installed cost	900	\$/kW
			Heat rate	9,500	BTU/kWh
<b>Load Match Analysis (see calculation method)</b>			Intermediate peaking CCGT		
ELCC (no loss)	40%	% of rating	Installed cost	1,200	\$/kW
PLR (no loss)	30%	% of rating	Heat rate	6,500	BTU/kWh
Loss Savings – Energy	8%	% of PV output	Other		
Loss Savings – PLR	5%	% of PV output	Solar-weighted heat rate (see calc. method)	8000	BTU per kWh
Loss Savings – ELCC	9%	% of PV output	Fuel Price Overhead	\$0.50	\$ per MMBtu
<b>PV Energy (see calculation method)</b>			Generation life	50	years
First year annual energy	1800	kWh per kW-AC	Heat rate degradation	0.100%	per year
			O&M cost (first Year) - Fixed	\$5.00	per kW-yr
			O&M cost (first Year) - Variable	\$0.0010	\$ per kWh
<b>Transmission (see calculation method)</b>			O&M cost escalation rate	2.00%	per year
Capacity-related transmission capital cost	\$33	\$ per kW-yr	Reserve planning margin	15%	
			<b>Distribution</b>		
			Capacity-related distribution capital cost	\$200	\$ per kW
			Distribution capital cost escalation	2.00%	per year
			Peak load	5000	MW
			Peak load growth rate	1.00%	per year

## Methodology: Technical Analysis

### Load Analysis Period

The VOS methodology requires that a number of technical parameters (PV energy production, effective load carrying capability (ELCC) and peak load reduction (PLR) load-match factors, and electricity-loss factors) be calculated over a fixed period of time in order to account for day-to-day variations and seasonal effects, such as changes in solar radiation. For this reason, the load analysis period must cover a 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.

Three types of time series data are required to perform the technical analysis:

- **Hourly Generation Load:** the hourly utility load over the Load Analysis Period. This is the sum of utility generation and import power needed to meet all customer load.
- **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).
- **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.

All three types of data must be provided as 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.

## PV Energy Production

### *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 the module PTC rating<sup>6</sup> [as listed by the California Energy Commission (CEC)<sup>7</sup>] to account for module de-rate effects. The result is then multiplied by the CEC-listed inverter efficiency rating<sup>8</sup> to account for inverter efficiency, and the result is multiplied by a loss factor to account for 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<sup>9</sup>. 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:<sup>10</sup>

Rating (kW-AC) = [Module Quantity] x [Module PTC rating (kW)] x [Inverter Efficiency Rating] x [Loss 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<sup>11</sup> installed to accurately derive a correct representation of aggregate PV production. Such metered data is to be gross PV output on the AC side of the

---

<sup>6</sup> 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.

<sup>7</sup> CEC module PTC ratings for most modules can be found at:

[http://www.gosolarcalifornia.ca.gov/equipment/pv\\_modules.php](http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php)

<sup>8</sup> CEC inverter efficiency ratings for most inverters can be found at:

<http://www.gosolarcalifornia.ca.gov/equipment/inverters.php>

<sup>9</sup> 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.

<sup>10</sup> 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.

<sup>11</sup> 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).

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:
    - Location (latitude and longitude)
    - System component ratings (e.g., module ratings and inverter ratings)
    - Tilt and azimuth angles
    - 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 6. 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 6. (EXAMPLE) 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.

### *PV Fleet Shape*

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 PV Fleet Shape. The units of the PV Fleet Shape are kWh per hour per kW-AC (or, equivalently, average kW per kW-AC).

### *Marginal PV Resource*

The PV Fleet Shape is hourly production of a Marginal PV Resource having a rating of 1 kW-AC.

### *Annual Avoided Energy*

Annual Avoided Energy (kWh per kW-AC per year) is the sum of the hourly PV Fleet Shape across all hours of the Load Analysis Period, divided by the numbers of years in the Load Analysis Period. The result is the annual output of the Marginal PV Resource.

$$\text{Annual Avoided Energy (kWh)} = \frac{\sum \text{Hourly PV Fleet Production}_h}{\text{NumberOfYearsInLoadAnalysisPeriod}} \quad (3)$$

- Defined in this way, the Annual Avoided Energy does not include the effects of loss savings. As described in the Loss Analysis subsection, however, it will have to be calculated for the two loss cases (with losses and without losses).

### **Load-Match Factors**

Capacity-related benefits are time dependent, so it is necessary to evaluate the effectiveness of PV in supporting loads during the critical peak hours. Two different measures of effective capacity are used:

- Effective Load Carrying Capability (ELCC)
- Peak Load Reduction (PLR)

Near term PV penetration levels are used in the calculation of the ELCC and PLR values so that the capacity-related value components will reflect the near term level of PV penetration on the grid. However, the ELCC and PLR will be re-calculated during the annual VOS adjustment and thus reflect any increase in future PV Penetration Levels.

### *Effective Load Carrying Capability (ELCC)*

The Effective Load Carrying Capability (ELCC) is the measure of the effective capacity for distributed PV that can be applied to the avoided generation capacity costs, the avoided reserve capacity costs, the avoided generation fixed O&M costs, and the avoided transmission capacity costs (see Figure 1).

Using current MISO rules for non-wind variable generation (MISO BPM-011, Section 4.2.2.4, page 35)<sup>12</sup>: the ELCC will be calculated from the PV Fleet Shape for hours ending 2pm, 3pm, and 4pm Central Standard Time during June, July, and August over the most recent three years. If three years of data are unavailable, MISO requires “a minimum of 30 consecutive days of historical data during June, July, or August” for the hours ending 2pm, 3pm and 4pm Central Standard Time.

The ELCC is calculated by averaging the PV Fleet Shape over the specified hours, and then dividing by the rating of the Marginal PV Resource (1 kW-AC), which results in a percentage value. Additionally, the ELCC must be calculated for the two loss cases (with and without T&D losses, as described in the Loss Analysis subsection).

### *Peak Load Reduction (PLR)*

The PLR is defined as the maximum distribution load over the Load Analysis Period (without the Marginal PV Resource) minus the maximum distribution load over the Load Analysis Period (with the Marginal PV Resource). The distribution load is the power entering the distribution system from the transmission system (i.e., generation load minus transmission losses). In calculating the PLR, it is not sufficient to limit modeling to the peak hour. All hours over the Load Analysis Period must be included in the calculation. This is because the reduced peak load may not occur in the same hour as the original peak load.

The PLR is calculated as follows. First, determine the maximum Hourly Distribution Load (D1) over the Load Analysis Period. Next, create a second hourly distribution load time series by subtracting the effect of the Marginal PV Resource, i.e., by evaluating what the new distribution load would be each hour given the PV Fleet Shape. Next, determine the maximum load in the second time series (D2). Finally, calculate the PLR by subtracting D2 from D1.

In other words, the PLR represents the capability of the Marginal PV Resource to reduce the peak distribution load over the Load Analysis Period. PLR is expressed in kW per kW-AC.

Additionally, the PLR must be calculated for the two loss cases (with distribution losses and without distribution losses, as described in the Loss Analysis subsection).

---

<sup>12</sup> <https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx>

## Loss Savings Analysis

In order to calculate the required Loss Savings Factors on a marginal basis as described below, it will be necessary to calculate ELCC, PLR and Annual Avoided Energy each twice. They should be calculated first by *including* the effects of avoided marginal losses, and second by *excluding* them. For example, the ELCC would first be calculated by including avoided transmission and distribution losses, and then re-calculated assuming no losses, i.e., as if the Marginal PV Resource was a central (not distributed) resource.

The calculations should observe the following

Table 7. Losses to be considered.

Technical Parameter	Loss Savings Considered
<b>Avoided Annual Energy</b>	Avoided transmission and distribution losses for every hour of the load analysis period.
<b>ELCC</b>	Avoided transmission and distribution losses during the MISO defined hours.
<b>PLR</b>	Avoided distribution losses (not transmission) at peak.

When calculating avoided marginal losses, the analysis must satisfy the following requirements:

1. Avoided losses are to be calculated on an hourly basis over the Load Analysis Period. The avoided losses are to be calculated based on the generation (and import) power during the hour and the expected output of the Marginal PV Resource during the hour.
2. Avoided losses in the transmission system and distribution systems are to be evaluated separately using distinct loss factors based on the most recent study data available.
3. Avoided losses should be calculated on a marginal basis. The marginal avoided losses are the difference in hourly losses between the case without the Marginal PV Resource, and the case with the Marginal PV Resource. Avoided average hourly losses are not calculated. For example, if the Marginal PV Resource were to produce 1 kW of power for an hour in which total customer load is 1000 kW, then the avoided losses would be the calculated losses at 1000 kW of customer load minus the calculated losses at 999 kW of load.
4. Distribution losses should be based on the power entering the distribution system, after transmission losses.
5. Avoided transmission losses should take into account not only the marginal PV generation, but also the avoided marginal distribution losses.



