PREPARED BY GDS ASSOCIATES, INC.

PEDERNALES ELECTRIC COOPERATIVE, INC.

Value of Solar Study

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GDS Associates, Inc.
ENGINEERS & CONSULTANTS

ACKNOWLEDGEMENTS

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 Executive Summary

Pedernales Electric Cooperative, Inc. ("PEC") engaged GDS Associates, Inc. ("GDS") to complete an independent, third-party, value of solar study. The study identifies and develops the avoided cost benefits of member-owned[1] distributed generation (DG).

It is important to note that this study is limited to the identification of avoided cost benefits and does not include a rate design process. Following the completion of this value of solar study, the avoided cost benefits will inform a separate process to develop a rate design to appropriately compensate members with DG for the cost-based value of their excess energy that is supplied to the PEC system.

1.1 STUDY METHODOLOGY

To meet the goals of the project, the value of solar study has been conducted using the following methodology:

- Identify the individual elements of the potential avoided cost benefits of member-owned DG that are applicable for the PEC system
- For each of the applicable avoided cost benefits, conduct a detailed analysis to determine the value to the PEC system associated with a typical generation profile for the current mix of PEC member-owned DG.

1.2 OBJECTIVES FOR VALUE OF SOLAR

PEC has established four objectives for the determination of the value of solar compensation methodology which provided guidance for this value of solar analysis.

1. ***The approach must be cost-based.*** The use of a cost-based method will ensure that the DG members are fairly compensated for the energy produced by their generation facilities, as well as limit the impacts of any subsidies paid by members that do not have solar generation.

   PEC is a nonprofit organization owned by the members of the cooperative. The cost basis to serve cooperative member-owners may differ significantly from other utilities. These differences include whether a utility owns and operates a generation fleet, whether a utility incurs regulatory costs that would be offset by DG, or other utility-specific costs not incurred by PEC.

   In addition, for the same reasons as above, no external costs, i.e., costs not directly incurred by PEC, have been included in determining the value of member generation. Such external costs, sometimes included by other utilities in value of solar computations, can be items such as societal, environmental, economic development costs, or others. These external costs have not been included in the development of the value of solar since they are not actual and direct costs incurred by PEC at this time and would result in subsidies paid by non-DG members. In the formulation of the Value of Solar these external costs are listed as avoided regulatory costs.

2. ***The scope of this report addresses systems with capacity of 50 kilowatts (kW) and below.*** PEC has a Board-approved rate design (Interconnect Wholesale Energy Rate) that will become effective January 1, 2022, to compensate members for the generation provided by solar facilities with

[1] "Member-owned" is intended to include both owned and leased facilities. Under either case, the PEC member retains the benefits of the generation.

capacities greater than 50 kW alternating current (AC). As such this study will only look at member systems with a capacity of 50 killowatts (kW) and below.

3. ***The report should consider reduced energy purchases resulting from member-owned DG equitably with Energy Efficiency.*** PEC has adopted a metering configuration of having a single meter with two registers, consisting of an inflow register and an outlflow register. This means that PEC does not have metered data from member-owned DG. From a rate standpoint, the reduced energy purchases of a member with DG will be treated the same for equity purposes as if a homeowner installed energy efficiency measures to reduce energy consumption. However, the study will use PVWatts generation curves to represent DG output behind the meter to appropriately value a member DG system.
4. ***The results of the value of solar calculation should be reported in a manner that is easily understood and informs the design of the compensation rate.*** As described herein, the value of solar analysis identifies the component benefits of solar generation and the value of each component as well as lays out the framework to include other costs in future studies as applicable.

1.3 BACKGROUND

As of December 2020, the PEC system had more than 5,000 installations of solar facilities with capacities of 50 kW or less. Data provided by PEC indicates that more than 3,200 of these solar systems were installed over the three-year period of 2018-2020. The data further indicates that the installations are being added at an increased pace. GDS analysis of the capacities of the member Installed solar generation illustrates that the average sized unit is 8.2 kW_{DC}, while the median is 7.0 kW_{DC}.

The large number of solar installations as well as the increased rate of implementation highlights the importance of determining an appropriate amount for the value of solar generation.

1.4 PVWATTS®

GDS used solar production curves generated by PVWatts® to represent average hourly and monthly generation output. These gross generation curves calculate the solar generation contribution to the 4-coincident peak (CP) transmission peaks, ancillary services, ERCOT LCRA Load Zone Settlement Point Prices (SPP) and the distribution non-coincident peaks (NCP), i.e., the drivers for the avoided cost benefits on the PEC system.

The NREL PVWatts® calculator is a web application developed by the National Renewable Energy Laboratory (NREL) that estimates the electricity production of a grid-connected photovoltaic system. GDS considers PVWatts® an acceptable model to use for this analysis and notes that it is a widely used tool in the electric utility industry.

GDS evaluated the use of both actual weather data and average weather to develop the PVWatts® analysis. In order to avoid irregular generation profiles, GDS relied on generation curves developed from average weather for each month. In addition, the PVWatts® analysis required the use of numerous other assumptions, all of which are described in detail in the report, as well as summarized in Table 3-1.

1.5 VALUE OF SOLAR METHODOLOGY

This section of the report explains the methods, data sources, and results of GDS' determination of the value of DG. The approach is designed to compute an avoided cost of all applicable cost elements. PEC currently has over 5,000 members that own distributed generation, all of which are solar save for one wind unit. Given that currently over 99% of DG in the PEC territory is solar, GDS has conducted a Value of Solar study. In the future, should battery storage or other distributed resources be deployed by PEC members, PEC will update the analysis to include the value of those resources.

The results of this analysis will be applicable to all sources of generation that are 50 kW or smaller. Therefore, we have termed the analysis a Value of Distributed Generation analysis.

Data was drawn from a variety of sources to develop the Value Of Distributed Generation, including both internal PEC sources and external sources to ensure the analysis is supportable and robust:

- PEC Member Metered Usage Databases
- PEC Financial Databases
- NREL PVWatts®
- Electric Reliability Council of Texas (ERCOT) Historical Pricing Databases

1.6 VALUE OF DISTRIBUTED GENERATION MODEL

GDS developed a model that considers the three primary functions of a utility grid: generation, transmission, and distribution.

The model recognizes that when a member installs a behind-the-meter generator, and that system generates power, PEC's costs are potentially reduced through reduced energy and ancillary service purchases in the ERCOT market, reduced transmission access expense, and avoided investment and operations and maintenece expense on the distribution system. The Value Of Distributed Generation, then, is a computation of avoided costs of the generation, transmission, ancillary services[2], and distribution functions. Additionally, the DG may allow PEC to avoid certain regulatory costs.

1.7 ANNUAL ENERGY PRODUCTION

As described in Section 4.4, GDS used solar production curves generated by PVWatts® to represent average hourly and monthly generation output. The generator was modelled using 14.1% system losses with an inverter efficiency of 96% and a direct current (DC) to AC size ratio of 1.2. This produces a maximum AC output of 833 watts for a 1 kW DC panel. The 1 kW DC system can be extrapolated to produce the same results for any size system. Curves were generated for six different locations in or near PEC's service territory. The locations include Austin, Fredericksburg, Johnson City, Junction, Lampasas, and San Antonio. A weighted average of the six locations was used to represent a typical generation curve. The weights represent the relative concentration of existing DG members respective of each geographic location.

All ERCOT-market interactions are settled at the wholesale point of delivery, whereas the PVWatts® generation curves are representative of load at the retail meter. Therefore, to appropriately account for distribution system losses, the generation curves are adjusted up for distribution losses. When computing

[2] Ancillary services are related to the generation and transmission function and are also purchased by PEC in the ERCOT market through its contract with LCRA.

avoided ERCOT costs (including market energy, transmission demand, and ancillary services), the generation output is grossed up by a 5.98% distribution loss factor.

1.8 AVOIDED ENERGY COSTS

ERCOT LCRA Load Zone SPPs are used to evaluate PEC's marginal cost of energy. To compute market energy costs, GDS used three years (2018-2020) of historical real-time SPP at the LCRA zone. Real time prices are used since they are representative of the final settlement price for energy in the ERCOT market. The average hourly generation profile was then used to compute the marginal cost savings of the generation output for three years. A three-year average was then computed.

There is significant variability in ERCOT energy prices annually, seasonally, day-to-day and even hourly. Using a three-year average captures that variation and ensures the avoided cost of market energy is reflective of typical conditions over a longer period of time. Summer prices tend to peak from 2 PM to 5 PM, when solar panels are generating but not at peak output. Winter prices tend to peak during cold and darker hours when heating requirements are highest. Therefore, solar panels are not generating electricity during many of the more expensive hours in the winter.

1.9 AVOIDED CAPACITY OR DEMAND COSTS

There is no avoided capacity cost value for generation demand. However, should either ERCOT adopt some form of a capacity market or PEC change its supply options or contracts in such a way that it has marginal capacity cost exposure, it would become appropriate at that time for PEC to update its Value Of Distributed Generation model and incorporate the avoided cost impacts.

1.10 AVOIDED TRANSMISSION COSTS

Transmission costs in ERCOT are incurred based on a utility's contribution to ERCOT's four summer peak demands, one for each month of June through September. The average of the four summer coincident peaks is called the 4-CP. A postage stamp rate for transmission is applied monthly based on the prior year's 4-CP.

The postage stamp rate is charged by all Transmission Owners in ERCOT as approved by the Public Utility Commission of Texas. In the last three years, the ERCOT 4-CPs have occurred most often in the 5PM hour. In fact, 10 of the 12 peaks in the past three years occurred in that hour. The other two peaks occurred at 6PM and at 3 PM.

To compute the avoided transmission cost, GDS applies a coincidence factor to the peak output of a generation unit times the average annual transmission rate. The coincidence factors represent the average percentage of maximum output being achieved by the generator at the specific date and hour of the 4-CP. The factors were computed by dividing the hourly solar generation adjusted for distribution losses at the time of the CP peaks by the maximum AC output of the generator adjusted for distribution losses. The solar production at each location and the coincidence factors are shown in Table 4-4.

GDS recognizes that the transmission rate has been increasing steadily over the three-year historical period. To both maintain consistency with a Value Of Distributed Generation analysis using historical avoided cost information but to recognize the increasing nature of transmission costs, GDS used the 2020 transmission rate for each year of the analysis. We then applied that average to the three-year historical coincidence factors to compute the transmission costs for solar generation. Table 4-5 demonstrates the avoided cost of transmission.

1.11 AVOIDED DISTRIBUTION COSTS

Determining the appropriate avoided cost of distribution plant investment is challenging, and there are various approaches that have been used in the industry. For many distribution system planners both the non-firm nature of distributed generation as well as the non-coincident nature of the distributed generation in relation to system and feeder level peaks means they cannot safely assume a lower demand for planning purposes. There are, however, differing opinions by system engineers regarding whether distribution costs are avoided by the additional of demand side management programs, conservation, or distributed generation.

While there is some debate among analysts, PEC's planning engineers, like much of the industry, have concluded that the distribution system costs are predominantly fixed and will not decline with a decrease in load resulting from the operation of DG at current levels. This is primarily due to the requirement that distribution investment must be sufficient to meet system peak demands at any time throughout the year. To illustrate that there is not any avoided expense value from the current PEC member-owned DG fleet a review of the historic PEC distribution system peaks used for system planning overlayed with the PVWatts® generation curves can be found in Section 4.8.2.

To determine the value associated with distributed generation, GDS computed a coincidence factor between the PVWatts® generation curves and the timing of the monthly PEC peak demands for 2018-2020. A coincidence factor of zero or less than 5% occurs in January, February, and December of each year.

1.12 AVOIDED ANCILLARY SERVICES COSTS

Ancillary services represent functions that help grid operators, such as ERCOT, maintain a reliable and functioning electricity system every hour of the day. An ancillary service is a service necessary to support the transmission of energy to members while maintaining reliable operation of the transmission system.

ERCOT makes use of and charges all loads in ERCOT for four different ancillary services, each of which are included in the analysis and defined in more detail in Section 4:

- Regulation Up Service.
- Regulation Down Service.
- Responsive Reserve.
- Non-Spinning Reserve

Each of the reserve categories are independently priced on an hourly basis.

To determine the avoided cost of ancillary services, GDS computed the effective cost per megawatt-hour (MWh) that LCRA settled as PEC's representative in the ERCOT market for each of the four services over the three-year period of 2018-2020. The effective price to PEC for these services in any hour is based on a load share ratio of the ERCOT hourly megawatts (MW) associated with each service. The effective hourly ancillary service price was multiplied by the hourly generation curves to determine the ancillary service benefit produced by solar generation. In Section 4.9, GDS identifies the average annual value of each of the ancillary services.

1.13 AVOIDED REGULATORY COSTS

PEC currently incurs no regulatory or environmental costs that can be offset by DG, therefore there is no avoided regulatory costs at this time. However, should a regulatory body adopt some regulatory requirement that would be impacted by member-owned DG it would become appropriate at that time for PEC to update its Value Of Distributed Generation model and incorporate the avoided cost impacts.

1.14 TOTAL VALUE OF DISTRIBUTED GENERATION

Given each of the avoided cost elements as described above, GDS calculated the aggregate value of DG for PEC as ranging from approximately $77 to $112 per kW-year in the 2018-2020 period. The three-year average is $84 per kW-year. This is the value that PEC can use to inform the rate design to appropriately compensate members for excess generation for members with distributed generation.

2 Project Methodology, Goals and Background

PEC engaged GDS for this project with the goal being to complete an independent, third-party, value of solar study. To meet this goal, the study identifies and develops the avoided cost benefits of member-owned[3] DG.

It is important to note that this study is limited to the identification of avoided cost benefits and does not include a rate design process. Following the completion of this value of solar study, the avoided cost benefits will inform a separate process to develop a rate design to appropriately compensate members with DG for the cost-based value of their excess energy that is supplied to the PEC system.

2.1 STUDY METHODOLOGY

To meet the goals of the project, the value of solar study has been conducted using the following methodology:

- Identify the individual elements of the potential avoided cost benefits of member-owned DG that are applicable for the PEC system
- For each of the applicable avoided cost benefits, conduct a detailed analysis to determine the value to the PEC system associated with a typical generation profile for the current mix of PEC member-owned DG.

2.2 OBJECTIVES FOR VALUE OF SOLAR

PEC has established the four objectives described below for the determination of the value of solar compensation methodology which provided guidance for this value of solar analysis.

1. ***The approach must be cost-based.*** The use of a cost-based method will ensure that the DG members are fairly compensated for the energy produced by their generation facilities, as well as limit the impacts of any subsidies paid by members that do not have solar generation. To ensure that the methodology is cost-based, GDS utilized actual PEC financial data for calendar year 2019 adjusted for noteworthy known changes in 2020, in our analysis. GDS also relied on other tools and data described throughout this report to ensure the approach to develop the appropriate compensation is cost-based.

   PEC is a nonprofit organization owned by the members of the cooperative. The cost basis to serve cooperative member-owners may differ significantly from other utilities. These differences include whether a utility owns and operates a generation fleet, whether a utility incurs regulatory costs that would be offset by DG, or other utility-specific costs not incurred by PEC.

   In addition, for the same reasons as above, no external costs, i.e., costs not directly incurred by PEC, have been included in determining the value of member generation. The framework that is built through the development of this study will allow for incorporating any external costs if they become actual costs that PEC incurs in the future. Such external costs, sometimes included by other utilities in value of solar computations, can be items such as societal, environmental, economic development costs, or others. These external costs have not been included in the development of the value of solar since they are not actual costs incurred by PEC at this time. If PEC were to include these external costs,

[3] “Member-owned” is intended to include both owned and leased facilities Under either case, the PEC member retains the benefits of the generation.

DG members that provide excess energy to PEC would be over-compensated for a cost that PEC does not incur, and non-DG members would pay the external cost. This resulting subsidy is not consistent with the object of a cost-based value of solar methodology. In the formulation of the Value of Solar these external costs are listed as avoided regulatory costs.

2. ***The scope of this report addresses systems with capacity of 50 kW and below.*** PEC has a Board-approved rate design (Interconnect Wholesale Energy Rate) that will become effective January 1, 2022 to compensate members for the generation provided by solar facilities with capacities greater than 50 kW AC. As provided for in the Interconnect Wholesale Energy Rate contained in PEC's Tariff and Business Rules For Electric Service[4], the Wholesale Energy Credit is determined as the energy received from the generation multiplied by the LCRA Load Zone SPP. Using a crediting methodology that settles every 15 minutes ensures that the value of the energy supplied by the generation is appropriately compensated at PEC's avoided cost of energy. All of the current members with DG systems above 50 kW are also billed under the Large Power Service rate and may receive a credit for transmission cost[5] if their metered load is negative during the Four Coincident Peak (4-CP) intervals.
3. ***The report should consider reduced energy purchases resulting from member-owned DG equitably with Energy Efficiency.*** PEC has adopted a metering configuration of having a single meter with two registers, consisting of an inflow register and an outlflow register. This means that PEC does not have metered data from member-owned DG. From a rate standpoint, the reduced energy purchases of a member with DG will be treated the same for equity purposes as if a homeowner installed energy efficiency measures to reduce energy consumption. However, the study will use PVWatts generation curves to represent DG output behind the meter to appropriately value a member DG system.
4. ***The results of the value of solar calculation should be reported in a manner that is easily understood and informs the design of the compensation rate.*** As described, herein, the value of solar analysis identifies the component benefits of solar generation and the value of each component as well as lays out the framework to include other costs in future studies as applicable. The values calculated should be able to be reproduced with either public information or information included as part of this study. The aggregate value of all the benefits should be expressed in an easily understood and transparent manner to ease the development of the compensation rate design in the next step.

2.3 BACKGROUND

2.3.1 Present Installation of Distributed Generation on the PEC System

As of December 2020, the PEC system has more than 5,000 installations of solar facilities with capacities of 50 kW or less. Data provided by PEC indicates that more than 3,200 of these solar systems have been installed over the three-year period of 2018-2020. This is illustrated in Figure 2-1.

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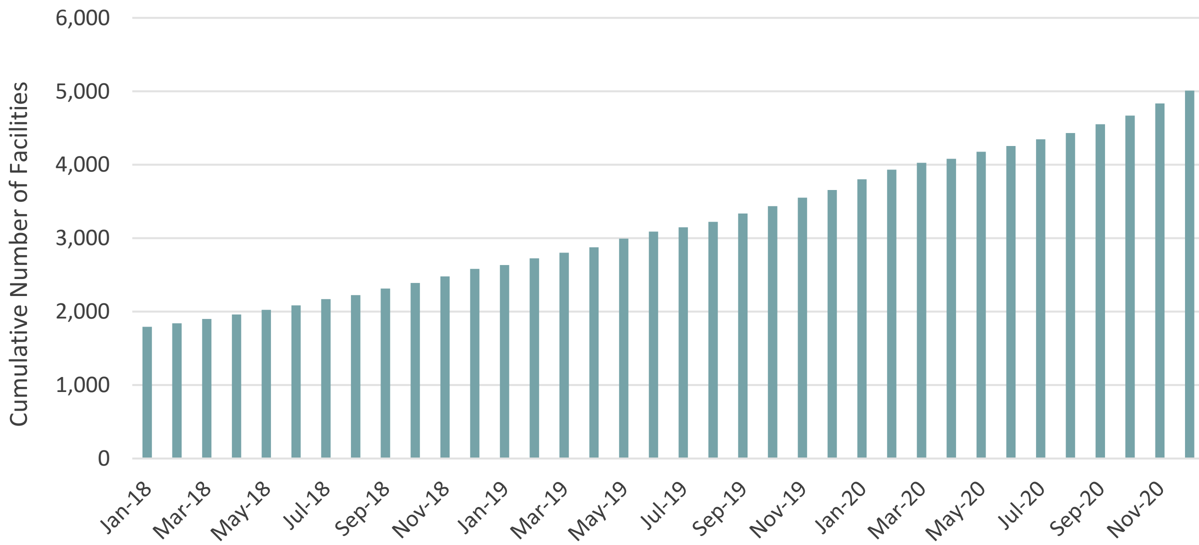
[4] Section 500.1.14, Wholesale Energy Credit

[5] Tariff and Business Rules For Electric Service, TCOS Charge, Section 500.1.9.2

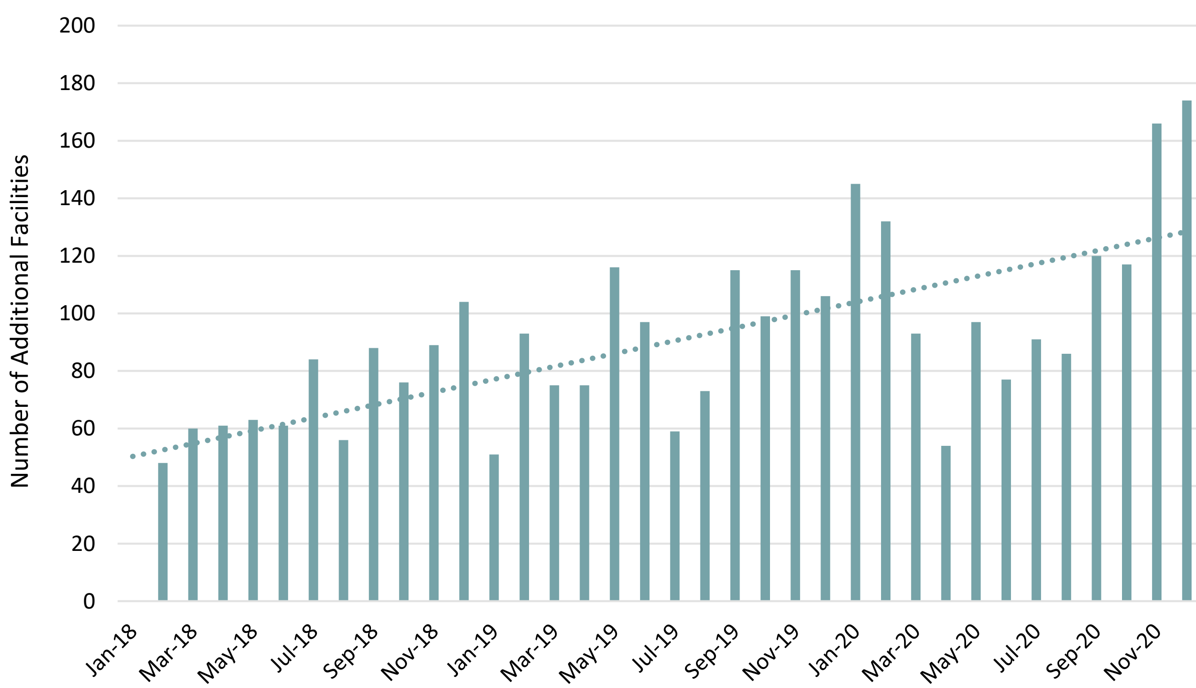
FIGURE 2-1 SOLAR FACILITIES ≤ 50KW



The data further indicates that the installations are being added at an increased pace. For the same 2018-2020 period, Figure 2-2 demonstrates the number of monthly installations. Further, the trend line shows that the number of installations is increasing.

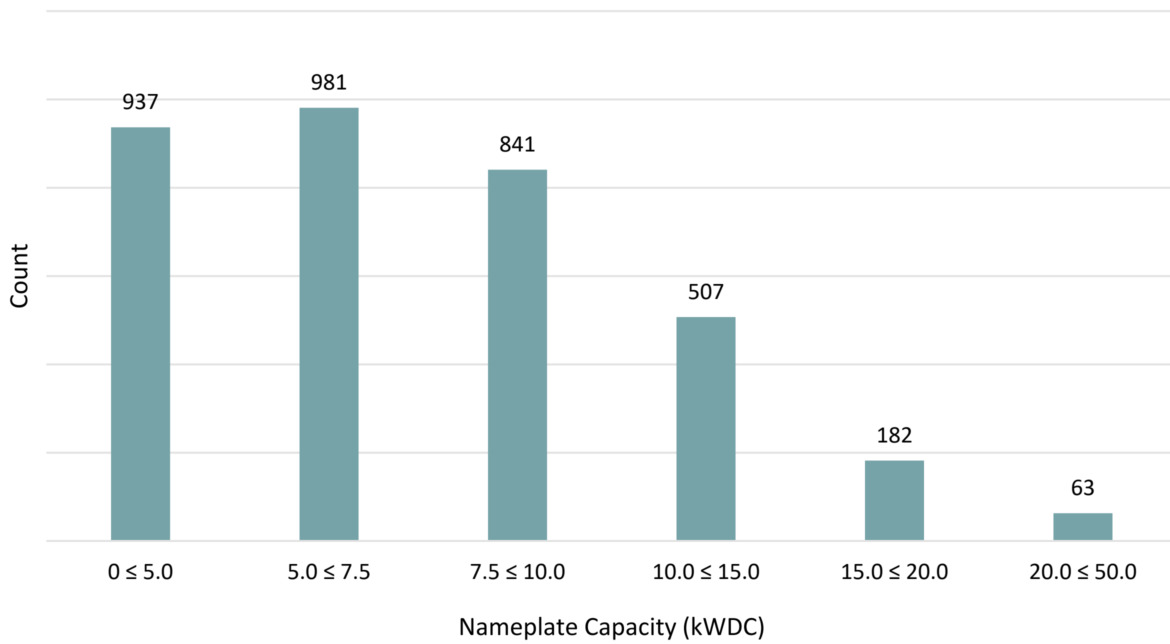
The large number of solar installations as well as the increased rate of implementation highlights the importance of determining an appropriate amount for the value of solar.

FIGURE 2-2 MONTHLY ADDITIONS SOLAR FACILITIES ≤ 50KW



Similar to many utilities, PEC indicates that the sizes of the solar generation facilities installed by members are increasing, with many of the new installation having capacities of 10 kW (AC) or more. GDS developed a summary of the solar generation facilities from registration data provided by PEC[6], with the count summarized in Figure 2-3. It should be noted that the count of solar facilities in Figure 2-3 is developed from those registered with PEC, with the registration data beginning in 2018. Further, Figure 2-3 reflects only data from among the registered facilities where PEC has a high confidence in the accuracy of the data. The data does not include solar facilities that have not been registered with PEC.

FIGURE 2-3 MEMBER REGISTERED SOLAR FACILITIES (AS OF 8-15-21)



From the same database of registered solar facilities, GDS compiled other statistics related to the capacities of the member installed solar generation. Table 2-1 illustrates that the average sized unit is 8.2 kW while the median is 7.0 kW.

TABLE 2-1 SUMMARY STATISTICS

Average	8.21 kW_{DC}
Median	6.98 kW_{DC}
Max	360.00 kW_{DC}
Min	0.29 kW_{DC}
10th Percentile	3.80 kW_{DC}
90th Percentile	12.99 kW_{DC}

[6] Received from PEC on 8-25-21. The count includes facilities that are labeled as either “Completed” or “Approved”. Other designations including “Denied”, “Review”, “Verify”, or “Engineering Approved” are not included in the count. The 6 units with capacities greater than 50 kW are not subject to this analysis.

PEC provided GDS with 60-minute calendar year 2020 interval load data for 783 members with DG. The interval load data contained values for the hourly inflows and outflows of energy to the member's meter. GDS concludes that a member data set of this magnitude provides a statistically significant sample size to conduct analyses.

3 PV Watts

GDS used solar output curves generated by version 5 of PVWatts® ® to represent average hourly and monthly generation output. These gross generation curves were used to calculate the solar generation contribution to the 4-CP transmission peaks, ancillary services, SPP and the distribution system monthly NCPs.

The NREL PVWatts® calculator is a web application developed by the NREL that estimates the electricity production of a grid-connected photovoltaic system based on a few simple inputs.[7] PVWatts® has been online since 1999, and the original algorithms in version 1 were largely based on the approach of the Sandia *PVFORM* tool developed in the 1980s[2]. Since then, several versions of PVWatts® have been made available, though the system performance calculations have remained largely the same as version 1.

PVWatts® is a widely used tool. In Fiscal Year 2019, the tool averaged approximately 7.8 million API hits per month. Of which 98% came from outside the NREL website – pointing to its broad application.[8] GDS considers PVWatts® an acceptable model to use for this analysis. Other available models would require more detailed information about the installed photovoltaic systems on the PEC system.

At each hour over the course of a year, PVWatts®_ calculates the sun position using the algorithm described in Astronomical Almanac[3]. The sun position is calculated at the midpoint of the hour: for example, from 2 p.m. to 3 p.m., the sun position is calculated at 2:30 p.m. to determine the solar zenith and azimuth angles. This is the case for normal daytime hours during which the sun is above the horizon for the whole hour. For the sunrise hour, the midpoint between the sunrise time and the end of the timestep is used for the sun position calculation. Similarly, the midpoint between the beginning of the timestep and sunset time is used for the sunset hour.[9]

PVWatts® allows the user to input several assumptions about the type, configuration, and operation of the system. The model estimates the results of an actual system operating in a year with typical weather. Errors may be as high as ±10% for annual energy totals and ±30% for monthly totals for weather data using long-term historical typical conditions. Actual performance in a specific year may deviate from the long-term average up to ±20% for annual and ±40% for monthly values.[10] PVWatts® interacts with three online databases[11] to access solar resource data but does not allow users to specify their own weather data.

The weather data uses hourly solar irradiance data that reflect the effect of clouds on the available solar energy throughout the year. This weather data can produce hourly results that dip from one hour to the next, creating a jagged daily production curve. Due to the jagged solar production curves, an addiointal production curve method was considered. To smooth out the curves, an average hourly production curve for each month was calculated by averaging each of the 24 hours for each day of the month to create one

[7] NREL PV Watts Calculator, https://pvwatts.nrel.gov/pvwatts.php

[8] NREL Article *PVWatts® at 20, Measuring Success in Megawatts and by the Millions, December 12, 2019.*

[9] NREL Version 5 Manual, Autored by A.P. Dobos, 09/14/2014

[10] NREL PV Watts Calculator

[11] PVWatts® can read solar resource data files from different sources and in different formats, including the National Solar Radiation Database (NSRDB) 1961-1990 data (TMY2) and 1991-2010 update (TMY3), and EnergyPlus weather files. It also reads files in the SAM CSV format which is a generic format suitable for customer solar resource data sets.

daily curve. Shown below are graphs that compare the differences in the hourly data produced by PVWatts and the hourly data produced by PVWatts averaged for the month. The curves were generated using PV Watts and adjusted for distribution losses of 5.98% using a 20° tilt and 180° azimuth.

FIGURE 3-1 DAILY CURVE – LAMPASAS, TX

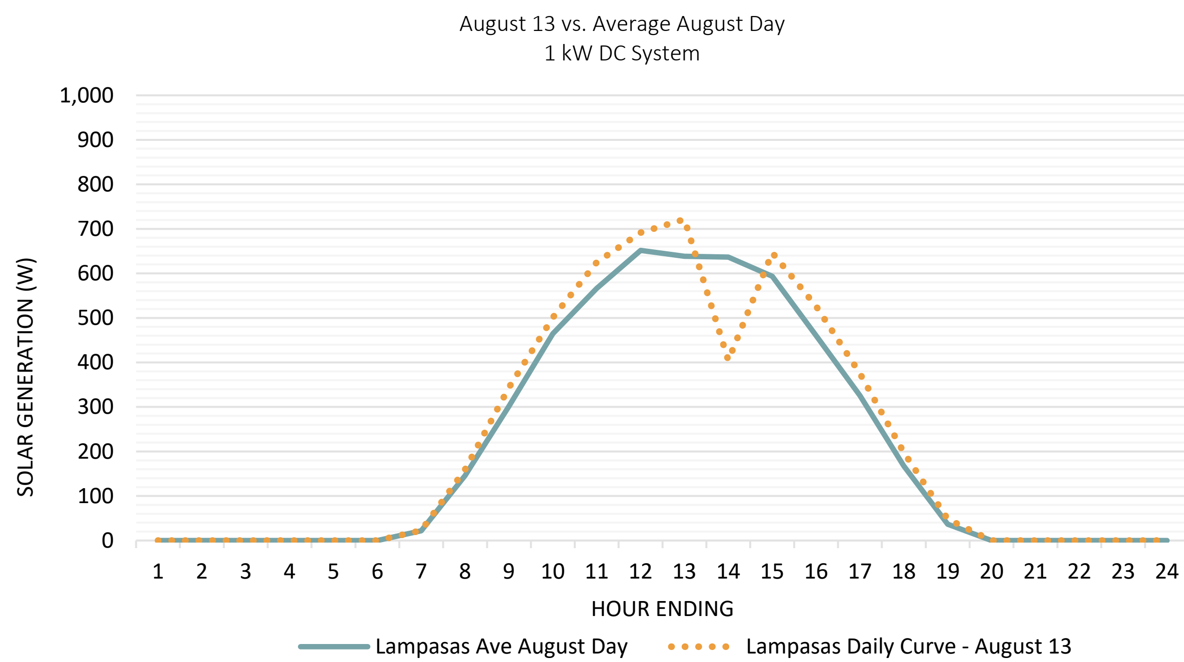


FIGURE 3-2 DAILY CURVE – JUNCTION, TX

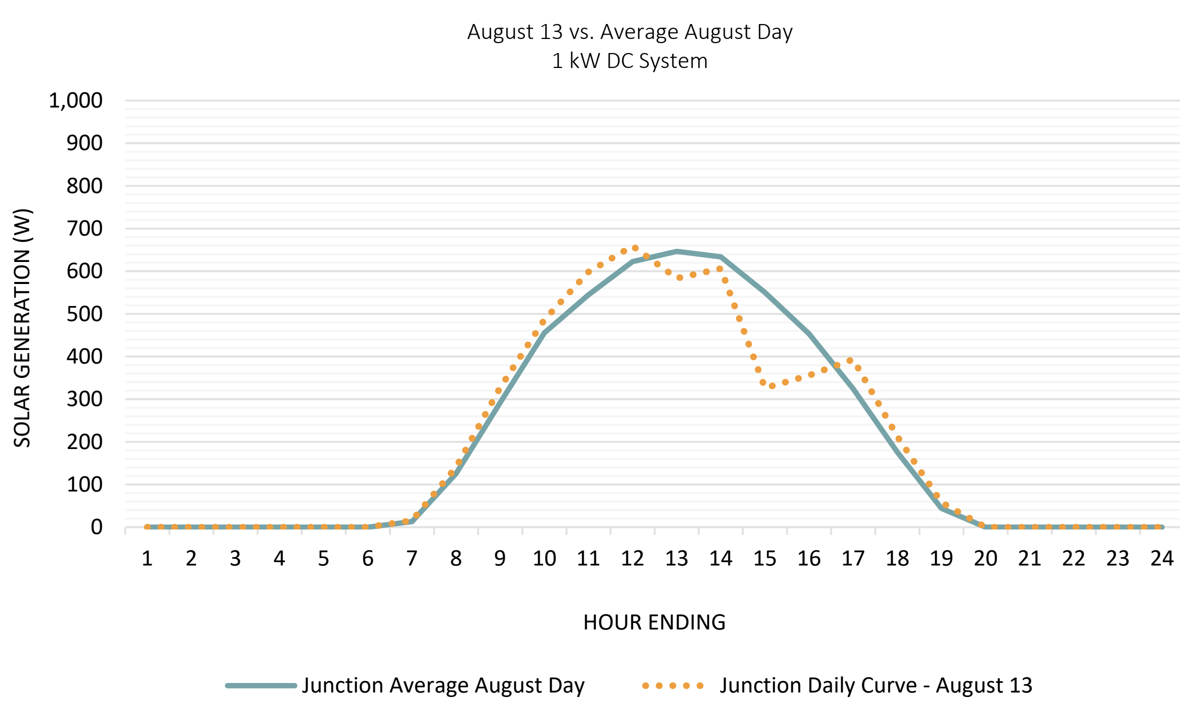


FIGURE 3-3 DAILY CURVE – SAN ANTONIO, TX

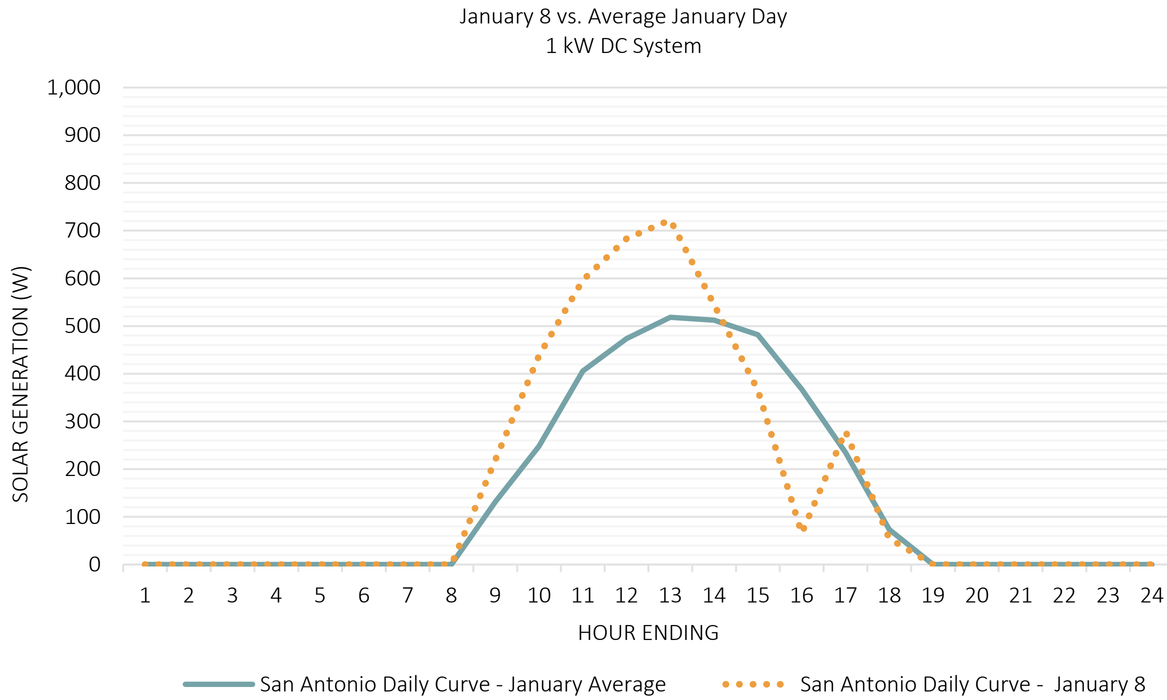


FIGURE 3-4 DAILY CURVE – JOHNSON CITY, TX

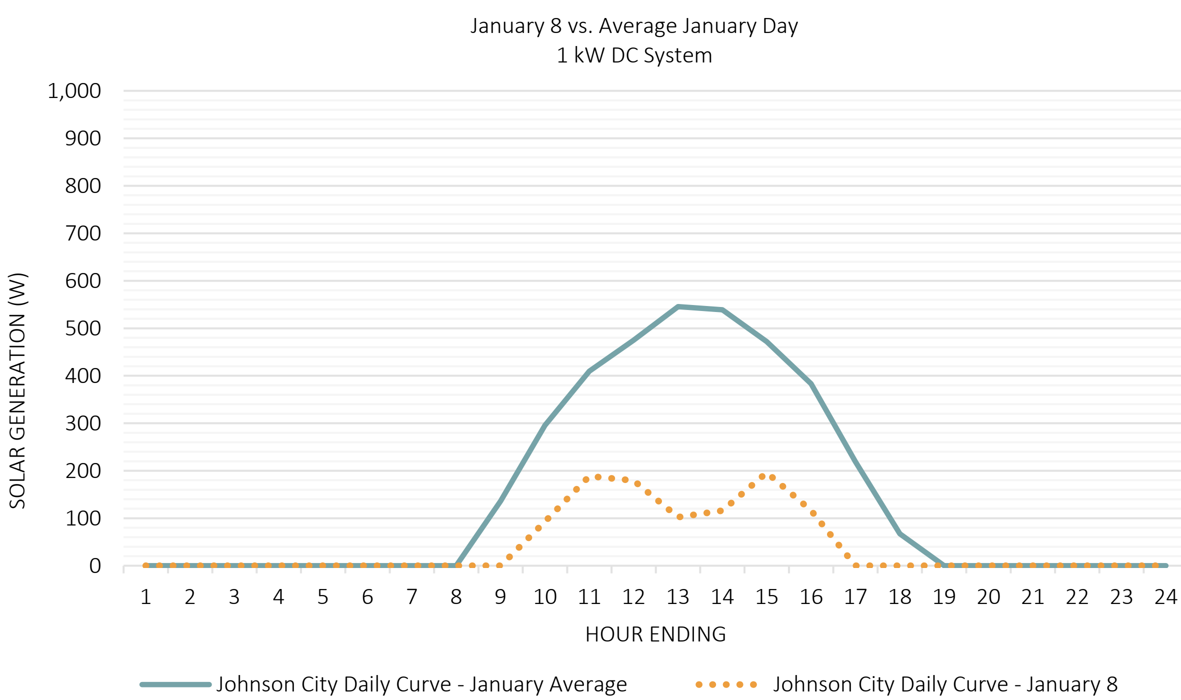
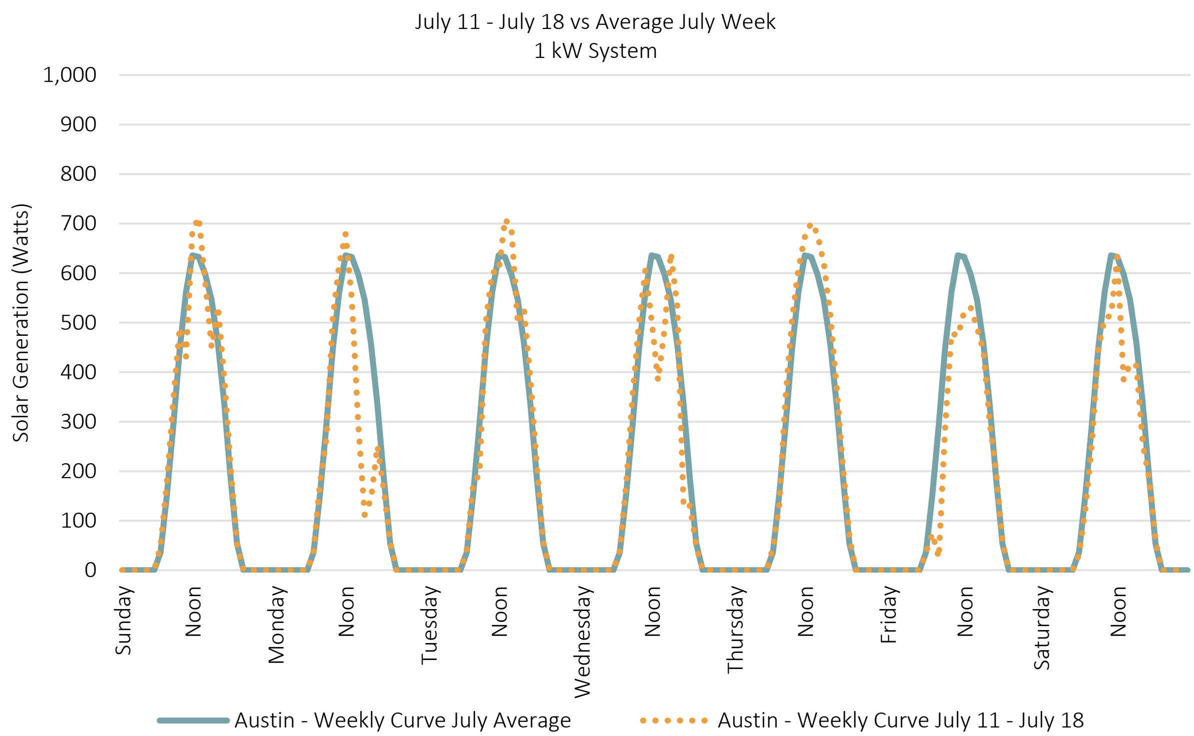


FIGURE 3-5 WEEKLY CURVE – AUSTIN, TX



After analyzing both methods, the average monthly daily curve was chosen for this analysis. This method takes into account average weather for the month which eliminates the coincidental cloud coverage that may occur on a specific day.

The model allows the user to input the following parameters. Table 3-1 illustrates the input options, the default value in the model and the option chosen for this analysis.

TABLE 3-1 PVWATTS® SYSTEM MODEL INPUTS

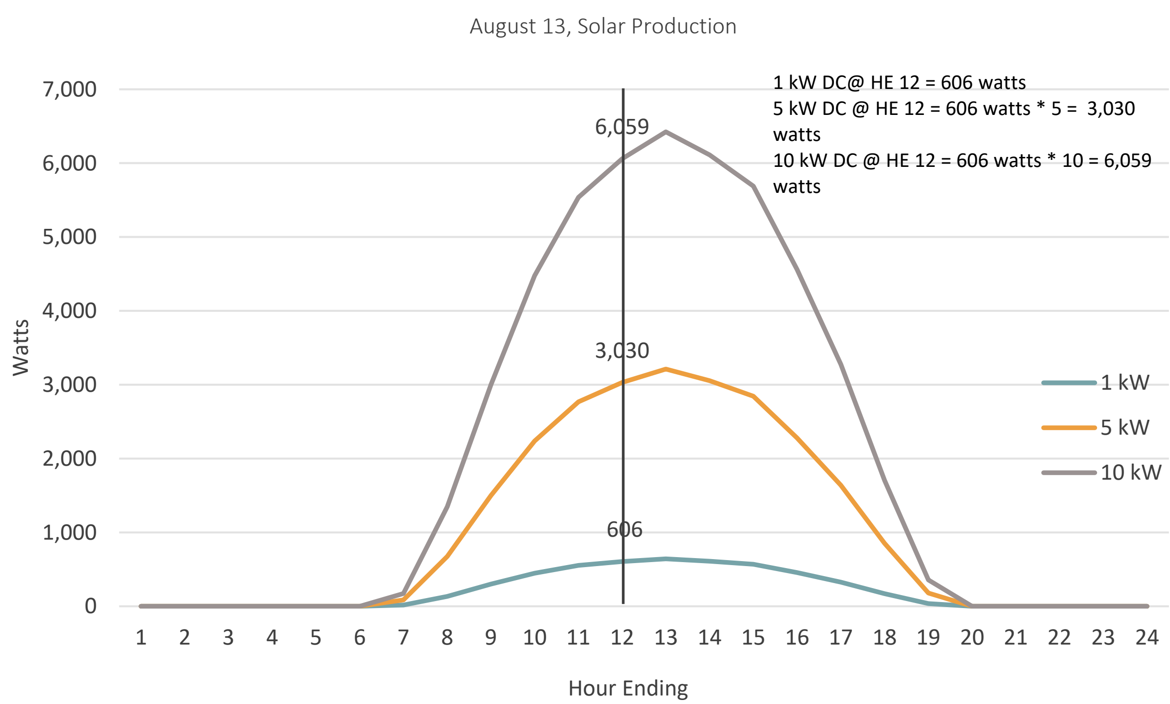
Input	Options	Default Value	Option Chosen
System Size	kW (DC)	4	1
Module Type	Standard, Premium, Thin film	Standard	Standard
System Losses	Input %	14%	14%
Array Type	Fixed open rack, Fixed roof mount, 1-Axis, Backtracked 1-Axis, 2 Axis	Fixed open rack	Roof Mount
Tilt Angle	Degrees	20°	20°

Input	Options	Default Value	Option Chosen
Azimuth Angle	Degrees	180°	180°
DC/AC Ratio	Ratio	1.1	1.1
Inverter Efficiency	Input %	96%	96%

Where detailed input information was not available, assumptions or default values were used for the analysis. These assumptions are described below.

- **SYSTEM SIZE:** A 1 kW system size was used for the analysis. The 1 kW DC system can be extrapolated to produce the same per unit results for any size system. The chart below shows the results of a 1 kW, 5 kW and 10 kW DC systems for Johnson City modelled using the same inputs in PV Watts.

FIGURE 3-6 PV WATTS OUTPUT – JOHNSON CITY, TX



Solar Production modeled using NREL's PVWatts online tool assuming 20° tilt and 180° azimuth.
No distribution losses applied.

- ## MODULE TYPE:
  - A standard fixed roof mount system was assumed as the module type. There are three module options in PVWatts®: Standard, Premium or Thin Film. Since only a fraction of the solar installations on the PEC system are commercial and thin film systems are commonly used with commercial solar installations, thin film was not used in this primarily residential analysis. Absent any additional information about the installations on the PEC system, the default standard option was used in the analysis.

- **SYSTEM LOSSES:** The following default system losses were used in the analysis:

TABLE 3-2 DETAIL OF SYSTEM LOSS ASSUMPTIONS

Source	Value	Notes
Soiling	2%	Losses due to dirt and other foreign matter on the PV's surface
Shading	3%[12]	Shadows caused by objects near the array; building, trees, etc.
Snow	0%	Reduction due to snow covering
Mismatch	2%	Electrical losses caused by manufacturing imperfections
Wiring	2%	Resistive losses in wires connecting modules, inverters, etc.
Connections	0.5%	Resistive losses in electrical connectors
Light-Induced Degradation	1.5%	Reduction in array's power due to light-induced degradation
Nameplate Rating	1%	Accounts for accuracy of manufacturer's nameplate rating
Age	0%	Effect of weather of the photovoltaic modules over time
Availability	3%	Reduction due to maintenance, grid outages, etc.