6. Calculations of avoided losses should not include no-load losses (e.g., corona, leakage current). Only load-related losses should be included.
7. Calculations of avoided losses in any hour should take into account the non-linear relationship between losses and load (load-related losses are proportional to the square of the load, assuming constant voltage). For example, the total load-related losses during an hour with a load of 2X would be approximately 4 times the total load-related losses during an hour with a load of only X.

### *Loss Savings Factors*

The Energy Loss Savings Factor (as a percentage) is defined for use within the VOS Calculation Table:

$$\begin{aligned} \text{Annual Avoided Energy}_{\text{WithLosses}} & \qquad \qquad \qquad (4) \\ & = \text{Annual Avoided Energy}_{\text{WithoutLosses}} (1 + \text{Loss Savings}_{\text{Energy}}) \end{aligned}$$

Equation 5 is then rearranged to solve for the Energy Loss Savings Factor:

$$\text{Loss Savings}_{\text{Energy}} = \frac{\text{Annual Avoided Energy}_{\text{WithLosses}}}{\text{Annual Avoided Energy}_{\text{WithoutLosses}}} - 1 \qquad (5)$$

Similarly, the PLR Loss Savings Factor is defined as:

$$\text{Loss Savings}_{\text{PLR}} = \frac{\text{PLR}_{\text{WithLosses}}}{\text{PLR}_{\text{WithoutLosses}}} - 1 \qquad (6)$$

and the ELCC Loss Savings Factor is defined as:

$$\text{Loss Savings}_{\text{ELCC}} = \frac{\text{ELCC}_{\text{WithLosses}}}{\text{ELCC}_{\text{WithoutLosses}}} - 1 \qquad (7)$$

## Methodology: Economic Analysis

The following subsections provide a methodology for performing the economic calculations to derive gross values in \$/kWh for each of the VOS components. These gross component values will then be entered into the VOS Calculation Table, which is the second of the two key transparency elements.

Important Note: The economic analysis is initially performed as if PV was centrally-located (without loss-saving benefits of distributed location) and with output perfectly correlated to load. Real-world adjustments are made later in the final VOS summation by including the results of the loss savings and load match analyses.

### Discount Factors

By convention, the analysis year 0 corresponds to the year in which the VOS tariff will begin. As an example, if a VOS was done in 2013 for customers entering a VOS tariff between January 1, 2014 and December 31, 2014, then year 0 would be 2014, year 1 would be 2015, and so on.

For each year  $i$ , a discount factor is given by

$$DiscountFactor_i = \frac{1}{(1 + DiscountRate)^i} \quad (8)$$

The *DiscountRate* is the utility Weighted Average Cost of Capital.

Similarly, a risk-free discount factor is given by:

$$RiskFreeDiscountFactor_i = \frac{1}{(1 + RiskFreeDiscountRate)^i} \quad (9)$$

The *RiskFreeDiscountRate* is based on the yields of current Treasury securities<sup>13</sup> of 1, 2, 3, 5, 7, 10, 20, and 30 year maturation dates. The *RiskFreeDiscountRate* is used once in the calculation of the Avoided Fuel Costs.

Finally, an environmental discount factor is given by:

$$EnvironmentalDiscountFactor_i = \frac{1}{(1 + EnvironmentalDiscountRate)^i} \quad (10)$$

---

<sup>13</sup> See <http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield>

The *EnvironmentalDiscountRate* is based on the 3% *real* discount rate that has been determined to be an appropriate societal discount rate for future environmental benefits.<sup>14</sup> As the methodology requires a nominal discount rate, this 3% *real* discount rate is converted into its equivalent 5.61% nominal discount rate as follows:<sup>15</sup>

$$\begin{aligned} \text{NominalDiscountRate} & & (11) \\ & = (1 + \text{RealDiscountRate}) \times (1 + \text{GeneralEscalationRate}) - 1 \end{aligned}$$

The *EnvironmentalDiscountRate* is used once in the calculation of the Avoided Environmental Costs.

PV degradation is accounted for in the economic calculations by reductions of the annual PV production in future years. As such, the PV production in kWh per kW-AC for the marginal PV resource in year *I* is given by:

$$PVProduction_i = PVProduction_0 \times (1 - PVDegradationRate)^i \quad (12)$$

where *PVDegradationRate* is the annual rate of PV degradation, assumed to be 0.5% per year – the standard PV module warranty guarantees a maximum of 0.5% power degradation per annum.

*PVProduction<sub>0</sub>* is the Annual Avoided Energy for the Marginal PV Resource.

PV capacity in year *i* for the Marginal PV Resource, taking into account degradation, equals:

$$PVCapacity_i = (1 - PVDegradationRate)^i \quad (13)$$

## Avoided Fuel Cost

Avoided fuel costs are based on long-term, risk-free fuel supply contracts. This value implicitly includes both the avoided cost of fuel as well as the avoided cost of price volatility risk that is otherwise passed from the utility to customers through fuel price adjustments.

PV displaces energy generated from the marginal unit, so it avoids the cost of fuel associated with this generation. Furthermore, the PV system is assumed to have a service life of 25 years, so the uncertainty in fuel price fluctuations is also eliminated over this period. For this reason, the avoided fuel cost must take into account the fuel as if it were purchased under a guaranteed, long term contract.

---

<sup>14</sup> <http://www.epa.gov/oms/climate/regulations/scc-tds.pdf>

<sup>15</sup> [http://en.wikipedia.org/wiki/Nominal\\_interest\\_rate](http://en.wikipedia.org/wiki/Nominal_interest_rate)

The methodology provides for three options to accomplish this:

- **Futures Market.** This option is described in detail below, and is based on the NYMEX NG futures with a fixed escalation for years beyond the 12-year trading period.
- **Long Term Price Quotation.** This option is identical to the above option, except the input pricing data is based on an actual price quotation from an AA-rated NG supplier to lock in prices for the 25-year guaranteed period.
- **Utility-guaranteed Price.** This is the 25-year fuel price that is guaranteed by the utilities. Tariffs using the utility guaranteed price will include a mechanism for removing the usage fuel adjustment charges and provide fixed prices over the term.

Table 8 presents the calculation of the economic value of avoided fuel costs.

For the Futures Market option, Guaranteed NG prices are calculated as follows. Prices for the first 12 years are based on NYMEX natural gas futures quotes. These quotes are published daily by the CME Group.<sup>16</sup>

Guaranteed NG prices are calculated by following these steps:

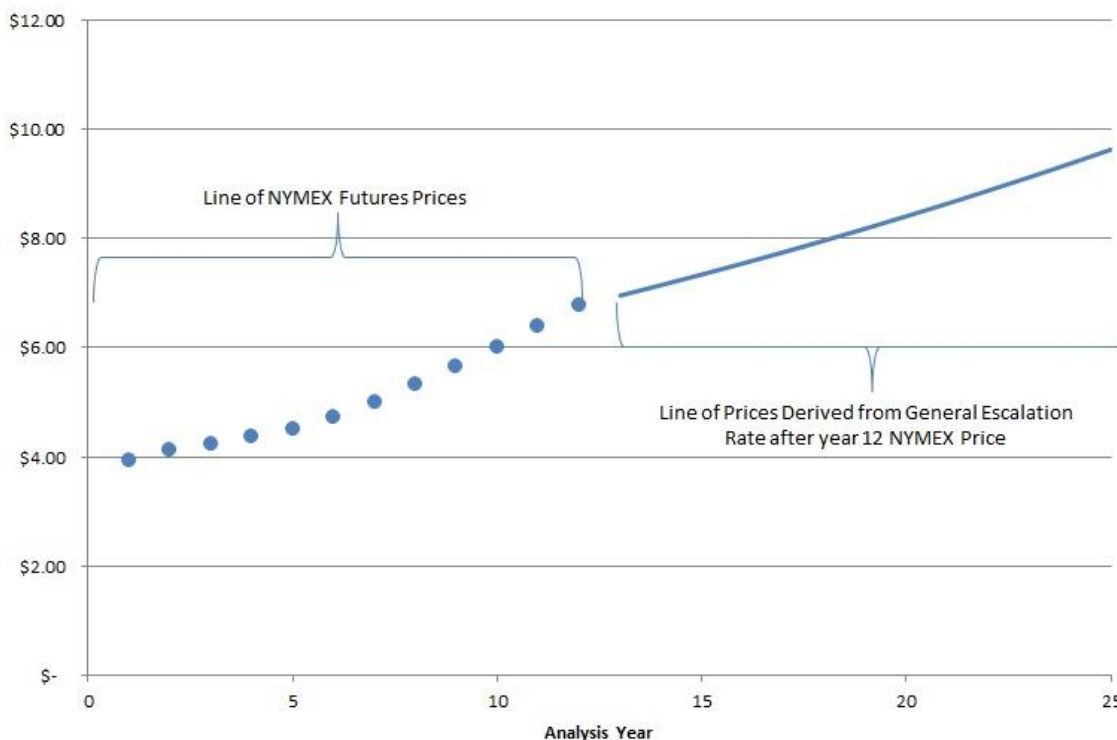
1. First, monthly prices are determined by averaging the 30 days of NYMEX prices for each month, starting with the most recent 30 daily prices and then repeating the same 30-day averaging for every other contract month of the 12 year period. If a utility calculating a VOS rate does not have historical daily NYMEX prices already collected internally they can obtain this data by recording quotes for 30 days. The timing of the data collection should be accounted for in planning the VOS rate calculation.
2. Then, the monthly prices are averaged to give a 12-month average in \$ per MMBtu, resulting in the first 12 annual prices in the set of 25 annual prices. Prices for years beyond this NYMEX limit are calculated by applying the general escalation rate. An assumed fuel price overhead amount, escalated by year using the general escalation rate, is added to the fuel price to give the burnertip fuel price.
3. Prices for years 13 through 25 are calculated by escalating the year 12 annual average NYMEX quote by the general escalation rate annually for each year.