- **ARRAY TYPE:** Due to the high percentage of the solar installations on the PEC system being residential, a roof mount system was assumed.

- **TILT ANGLE:** A 20° tilt angle was assumed for the analysis. The tilt angle is the angle from horizontal of the PV modules in the array. For a fixed array, the tilt angle is the angle from horizontal of the array where 0° = horizontal, and 90° = vertical. For a fixed array, the default value is 20 degrees. For a roof mount system, the tilt angle is most likely equal to the roof pitch. The following table shows the tilt angle in degrees for varying roof pitches in a ratio of rise (vertical) over run (horizontal) to tilt angle.

TABLE 3-3 PVWATTS® ROOF PITCH TO TILT ANGLE CONVERSION

Roof Pitch	Tilt Angle
4/12	18.4°
5/12	22.6°
6/12	26.6°
7/12	30.3°
8/12	33.7°
9/12	36.9°
10/12	39.8°
11/12	42.5°
12/12	45.0°

[12] The default assumption for shading losses represents blocking of the horizon due to faraway features such as large buildings, mountains or other obstructions. Surveys of installed systems indicated that the average losses due to shading on systems described as "unshaded" was roughly 3%. PV Watts Version 5 Manual, September 4, 2014.

Detailed information for common roof pitches in PEC's service territory is not available. As part of the now closed California Solar Initiative, investor-owned utilities collected data from net metering applications that included tilt angles and azimuth that can be found in the California Working Data Set[13]. The data set has 83,708 residential applications that are single family homes with fixed arrays that have tilts between 0 and 90 degrees. As shown below, most of the tilt angles are 30° and less.

FIGURE 3-7 TILT – RESIDENTIAL SINGLE FAMILY HOMES

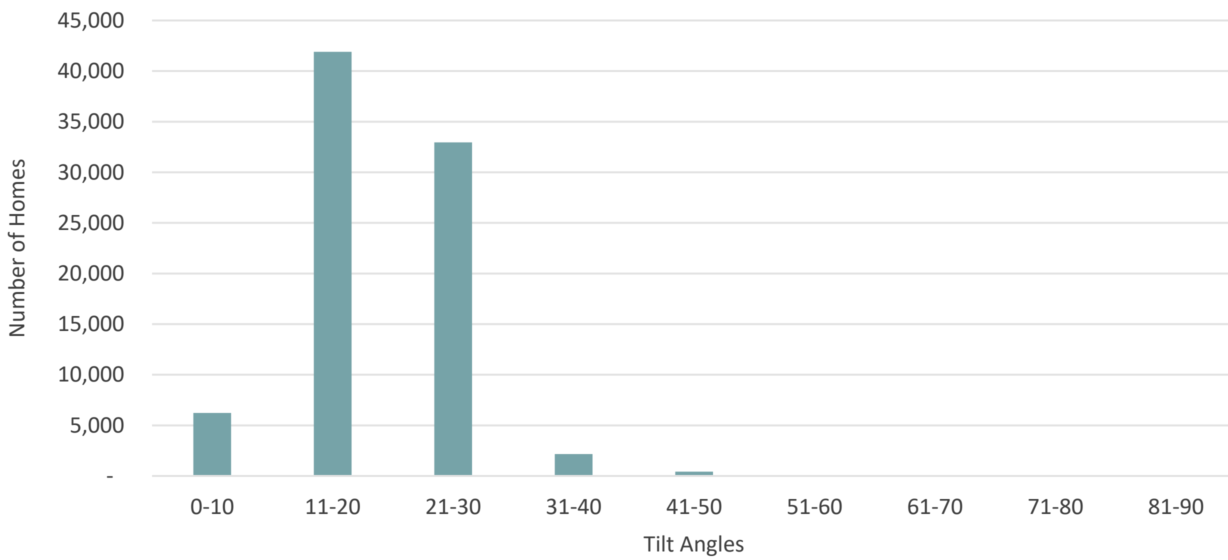
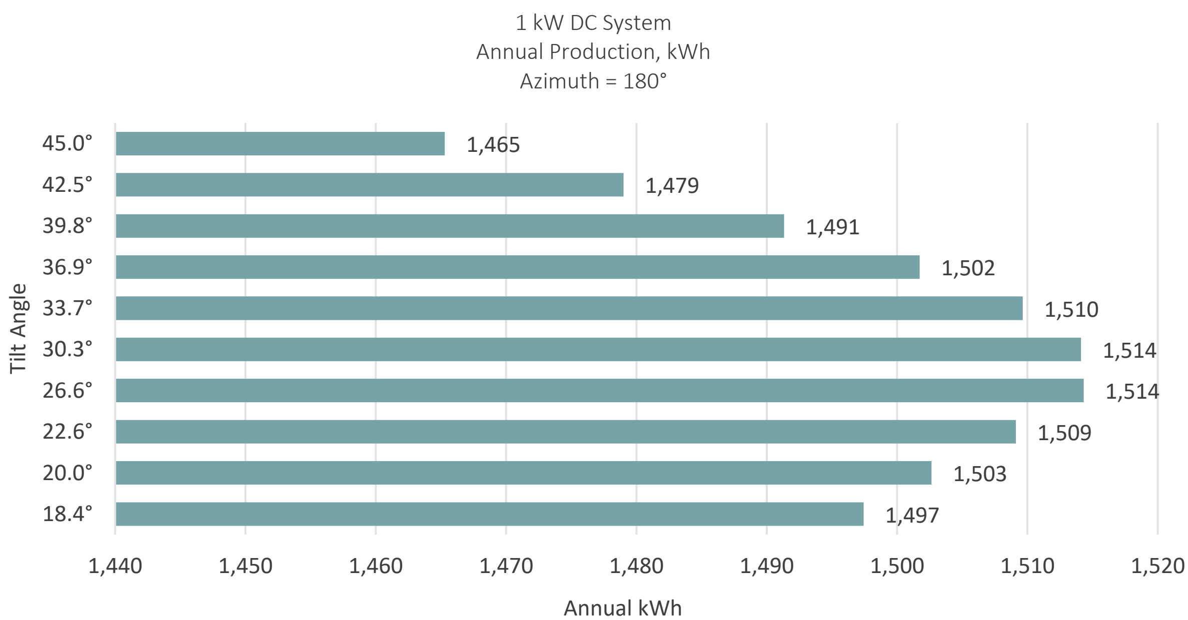


Figure 3-8 represents the annual solar generation calculated using PVWatts® for Johnson City, TX using the assumptions shown in Table 3-4 with varying degrees of tilt angles.

FIGURE 3-8 SOLAR PRODUCTION WITH VARYING TILT – JOHNSON CITY, TX

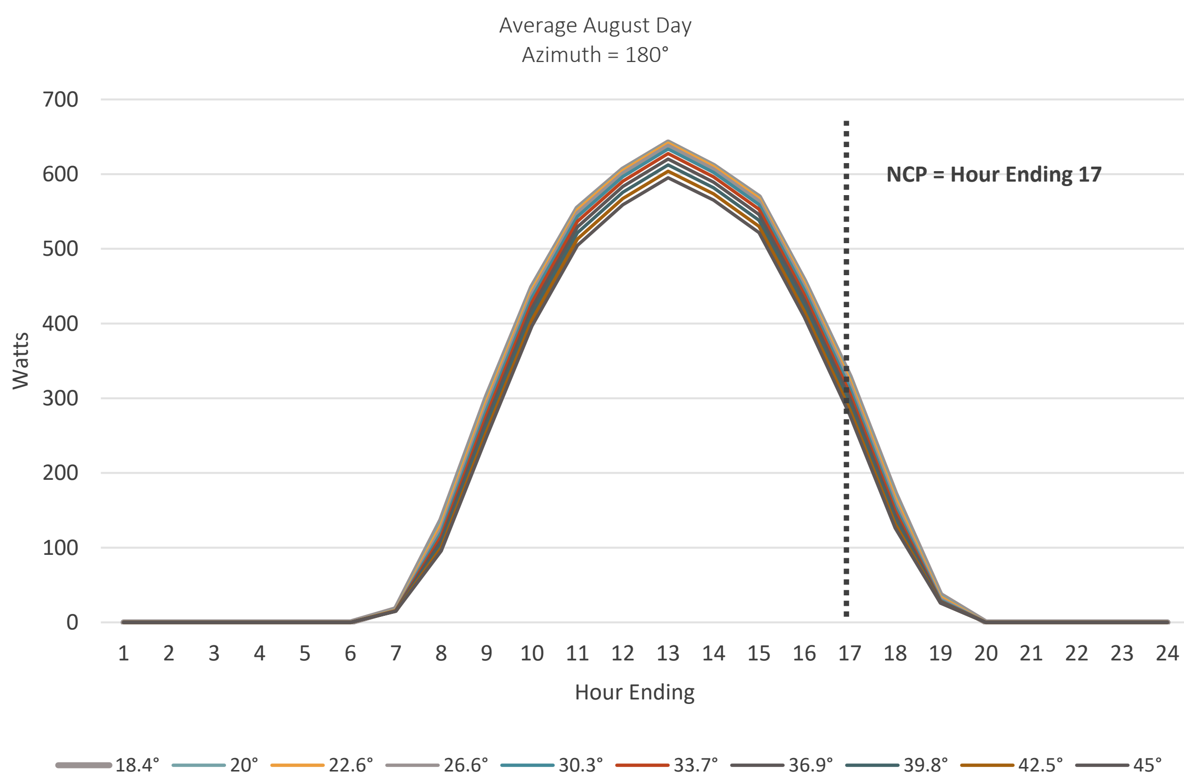


[13] The California Working Data Set (https://www.californiadgstats.ca.gov/downloads/#_csi_wds). Represents the California Solar Initiative application data from PG&E, SCE and SDG&E service territories.

The difference between the common roof pitches (30.3° and less) is minimal with a range of 17kWh's between the low tilt angle of 18.4° and the 30.3° pitch angle.

The next chart represents how hourly solar production is affected by tilt angle for an average August day at the Johnson City, TX location for a 1 kW system. The assumptions shown on Table 3-4 were used to calculate the generation.

FIGURE 3-9 SOLAR PRODUCTION WITH VARYING TILT – JOHNSON CITY, TX



The time of the NCP occurred at hour ending 17. The percent of the maximum generation at the time of the NCP is the coincidence factor. For example, with a 20° tilt angle at hour ending 17, the generator was modelled to produce 328 watts for that hour. The maximum generation of the 1 kW DC generator is 883 watts. Dividing the 328 watts by the maximum 883 watts, results in a 37.25% coincidence factor. As shown in Table 3-4, the difference in coincidence factors for the varying degrees of tilt angles are small.

TABLE 3-4 COINCIDENCE FACTORS WITH VARYING DEGREES OF TILT

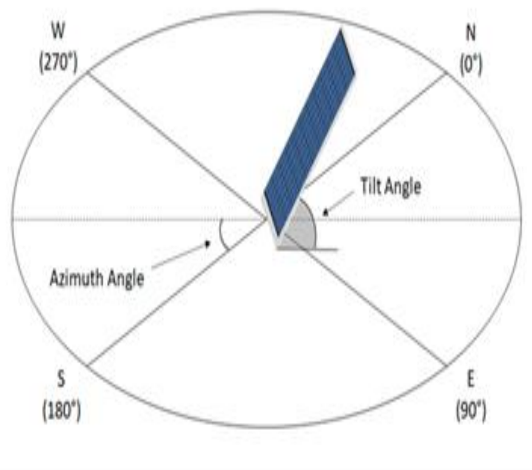
Tilt		18.4°	20°	22.6°	26.6°	30.3°
Solar Gen, Aug 13	watts	374	372	369	362	354
Coincidence Factor	%	44.92%	44.69%	44.26%	43.43%	42.49%

Absent any actual data for PEC's system, the default tilt angle of 20° is reasonable to use for the analysis.

- **AZIMUTH ANGLE:** The default value is an azimuth angle of 180° (south-facing). These values typically maximize electricity production over the year, although local weather patterns may cause the optimal azimuth angle to be slightly more or less than the default values. For the northern hemisphere, increasing the azimuth angle favors afternoon energy production, and decreasing the azimuth angle favors morning energy production.

The difference in the tilt angle and the azimuth is illustrated in Figure 3-10 below.

FIGURE 3-10 ILLUSTRATION OF TILT ANGLE AND AZIMUTH ANGLE



The following table shows the monthly and annual solar production with varying degrees of azimuth using the same defaults as stated in Table 3-6 at Johnson City, TX. As shown, the south facing solar panels generate the most kWh's on an annual basis.

TABLE 3-5 SOLAR PRODUCTION WITH VARYING DEGREES OF AZIMUTH

Month	90° (E)	135° (SE)	180° (S)	225° (SW)	270° (W)
1	74	94	104	96	77
2	79	95	104	99	84
3	112	125	132	128	117
4	126	132	136	136	131
5	131	132	133	134	134
6	149	147	145	147	149
7	149	149	148	149	148
8	144	149	151	150	145
9	116	127	132	129	119
10	98	115	123	116	100
11	72	89	97	91	74
12	69	89	98	89	68
Total kWh	**1,319**	**1,444**	**1,503**	**1,464**	**1,346**

Using the same assumptions, the next table shows the coincidence factors at the time of the NCPs for the varying degrees of azimuth at Johnson City, TX.

TABLE 3-6 COINCIDENCE FACTORS FOR VARYING DEGREES OF AZIMUTH AT JOHNSON CITY, TX AT NCP TIMES

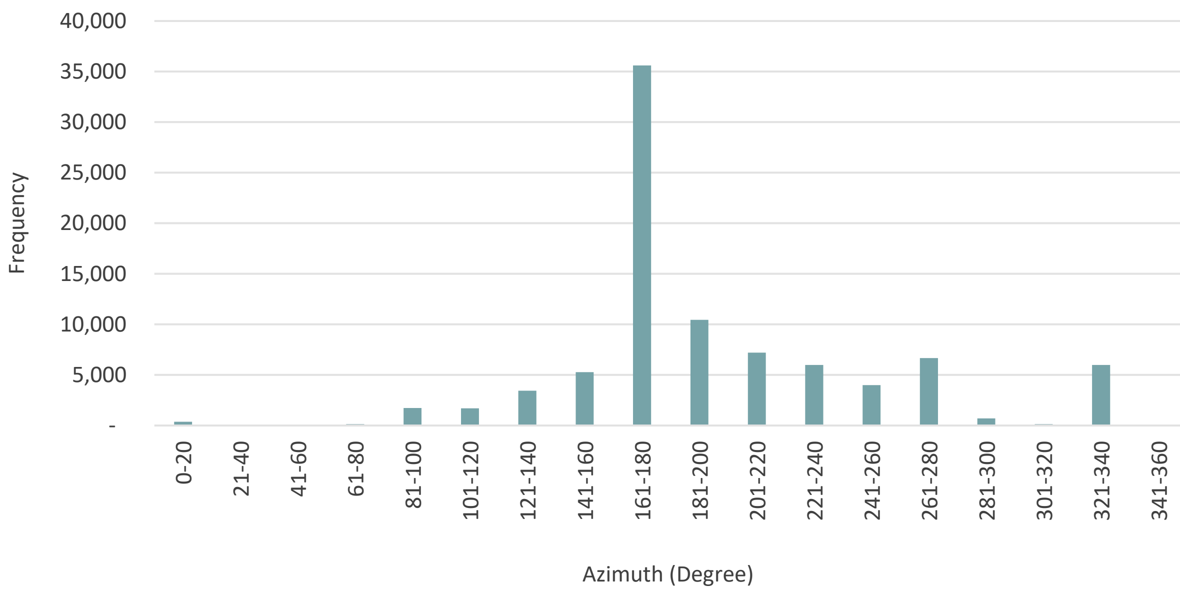
Date & Time		90° East Facing		135° Southeast Facing		180° South Facing		225° Southwest Facing		270° West Facing		Average	
4 CP Events		AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %
6/27/2018	17:00	197	22.3%	228	25.8%	327	37.0%	426	48.2%	473	53.6%	276	31.2%
7/19/2018	17:00	198	22.4%	232	26.3%	323	36.6%	411	46.5%	450	50.9%	269	30.5%
8/23/2018	17:00	166	18.8%	219	24.8%	328	37.1%	421	47.6%	451	51.1%	264	29.9%
9/19/2018	17:00	89	10.1%	154	17.4%	269	30.5%	355	40.2%	370	41.9%	207	23.4%
6/19/2019	17:00	197	22.3%	228	25.8%	327	37.0%	426	48.2%	473	53.6%	276	31.2%
7/30/2019	17:00	198	22.4%	232	26.3%	323	36.6%	411	46.5%	450	50.9%	269	30.5%
8/12/2019	17:00	166	18.8%	219	24.8%	328	37.1%	421	47.6%	451	51.1%	264	29.9%
9/6/2019	17:00	89	10.1%	154	17.4%	269	30.5%	355	40.2%	370	41.9%	207	23.4%
6/8/2020	18:00	76	8.7%	90	10.2%	177	20.1%	284	32.2%	343	38.8%	162	18.4%
7/13/2020	17:00	198	22.4%	232	26.3%	323	36.6%	411	46.5%	450	50.9%	201	22.7%
8/13/2020	17:00	166	18.8%	219	24.8%	328	37.1%	421	47.6%	451	51.1%	264	29.9%
9/1/2020	15:00	363	41.1%	441	50.0%	520	58.9%	558	63.2%	538	60.9%	404	45.8%
Average		175	19.9%	221	25.0%	320	36.2%	408	46.2%	439	49.7%	261	29.6%
Weight			0.167		0.167		0.167		0.167		0.167		0.84
Weighted Average			3.3%		4.2%		6.1%		7.7%		8.3%		29.6%

AC Output in watts are based on monthly averages calculated from solar generation modeled using NREL's PV Watts online tool assuming a 20° tilt and varying azimuth.

Increasing the azimuth angle favors afternoon energy production (west-facing) and decreasing the azimuth angle (east-facing) favors morning energy production. This is supported by the table above which shows that the west facing panels produce more generation during the NCP hours which occur during the late afternoon. Although the west facing panels produce more during the NCP, to maximize energy production a south-facing system would be used.

As explained above, the California Solar Initiative collected azimuth information from net metering applications at investor-owned utilities. These can be found in the California Working Data Set[14]. The data set has 83,708 residential applications that are single family homes with fixed arrays that have azimuth between 0 and 360 degrees. As shown below, the majority of the tilt angles are between 161°- 180°, with 32.8% having an azimuth of 180°

FIGURE 3-11 AZIMUTH – RESIDENTIAL SINGLE FAMILY HOMES



Absent a statistically significant sample of actual panel configurations on the PEC system, the 180° azimuth seems to be a reasonable assumption.

- **DC/AC RATIO:** The DC to AC size ratio is the ratio of the array's DC rated size to the inverter's AC rated size. For a system with a high DC to AC size ratio, for times when the array's DC power output exceeds the inverter's rated DC input power, the inverter limits the array's power output by increasing the DC operating voltage, which moves the array's operating point down its current-voltage (I-V) curve. PVWatts® ® models this effect by limiting the inverter's power output to its rated AC size. The default value of 1.20 is reasonable for most systems. A typical range is 1.10 to 1.25, although some large-scale systems have ratios as high as 1.50. The optimal value depends on the system's location, array orientation, and module and inverter costs.

- **INVERTER EFFICIENCY:** The inverter's nominal rated DC-to-AC conversion efficiency, defined as the inverter's rated AC power output divided by its rated DC power output. The default value is 96%.

[14] The California Working Data Set (https://www.californiadgstats.ca.gov/downloads/#_csi_wds).

After defining the inputs for the solar systems in PEC's service territory, generation curves could be produced. Curves were generated for six different locations in or near PEC's service territory. This is to account for PEC's vast service territory which spans 8,100 square miles in the Texas Hill Country. As described herein, the locations include Austin, Fredericksburg, Johnson City, Junction, Lampasas, and San Antonio. A simple average of the six locations was used to represent a typical generation curve, as shown in Figure 4-3.

4 Value of Solar Methodology

As described previously in this report, several utilities including Austin Energy, use a Value of Solar methodology to compute the rate at which they pay, or credit, owners of solar generation for their output. The approach is designed to compute an avoided cost of all cost elements. PEC currently has over 5,000 members that own DG, all of which are solar save for one wind unit. In the future, should battery storage or other distributed resources be deployed by PEC members, PEC will update the analysis to include the value of those resources. Given that currently over 99% of DG in the PEC territory is solar, GDS has conducted a Value of Solar study. The results will be applicable to all sources of generation that are 50 kW or smaller. Therefore, we have termed the analysis a Value Of Distributed Generation analysis. This section of the report explains the methods, data sources, and results of GDS' determination of the value of DG.

4.1 OBJECTIVE

The objective of the Value Of Distributed Generation analysis is to determine an appropriate credit to be applied to PEC bills for members who own generation with maximum capacity equal to or below 50 kW and produce excess generation that flows back onto the PEC distribution system. The Value Of Distributed Generation approach seeks to compute PEC's avoided costs associated with an average generation profile, including all potential avoided costs. The goal is to develop a credit that appropriately distributes the cost savings from DG to the owners of the DG and ensure there are not subsidies between DG and non-DG members, recognizing any cost not recovered by one member must be recovered by all other members.

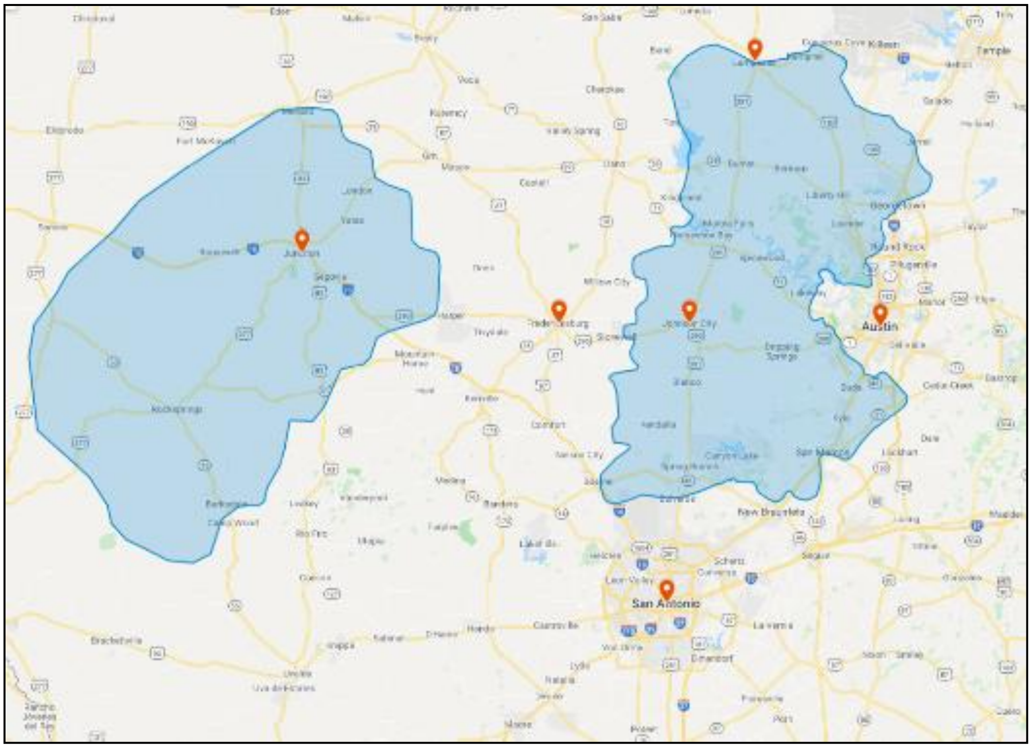
4.2 DATA SOURCES

Data was drawn from a variety of sources to develop the Value Of Distributed Generation, including both internal PEC sources and external sources to ensure the analysis is supportable and robust.

- **PEC Databases.** Data sourced from PEC include registration data on all existing DG accounts, hourly energy usage data for a sample of 783 DG accounts, rate schedules, interconnection policies, member and billing data, line loss factors, and power bills from LCRA.
- **PEC Financial Databases.** PEC provided all cost information regarding PEC's distribution system. The data represents 2019 actual information adjusted for known and measurable changes to represent an adjusted test year.
- **PVWatts®.** This tool[15], developed by NREL, allows GDS to calculate typical solar generation load profiles at the hourly level. Solar generation profiles were developed for six locations at or near PEC's service territory. Five of the cities are included for weather profiles as part of LCRA's load forecasting process. The sixth, Lampasas, was selected by GDS to ensure representation in PEC's northernmost territory.
- **ERCOT.** ERCOT data, 2018-2020, used by GDS includes hourly LCRA Load Zone SPPs, monthly 4-CP demand dates and times and postage stamp rates, and hourly ancillary services rates for Regulation Service – Up, Regulation Service – Down, Non-spinning Reserves, and Responsive Reserve Service.