The guaranteed fuel prices for the methodology's example calculation are shown in figure 2 below.

---

<sup>16</sup> CME Group's Natural Gas (Henry Hub) Physical Futures Quotes can be found at: <http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html>.

Figure 2. (EXAMPLE) Guaranteed Fuel Prices



The first-year solar-weighted heat rate is calculated as follows:

$$SolarWeighedHeatRate_0 = \frac{\sum HeatRate_j \times FleetProduction_j}{\sum FleetProduction_j} \tag{14}$$

where the summation is over all hours  $j$  of the load analysis period,  $HeatRate$  is the actual heat rate of the plant on the margin, and  $FleetProduction$  is the Fleet Production Shape time series.

The solar-weighted heat rate for future years is calculated as:

$$SolarWeighedHeatRate_i = SolarWeighedHeatRate_0 \times (1 + HeatRateDegradationRate)^i \tag{15}$$

The utility price in year  $i$  is:

$$UtilityPrice_i = \frac{BurnertipFuelPrice_i \times SolarWeighedHeatRate_i}{10^6} \tag{16}$$

where the burnertip price is in \$ per MMBtu and the heat rate is in Btu per kWh.

Utility cost is the product of the utility price and the per unit PV production. These costs are then discounted using the risk free discount rate and summed for all years. A risk-free discount rate (fitted to the US Treasury yields shown in Table 3) has been selected to account for the fact that there is no risk in the avoided fuel cost.

The VOS price (shown in red in Table 8) is the levelized amount that results in the same discounted amount as the utility price for the Avoided Fuel Cost component.

Table 8. (EXAMPLE) Economic Value of Avoided Fuel Costs.

Year				Prices		p.u. PV Production (kWh)	Costs		Discount Factor (risk free)	Disc. Costs	
	Guaranteed NG Price	Burnertip NG Price	Heat Rate	Utility	VOS		Utility	VOS		Utility	VOS
	(\$/MMBtu)	(\$/MMBtu)	(Btu/kWh)	(\$/kWh)	(\$/kWh)		(\$)	(\$)		(\$)	(\$)
2014	\$3.93	\$4.43	8000	\$0.035	\$0.056	1,800	\$64	\$101	1.000	\$64	\$101
2015	\$4.12	\$4.64	8008	\$0.037	\$0.056	1,791	\$67	\$100	0.999	\$66	\$100
2016	\$4.25	\$4.77	8016	\$0.038	\$0.056	1,782	\$68	\$100	0.994	\$68	\$99
2017	\$4.36	\$4.90	8024	\$0.039	\$0.056	1,773	\$70	\$99	0.986	\$69	\$98
2018	\$4.50	\$5.05	8032	\$0.041	\$0.056	1,764	\$72	\$99	0.971	\$70	\$96
2019	\$4.73	\$5.30	8040	\$0.043	\$0.056	1,755	\$75	\$98	0.951	\$71	\$94
2020	\$5.01	\$5.60	8048	\$0.045	\$0.056	1,747	\$79	\$98	0.927	\$73	\$91
2021	\$5.33	\$5.94	8056	\$0.048	\$0.056	1,738	\$83	\$97	0.899	\$75	\$88
2022	\$5.67	\$6.29	8064	\$0.051	\$0.056	1,729	\$88	\$97	0.872	\$76	\$85
2023	\$6.02	\$6.66	8072	\$0.054	\$0.056	1,721	\$92	\$96	0.842	\$78	\$81
2024	\$6.39	\$7.04	8080	\$0.057	\$0.056	1,712	\$97	\$96	0.809	\$79	\$78
2025	\$6.77	\$7.44	8088	\$0.060	\$0.056	1,703	\$103	\$96	0.786	\$81	\$75
2026	\$6.95	\$7.64	8097	\$0.062	\$0.056	1,695	\$105	\$95	0.762	\$80	\$72
2027	\$7.14	\$7.86	8105	\$0.064	\$0.056	1,686	\$107	\$95	0.737	\$79	\$70
2028	\$7.34	\$8.07	8113	\$0.065	\$0.056	1,678	\$110	\$94	0.713	\$78	\$67
2029	\$7.54	\$8.29	8121	\$0.067	\$0.056	1,670	\$112	\$94	0.688	\$77	\$64
2030	\$7.75	\$8.52	8129	\$0.069	\$0.056	1,661	\$115	\$93	0.663	\$76	\$62
2031	\$7.96	\$8.76	8137	\$0.071	\$0.056	1,653	\$118	\$93	0.637	\$75	\$59
2032	\$8.18	\$9.00	8145	\$0.073	\$0.056	1,645	\$121	\$92	0.612	\$74	\$56
2033	\$8.41	\$9.24	8153	\$0.075	\$0.056	1,636	\$123	\$92	0.587	\$72	\$54
2034	\$8.64	\$9.50	8162	\$0.078	\$0.056	1,628	\$126	\$91	0.563	\$71	\$51
2035	\$8.88	\$9.76	8170	\$0.080	\$0.056	1,620	\$129	\$91	0.543	\$70	\$49
2036	\$9.12	\$10.03	8178	\$0.082	\$0.056	1,612	\$132	\$90	0.523	\$69	\$47
2037	\$9.37	\$10.30	8186	\$0.084	\$0.056	1,604	\$135	\$90	0.504	\$68	\$45
2038	\$9.63	\$10.59	8194	\$0.087	\$0.056	1,596	\$138	\$89	0.485	\$67	\$43
<b>Validation: Present Value</b>										<b>\$1,826</b>	<b>\$1,826</b>

### **Avoided Plant O&M – Fixed**

Economic value calculations for fixed plant O&M are presented in Table 9. The first year fixed value is escalated at the O&M escalation rate for future years.

Similarly, PV capacity has an initial value of one during the first year because it is applicable to PV systems installed in the first year. Note that effective capacity (load matching) is handled separately, and this table represents the “ideal” resource, as if PV were able to receive the same capacity credit as a fully dispatchable technology.

The utility cost is the fixed O&M cost times the PV capacity divided by the utility capacity. Utility prices are the cost divided by the PV production. Costs are discounted using the utility discount factor and are summed for all years.

The VOS component value is calculated as before such that the discounted total is equal to the discounted utility cost.