[15] Access the tool at https://pvwatts.nrel.gov/.

FIGURE 4-1 PVWATTS® ANALYSIS LOCATIONS



4.3 VALUE OF DISTRIBUTED GENERATION MODEL

In the traditional model of the electric grid, central power stations produce electricity that is transmitted to the ultimate consumers of electricity. Three primary functions are identified in such a grid: generation, transmission, and distribution. When a member installs a PV system (or other behind-the-meter generator) and that system generates power, PEC's costs are potentially reduced energy and ancillary service costs, reduction in transmission access expense, and avoided investement and operations and maintenece expense for the PEC distribution system. Additionally, the DG may allow PEC to avoid certain regulatory costs. The Value Of Distributed Generation, then, is a computation of avoided costs of the generation (energy and capacity/demand), transmission, ancillary services[16], and distribution functions. The Value Of Distributed Generation model as computed by GDS is shown in Equation 4-1. GDS' analysis includes the historical timeframe of 2018-2020 and thus computes a three-year average Value Of Distributed Generation.

EQUATION 4-1

$$DG_{Val} = \frac{\sum_{y=1}^{n}\left(Gen_{E,y} + Gen_{D,y} + Trans_{4CP,y} + AS_{ERCOT,y} + Dist_y + Reg_y\right)}{n}$$

Where:

DG_{Val}	Average Value of Distribution Generation
y	Year
n	Number of Years included in Analysis

[16] Ancillary services are related to the generation and transmission function and are also purchased by PEC in the ERCOT market through its contract with LCRA.

$Gen_{E,y}$	Avoided Energy Costs in Year y
$Gen_{D,y}$	Avoided Capacity or Demand Costs in Year y
$Trans_{4\text{-}CP}$	Avoided Transmission Costs at ERCOT 4-CP in Year y
AS_{ERCOT}	Avoided Ancillary Services Costs in ERCOT in Year y
$Dist_{Avoid\ Cost}$	Avoided Distribution Costs in Year y
$Reg_{\ Avoid\ Cost}$	Avoided Regulatory Costs in Year y

In the succeeding sections, each element of the analysis will be presented with details on how GDS computed each component. If any other costs are realized in the future that may be reduced by member-owned DG it will be appropriately added in this calculation.

4.4 ANNUAL ENERGY PRODUCTION

Given that over 99% of the DG units on the PEC system are currently solar panels, GDS used solar output curves generated by PVWatts® to represent average hourly and monthly generation output. A standard 1 kW DC fixed roof mount system was modelled with a 20° array tilt and a 180° array azimuth. The generator was modelled using 14.1% system losses with an inverter efficiency of 96% and a DC to AC size ratio of 1.2. This produces a maximum AC output of 833 watts for a 1 kW DC panel. The 14.1% system losses include the following assumptions:

TABLE 4-1 DETAIL OF SYSTEM LOSS ASSUMPTIONS

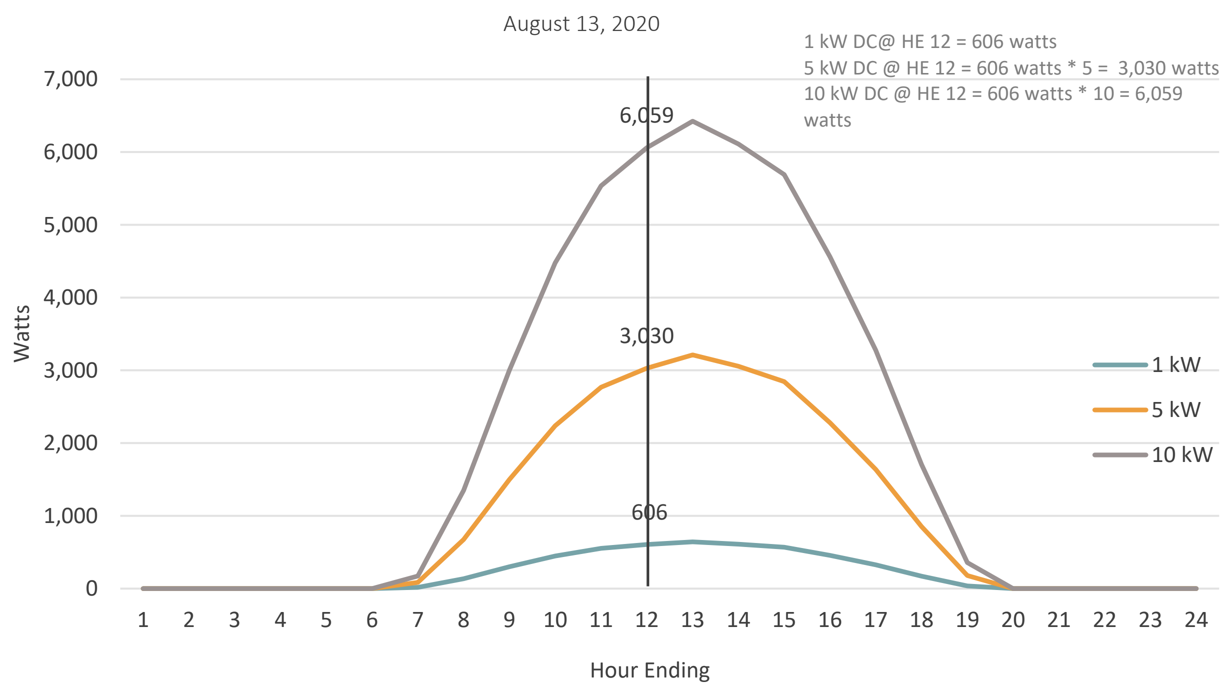
Source	Value	Notes
Soiling	2%	Losses due to dirt and other foreign matter on the PV's surface
Shading	3%[17]	Shadows caused by objects near the array; building, trees, etc.
Snow	0%	Reduction due to snow covering
Mismatch	2%	Electrical losses caused by manufacturing imperfections
Wiring	2%	Resistive losses in wires connecting modules, inverters, etc.
Connections	0.5%	Resistive losses in electrical connectors
Light-Induced Degradation	1.5%	Reduction in array's power due to light-induced degradation
Nameplate Rating	1%	Accounts for accuracy of manufacturer's nameplate rating
Age	0%	Effect of weather of the photovoltaic modules over time
Availability	3%	Reduction due to maintenance, grid outages, etc.

As shown in Figure 3-1, the 1 kW DC system can be extrapolated to produce the same results for any size system. Figure 4-2 to the left shows the results of a 1 kW, 5 kW and 10 kW DC systems for Johnson City modelled using the same inputs in PV Watts.

Curves were generated for six different locations in or near PEC's service territory. The locations include Austin, Fredericksburg, Johnson City, Junction, Lampasas, and San Antonio. A simple average of the six locations was used to represent a typical generation curve.

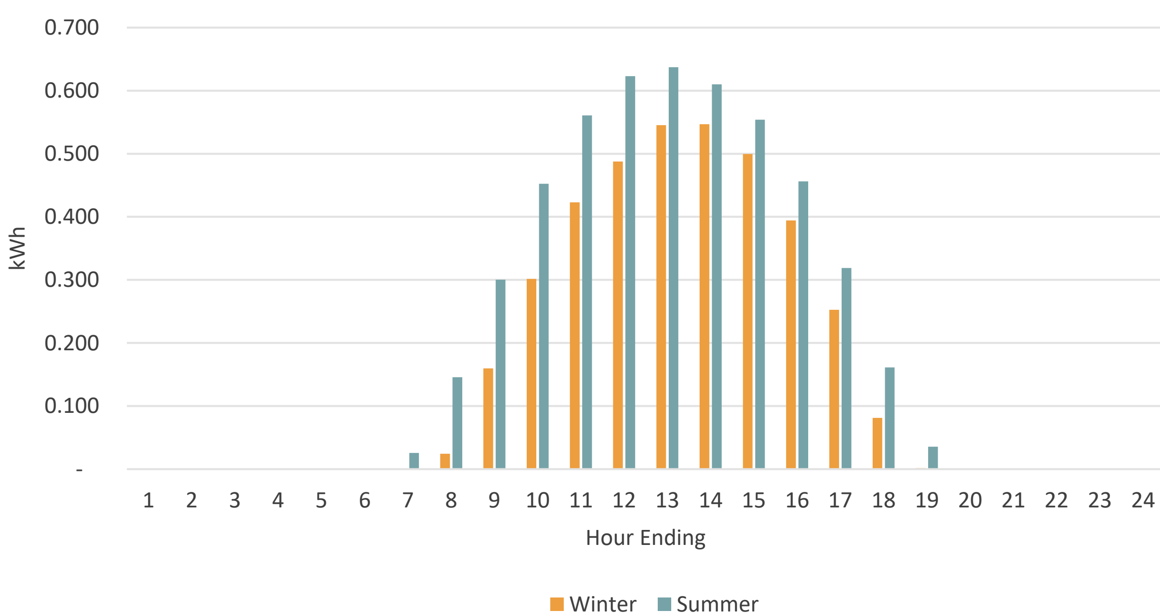
[17] The default assumption for shading losses represents blocking of the horizon due to faraway features such as large buildings, mountains or other obstructions. Surveys of installed systems indicated that the average losses due to shading on systems described as "unshaded" was roughly 3%. PV Watts Version 5 Manual, September 4, 2014.

FIGURE 4-2 PV WATTS OUTPUT SOLAR PRODUCTION – JOHNSON CITY, TX



Solar Production modeled using NREL's PVWatts online tool assuming 20° tilt and 180° azimuth.
No distribution losses applied.

FIGURE 4-3 TYPICAL HOURLY GENERATION PROFILE



All ERCOT-market interactions are settled at the wholesale point of delivery, whereas the PVWatts® generation curves are representative of load at the retail meter. Therefore, to appropriately account for distribution system losses, the generation curves are adjusted up. As shown in Table 4-2, the three-year load weighted distribution losses average 5.98%. When computing avoided ERCOT costs (including market energy, transmission demand, and ancillary services), the generation output is grossed up by a 5.98% loss factor. The generation profile for 2020 accounts for Leap Year as well.

TABLE 4-2 PEC SYSTEM ENERGY LOSSES

Item	2018	2019	2020	Three-Year Total
kWh Purchases	6,674,945,386	6,916,900,447	6,961,106,874	20,552,952,707
kWh Sales	6,310,255,242	6,493,067,751	6,520,970,373	19,324,293,366
Distribution Loss Factor	5.46%	5.98%	6.32%	5.93%

4.5 AVOIDED ENERGY COSTS – GEN_E

Given complexities in PEC's contract with LCRA and other power supply arrangements, evaluating the true hourly margin avoided cost of energy is complex. However, ERCOT SPP are a close approximation of PEC's marginal cost of energy, so for the Value Of Distributed Generation analysis, SPP will be used. To compute market energy costs, GDS used three years (2018-2020) of historical SPP at the LCRA zone[18]. The SPP are quarter-hour prices but tend to be stable across an hour. The quarter-hour data was converted to hourly using an average of the four intra-hour prices. Real time prices are used since they are representative of the final settlement price for energy in the ERCOT market. The average hourly generation profile was then used to compute the avoided cost savings of the generation output for three years. A three-year average was then computed.

EQUATION 4-2

$$Gen_{E,y} = \sum_{h=1}^{8760} kWh_{PV,h} \times SPP_{RT,h}$$

Where:

$Gen_{E,y}$	Avoided Energy Costs in Year y
y	Year
h	Hour of the Year (note: summation would be through 8784 in leap year 2020)
$kWh_{PV,h}$	PV Generation Production in Hour h
$SPP_{RT,h}$	Real-time SPP at Hour h

4.5.1 Determination of SPPs

The SPP are prices calculated by ERCOT using Locational Marginal Pricing ("LMP") data and several formulas associated with ERCOT's Day Ahead Market ("DAM"). As described in ERCOT's current nodal protocols, the day-ahead SPP for load zone settlement point for an hour is calculated as follows[19]:

$$\textbf{DASPP} = \textbf{DASL} - \sum_{c} (\textbf{DALZSF}_c * \textbf{DASP}_c)$$

Where:

$$\text{DALZSF}_c = \sum_{pb} (\text{DADF}_{pb,\,c} * \text{DASF}_{pb,\,c})$$

$$\text{DADF}_{pb,\,c} = \text{DAL}_{pb,\,c} / (\sum_{pb} \text{DAL}_{pb,\,c})$$

For a DC Tie Load Zone:

$$\textbf{DASPP} = \textbf{DALMP}_b$$

The above variables are defined as follows:

Variable	Unit	Definition
DASPP	$/MWh	*Day-Ahead SPP*—The DAM SPP at the Load Zone, for the hour.

[18] Source of data: NRG stream, hourly average of 15-minute SPP for LCRA Load Zone, non-energy weighted.
[19] ERCOT Nodal Protocols. August 20, 2021. Section 4.6.1., http://www.ercot.com/mktrules/nprotocols/current.

Variable	Unit	Definition
$DALMP_{b}$	\$/MWh	*Day-Ahead Locational Marginal Price per bus*—The DAM LMP at Electrical Bus *b* for the hour.
DASL	\$/MWh	*Day-Ahead System Lambda*—The DAM Shadow Price for the system power balance constraint for the hour.
$DASP_{c}$	\$/MWh	*Day-Ahead Shadow Price for a binding transmission constraint*—The DAM Shadow Price for the constraint *c* for the hour.
$DALZSF_{c}$	none	*Day-Ahead Shift factor of the Load Zone* —The DAM aggregated Shift Factor of a Load Zone for the constraint *c* for the hour.
$DASF_{pb,\,,c}$	none	*Day-Ahead Shift factor of the power flow bus*—The DAM Shift Factor of a power flow bus *pb* that is a component of the Load Zone for the constraint *c* for the hour.
$DADF_{pb,\,c}$	none	*Day-Ahead Distribution factor per power flow bus for a constraint*—The Load distribution factor for power flow bus *pb* in the Load Zone for the constraint *c* for the hour.
$DAL_{pb,\,c}$	MW	*Day-Ahead Load at power flow bus for a constraint*—The DAM distributed load for power flow bus *pb* in the Load Zone for the constraint *c* for the hour.
b	none	An Electrical Bus that is assigned to the DC Tie Load Zone.
pb	none	An energized power flow bus that is assigned to the Load Zone for the constraint *c*.
c	None	A DAM binding transmission constraint for the hour caused by either base case or a contingency.

ERCOT further defines the adjustments made to day-ahead SPP to develop real time SPP in Section 6.6 of their nodal protocols[20]:

The Real-Time SPP for a Load Zone Settlement Point is based on the state-estimated Load in MW and the time-weighted average Real-Time LMPs at Electrical Buses that are included in the Load Zone. The Real-Time SPP for a Load Zone Settlement Point for a 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP} \quad = \quad \mathbf{Max\ (-\$251, ((\sum_{y} TLMP_{y} * LZLMP_{y}) / \sum_{y} TLMP_{y}) + RTRSVPOR + RTRDP)}$$

For all Load Zones except Direct Current Tie (DC Tie) Load Zones:

$$LZLMP_{y} \quad = \quad \sum_{b} (RTLMP_{b,\,y} * SEL_{b,\,y}) / \sum_{b} SEL_{b,\,y}$$

For a DC Tie Load Zone:

$$LZLMP_{y} \quad = \quad RTLMP_{b,\,y}$$

Where:

$$RTRSVPOR = \sum_{y} (RNWF_{y} * RTORPA_{y})$$

$$RTRDP = \sum_{y} (RNWF_{y} * RTORDPA_{y})$$

$$RNWF_{y} = TLMP_{y} / \sum_{y} TLMP_{y}$$

[20] ERCOT Nodal Protocols. August 20, 2021. Section 6.6.

For all Settlement calculations in which a 15-minute Real-Time SPP for a Load Zone is required in order to perform Settlement for a 15-minute quantity that is represented as one value (the integrated value for the 15-minute interval) but varies with each SCED interval within the 15-minute Settlement Interval, an energy-weighted Real-Time SPP shall be used and is calculated as follows:

$$\textbf{RTSPPEW} = \textbf{Max [-\$251, (}\sum_{y}\sum_{b}\textbf{(RTLMP}_{b,y} * \textbf{LZWF}_{b,y}\textbf{) + RTRSVPOR + RTRDP)]}$$

For all Load Zones except DC Tie Load Zones:

$$\text{LZWF}_{b,y} = (\text{SEL}_{b,y} * \text{TLMP}_{y}) / [\sum_{y}\sum_{b}(\text{SEL}_{b,y} * \text{TLMP}_{y})]$$

For a DC Tie Load Zone:

$$\text{LZWF}_{b,y} = (\text{SEL}_{b,y} * \text{TLMP}_{y}) / [\sum_{y}\sum_{b}(\text{SEL}_{b,y} * \text{TLMP}_{y})]$$

$$\text{SEL}_{b,y} = 1$$

Where:

$$\text{RTRSVPOR} = \sum_{y}(\text{RNWF}_{y} * \text{RTORPA}_{y})$$

$$\text{RTRDP} = \sum_{y}(\text{RNWF}_{y} * \text{RTORDPA}_{y})$$

$$\text{RNWF}_{y} = \text{TLMP}_{y} / \sum_{y}\text{TLMP}_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTSPP	\$/MWh	*Real-Time SPP*—The Real-Time SPP at the Settlement Point, for the 15-minute Settlement Interval.
RTSPPEW	\$/MWh	*Real-Time SPP Energy-Weighted*—The Real-Time SPP at the Settlement Point *p*, for the 15-minute Settlement Interval that is weighted by the state-estimated Load of the Load Zone of each SCED interval within the 15-minute Settlement Interval.
$\text{RTLMP}_{b,y}$	\$/MWh	*Real-Time Locational Marginal Price at bus per interval*—The Real-Time LMP at Electrical Bus *b* in the Load Zone, for the SCED interval *y*.
RTRSVPOR	\$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTORPA_{y}	\$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time Price Adder for On-Line Reserves for the SCED interval *y*.
RTRDP	\$/MWh	*Real-Time On-Line Reliability Deployment Price* —The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-time On-Line Reliability Deployment Price Adder.
RTORDPA_{y}	\$/MWh	*Real-Time On-Line Reliability Deployment Price Adder* —The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
RNWF_{y}	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node SPP calculation for the portion of the SCED interval *y* within the Settlement Interval.
$\text{LZWF}_{b,y}$	none	*Load Zone Weighting Factor per bus per interval*—The weight used in the Load Zone SPP calculation for Electrical Bus *b*, for the portion of the SCED interval *y* within the 15-minute Settlement Interval.

Variable	Unit	Description
$LZLMP_{y}$	$/MWh	*Load Zone Locational Marginal Price*—The Load Zone LMP for the Load Zone for the SCED Interval *y*.
$SEL_{b, y}$	MW	*State Estimator Load at bus per interval*—The Load from State Estimator, including a calculated net Load value at each Private Use Network, excluding Wholesale Storage Load (WSL) and Non-WSL Energy Storage Resource (ESR) Charging Load for Electrical Bus *b* in the Load Zone, for the SCED interval *y*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An Electrical Bus in the Load Zone. The summation is over all of the Electrical Buses in the Load Zone.

[NPRR1010 and NPRR1016: Replace applicable portions of paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1016:]

(2) For all Settlement calculations in which a 15-minute Real-Time SPP for a Load Zone is required in order to perform Settlement for a 15-minute quantity that is represented as one value (the integrated value for the 15-minute interval) but varies with each SCED interval within the 15-minute Settlement Interval, an energy-weighted Real-Time SPP shall be used and is calculated as follows:

$$\mathbf{RTSPPEW} = \mathbf{Max\ [-\$251,\ (\sum_{y} \sum_{b} (RTLMP_{b,y} * LZWF_{b,y}) + RTRDP)]}$$

For all Load Zones except DC Tie Load Zones:

$$LZWF_{b,y} = (SEL_{b,y} * TLMP_{y}) \,/\, [\sum_{y} \sum_{b} (SEL_{b,y} * TLMP_{y})]$$

For a DC Tie Load Zone:

$$LZWF_{b,y} = (SEL_{b,y} * TLMP_{y}) \,/\, [\sum_{y} \sum_{b} (SEL_{b,y} * TLMP_{y})]$$

$$SEL_{b,y} = 1$$

Where:

$$RTRDP = \sum_{y} (RNWF_{y} * RTRDPA_{y})$$

$$RNWF_{y} = TLMP_{y} \,/\, \sum_{y} TLMP_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTSPP	\$/MWh	*Real-Time SPP*—The Real-Time SPP at the Settlement Point, for the 15-minute Settlement Interval.
RTSPPEW	\$/MWh	*Real-Time SPP Energy-Weighted*—The Real-Time SPP at the Settlement Point *p*, for the 15-minute Settlement Interval that is weighted by the state-estimated Load of the Load Zone of each SCED interval within the 15-minute Settlement Interval.
$RTLMP_{b,y}$	\$/MWh	*Real-Time Locational Marginal Price at bus per interval*—The Real-Time LMP at Electrical Bus *b* in the Load Zone, for the SCED interval *y*.
RTRDP	\$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time Reliability Deployment Price Adder for Energy.
$RTRDPA_{y}$	\$/MWh	*Real-Time Reliability Deployment Price Adder for Energy* —The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$RNWF_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node SPP calculation for the portion of the SCED interval *y* within the Settlement Interval.
$LZWF_{b,y}$	none	*Load Zone Weighting Factor per bus per interval*—The weight used in the Load Zone SPP calculation for Electrical Bus *b*, for the portion of the SCED interval *y* within the 15-minute Settlement Interval.
$LZLMP_{y}$	\$/MWh	*Load Zone Locational Marginal Price*—The Load Zone LMP for the Load Zone for the SCED Interval *y*.
$SEL_{b,y}$	MW	*State Estimator Load at bus per interval*—The Load value from State Estimator, including a calculated net Load value at each Private Use Network and adjustments to account for Distribution Generation Resource (DGR) and Distribution Energy Storage Resource (DESR) injections and withdrawals that are settled at a Resource Node, excluding Wholesale Storage Load (WSL) and Non-WSL ESR Charging Load, for Electrical Bus *b* in the Load Zone, for the SCED interval *y*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An Electrical Bus in the Load Zone. The summation is over all of the Electrical Buses in the Load Zone.

4.5.2 Summary of SPP

There may be significant variability in energy prices annually, seasonally, day-to-day, and even hourly. Using a three-year average captures that variation and ensures the avoided cost of market energy is reflective of typical conditions over a longer period of time. Summer prices tend to peak from 2 PM to 5 PM, when solar panels are generating but not at peak output. Winter prices tend to peak during cold and darker hours when heating requirements are highest. Therefore, solar panels are not generating electricity during many of the more expensive hours in the winter.