Table 9. (EXAMPLE) Economic value of avoided plant O&M – fixed

Year	O&M Fixed (\$/kW)	Utility Capacity (p.u.)	PV Capacity (kW)	Prices		p.u. PV Production (kWh)	Costs		Discount Factor	Disc. Costs	
				Utility (\$/kWh)	VOS (\$/kWh)		Utility (\$)	VOS (\$)		Utility (\$)	VOS (\$)
2014	\$5.00	1.000	1.000	\$0.003	\$0.003	1800	\$5	\$6	1.000	\$5	\$6
2015	\$5.11	0.999	0.995	\$0.003	\$0.003	1791	\$5	\$6	0.926	\$5	\$6
2016	\$5.21	0.998	0.990	\$0.003	\$0.003	1782	\$5	\$6	0.857	\$4	\$5
2017	\$5.32	0.997	0.985	\$0.003	\$0.003	1773	\$5	\$6	0.794	\$4	\$5
2018	\$5.43	0.996	0.980	\$0.003	\$0.003	1764	\$5	\$6	0.735	\$4	\$4
2019	\$5.55	0.995	0.975	\$0.003	\$0.003	1755	\$5	\$6	0.681	\$4	\$4
2020	\$5.66	0.994	0.970	\$0.003	\$0.003	1747	\$6	\$6	0.630	\$3	\$4
2021	\$5.78	0.993	0.966	\$0.003	\$0.003	1738	\$6	\$6	0.583	\$3	\$3
2022	\$5.91	0.992	0.961	\$0.003	\$0.003	1729	\$6	\$6	0.540	\$3	\$3
2023	\$6.03	0.991	0.956	\$0.003	\$0.003	1721	\$6	\$6	0.500	\$3	\$3
2024	\$6.16	0.990	0.951	\$0.003	\$0.003	1712	\$6	\$6	0.463	\$3	\$3
2025	\$6.29	0.989	0.946	\$0.004	\$0.003	1703	\$6	\$6	0.429	\$3	\$2
2026	\$6.42	0.988	0.942	\$0.004	\$0.003	1695	\$6	\$6	0.397	\$2	\$2
2027	\$6.55	0.987	0.937	\$0.004	\$0.003	1686	\$6	\$6	0.368	\$2	\$2
2028	\$6.69	0.986	0.932	\$0.004	\$0.003	1678	\$6	\$6	0.340	\$2	\$2
2029	\$6.83	0.985	0.928	\$0.004	\$0.003	1670	\$6	\$6	0.315	\$2	\$2
2030	\$6.97	0.984	0.923	\$0.004	\$0.003	1661	\$7	\$6	0.292	\$2	\$2
2031	\$7.12	0.983	0.918	\$0.004	\$0.003	1653	\$7	\$6	0.270	\$2	\$1
2032	\$7.27	0.982	0.914	\$0.004	\$0.003	1645	\$7	\$5	0.250	\$2	\$1
2033	\$7.42	0.981	0.909	\$0.004	\$0.003	1636	\$7	\$5	0.232	\$2	\$1
2034	\$7.58	0.980	0.905	\$0.004	\$0.003	1628	\$7	\$5	0.215	\$2	\$1
2035	\$7.74	0.979	0.900	\$0.004	\$0.003	1620	\$7	\$5	0.199	\$1	\$1
2036	\$7.90	0.978	0.896	\$0.004	\$0.003	1612	\$7	\$5	0.184	\$1	\$1
2037	\$8.07	0.977	0.891	\$0.005	\$0.003	1604	\$7	\$5	0.170	\$1	\$1
2038	\$8.24	0.976	0.887	\$0.005	\$0.003	1596	\$7	\$5	0.158	\$1	\$1
<b>Validation: Present Value</b>										<b>\$67</b>	<b>\$67</b>

### Avoided Plant O&M – Variable

An example calculation of avoided plant O&M is displayed in Table 10. Utility prices are given in the VOS Data Table, escalated each year by the O&M escalation rate. As before, the per unit PV production is shown with annual degradation taken into account. The utility cost is the product of the utility price and the per unit production, and these costs are discounted. The VOS price of variable O&M is the levelized value resulting in the same total discounted cost.

Table 10. (EXAMPLE) Economic value of avoided plant O&M – variable.

Year	Prices		p.u. PV Production (kWh)	Costs		Discount Factor	Disc. Costs	
	Utility	VOS		Utility	VOS		Utility	VOS
	(\$/kWh)	(\$/kWh)		(\$)	(\$)		(\$)	(\$)
2014	\$0.001	\$0.001	1,800	\$2	\$2	1.000	\$2	\$2
2015	\$0.001	\$0.001	1,791	\$2	\$2	0.926	\$2	\$2
2016	\$0.001	\$0.001	1,782	\$2	\$2	0.857	\$2	\$2
2017	\$0.001	\$0.001	1,773	\$2	\$2	0.794	\$1	\$2
2018	\$0.001	\$0.001	1,764	\$2	\$2	0.735	\$1	\$2
2019	\$0.001	\$0.001	1,755	\$2	\$2	0.681	\$1	\$1
2020	\$0.001	\$0.001	1,747	\$2	\$2	0.630	\$1	\$1
2021	\$0.001	\$0.001	1,738	\$2	\$2	0.583	\$1	\$1
2022	\$0.001	\$0.001	1,729	\$2	\$2	0.540	\$1	\$1
2023	\$0.001	\$0.001	1,721	\$2	\$2	0.500	\$1	\$1
2024	\$0.001	\$0.001	1,712	\$2	\$2	0.463	\$1	\$1
2025	\$0.001	\$0.001	1,703	\$2	\$2	0.429	\$1	\$1
2026	\$0.001	\$0.001	1,695	\$2	\$2	0.397	\$1	\$1
2027	\$0.001	\$0.001	1,686	\$2	\$2	0.368	\$1	\$1
2028	\$0.001	\$0.001	1,678	\$2	\$2	0.340	\$1	\$1
2029	\$0.001	\$0.001	1,670	\$2	\$2	0.315	\$1	\$1
2030	\$0.001	\$0.001	1,661	\$2	\$2	0.292	\$1	\$1
2031	\$0.001	\$0.001	1,653	\$2	\$2	0.270	\$1	\$1
2032	\$0.001	\$0.001	1,645	\$2	\$2	0.250	\$1	\$0
2033	\$0.001	\$0.001	1,636	\$2	\$2	0.232	\$1	\$0
2034	\$0.001	\$0.001	1,628	\$2	\$2	0.215	\$1	\$0
2035	\$0.002	\$0.001	1,620	\$2	\$2	0.199	\$0	\$0
2036	\$0.002	\$0.001	1,612	\$2	\$2	0.184	\$0	\$0
2037	\$0.002	\$0.001	1,604	\$3	\$2	0.170	\$0	\$0
2038	\$0.002	\$0.001	1,596	\$3	\$2	0.158	\$0	\$0

<b>Validation: Present Value</b>	<b>\$24</b>	<b>\$24</b>
----------------------------------	-------------	-------------

### Avoided Generation Capacity Cost

The solar-weighted capacity cost is based on the installed capital cost of a peaking combustion turbine and the installed capital cost of a combined cycle gas turbine, interpolated based on heat rate:

$$Cost = Cost_{CCGT} + (HeatRate_{PV} - HeatRate_{CCGT}) \times \frac{Cost_{CT} - Cost_{CCGT}}{HeatRate_{CT} - HeatRate_{CCGT}} \quad (17)$$

Where  $HeatRate_{PV}$  is the solar-weighted heat rate calculated in equation ( 14 ).

Using equation ( 17 ) with the CT/CCGT heat rates and costs from the example VOS Data Table, we calculated a solar-weighted capacity cost of \$1,050 per kW. In the example, the amortized cost is \$86 per kW-yr.

Table 11 illustrates how utility costs are calculated by taking into account the degrading heat rate of the marginal unit and PV. For example, in year 2015, the utility cost is \$86 per kW-yr x 0.999 / 0.995 to give \$85 for each unit of effective PV capacity. Utility prices are back-calculated for reference from the per unit PV production. Again, the VOS price is selected to give the same total discounted cost as the utility costs for the Generation Capacity Cost component.

Table 11. (EXAMPLE) Economic value of avoided generation capacity cost.

Year				Prices		p.u. PV Production (kWh)	Costs		Discount Factor	Disc. Costs	
	Capacity Cost	Utility Capacity	PV Capacity	Utility	VOS		Utility	VOS		Utility	VOS
	(\$/kW-yr)	(p.u.)	(kW)	(\$/kWh)	(\$/kWh)		(\$)	(\$)		(\$)	(\$)
2014	\$86	1.000	1.000	\$0.048	\$0.048	1800	\$86	\$87	1.000	\$86	\$87
2015	\$86	0.999	0.995	\$0.048	\$0.048	1791	\$85	\$86	0.926	\$79	\$80
2016	\$86	0.998	0.990	\$0.048	\$0.048	1782	\$85	\$86	0.857	\$73	\$73
2017	\$86	0.997	0.985	\$0.048	\$0.048	1773	\$85	\$85	0.794	\$67	\$68
2018	\$86	0.996	0.980	\$0.048	\$0.048	1764	\$84	\$85	0.735	\$62	\$62
2019	\$86	0.995	0.975	\$0.048	\$0.048	1755	\$84	\$84	0.681	\$57	\$57
2020	\$86	0.994	0.970	\$0.048	\$0.048	1747	\$84	\$84	0.630	\$53	\$53
2021	\$86	0.993	0.966	\$0.048	\$0.048	1738	\$83	\$84	0.583	\$49	\$49
2022	\$86	0.992	0.961	\$0.048	\$0.048	1729	\$83	\$83	0.540	\$45	\$45
2023	\$86	0.991	0.956	\$0.048	\$0.048	1721	\$83	\$83	0.500	\$41	\$41
2024	\$86	0.990	0.951	\$0.048	\$0.048	1712	\$82	\$82	0.463	\$38	\$38
2025	\$86	0.989	0.946	\$0.048	\$0.048	1703	\$82	\$82	0.429	\$35	\$35
2026	\$86	0.988	0.942	\$0.048	\$0.048	1695	\$82	\$81	0.397	\$32	\$32
2027	\$86	0.987	0.937	\$0.048	\$0.048	1686	\$81	\$81	0.368	\$30	\$30
2028	\$86	0.986	0.932	\$0.048	\$0.048	1678	\$81	\$81	0.340	\$28	\$27
2029	\$86	0.985	0.928	\$0.048	\$0.048	1670	\$81	\$80	0.315	\$25	\$25
2030	\$86	0.984	0.923	\$0.048	\$0.048	1661	\$80	\$80	0.292	\$23	\$23
2031	\$86	0.983	0.918	\$0.049	\$0.048	1653	\$80	\$79	0.270	\$22	\$21
2032	\$86	0.982	0.914	\$0.049	\$0.048	1645	\$80	\$79	0.250	\$20	\$20
2033	\$86	0.981	0.909	\$0.049	\$0.048	1636	\$80	\$79	0.232	\$18	\$18
2034	\$86	0.980	0.905	\$0.049	\$0.048	1628	\$79	\$78	0.215	\$17	\$17
2035	\$86	0.979	0.900	\$0.049	\$0.048	1620	\$79	\$78	0.199	\$16	\$15
2036	\$86	0.978	0.896	\$0.049	\$0.048	1612	\$79	\$77	0.184	\$14	\$14
2037	\$86	0.977	0.891	\$0.049	\$0.048	1604	\$78	\$77	0.170	\$13	\$13
2038	\$86	0.976	0.887	\$0.049	\$0.048	1596	\$78	\$77	0.158	\$12	\$12
<b>Validation: Present Value</b>										<b>\$958</b>	<b>\$958</b>

### **Avoided Reserve Capacity Cost**

An example of the calculation of avoided reserve capacity cost is shown in Table 12. This is identical to the generation capacity cost calculation, except utility costs are multiplied by the reserve capacity margin. In the example, the reserve capacity margin is 15%, so the utility cost for 2014 is calculated as \$86 per unit effective capacity x 15% = \$13. The rest of the calculation is identical to the capacity cost calculation.

### **Avoided Transmission Capacity Cost**

Avoided transmission costs are calculated the same way as avoided generation costs except in two ways. First, transmission capacity is assumed not to degrade over time (PV degradation is still accounted for). Second, avoided transmission capacity costs are calculated based on the utility's 5-year average MISO OATT Schedule 9 charge in Start Year USD, e.g., in 2014 USD if year one of the VOS tariff was 2014. Table 13 shows the example calculation.

Table 12. (EXAMPLE) Economic value of avoided reserve capacity cost.

Year				Prices		p.u. PV Production	Costs		Discount Factor	Disc. Costs	
	Capacity Cost	Gen. Capacity	PV Capacity	Utility	VOS		Utility	VOS		Utility	VOS
	(\$/kW-yr)	(p.u.)	(kW)	(\$/kWh)	(\$/kWh)		(\$)	(\$)		(\$)	(\$)
2014	\$86	1.000	1.000	\$0.007	\$0.007	1800	\$13	\$13	1.000	\$13	\$13
2015	\$86	0.999	0.999	\$0.007	\$0.007	1791	\$13	\$13	0.926	\$12	\$12
2016	\$86	0.998	0.994	\$0.007	\$0.007	1782	\$13	\$13	0.857	\$11	\$11
2017	\$86	0.997	0.986	\$0.007	\$0.007	1773	\$13	\$13	0.794	\$10	\$10
2018	\$86	0.996	0.971	\$0.007	\$0.007	1764	\$13	\$13	0.735	\$9	\$9
2019	\$86	0.995	0.951	\$0.007	\$0.007	1755	\$13	\$13	0.681	\$9	\$9
2020	\$86	0.994	0.927	\$0.007	\$0.007	1747	\$13	\$13	0.630	\$8	\$8
2021	\$86	0.993	0.899	\$0.007	\$0.007	1738	\$13	\$13	0.583	\$7	\$7
2022	\$86	0.992	0.872	\$0.007	\$0.007	1729	\$12	\$12	0.540	\$7	\$7
2023	\$86	0.991	0.842	\$0.007	\$0.007	1721	\$12	\$12	0.500	\$6	\$6
2024	\$86	0.990	0.809	\$0.007	\$0.007	1712	\$12	\$12	0.463	\$6	\$6
2025	\$86	0.989	0.786	\$0.007	\$0.007	1703	\$12	\$12	0.429	\$5	\$5
2026	\$86	0.988	0.762	\$0.007	\$0.007	1695	\$12	\$12	0.397	\$5	\$5
2027	\$86	0.987	0.737	\$0.007	\$0.007	1686	\$12	\$12	0.368	\$4	\$4
2028	\$86	0.986	0.713	\$0.007	\$0.007	1678	\$12	\$12	0.340	\$4	\$4
2029	\$86	0.985	0.688	\$0.007	\$0.007	1670	\$12	\$12	0.315	\$4	\$4
2030	\$86	0.984	0.663	\$0.007	\$0.007	1661	\$12	\$12	0.292	\$4	\$3
2031	\$86	0.983	0.637	\$0.007	\$0.007	1653	\$12	\$12	0.270	\$3	\$3
2032	\$86	0.982	0.612	\$0.007	\$0.007	1645	\$12	\$12	0.250	\$3	\$3
2033	\$86	0.981	0.587	\$0.007	\$0.007	1636	\$12	\$12	0.232	\$3	\$3
2034	\$86	0.980	0.563	\$0.007	\$0.007	1628	\$12	\$12	0.215	\$3	\$3
2035	\$86	0.979	0.543	\$0.007	\$0.007	1620	\$12	\$12	0.199	\$2	\$2
2036	\$86	0.978	0.523	\$0.007	\$0.007	1612	\$12	\$12	0.184	\$2	\$2
2037	\$86	0.977	0.504	\$0.007	\$0.007	1604	\$12	\$12	0.170	\$2	\$2
2038	\$86	0.976	0.485	\$0.007	\$0.007	1596	\$12	\$12	0.158	\$2	\$2
							<b>Validation: Present Value</b>			<b>\$144</b>	<b>\$144</b>

Table 13. (EXAMPLE) Economic value of avoided transmission capacity cost.

Year				Prices		p.u. PV Production (kWh)	Costs		Discount Factor	Disc. Costs	
	Capacity Cost	Trans. Capacity	PV Capacity	Utility	VOS		Utility	VOS		Utility	VOS
	(\$/kW-yr)	(p.u.)	(kW)	(\$/kWh)	(\$/kWh)		(\$)	(\$)		(\$)	(\$)
2014	\$33	1.000	1.000	\$0.018	\$0.018	1800	\$33	\$33	1.000	\$33	\$33
2015	\$33	1.000	0.995	\$0.018	\$0.018	1791	\$33	\$33	0.926	\$30	\$30
2016	\$33	1.000	0.990	\$0.018	\$0.018	1782	\$33	\$33	0.857	\$28	\$28
2017	\$33	1.000	0.985	\$0.018	\$0.018	1773	\$33	\$33	0.794	\$26	\$26
2018	\$33	1.000	0.980	\$0.018	\$0.018	1764	\$32	\$32	0.735	\$24	\$24
2019	\$33	1.000	0.975	\$0.018	\$0.018	1755	\$32	\$32	0.681	\$22	\$22
2020	\$33	1.000	0.970	\$0.018	\$0.018	1747	\$32	\$32	0.630	\$20	\$20
2021	\$33	1.000	0.966	\$0.018	\$0.018	1738	\$32	\$32	0.583	\$19	\$19
2022	\$33	1.000	0.961	\$0.018	\$0.018	1729	\$32	\$32	0.540	\$17	\$17
2023	\$33	1.000	0.956	\$0.018	\$0.018	1721	\$32	\$32	0.500	\$16	\$16
2024	\$33	1.000	0.951	\$0.018	\$0.018	1712	\$31	\$31	0.463	\$15	\$15
2025	\$33	1.000	0.946	\$0.018	\$0.018	1703	\$31	\$31	0.429	\$13	\$13
2026	\$33	1.000	0.942	\$0.018	\$0.018	1695	\$31	\$31	0.397	\$12	\$12
2027	\$33	1.000	0.937	\$0.018	\$0.018	1686	\$31	\$31	0.368	\$11	\$11
2028	\$33	1.000	0.932	\$0.018	\$0.018	1678	\$31	\$31	0.340	\$10	\$10
2029	\$33	1.000	0.928	\$0.018	\$0.018	1670	\$31	\$31	0.315	\$10	\$10
2030	\$33	1.000	0.923	\$0.018	\$0.018	1661	\$30	\$30	0.292	\$9	\$9
2031	\$33	1.000	0.918	\$0.018	\$0.018	1653	\$30	\$30	0.270	\$8	\$8
2032	\$33	1.000	0.914	\$0.018	\$0.018	1645	\$30	\$30	0.250	\$8	\$8
2033	\$33	1.000	0.909	\$0.018	\$0.018	1636	\$30	\$30	0.232	\$7	\$7
2034	\$33	1.000	0.905	\$0.018	\$0.018	1628	\$30	\$30	0.215	\$6	\$6
2035	\$33	1.000	0.900	\$0.018	\$0.018	1620	\$30	\$30	0.199	\$6	\$6
2036	\$33	1.000	0.896	\$0.018	\$0.018	1612	\$30	\$30	0.184	\$5	\$5
2037	\$33	1.000	0.891	\$0.018	\$0.018	1604	\$29	\$29	0.170	\$5	\$5
2038	\$33	1.000	0.887	\$0.018	\$0.018	1596	\$29	\$29	0.158	\$5	\$5
<b>Validation: Present Value</b>										<b>\$365</b>	<b>\$365</b>

## Avoided Distribution Capacity Cost

Avoided distribution capacity costs may 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 14 will be utility specific.