FIGURE 4-4 SUMMER HOURLY PRICE

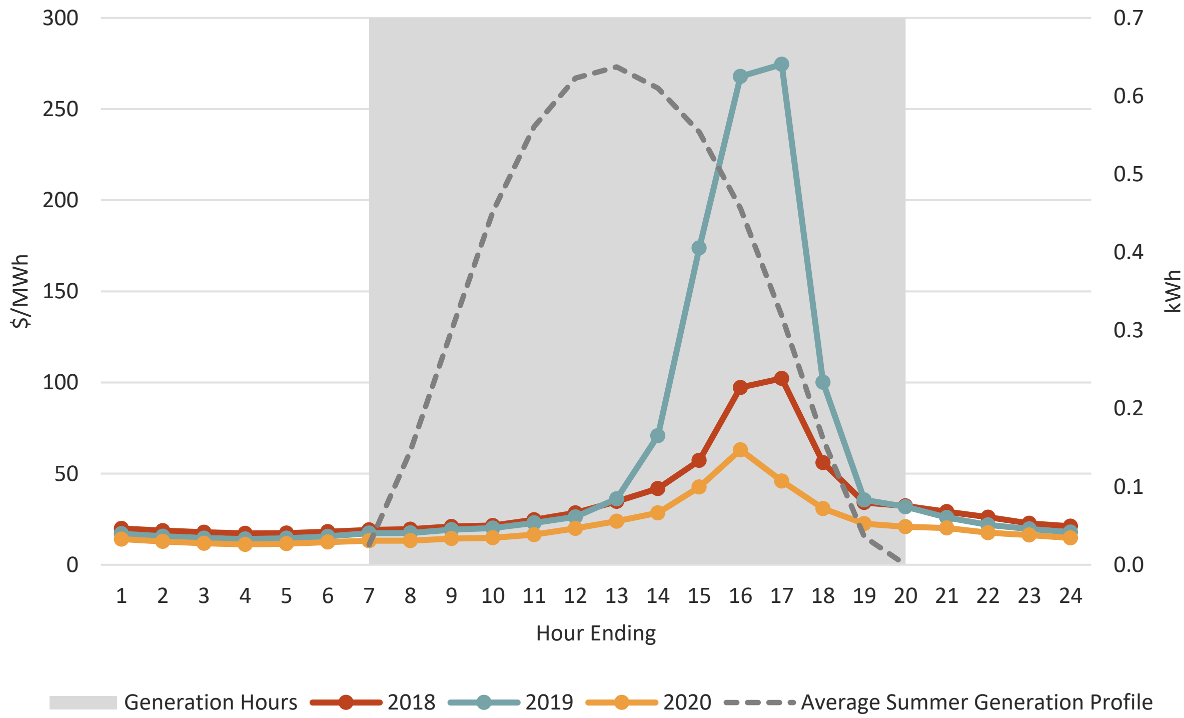
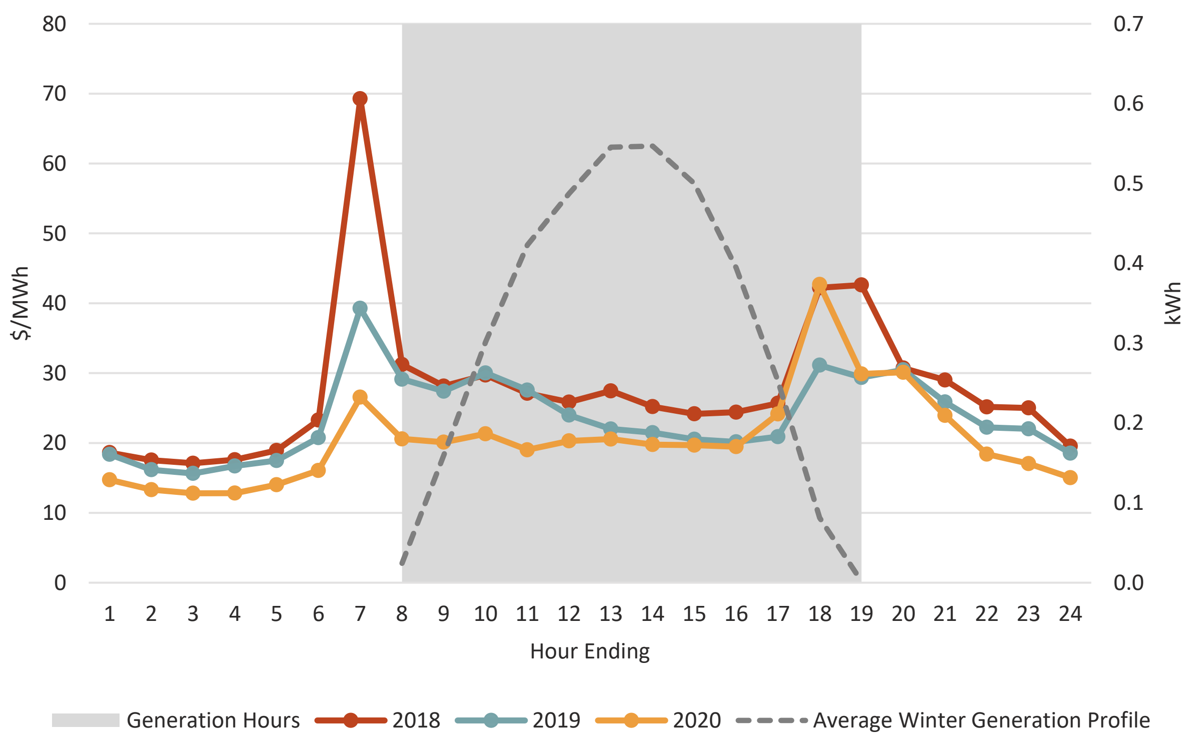


FIGURE 4-5 WINTER HOURLY PRICE



4.5.3 Avoided Energy Costs

Avoided energy costs are determined by applying the hourly SPPs over a three-year period and the generation output curve GDS developed for the Value Of Distributed Generation analysis (as described in Equation 4-2). As shown in Table 4-3, avoided energy costs can vary considerably from one-year to the next. Using a three-year historical average helps smooth such variability. The avoided energy cost of a 1 kW unit averages $62.31 per year, equivalent to $62.31/kW-year of installed capacity.

TABLE 4-3 AVOIDED ENERGY COSTS

Line No.	Item	3-Year Average	2018	2019	2020
1	Total Cost of Energy	$62.31	$56.85	$88.78	$41.31
2	Installed Capacity (kW_{DC})	1	1	1	1
3	Avoided Energy Costs ($/kW-year)	$62.31	$56.85	$88.78	$41.31

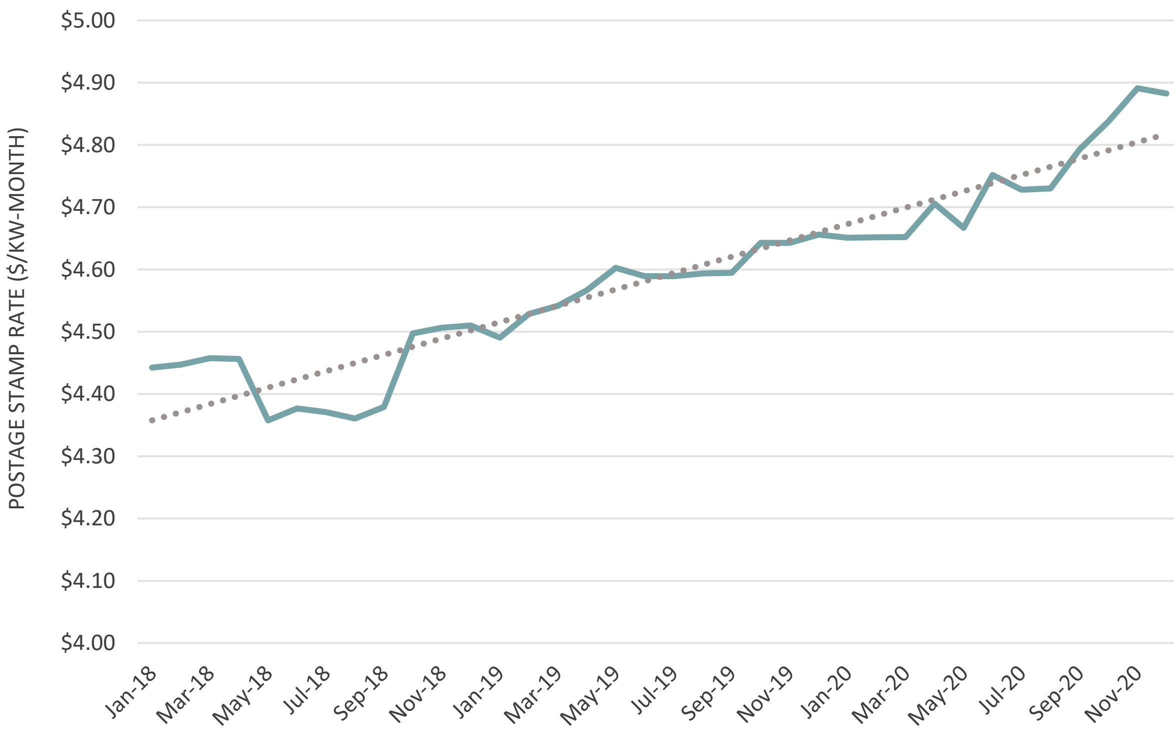
4.6 AVOIDED CAPACITY OR DEMAND COSTS – GEN_D

As discussed earlier, there is no avoided generation capacity cost value for generation demand or market-based demand. However, should either ERCOT adopt some form of a capacity market or PEC change its supply options or contracts in such a way that they have marginal capacity cost exposure, it would become appropriate at that time for PEC to update its Value Of Distributed Generation model and incorporate the avoided cost impacts. For that reason, GDS has chosen to include this element in the Value Of Distributed Generation formula but show it as having no value in PEC's current situation.

4.7 AVOIDED TRANSMISSION COSTS AT ERCOT 4-CP – TRANS$_{4\text{-}CP}$

Transmission costs in ERCOT are incurred based on a Load Serving Entity's (LSE) contribution to ERCOT's four summer peak demands, one for each month of June through September. The average of the four summer coincident peaks is called the 4-CP. A postage stamp rate for transmission is applied monthly based on the prior year's 4-CP. The postage stamp rates are charged by all Transmission Owners in ERCOT at a rate approved by the Public Utility Commission of Texas. In the last three years, the ERCOT 4-CPs have occurred most often in the 5PM hour. In fact, 10 of the 12 peaks in the past three years occurred in that hour. The other two peaks occurred at 6PM and at 3 PM.

FIGURE 4-6 ERCOT TRANSMISSION RATE ($/KW-MONTH)



The avoided transmission cost is computed as:

EQUATION 4-3

$$Trans_{4\text{-CP},y} = \sum_{m=1}^{4} Rate_{m,y} \times Cap_{AC} \times CF_{m,y}$$

Where:

$Trans_{4\text{-}CP,y}$	Avoided Transmission Cost at ERCOT 4-CP in Year y
y	Year
m	Month of the Year (note: the four months are June through September)
$Rate_{m,y}$	ERCOT Postage Stamp Rate in Month m in Year y
Cap_{AC}	Peak Capacity Output of PV Unit in AC and Adjusted for Losses
$CF_{\boldsymbol{m,y}}$	Coincidence Factor for PV Generation Output at Time of ERCOT Peak in Month m in Year y

4.7.1 Definition of 4-CP Hours

ERCOT defines it's average 4-CP as follows [21]:

ERCOT average 4-CP is defined as the average of the coincidental MW peaks occurring during the months of June, July, August, and September.

Coincidental MW peak is defined as the highest monthly Settlement Interval 15-minute MW peak for the entire ERCOT Transmission Grid as calculated per the following formula: The sum of all net energy produced by Generation Resources + Settlement Only Generators (SOGs) + Block Load Transfers (BLTs) from ERCOT to another Control Area that have been registered for Settlement purposes + actual DC Tie imports - BLTs to ERCOT from another Control Area that are not reflected in a Non-Opt-In Entity's (NOIE's) Load - actual DC Tie exports - Wholesale Storage Load (WSL).

Any difference between the coincidental MW peak (converted to MWh) and the ERCOT Settlement volumes, excluding DC Tie exports, BLTs to ERCOT from another Control Area that are not reflected in a NOIE's Load, and WSL, shall be allocated amongst all DSPs and ELSEs that are included in the ERCOT 4-CP Report on a pro rata basis as per the formula below:

$$\textbf{LTDSP\_4-CP}_{\ tdsp} = (\textbf{PLTDSP4-CPLRS}_{\ tdsp} * \textbf{NLADJ}) + \textbf{PLTDSP4-CP}_{\ tdsp}$$

The above variables are defined as follows:

Variable	Unit	Definition
LTDSP_4-CP $_{tdsp}$	MWh	*Load by TDSP for 4-CP* - The load for each DSP and ELSE coincident to the coincidental MW peak adjusted for NLADJ
PLTDSP4-CPLRS $_{tdsp}$	%	*Preliminary Load by TDSP for 4-CP Load Ratio Share* - The Load Ratio Share (LRS) for each DSP and ELSE coincident to the coincidental MW peak prior to adjusting for NLADJ
NLADJ	MWh	*Native Load Adjustment* - The difference between the coincidental MW peak (converted to MWh) and the ERCOT settlement volumes, excluding DC Tie exports, BLTs to ERCOT from another Control Area that are not reflected in a NOIE's Load, and WSL
PLTDSP4-CP $_{tdsp}$	MWh	*Preliminary Load by TDSP for 4-CP* - The Load for each DSP and ELSE coincident to the coincidental MW peak prior to adjusting for NLADJ
tdsp	None	A DSP or ELSE

4.7.2 Computation of Coincidence Factors for ERCOT 4-CP

To compute the avoided transmission costs, GDS applies a coincidence factor to the peak output of a generation unit times the average annual postage stamp rate. The coincidence factors represent the average percentage of maximum output being achieved by the generator at the specific date and hour of the 4-CP. The factors were computed by dividing the hourly solar generation adjusted for distribution losses at the time of the 4-CP peaks by the maximum AC output of the generator adjusted for distribution losses. The solar production at each location and the coincidence factors are shown in Table 4-4.

[21] ERCOT Nodal Protocols. August 20, 2021. Section 9.17.

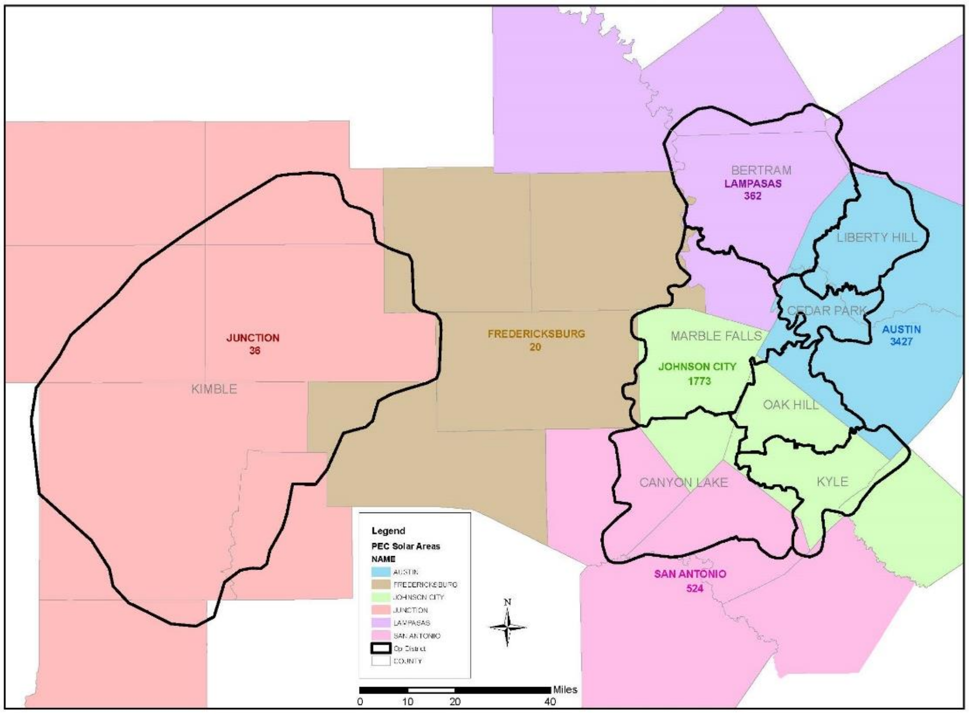
TABLE 4-4 COINCIDENCE FACTORS FOR PEC'S ANNUAL 4-CP HOURS

Date & Time		Johnson City		Lampasas		Austin		Fredricksburg		Junction		San Antonio Airport		Average	
4 CP Events		AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %
6/27/2018	17:00	346	39.2%	336	38.0%	324	36.6%	359	40.6%	377	42.6%	328	37.1%	332	37.5%
7/19/2018	17:00	342	38.7%	346	39.2%	335	37.9%	374	42.3%	362	41.0%	349	39.5%	339	38.4%
8/23/2018	17:00	347	39.3%	326	36.9%	313	35.5%	316	35.8%	324	36.7%	349	39.5%	327	37.0%
9/19/2018	17:00	285	32.3%	295	33.4%	267	30.2%	308	34.8%	290	32.9%	301	34.1%	277	31.3%
6/19/2019	17:00	346	39.2%	336	38.0%	324	36.6%	359	40.6%	377	42.6%	328	37.1%	332	37.5%
7/30/2019	17:00	342	38.7%	346	39.2%	335	37.9%	374	42.3%	362	41.0%	349	39.5%	339	38.4%
8/12/2019	17:00	347	39.3%	326	36.9%	313	35.5%	316	35.8%	324	36.7%	349	39.5%	327	37.0%
9/6/2019	17:00	285	32.3%	295	33.4%	267	30.2%	308	34.8%	290	32.9%	301	34.1%	277	31.3%
6/8/2020	18:00	188	21.3%	187	21.2%	171	19.4%	189	21.4%	215	24.4%	188	21.3%	179	20.2%
7/13/2020	17:00	342	38.7%	346	39.2%	335	37.9%	374	42.3%	362	41.0%	349	39.5%	339	38.4%
8/13/2020	17:00	347	39.3%	326	36.9%	313	35.5%	316	35.8%	324	36.7%	349	39.5%	327	37.0%
9/1/2020	15:00	551	62.4%	519	58.8%	524	59.3%	575	65.1%	520	58.9%	535	60.6%	533	60.3%
Average		339	38.4%	332	37.6%	318	36.0%	347	39.3%	344	39.0%	340	38.4%	327	37.0%
Weight			0.289		0.059		0.558		0.003		0.006		0.085		1.00
Weighted Average			11.1%		2.2%		20.1%		0.1%		0.2%		3.3%		37.0%

AC Output in watts are based on monthly averages calculated from solar generation modeled using NREL's PV Watts online tool assuming a 20° tilt and 180° azimuth, adjusted for 5.98% distribution losses.

The average AC output in Table 4-4 was weighted by the number of installations in each area. The map below shows the locations of the installations in relation to PEC's service territory.

FIGURE 4-7 PEC SOLAR AREA AND INSTALLATION COUNT (SEPT 2021)



Typical solar production curves for an average August day and coincidence factors at the time of the 4-CP on 8/13/20 are shown below for each location. The curves were generated using PV Watts and adjusted for distribution losses of 5.98%.