Table 14. (EXAMPLE) Determination of deferrable costs.

Account	Account Name	Additions (\$) [A]	Retirements (\$) [R]	Net Additions (\$) = [A] - [R]	Capacity Related?	Deferrable (\$)
<b>DISTRIBUTION PLANT</b>						
360	Land and Land Rights	13,931,928	233,588	13,698,340	100%	13,698,340
361	Structures and Improvements	35,910,551	279,744	35,630,807	100%	35,630,807
362	Station Equipment	478,389,052	20,808,913	457,580,139	100%	457,580,139
363	Storage Battery Equipment					
364	Poles, Towers, and Fixtures	310,476,864	9,489,470	300,987,394		
365	Overhead Conductors and Devices	349,818,997	22,090,380	327,728,617	25%	81,932,154
366	Underground Conduit	210,115,953	10,512,018	199,603,935	25%	49,900,984
367	Underground Conductors and Devices	902,527,963	32,232,966	870,294,997	25%	217,573,749
368	Line Transformers	389,984,149	19,941,075	370,043,074		
369	Services	267,451,206	5,014,559	262,436,647		
370	Meters	118,461,196	4,371,827	114,089,369		
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	50,391,546		
374	Asset Retirement Costs for Distribution Plant	15,474,098	2,432,400	13,041,698		
<b>TOTAL</b>		<b>3,168,661,143</b>	<b>130,429,387</b>	<b>3,038,231,756</b>		<b>\$856,316,173</b>

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):

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

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

Year	Distribution Cost	Conventional Distribution Planning				Deferred Distribution Planning			
		New Dist. Capacity	Capital Cost	Disc. Capital Cost	Amortized	Def. Dist. Capacity	Def. Capital Cost	Disc. Capital Cost	Amortized
		(\$/kW)	(MW)	(\$M)	(\$M)	\$/yr	(MW)	(\$M)	(\$M)
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 15. (EXAMPLE) Economic value of avoided distribution capacity cost, system-wide.

Year	p.u. PV Production	Costs		Discount Factor	Disc. Costs		Prices	
		Utility	VOS		Utility	VOS	Utility	VOS
		(kWh)	(\$)		(\$)	(\$)	(\$)	(\$/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								

<b>Validation: Present Value</b>	<b>\$166</b>	<b>\$166</b>
----------------------------------	--------------	--------------

### Avoided Environmental Cost

Environmental costs are included as a required component and are based on existing Minnesota and federal externality costs. CO<sub>2</sub> and non-CO<sub>2</sub> natural gas emissions factors (lb per MM BTU of natural gas) are from the EPA<sup>17</sup> and NaturalGas.org.<sup>18</sup> Avoided environmental costs are based on the federal social cost of CO<sub>2</sub> emissions<sup>19</sup> plus the Minnesota PUC-established externality costs for non-CO<sub>2</sub> emissions.<sup>20</sup>

The externality cost of CO<sub>2</sub> emissions shown in Table 4 are calculated as follows. The Social Cost of Carbon (CO<sub>2</sub>) values for each year through 2050 are published in 2007 dollars per metric ton.<sup>21</sup> These costs are adjusted for inflation (converted to current dollars), converted to dollars per short ton, and then converted to cost per unit fuel consumption using the assumed values in Table 16.

For example, the CO<sub>2</sub> externality cost for 2020 (3.0% discount rate, average) is \$43 per metric ton of CO<sub>2</sub> emissions in 2007 dollars. This is converted to current dollars by multiplying by a CPI adjustment factor; for 2014, the CPI adjustment factor is of 1.13.<sup>22</sup> The resulting CO<sub>2</sub> costs per metric ton in current dollars are then converted to dollars per short ton by dividing by 1.102. Finally, the costs are escalated using the general escalation rate of 2.75% per year to give \$54.76 per ton. The \$54.76 per ton of CO<sub>2</sub> is then divided by 2000 pounds per ton and multiplied by 117.0 pounds of CO<sub>2</sub> per MMBtu = \$3.204 per MMBtu in 2020 dollars.

Table 16. Natural Gas Emissions.

	NG Emissions (lb/MMBtu)
PM <sub>10</sub>	0.007
CO	0.04
NO <sub>x</sub>	0.092
Pb	0.00
CO <sub>2</sub>	117.0

<sup>17</sup> <http://www.epa.gov/climatechange/ghgemissions/ind-assumptions.html> and <http://www.epa.gov/ttnchie1/ap42/>

<sup>18</sup> <http://www.naturalgas.org/environment/naturalgas.asp>

<sup>19</sup> See <http://www.epa.gov/climatechange/EPAactivities/economics/scc.html>, technical support document appendix, May 2013.

<sup>20</sup> “Notice of Updated Environmental Externality Values,” issued June 5, 2013, PUC docket numbers E-999/CI-93-583 and E-999/CI-00-1636.

<sup>21</sup> The annual Social Cost of Carbon values are listed in table A1 of the Social Cost of Carbon Technical Support Document. The Technical Support Document can be found at: <http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf>.

<sup>22</sup> The CPI adjustment factor can be calculated through the Bureau of Labor Statistics CPI inflation calculator. The calculator can be found at: <http://data.bls.gov/cgi-bin/cpicalc.pl>.

Pollutants other than CO<sub>2</sub> are calculated using the Minnesota externality costs using the following method. Externality costs are calculated as the midpoint of the low and high values for the urban scenario, adjusted to current dollars, and converted to a fuel-based value using Table 16. Each utility may select the set of non-CO<sub>2</sub> externality values that is most appropriate for their service territory (e.g. urban or metropolitan fringe or rural).

For the example, MN PUC's published 2012 urban externality values for PM10 are \$6,291 per ton (low case) and \$9,056 per ton (high case). These are averaged to be  $(\$6291 + \$9056) / 2 = \$7674$  per ton of PM10 emissions. For 2020, these are escalated using the general escalation rate of 2.75% per year to \$9,533 per ton. The \$9,533 per ton of PM10 is then divided by 2000 pounds per ton and multiplied by 0.007 pounds of PM10 per MMBtu to arrive at a PM10 externality cost of \$0.033 per MMBtu. Similar calculations are done for the other pollutants.

In the example shown in Table 17, the environmental cost is the sum of the costs of all pollutants. For example, in 2020, the total cost of \$3.287 per MMBtu corresponds to the 2020 total cost in Table 4. This cost is multiplied by the heat rate for the year (see Avoided Fuel Cost calculation) and divided by 10<sup>6</sup> (to convert Btus to MMBtus), which results in the environmental cost in dollars per kWh for each year. The remainder of the calculation follows the same method as the avoided variable O&M costs but using the environmental discount factor (see Discount Factors for a description of the environmental discount factor and its calculation).

### **Avoided Voltage Control Cost**

This is reserved for future updates to the methodology.

### **Solar Integration Cost**

This is reserved for future updates to the methodology.

Table 17. (EXAMPLE) Economic value of avoided environmental cost.