FIGURE 4-8 4-CP SOLAR COINCIDENCE FACTOR EXAMPLE – JOHNSON CITY, TX

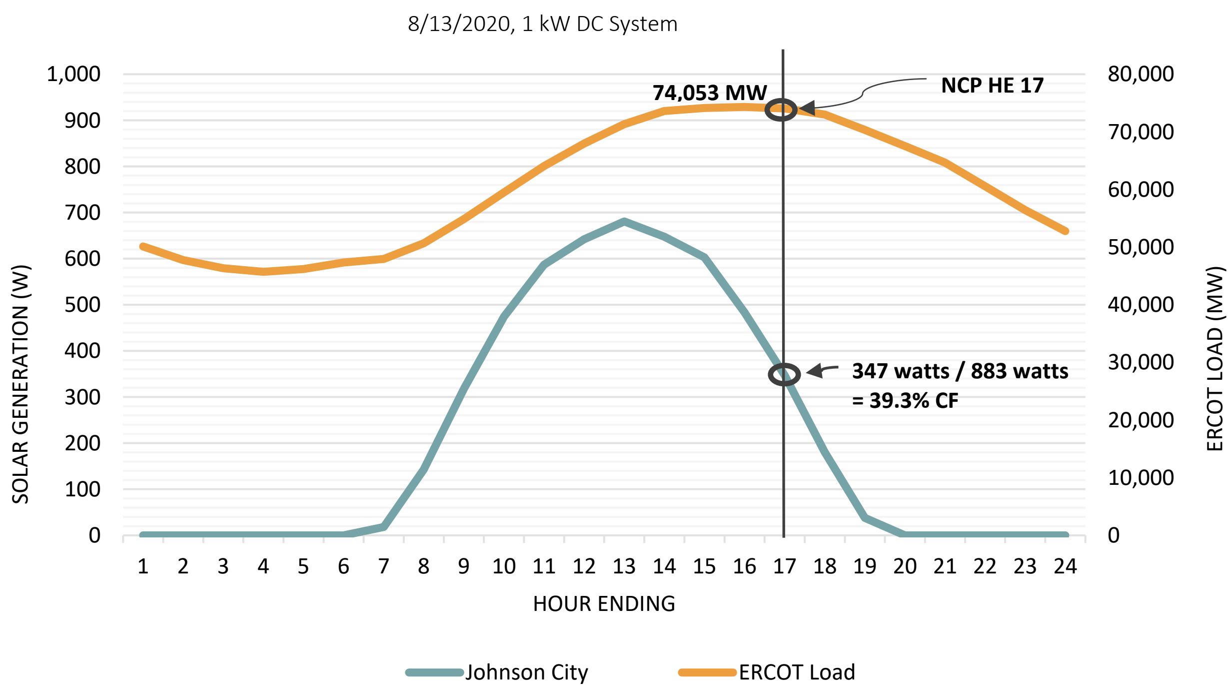


FIGURE 4-9 4-CP SOLAR COINCIDENCE FACTOR EXAMPLE – LAMPASAS, TX

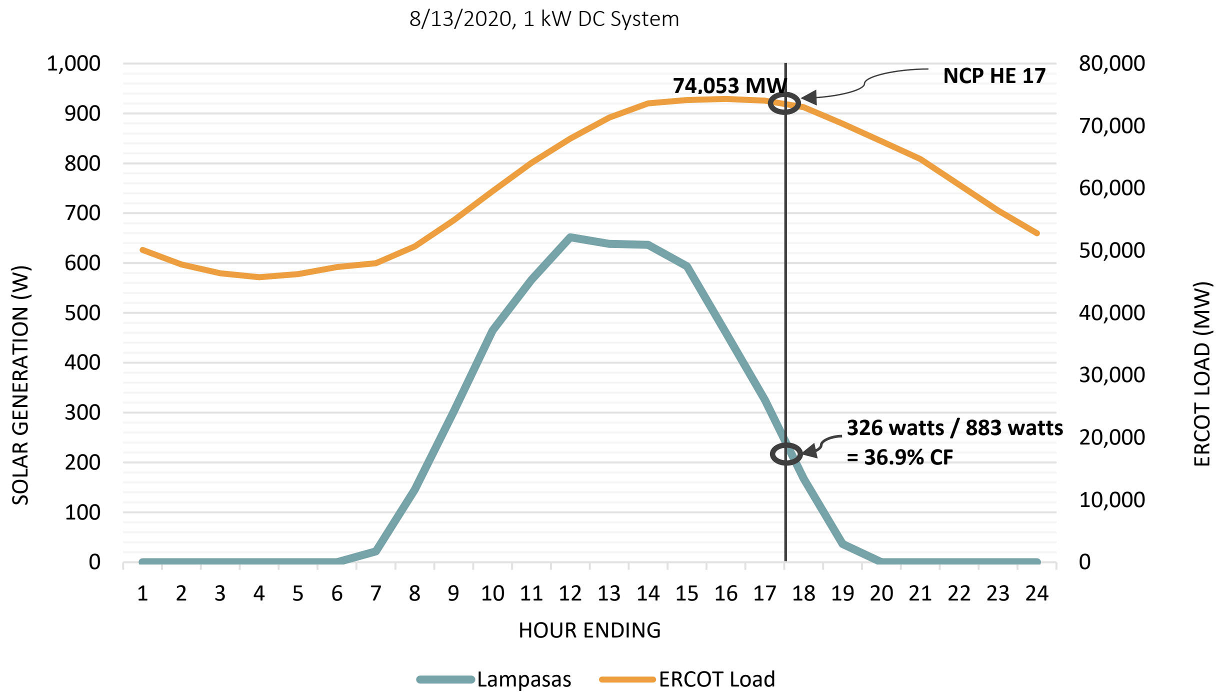


FIGURE 4-10 4-CP SOLAR COINCIDENCE FACTOR EXAMPLE – AUSTIN, TX

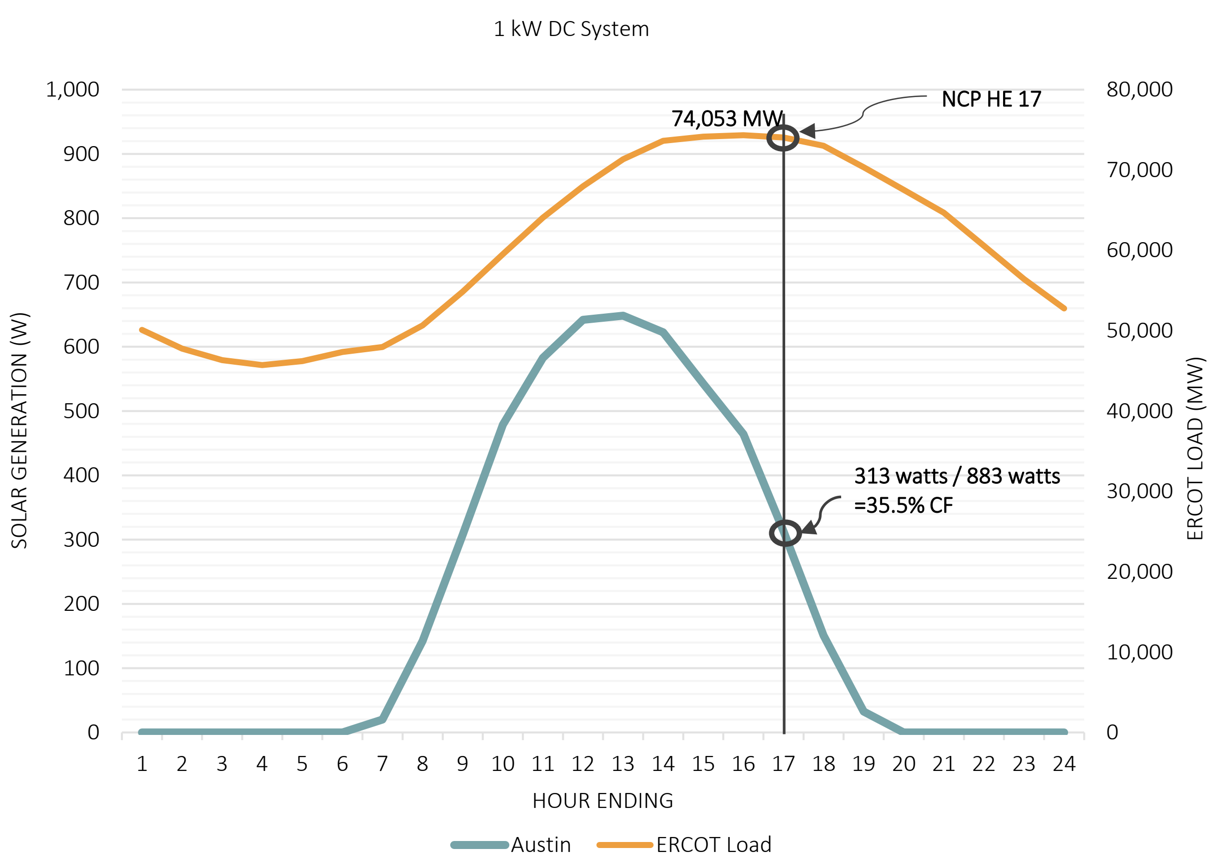


FIGURE 4-11 4-CP SOLAR COINCIDENCE FACTOR EXAMPLE – FREDERICKSBURG, TX

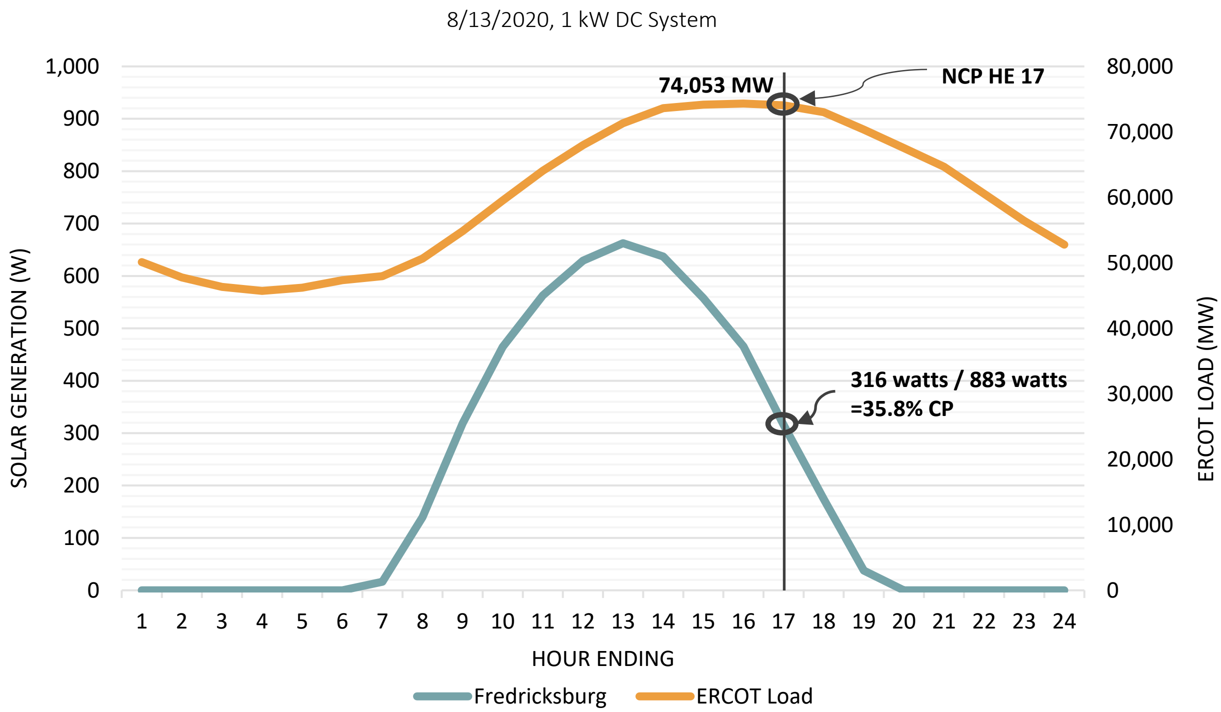


FIGURE 4-12 4-CP SOLAR COINCIDENCE FACTOR EXAMPLE – JUNCTION, TX

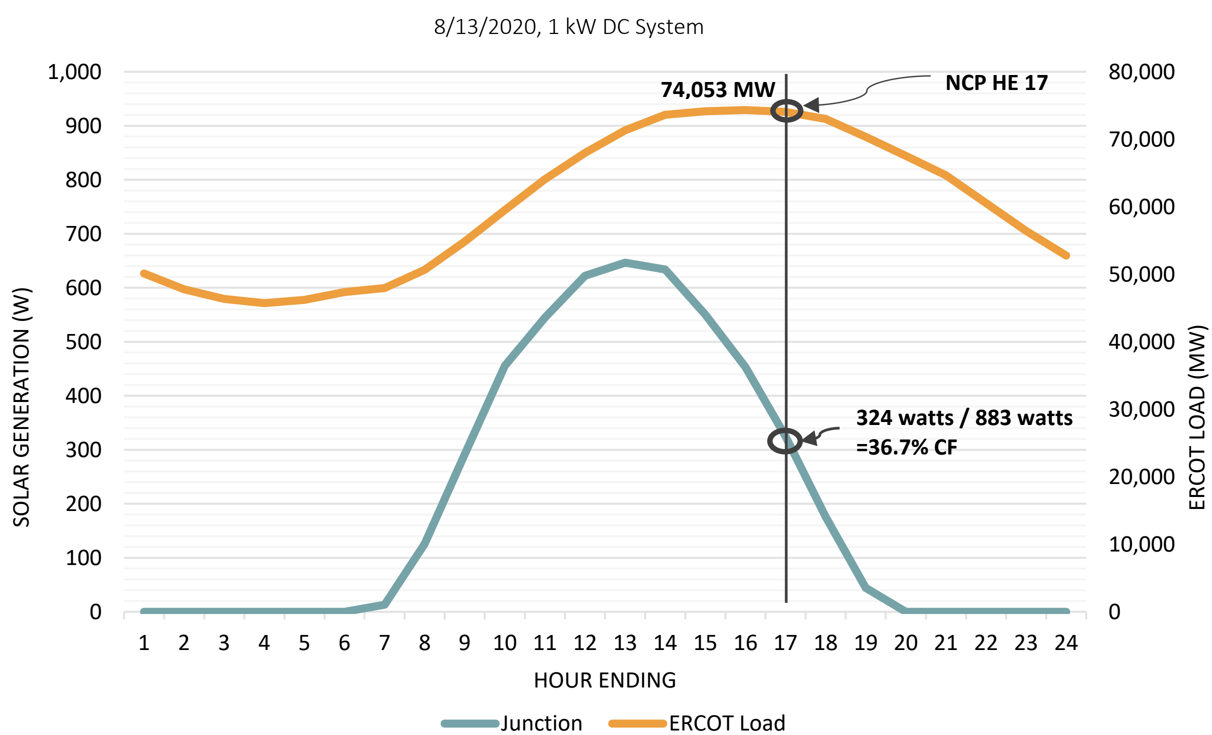
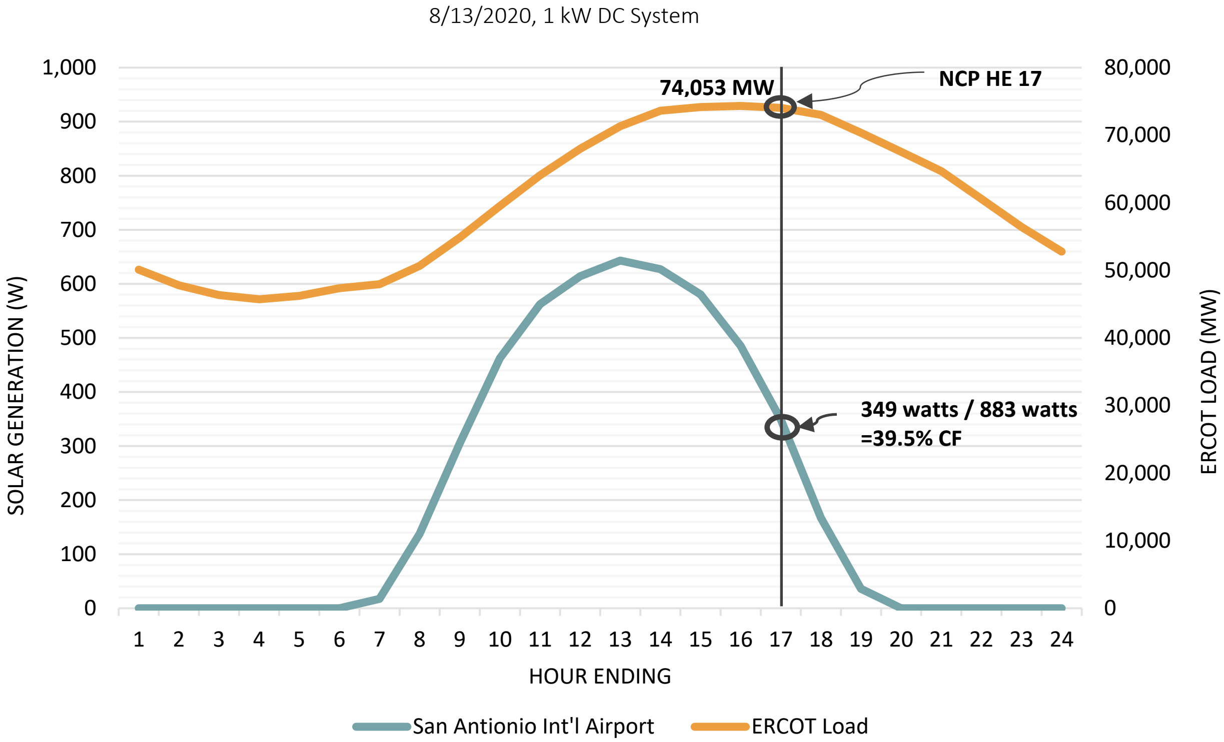


FIGURE 4-13 4-CP SOLAR COINCIDENCE FACTOR EXAMPLE – SAN ANTONIO, TX



4.7.3 Avoided Transmission Costs at 4-CP

GDS recognizes that the transmission rate has been increasing steadily over the three-year historical period (see Table 4-5). To both maintain consistency with a Value Of Distributed Generation analysis using historical avoided cost information but to recognize the increasing nature of transmission costs, GDS uses the 2020 average postage stamp rate for each year of the analysis of avoided transmission cost. We then applied that average to the three-year historical coincidence factors to compute the transmission costs for generation. As shown in Table 4-6, the avoided cost of transmission for the typical solar profile in PEC ranged from \$18.14-\$19.61 per year over the past three years.

TABLE 4-5 AVOIDED TRANSMISSION COST CALCULATIONS

Line No.	Time of ERCOT 4-CP Year	Month	Hour	4-CP Rate ($/kW-Mo)	DG Max Output (kW)[1]	Average DG Output (kWh/yr)[1]	Coincidence Factor	Contribution to 4-CP (kW)	Transmission Cost ($)	Transmission Cost (¢/kWh)
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Average								$18.63	1.160
2	2018	6	17		0.883		37.5%	0.332		
3	2018	7	17		0.883		38.4%	0.339		
4	2018	8	17		0.883		37.0%	0.327		
5	2018	9	17		0.883		31.3%	0.277		
6		4-CP		$4.7451		1,563		0.319	$18.14	1.160
7	2019	6	17		0.883		37.5%	0.332		
8	2019	7	17		0.883		38.4%	0.339		
9	2019	8	17		0.883		37.0%	0.327		
10	2019	9	17		0.883		31.3%	0.277		
11		4-CP		$4.7451		1,563		0.319	$18.14	1.160
12	2020	6	18		0.883		20.2%	0.179		
13	2020	7	17		0.883		38.4%	0.339		
14	2020	8	17		0.883		37.0%	0.327		
15	2020	9	15		0.883		60.3%	0.533		
16		4-CP		$4.7451		1,567		0.344	$19.61	1.251

1 - Adjusted for 5.98% distribution losses.

The avoided cost value is the same in 2018 and 2019, which is a function of two factors. The first is that the hour of the ERCOT 4-CP is the same in each month of those years, and with an average generation hourly load profile, the resultant coincidence factors are the same. Furthermore, by using the average 2020 postage stamp rate in each year means the avoided cost value is the same in each year.

TABLE 4-6 AVOIDED COST OF TRANSMISSION

Line No.	Item	3-Year Average	2018	2019	2020
1	Total Cost of Transmission	$18.63	$18.14	$18.14	$19.61
2	Installed Capacity (kW_{DC})	1	1	1	1
3	Avoided Transmission Costs ($/kW-year)	$18.63	$18.14	$18.14	$19.61

4.8 AVOIDED DISTRIBUTION COSTS

Investment in the distribution system is often driven by the interplay between making enhancements for reliability and sustainability and meeting growth in new connections. Utility peak demands or circuit level demands can also drive investments in upgrades to substation equipment and the distribution system backbone. Radial feeders off the backbone are often built to respond to member growth as are investments in meters and services.

The question of whether DG provides an avoided cost benefit with respect to the distribution system is a topic of debate that is tied to system planning. When developing plans for the expansion of a distribution system, a set of planning criteria is used to define adequate levels of services and system capacities. The first criterion usually concerns the system in a normal configuration, and a second criterion is the consideration of the system during a single-contingency outage (N-1). The N-1 outage means that one component such as a substation transformer, substation bus, or a single feeder is out of service. With that one component out of service, the system should be designed to continue electric service to the system with the one component isolated. This allows for routine maintenance as well as planning for failure of a key component at a critical time of high electric demand. A simple way to consider this design is that two feeders that are tied together are each limited to 50% of their respective capacity. Thus, if one feeder fails, the remaining feeder can serve 100% of the load of both feeders. An urban/suburban system such as PEC's is often capacity limited due to the N-1 criteria. While a solar resource may be a firm, predictable resource of some capacity at peak for normal conditions, many utilities do not consider solar a firm resource for an N-1 analysis. The IEEE 1547[22] standard requires inverters on solar panels to be shut off with loss of utility voltage specifically when voltage is less than 45 volts it must stop generating within 0.16 seconds. An N-1 event is characterized as an outage with loss of voltage. After an outage, when utility power is available and stable, the inverter has a time delay which can be 5 minutes before the inverter reconnects with the system.[23] Thus for some period of time, the solar resource is not available to reduce system capacity. Another reason most utilities do not consider solar a firm resource for N-1 is that in most cases the magnitude of the solar capacity has not been sufficient to be a viable issue.

An alternate theory is that the system planning criteria should include the PV resource during an N-1 condition. Specifically, the N-1 condition is based on an integrated one-hour peak load so a dynamic analysis is not normally conducted in the distribution system planning. Also when the distribution system is reconfigured as a result of an N-1 condition, the existing voltage regulation equipment needs time to respond to the change in load. Voltage regulators typically have a 30 to 90 second time delay to verify stable voltage before a step change in voltage. If the voltage change due to the load shift is significant, it may take the voltage regulators 3 to 6 minutes to permit multiple voltage steps to bring the voltage back into compliance with ANSI C84.1. So the time delay for the regulator controls and the delay for the solar resource are not significantly different.

Determining the appropriate avoided cost of distribution plant investment is challenging, and there are various approaches that have been used in the industry. Many of the approaches rely on use of sophisticated system-wide simulation tools or development of complicated forecasts.[24] For example, in California, planners work to assess Specified and Unspecified deferrals of distribution investments and

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[22] IEEE1547.4 Guide for Design, Operation, and Integration of Distribution Island Systems with Electric Power Systems.

[23] The delay is variable for some inverters but because utilities use multiple reclosing on a fault to try to clear temporary faults, it is necessary for the inverter to wait until all reclosing efforts are completed and voltage is stable prior to re-energizing.

[24] Chan, Gabriel. Letter *RE: Reply Comments on Xcel Energy's May 1, 2019 Filing on the Calculation of the Avoided Distribution Cost Component of the Value of Solar (Docket No. M-13-867)*. August 23, 2019.

the Unspecified deferrals require development of a counterfactual load forecast, where the objective is to determine what load would have been without natural growth in DER over the forecast horizon:

- Specified deferrals – avoided cost value of deferring distribution investment projects through the addition of DER or other load reducing measures that are above and beyond the DER growth the utility expects to be adopted in the project area because of current DER policies, incentives, and programs
- Unspecified deferrals – avoided costs that reflect the increased need for capacity projects that would have occurred if there were less DER growth embedded in the utility base forecasts.[25]

To determine the Unspecified deferrals in California, a counterfactual load forecast must be developed. This is the load forecast that removes adoption of load-modifying distributed energy resources, including energy efficiency, demand response, battery storage, rooftop photovoltaics, and electric vehicles.[26] Note that this approach requires circuit-level modeling, and development of special load forecasts to determine the avoided distribution costs of not just DG, but energy efficiency and other load-modifying resources.

A paper produced in 2018 that assessed the current methods of valuing net metering through solar photovoltaics likewise concluded that determining avoided distribution costs is difficult:

> *The calculation around the distribution system, however, is more nuanced and complicated. At this point in time, no state has finalized a specific value, but some states are working on determining the methodology that they will use.*
>
> *The distribution system was originally designed for one-way flows of electricity (i.e., from a power plant to a home). With two-way flows, several scenarios are possible. With certain scenarios, distributed generation can lead to decreased distribution spending (by avoiding the need for infrastructure upgrades, for example); with others, adding distributed generation on the system may lead to additional cost (where equipment needs to be updated to handle the additional generation coming into the system). The conditions will depend on circuit-level circumstances, potentially leading to difficulties in valuation. Other factors that could influence valuation include increases in the amount of distributed generation on a particular circuit, the amount of distributed generation consumed on-site, the location of the distributed generation on the circuit (in relation to the transformer), and changes to the timing of peak use on that distribution circuit.*[27]

Gabriel Chan, in his research and comments in Minnesota, likewise concluded the task is difficult:

> *Across all extant studies for calculating avoided distribution costs, we observed an implicit or explicit reckoning with the difficulty of this analytic task. Coordinating growing distribution capacity with growing generation capacity (of either centralized or distributed facilities) is an unsolved problem of markets and utility modeling in general.*
>
> *Perhaps for these tensions between accuracy, fairness, and reasonableness, there is a wide range of methods to estimate avoided distribution costs. They include system planning approaches, using combinations of historical and forecast information, marginal cost of service studies, and simple distribution cost sampling (see Section 2.3 for a list of proposed methods for avoided transmission and distribution costs in the context of energy*

[25] "Energy Division Staff Proposal for 2020 Avoided Cost Calculator Update." Integrated Distributed Energy Resources Rulemaking (R.14-10-003). California. April 16, 2020.
[26] *Ibid*.
[27] Payne, Heather and Jonas Monast. "Valuing Distributed Energy Resources: A Comparative Analysis." UNC Center for Climate, Energy, Environment, and Economics. June 4, 2018.

> *efficiency programs). A 2014 survey of these methods (in the context of energy efficiency) found that 24 utilities had avoided distribution costs between $0 and $171 per kW-year, with an average avoided distribution cost of $48.37 kW-year. While indicative of the variety of methods and the variety of estimated avoided costs, this survey says nothing of the validity of those methods.*[28]

Mr. Chan provides a helpful table summarizing approaches that have been used:

[28] Chan, Gabriel. Letter *RE: Reply Comments on Xcel Energy's May 1, 2019.*

FIGURE 4-14 APPROACHES TO CALCULATING AVOIDED T&D COSTS (CHAN, GABRIEL)[29]

Table 1: Approaches to Calculating Avoided T&D Costs[7]

Method	Brief Description	Examples	Strengths	Weaknesses
System Planning Approach	• Uses costs and load growth for specific T&D projects based on a system planning study	• Vermont Electric Company (2003) - focused on specific transmission upgrade	• Potentially more accurate • Uses specific project data to develop estimates • Forces consideration of DER effects on project-by-project basis	• Costly and time consuming • May not be appreciably more accurate than other approaches • Dependent upon individual projects included in analysis
Mix of Historical and Forecast Information	• Uses data on historical and forecast T&D investments, determines what's related to load growth, and weighs the historical and forecast contributions	• ICF Tool used in the Northeast, Vermont DPS variation	• Uses publicly available FERC Form 1 data • Easily calculated and updated • Uses a form of marginal costs • Addresses "lumpiness" of T&D investments • Used by multiple other states • Relies upon historical as well as forecast information	• Assumes it's possible to differentiate amount of T&D investment that corresponds to load growth rather than maintenance, reliability and customer growth • Does not incorporate variability associated with time/location differences • Can't readily handle low forecast growth
Current Values	• Develops average cost to serve existing load by dividing each system's net cost	• MidAmerican Energy (IA, IL, SD), Commonwealth Edison (IL)	• Uses publicly available FERC Form 1 data • Easily calculated and updated	• May tend to undervalue • Does not incorporate variability associated with time/location differences
Rate case marginal cost data with allocators	• Uses T&D marginal cost of service data from utility rate cases and apply time and locational factors related to weather or specific substation loadings	• California IOUs	• Uses publicly available data (rate case portion) • Uses approach consistent with ratemaking • Uses time and location differentiated data • Uses marginal cost information	• Potentially costly and time consuming • May not be appreciably more accurate than other approaches • Somewhat assumes use of hourly avoided costs for Generation • Requires estimation of investments deferred by EE
Rate case marginal cost data	• Use T&D marginal cost of service data from most recent rate case	• Ameren (MO), PacifiCorp (OR, UT, WA), Nevada Energy, Consolidated Edison (NY)	• Uses publicly available data • Is approach consistent with ratemaking • Uses marginal cost information	• May not be appreciably more accurate than other approaches • Requires estimation of investments deferred by EE
IRP Method	• Uses with and without EE runs to determine avoided transmission costs	• Tucson Electric Power	• Is consistent with integrated resource plan	• Is highly dependent on IRP's model ability to calculate transmission costs • Requires integrated resource plan • Only updated as frequently as resource plan • Typically can only provide transmission
Averaging method	• Take simple average of a selection of similar jurisdictions	• Wisconsin Focus on Energy Market Potential Study (used Iowa) • Northwest Conservation and Electric Power Plan (used 8 utilities)	• Uses publicly available data • Very easily calculated	• Must pick appropriate proxy utilities for Averaging • Not specific to one utility
Simple Method	• Take representative sample of recent T&D upgrade projects, divide by increased capacity and annualize	• Unknown	• Very simple • Provides real information from specific example • Can be done for transmission, distribution and sub-transmission	• Project may not be system representative • Must still determine what portion of increased capacity relates to load growth

[29] *Ibid*.

4.8.1 GDS Approach to Avoided Distribution Costs

While there is some debate among analysts, PEC's planning engineers, like much of the industry, have concluded that the distribution system costs are predominantly fixed and will not decline with a decrease in load resulting from the operation of DG at current levels. This is primarily due to the requirement that distribution investment must be sufficient to meet system peak demands at any time throughout the year, or the Non-Coincident Peak (NCP). That is, distribution investment is sized to meet a single annual system peak, and not the energy requirements throughout the year. Although DG could be producing output during certain peaks of the year, especially in summer months for PV systems, they are not consistently producing output during the single highest peaks of the year and therefore do not provide a firm and consistent reduction in peak demand that can be counted on to delay investment in distribution system infrastructure. Therefore, the expectation is that there is no avoided distribution costs due to the installation of DG. To the extent that future DG consistently reduces system peak demands that allows planning engineers to delay investment in the system, PEC will update the Value Of Distributed Generation analysis to reflect value arising from such reduction.

4.8.2 Coincidence Factors During Monthly PEC Peaks

To illustrate there is currently no avoided distribution costs this section details the value associated with distributed generation, GDS computed a coincidence factor between the PVWatts® generation curves and the timing of the monthly PEC peak demands for 2018-2020. A coincidece factor of zero or less than 5% occurs in January, February, and December of each year. The PEC system peaked in January of 2019, meaning DG was producing no output to offset the peak in that year. Likewise, given the severity of the winter storm event in 2021, PEC expects to set a winter peak demand again in 2021, which would represent 50% of peaks occurring in the winter in the last four years.

TABLE 4-7 COINCIDENCE FACTORS FOR GENERATION COINCIDENT WITH PEC MONTHLY PEAK DEMANDS

Coincidence Factors for PEC's Annual NCP Hours - 2018															
Date & Time		Johnson City		Lampasas		Austin		Fredricksburg		Junction		San Antonio Airport		Average	
12 CP Events		AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %
1/17/2018	8:00	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
2/12/2018	8:00	15	1.7%	19	2.1%	32	3.7%	14	1.5%	10	1.1%	16	1.8%	25	2.8%
3/26/2018	17:00	333	37.8%	323	36.6%	297	33.6%	341	38.6%	328	37.2%	307	34.8%	310	35.1%
4/13/2018	18:00	157	17.8%	160	18.1%	160	18.1%	166	18.8%	173	19.6%	160	18.1%	159	18.0%
5/26/2018	17:00	282	32.0%	311	35.2%	311	35.2%	342	38.7%	333	37.7%	322	36.4%	304	34.4%
6/27/2018	18:00	188	21.3%	187	21.2%	171	19.4%	189	21.4%	215	24.4%	188	21.3%	179	20.2%
7/23/2018	18:00	195	22.1%	192	21.7%	186	21.0%	212	24.1%	206	23.3%	186	21.0%	189	21.4%
8/21/2018	17:00	347	39.3%	326	36.9%	313	35.5%	316	35.8%	324	36.7%	349	39.5%	327	37.0%
9/1/2018	17:00	285	32.3%	295	33.4%	267	30.2%	308	34.8%	290	32.9%	301	34.1%	277	31.4%
10/3/2018	17:00	214	24.3%	226	25.6%	217	24.6%	247	27.9%	237	26.8%	231	26.1%	218	24.7%
11/14/2018	8:00	55	6.2%	72	8.2%	67	7.6%	66	7.4%	50	5.7%	72	8.2%	64	7.3%
12/10/2018	8:00	9	1.0%	7	0.8%	16	1.8%	5	0.5%	1	0.1%	8	0.9%	13	1.4%
Average		173	19.6%	176	20.0%	170	19.2%	184	20.8%	181	20.5%	178	20.2%	172	19.5%
Weight			28.9%		5.9%		55.8%		0.3%		0.6%		8.5%		100.0%
Weighted Average			0.057		0.012		0.107		0.001		0.001		0.017		0.195

AC Output in watts was generated from NREL's PV Watts online tool assuming a 20° tilt and 180° azimuth, adjusted for 5.98% distribution losses.

Coincidence Factors for PEC's Annual NCP Hours - 2019															
Date & Time		Johnson City		Lampasas		Austin		Fredricksburg		Junction		San Antonio Airport		Average	
12 CP Events		AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %
1/24/2019	8:00	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
2/8/2019	19:00	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
3/5/2019	8:00	58	6.6%	66	7.5%	59	6.7%	62	7.0%	55	6.2%	65	7.3%	60	6.8%
4/10/2019	18:00	157	17.8%	160	18.1%	160	18.1%	166	18.8%	173	19.6%	160	18.1%	159	18.0%
5/19/2019	17:00	282	32.0%	311	35.2%	311	35.2%	342	38.7%	333	37.7%	322	36.4%	304	34.4%
6/20/2019	17:00	346	39.2%	336	38.0%	324	36.6%	359	40.6%	377	42.6%	328	37.1%	332	37.6%
7/31/2019	17:00	342	38.7%	346	39.2%	335	37.9%	374	42.3%	362	41.0%	349	39.5%	339	38.4%
8/13/2019	17:00	347	39.3%	326	36.9%	313	35.5%	316	35.8%	324	36.7%	349	39.5%	327	37.0%
9/6/2019	17:00	285	32.3%	295	33.4%	267	30.2%	308	34.8%	290	32.9%	301	34.1%	277	31.4%
10/6/2019	16:00	390	44.2%	369	41.8%	375	42.4%	410	46.4%	395	44.8%	403	45.6%	381	43.2%
11/12/2019	9:00	194	22.0%	240	27.2%	220	24.9%	235	26.6%	213	24.1%	238	27.0%	215	24.4%
12/18/2019	8:00	9	1.0%	7	0.8%	16	1.8%	5	0.5%	1	0.1%	8	0.9%	13	1.4%
Average		201	22.8%	205	23.2%	198	22.4%	215	24.3%	210	23.8%	210	23.8%	201	22.7%
Weight			28.9%		5.9%		55.8%		0.3%		0.6%		8.5%		100.0%
Weighted Average			0.066		0.014		0.125		0.001		0.001		0.020		0.227

AC Output in watts was generated from NREL's PV Watts online tool assuming a 20° tilt and 180° azimuth, adjusted for 5.98% distribution losses.

Coincidence Factors for PEC's Annual NCP Hours - 2020														
Date & Time	Johnson City		Lampasas		Austin		Fredricksburg		Junction		San Antonio Airport		Average	
12 CP Events	AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %
1/8/2020 8:00	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
2/6/2020 8:00	15	1.7%	19	2.1%	32	3.7%	14	1.5%	10	1.1%	16	1.8%	25	2.8%
3/25/2020 18:00	139	15.8%	154	17.4%	129	14.6%	161	18.3%	167	18.9%	158	17.8%	136	15.4%
4/28/2020 17:00	341	38.6%	334	37.8%	319	36.1%	348	39.4%	347	39.3%	319	36.2%	326	37.0%
5/19/2020 17:00	282	32.0%	311	35.2%	311	35.2%	342	38.7%	333	37.7%	322	36.4%	304	34.4%
6/8/2020 18:00	188	21.3%	187	21.2%	171	19.4%	189	21.4%	215	24.4%	188	21.3%	179	20.2%
7/13/2020 17:00	342	38.7%	346	39.2%	335	37.9%	374	42.3%	362	41.0%	349	39.5%	339	38.4%
8/15/2020 17:00	347	39.3%	326	36.9%	313	35.5%	316	35.8%	324	36.7%	349	39.5%	327	37.0%
9/1/2020 18:00	119	13.5%	113	12.8%	110	12.4%	121	13.7%	129	14.6%	125	14.1%	114	12.9%
10/11/2020 17:00	214	24.3%	226	25.6%	217	24.6%	247	27.9%	237	26.8%	231	26.1%	218	24.7%
11/30/2020 8:00	55	6.2%	72	8.2%	67	7.6%	66	7.4%	50	5.7%	72	8.2%	64	7.3%
12/17/2020 8:00	9	1.0%	7	0.8%	16	1.8%	5	0.5%	1	0.1%	8	0.9%	13	1.4%
Average	171	19.4%	175	19.8%	168	19.1%	182	20.6%	181	20.5%	178	20.2%	170	19.3%
Weight		28.9%		5.9%		55.8%		0.3%		0.6%		8.5%		100.0%
Weighted Average		0.056		0.012		0.106		0.001		0.001		0.017		0.193

AC Output in watts was generated from NREL's PV Watts online tool assuming a 20° tilt and 180° azimuth, adjusted for 5.98% distribution losses.

Coincidence Factors for PEC's Annual NCP Hours - 2018-2020														
Date & Time	Johnson City		Lampasas		Austin		Fredricksburg		Junction		San Antonio Airport		Average	
36 CP Events	AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %	AC Output	CF %
2018 Average	173	19.6%	176	20.0%	170	19.2%	184	20.8%	181	20.5%	178	20.2%	172	19.5%
2019 Average	201	22.8%	205	23.2%	198	22.4%	215	24.3%	210	23.8%	210	23.8%	201	22.7%
2020 Average	171	19.4%	175	19.8%	168	19.1%	182	20.6%	181	20.5%	178	20.2%	170	19.3%
Average	182	20.6%	185	21.0%	179	20.2%	193	21.9%	191	21.6%	189	21.4%	181	20.5%
Weight		28.9%		5.9%		55.8%		0.3%		0.6%		8.5%		100.0%
Weighted Average		0.059		0.012		0.113		0.001		0.001		0.018		0.205

AC Output in watts was generated from NREL's PV Watts online tool assuming a 20° tilt and 180° azimuth, adjusted for 5.98% distribution losses.

FIGURE 4-15 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – JOHNSON CITY, TX

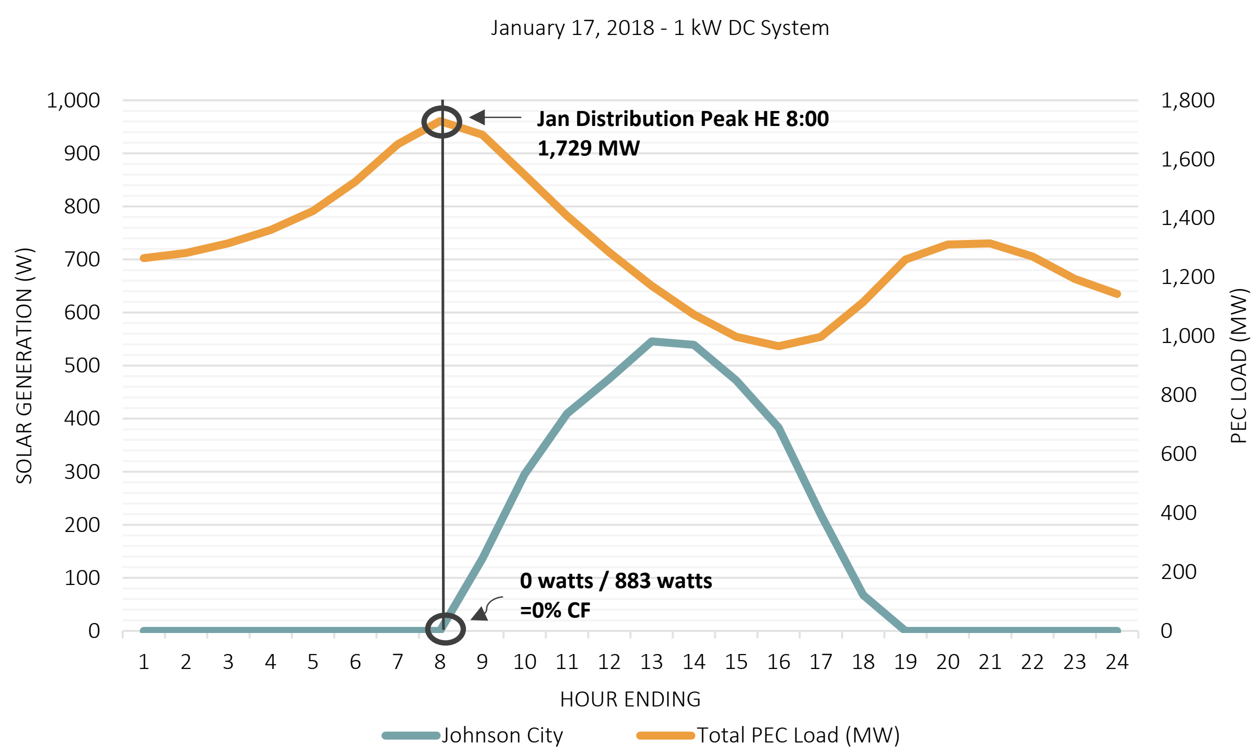


FIGURE 4-16 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – LAMPASAS, TX

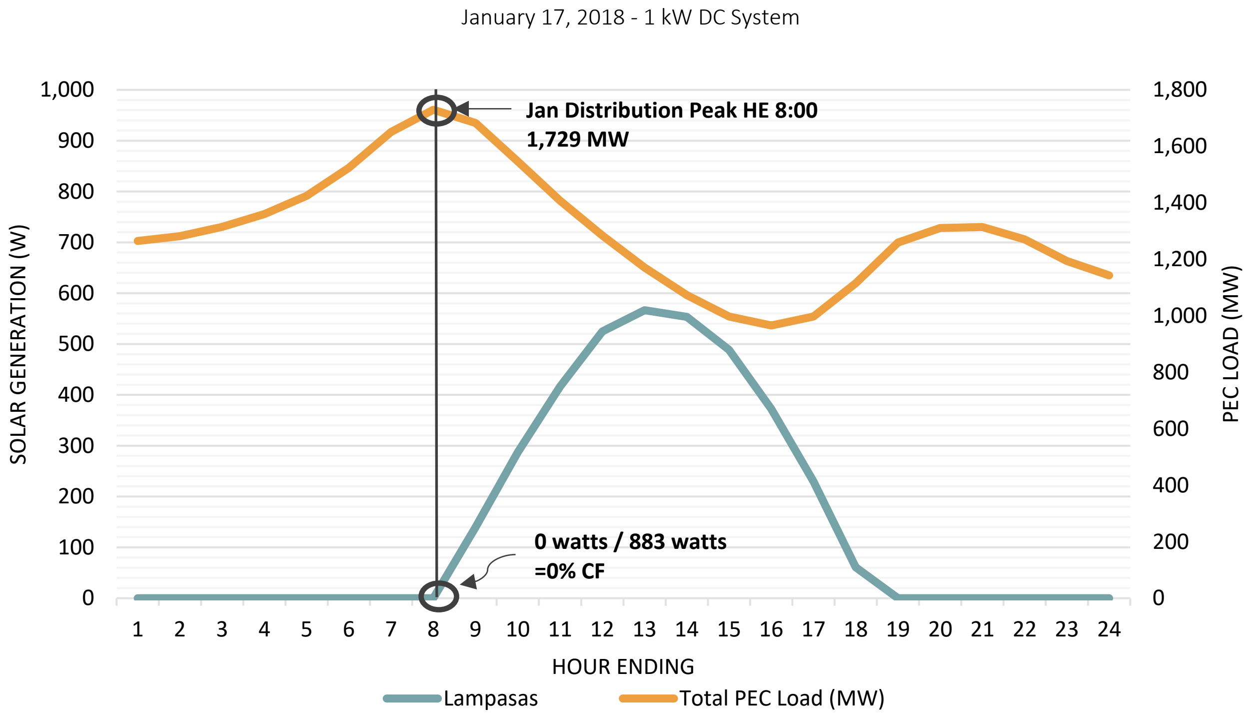


FIGURE 4-17 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – AUSTIN, TX

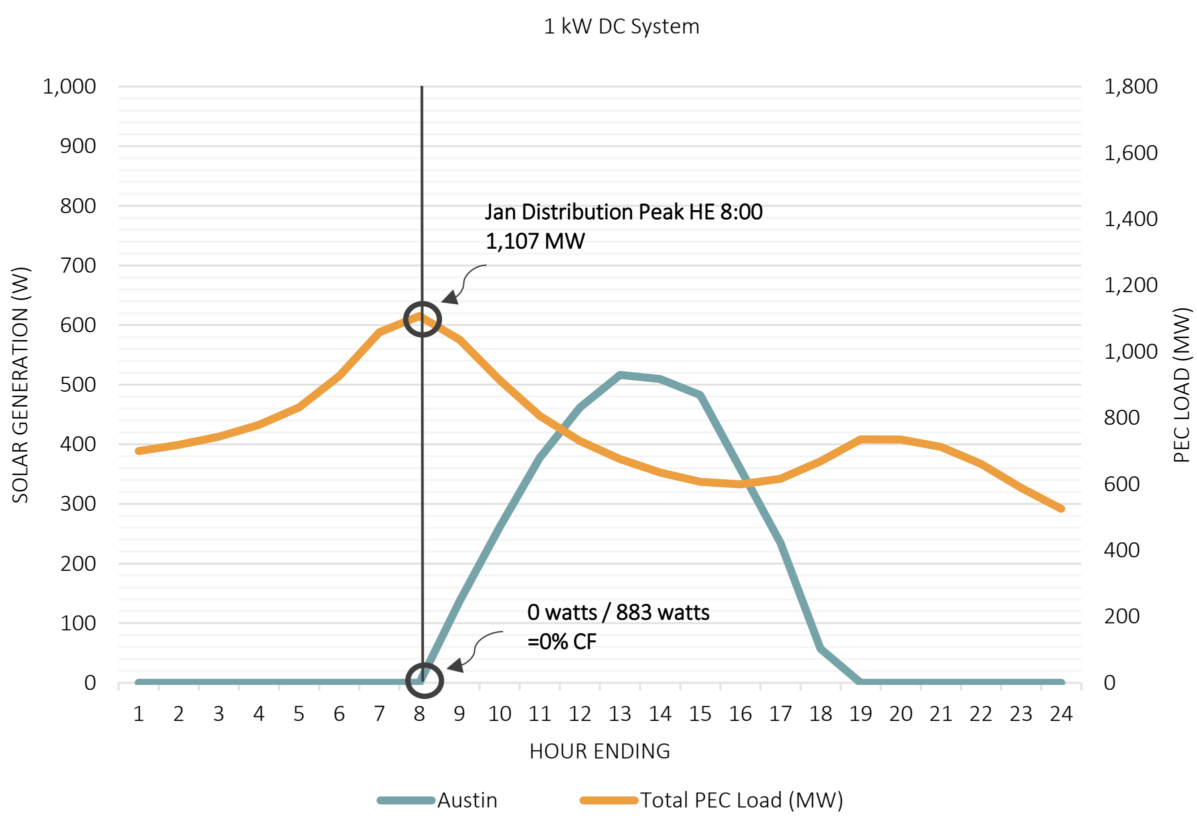


FIGURE 4-18 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – FREDERICKSBURG, TX

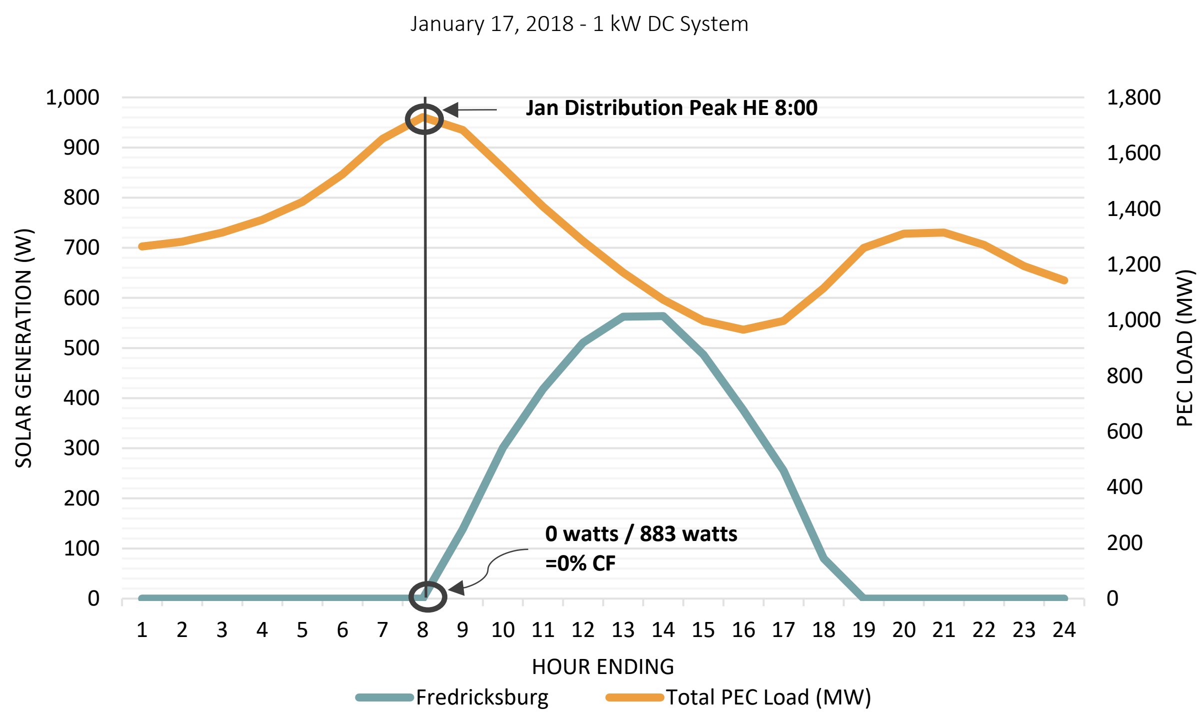


FIGURE 4-19 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – JUNCTION, TX

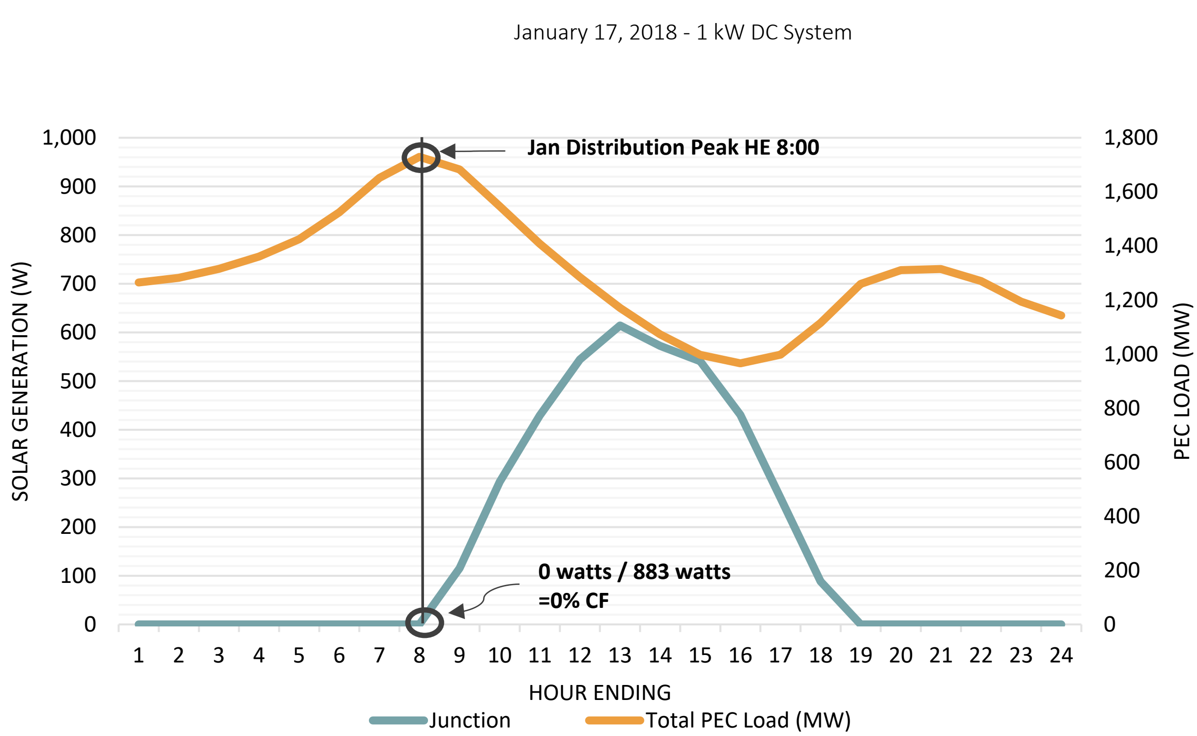


FIGURE 4-20 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – SAN ANTONIO, TX

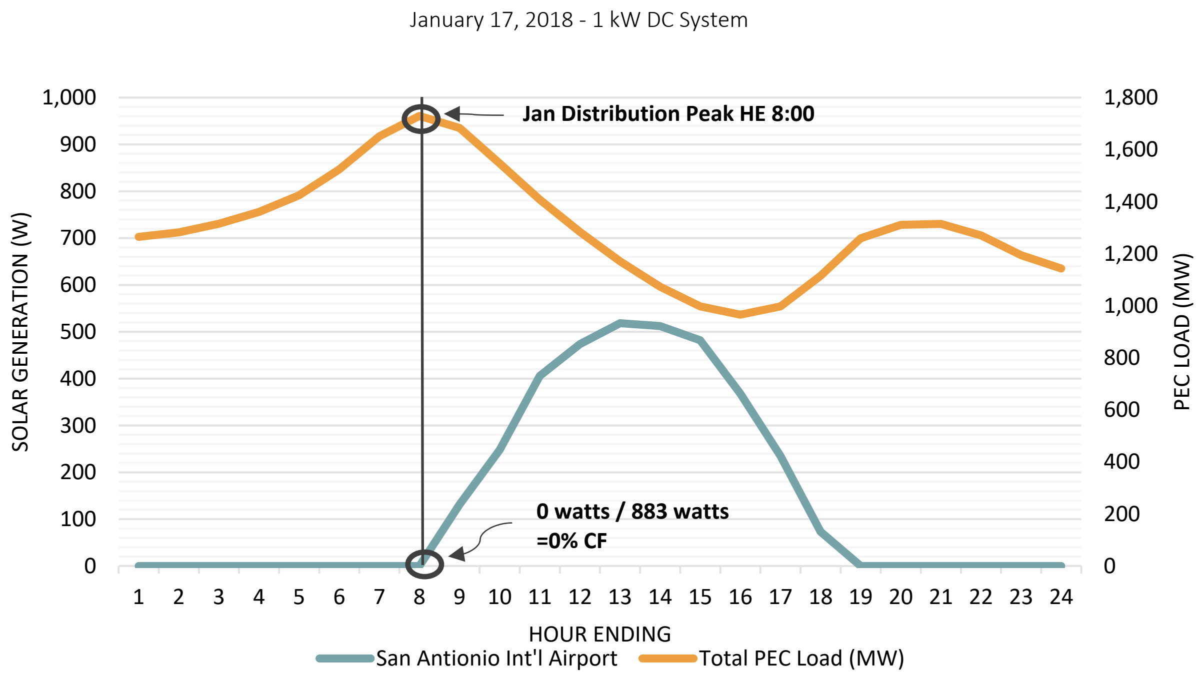


FIGURE 4-21 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – JOHNSON CITY, TX

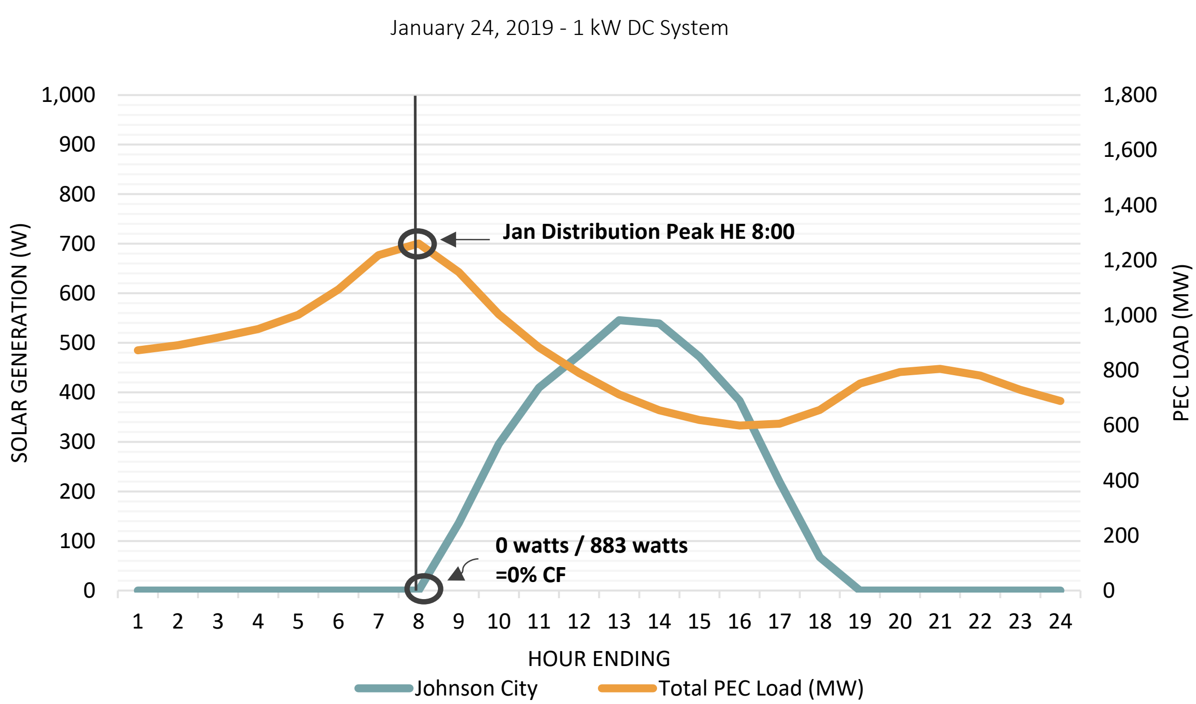


FIGURE 4-22 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – LAMPASAS, TX

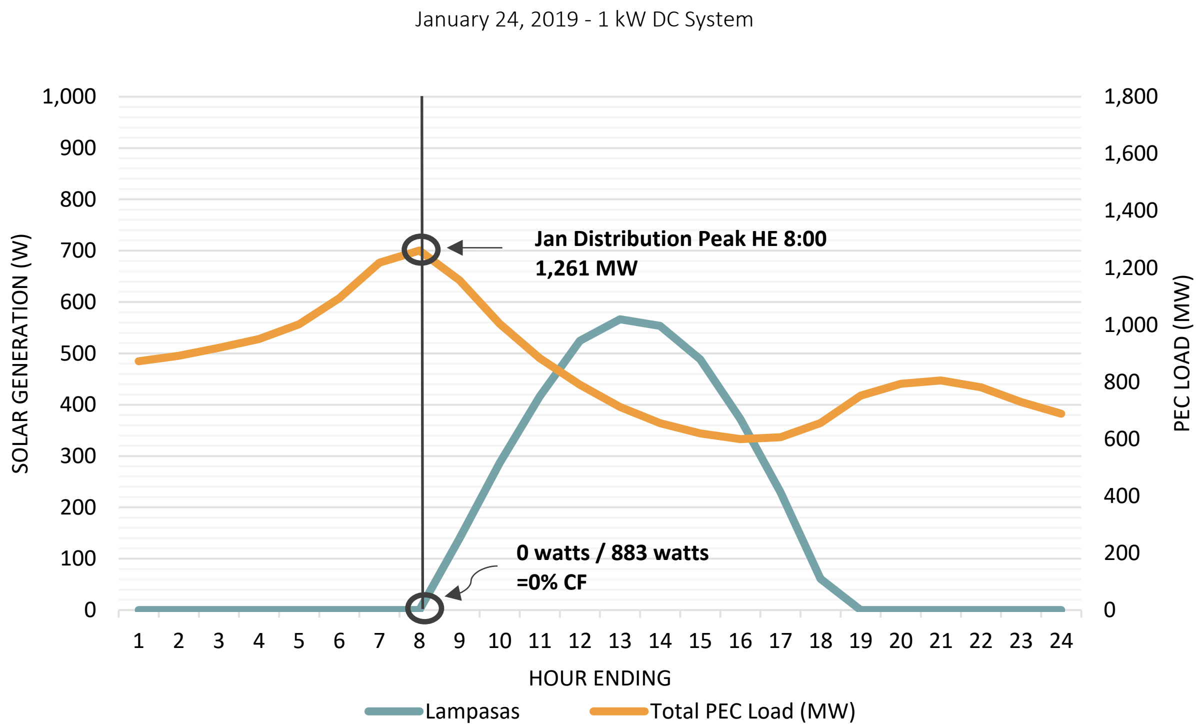


FIGURE 4-23 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – AUSTIN, TX

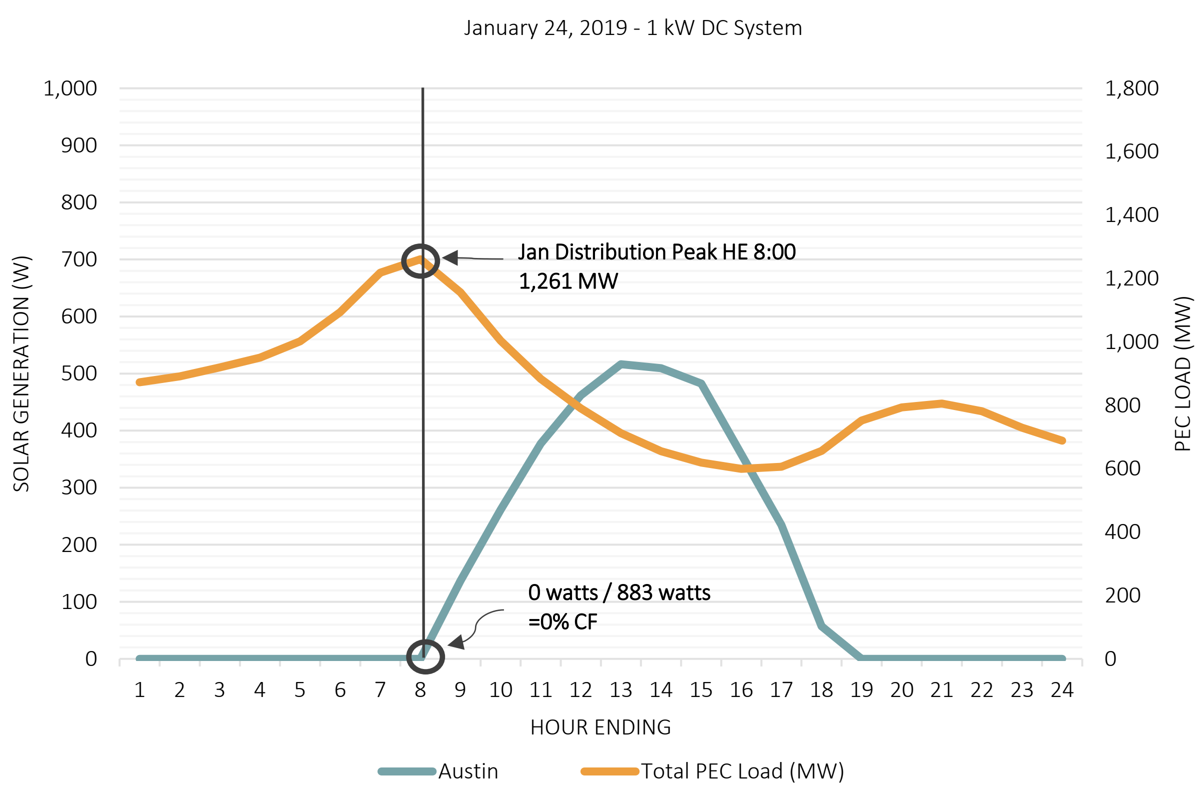


FIGURE 4-24 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – FREDERICKSBURG, TX

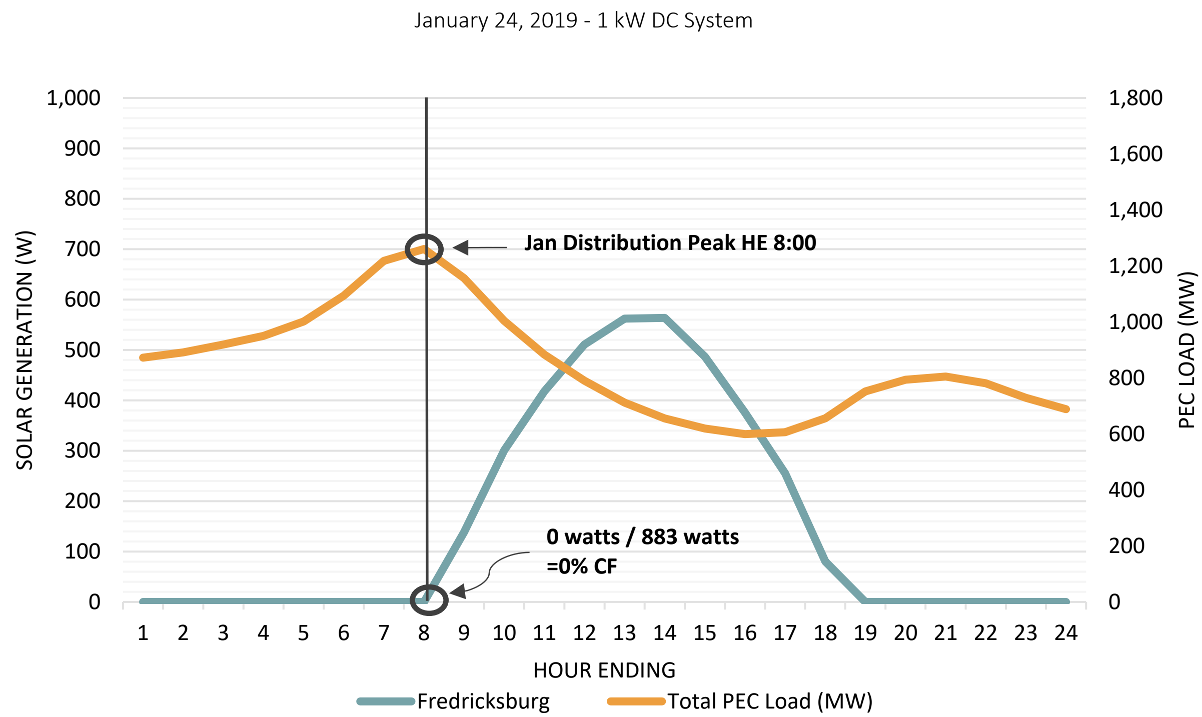


FIGURE 4-25 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – JUNCTION, TX

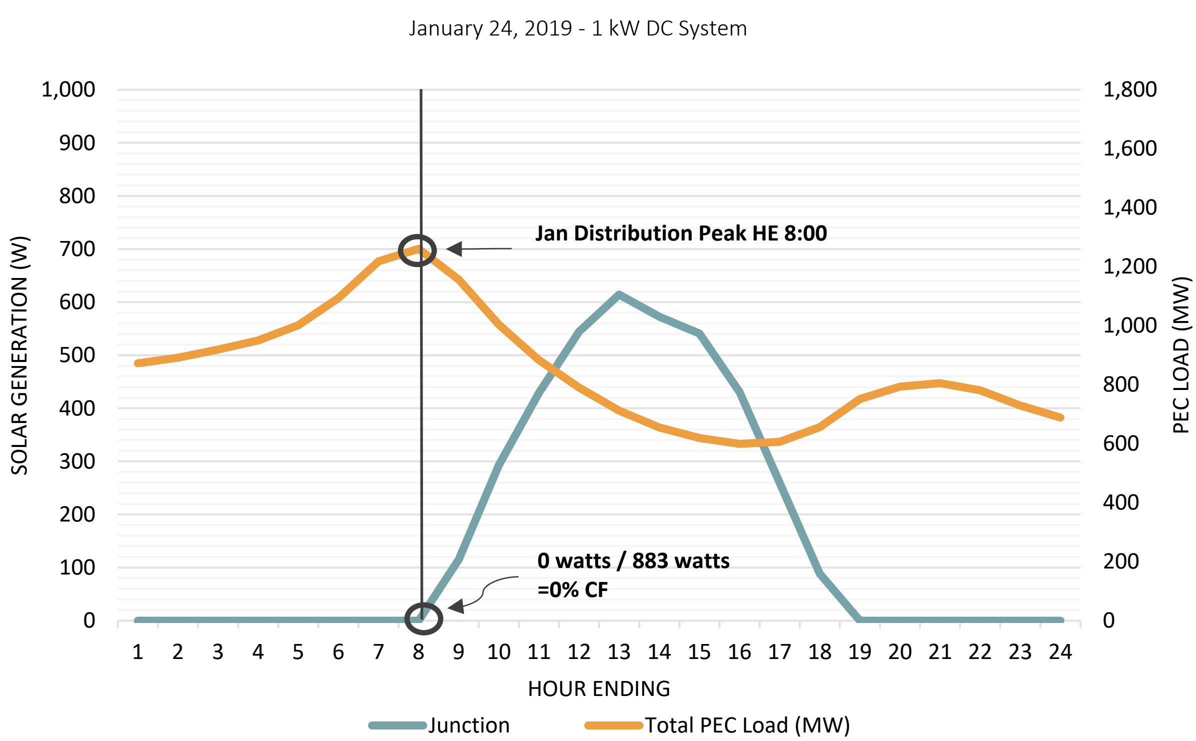


FIGURE 4-26 NCP SOLAR COINCIDENCE FACTOR EXAMPLE - SAN ANTONIO, TX

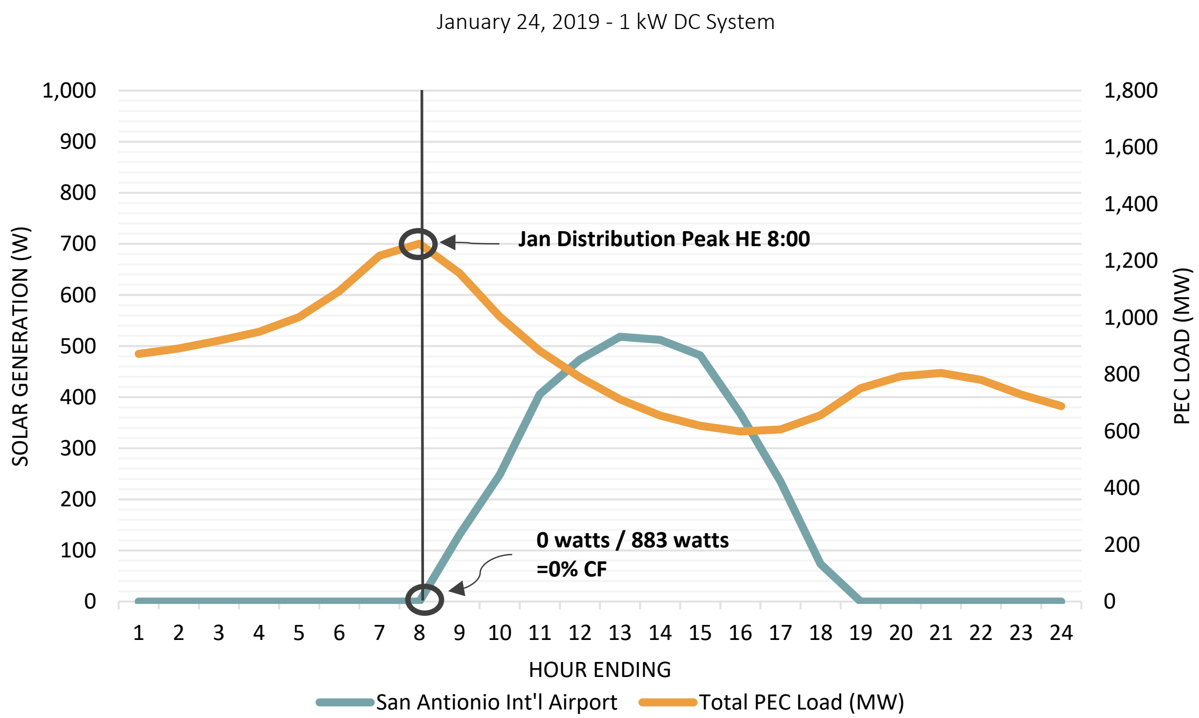


FIGURE 4-27 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – JOHNSON CITY, TX

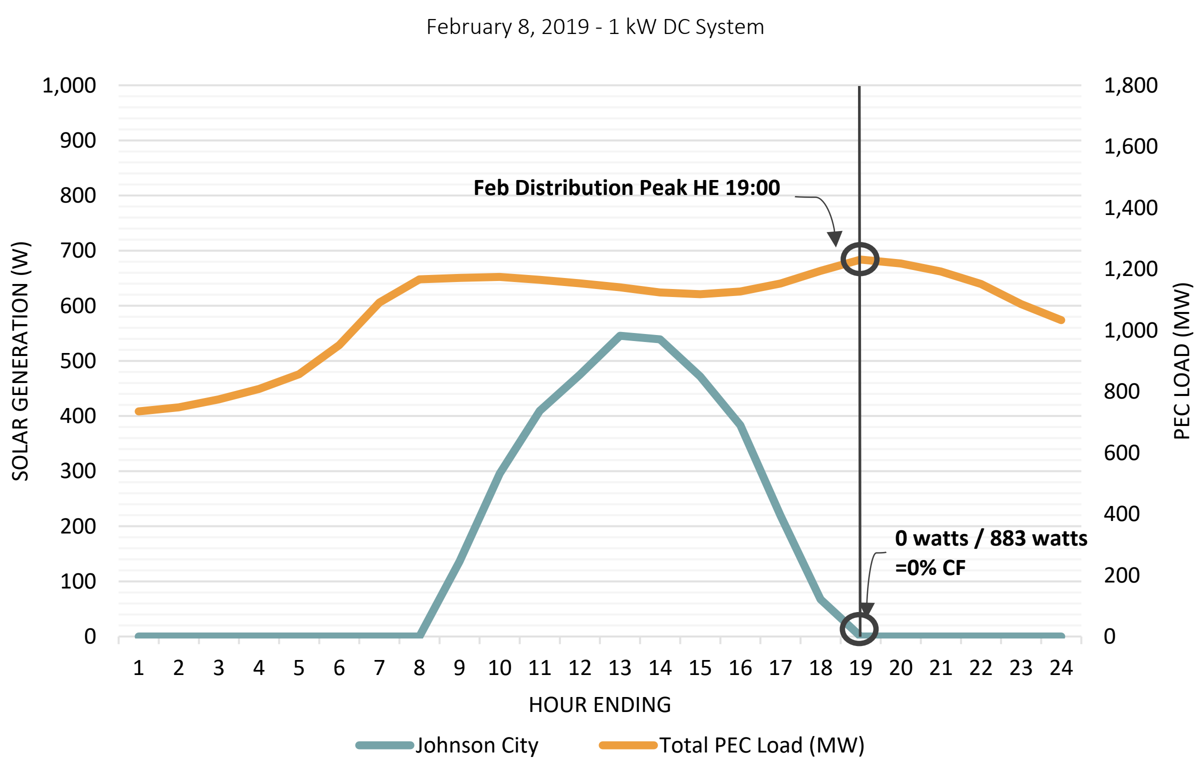


FIGURE 4-28 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – LAMPASAS, TX

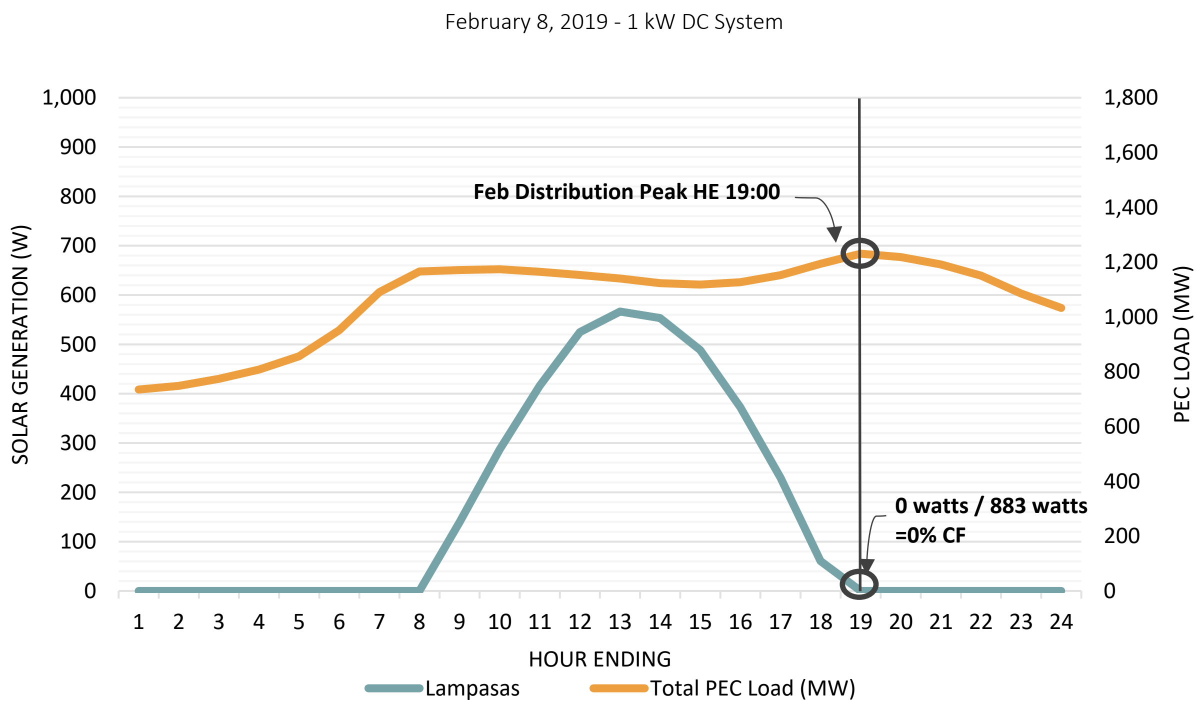


FIGURE 4-29 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – AUSTIN, TX