Year	Env. Cost (\$/MMBtu)	Heat Rate (Btu/kWh)	Prices		p.u. PV Production (kWh)	Costs		Discount Factor	Disc. Costs	
			Utility	VOS		Utility	VOS		Utility	VOS
			(\$/kWh)	(\$/kWh)		(\$)	(\$)		(\$)	(\$)
2014	2.022	8000	\$0.016	\$0.027	1,800	\$29	\$48	1.000	\$29	\$48
2015	2.131	8008	\$0.017	\$0.027	1,791	\$31	\$48	0.945	\$29	\$45
2016	2.245	8016	\$0.018	\$0.027	1,782	\$32	\$47	0.893	\$29	\$42
2017	2.363	8024	\$0.019	\$0.027	1,773	\$34	\$47	0.844	\$28	\$40
2018	2.487	8032	\$0.020	\$0.027	1,764	\$35	\$47	0.797	\$28	\$37
2019	2.615	8040	\$0.021	\$0.027	1,755	\$37	\$47	0.753	\$28	\$35
2020	2.749	8048	\$0.022	\$0.027	1,747	\$39	\$46	0.712	\$28	\$33
2021	2.888	8056	\$0.023	\$0.027	1,738	\$40	\$46	0.673	\$27	\$31
2022	3.032	8064	\$0.024	\$0.027	1,729	\$42	\$46	0.636	\$27	\$29
2023	3.182	8072	\$0.026	\$0.027	1,721	\$44	\$46	0.601	\$27	\$27
2024	3.338	8080	\$0.027	\$0.027	1,712	\$46	\$46	0.567	\$26	\$26
2025	3.501	8088	\$0.028	\$0.027	1,703	\$48	\$45	0.536	\$26	\$24
2026	3.669	8097	\$0.030	\$0.027	1,695	\$50	\$45	0.507	\$26	\$23
2027	3.770	8105	\$0.031	\$0.027	1,686	\$52	\$45	0.479	\$25	\$21
2028	3.950	8113	\$0.032	\$0.027	1,678	\$54	\$45	0.452	\$24	\$20
2029	4.138	8121	\$0.034	\$0.027	1,670	\$56	\$44	0.427	\$24	\$19
2030	4.332	8129	\$0.035	\$0.027	1,661	\$59	\$44	0.404	\$24	\$18
2031	4.534	8137	\$0.037	\$0.027	1,653	\$61	\$44	0.382	\$23	\$17
2032	4.744	8145	\$0.039	\$0.027	1,645	\$64	\$44	0.361	\$23	\$16
2033	4.962	8153	\$0.040	\$0.027	1,636	\$66	\$44	0.341	\$23	\$15
2034	5.189	8162	\$0.042	\$0.027	1,628	\$69	\$43	0.322	\$22	\$14
2035	5.424	8170	\$0.044	\$0.027	1,620	\$72	\$43	0.304	\$22	\$13
2036	5.668	8178	\$0.046	\$0.027	1,612	\$75	\$43	0.287	\$21	\$12
2037	5.922	8186	\$0.048	\$0.027	1,604	\$78	\$43	0.272	\$21	\$12
2038	6.185	8194	\$0.051	\$0.027	1,596	\$81	\$42	0.257	\$21	\$11
<b>Validation: Present Value</b>									<b>\$629</b>	<b>\$629</b>



## VOS Example Calculation

The gross economic value, load match, distributed loss savings factor, and distributed PV value are combined in the required VOS Levelized Calculation Chart. An example is presented in Figure 2 using the assumptions made for the example calculation. Actual VOS results will differ from those shown in the example, but utilities will include in their application a VOS Levelized Calculation Chart in the same format. For completeness, Figure 3 (not required of the utilities) is presented showing graphically the relative importance of the components in the example.

Figure 3. (EXAMPLE) VOS Levelized Calculation Chart (Required).

25 Year Levelized Value		Economic Value	Load Match (No Losses)	Distributed Loss Savings	Distributed PV Value
		(\$/kWh)	(%)	(%)	(\$/kWh)
	Avoided Fuel Cost	\$0.056		8%	\$0.061
	Avoided Plant O&M - Fixed	\$0.003	40%	9%	\$0.001
	Avoided Plant O&M - Variable	\$0.001		8%	\$0.001
	Avoided Gen Capacity Cost	\$0.048	40%	9%	\$0.021
	Avoided Reserve Capacity Cost	\$0.007	40%	9%	\$0.003
	Avoided Trans. Capacity Cost	\$0.018	40%	9%	\$0.008
	Avoided Dist. Capacity Cost	\$0.008	30%	5%	\$0.003
	Avoided Environmental Cost	\$0.027		8%	\$0.029
	Avoided Voltage Control Cost				
	Solar Integration Cost				
					\$0.127

Having calculated the levelized VOS credit, an inflation-adjusted VOS can then be found. An EXAMPLE inflation-adjusted VOS is provided in Figure 5 by using the general escalation rate as the annual inflation rate for all years of the analysis period. Both the inflation-adjusted VOS and the levelized VOS in Figure 5 represent the same long-term value. The methodology requires that the inflation-adjusted (real) VOS be used and updated annually to account for the current year’s inflation rate.

To calculate the inflation-adjusted VOS for the first year, the products of the levelized VOS, PV production and the discount factor are summed for each year of the analysis period and then divided by the sum of the products of the escalation factor, PV production, and the discount factor for each year of the analysis period, as shown below in Equation ( 17).

Figure 4. (EXAMPLE) Levelized value components.

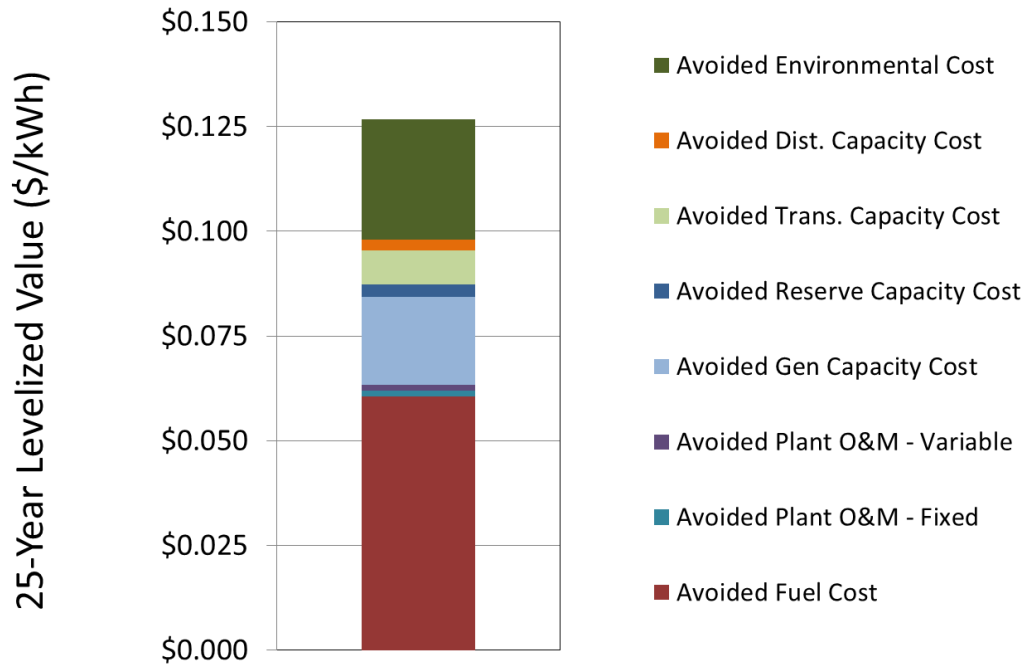
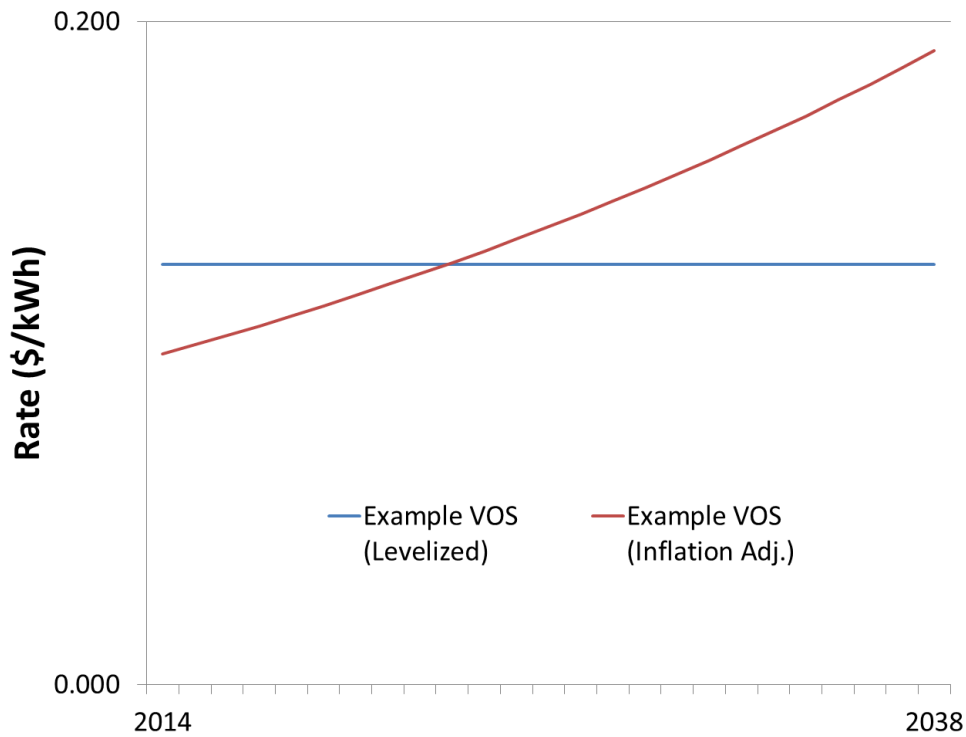


Figure 5. (EXAMPLE) Inflation-Adjusted VOS.



$$InflationAdjustedVOS_{Year0} \left( \frac{\$}{kWh} \right) \quad (19)$$

$$= \frac{\sum_i LevelizedVOS \times PVProduction_i \times DiscountFactor_i}{\sum_i EscalationFactor_i \times PVProduction_i \times DiscountFactor_i}$$

Once the first-year inflation-adjusted VOS is calculated, the value will then be updated on an annual basis in accordance with the observed inflation-rate. Table 18 provides the calculation of the EXAMPLE inflation-adjusted VOS shown in Figure 5. In this EXAMPLE, the inflation rate in future years is set equal to the general escalation rate of 2.75%.

Table 18. (EXAMPLE) Calculation of inflation-adjusted VOS.

Year	Discount Factor	Escalation Factor	Example VOS (Levelized)	Disc.	Example VOS (Inflation Adj.)	Disc.
2014	1.000	1.000	0.127	0.127	0.100	0.100
2015	0.926	1.027	0.127	0.117	0.102	0.095
2016	0.857	1.056	0.127	0.109	0.105	0.090
2017	0.794	1.085	0.127	0.101	0.108	0.086
2018	0.735	1.115	0.127	0.093	0.111	0.082
2019	0.681	1.145	0.127	0.086	0.114	0.078
2020	0.630	1.177	0.127	0.080	0.117	0.074
2021	0.583	1.209	0.127	0.074	0.121	0.070
2022	0.540	1.242	0.127	0.068	0.124	0.067
2023	0.500	1.276	0.127	0.063	0.127	0.064
2024	0.463	1.311	0.127	0.059	0.131	0.061
2025	0.429	1.347	0.127	0.054	0.134	0.058
2026	0.397	1.384	0.127	0.050	0.138	0.055
2027	0.368	1.422	0.127	0.047	0.142	0.052
2028	0.340	1.462	0.127	0.043	0.146	0.050
2029	0.315	1.502	0.127	0.040	0.150	0.047
2030	0.292	1.543	0.127	0.037	0.154	0.045
2031	0.270	1.585	0.127	0.034	0.158	0.043
2032	0.250	1.629	0.127	0.032	0.162	0.041
2033	0.232	1.674	0.127	0.029	0.167	0.039
2034	0.215	1.720	0.127	0.027	0.172	0.037
2035	0.199	1.767	0.127	0.025	0.176	0.035
2036	0.184	1.815	0.127	0.023	0.181	0.033
2037	0.170	1.865	0.127	0.022	0.186	0.032
2038	0.158	1.917	0.127	0.020	0.191	0.030
				1.461		1.461

## Glossary

Table 19. Input data definitions

Input Data	Used in Methodology Section	Definition
<b>Annual Energy</b>	PV Energy Production	The annual PV production (kWh per year) per Marginal PV Resource (initially 1 kW-AC) in the first year (before any PV degradation) of the marginal PV resource. This is calculated in the Annual Energy section of PV Energy Production and used in the Equipment Degradation section.
<b>Capacity-related distribution capital cost</b>	Avoided Distribution Capacity Cost	This is described more fully in the Avoided Distribution Capacity Cost section.
<b>Capacity-related transmission capital cost</b>	Avoided Transmission Capacity Cost	The cost per kW of new construction of transmission, including lines, towers, insulators, transmission substations, etc. Only capacity-related costs should be included.
<b>Discount rate (WACC)</b>	Multiple	The utility’s weighted average cost of capital, including interest on bonds and shareholder return.
<b>Distribution capital cost escalation</b>	Avoided Distribution Capacity Cost	Used to calculate future distribution costs.
<b>ELCC (no loss), PLR (no loss)</b>	Load Match Factors	The “Effective Load Carrying Capability” and the “Peak Load Reduction” of a PV resource expressed as percentages of rated capacity (kW-AC). These are described more fully in the Load Match section.
<b>Environmental Costs</b>	Avoided Environmental Cost	The costs required to calculate environmental impacts of conventional generation. These are described more fully in the Avoided Environmental Cost section

Input Data	Used in Methodology Section	Definition
<b>Environmental Discount Rate</b>	Avoided Environmental Cost	The societal discount rate used to calculate the present value of future environmental costs.
<b>Fuel Price Overhead</b>	Avoided Fuel Cost	The difference in cost of fuel as delivered to the plant and the cost of fuel as available in market prices. This cost reflects transmission, delivery, and taxes.
<b>General escalation rate</b>	Avoided Environmental Cost, Example Results	The annual escalation rate corresponding to the most recent 25 years of CPI index data <sup>23</sup> , used to convert constant dollar environmental costs into current dollars and to translate levelized VOS into inflation-adjusted VOS.
<b>Generation Capacity Degradation</b>	Avoided Generation Capacity Cost	The percentage decrease in the generation capacity per year
<b>Generation Life</b>	Avoided Generation Capacity Cost	The assumed service life of new generation assets.
<b>Guaranteed NG Fuel Prices</b>	Avoided Fuel Cost	The annual average prices to be used when the utility elects to use the Futures Market option. These are not applicable when the utility elects to use options other than the Futures Market option. They are calculated as the annual average of monthly NYMEX NG futures <sup>24</sup> .
<b>Heat rate degradation</b>	Avoided Generation Capacity Cost	The percentage increase in the heat rate (BTU per kWh) per year

<sup>23</sup> [www.bls.gov](http://www.bls.gov).

<sup>24</sup> See for example <http://futures.tradingcharts.com/marketquotes/NG.html>.

Input Data	Used in Methodology Section	Definition
<b>Installed cost and heat rate for CT and CCGT</b>	Avoided Generation Capacity Cost	The capital costs for these units (including all construction costs, land, ad valorem taxes, etc.) and their heat rates.
<b>Loss Savings (Energy, PLR, and ELCC)</b>	Loss Savings Analysis	The additional savings associated with Energy, PRL and ELCC, expressed as a percentage. These are described more fully in the Loss Savings section.
<b>O&amp;M cost escalation rate</b>	Avoided Plant O&M – Fixed, Avoided Plant O&M – Variable	Used to calculate future O&M costs.
<b>O&amp;M fixed costs</b>	Avoided Plant O&M – Fixed	The costs to operate and maintain the plant that are not dependent on the amount of energy generated.
<b>O&amp;M variable costs</b>	Avoided Plant O&M – Variable	The costs to operate and maintain the plant (excluding fuel costs) that are dependent on the amount of energy generated.
<b>Peak Load</b>	Avoided Distribution Capacity Cost	The utility peak load as expected in the VOS start year.
<b>Peak load growth rate</b>	Avoided Distribution Capacity Cost	This is described more fully in the Avoided Distribution Capacity Cost section.
<b>PV Degradation</b>	Equipment Degradation Factors	The reduction in percent per year of PV capacity and PV energy due to degradation of the modules. The value of 0.5 percent is the median value of 2000 observed degradation rates. <sup>25</sup>

<sup>25</sup> [D. Jordan and S. Kurtz, “Photovoltaic Degradation Rates – An Analytical Review,” NREL, June 2012.](#)

Input Data	Used in Methodology Section	Definition
<b>PV Life</b>	Multiple	The assumed service life of PV. This value is also used to define the study period for which avoided costs are determined and the period over which the VOS rate would apply.
<b>Reserve planning margin</b>	Avoided Reserve Capacity Cost	The planning margin required to ensure reliability.
<b>Solar-weighted heat rate</b>	Avoided Fuel Costs	This is described in the described in the Avoided Fuel Costs section.
<b>Start Year for VOS applicability</b>	Multiple	This is the first year in which the VOS would apply and the first year for which avoided costs are calculated.
<b>Transmission capital cost escalation</b>	Avoided Transmission Capacity Cost	Used to adjust costs for future capital investments.
<b>Transmission life</b>	Avoided Transmission Capacity Cost	The assumed service life of new transmission assets.
<b>Treasury Yields</b>	Escalation and Discount Rates	Yields for U.S. Treasuries, used as the basis of the risk-free discount rate calculation. <sup>26</sup>
<b>Years until new transmission capacity is needed</b>	Avoided Transmission Capacity Cost	This is used to test whether avoided costs for a given analysis year should be calculated and included.

<sup>26</sup> See <http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield>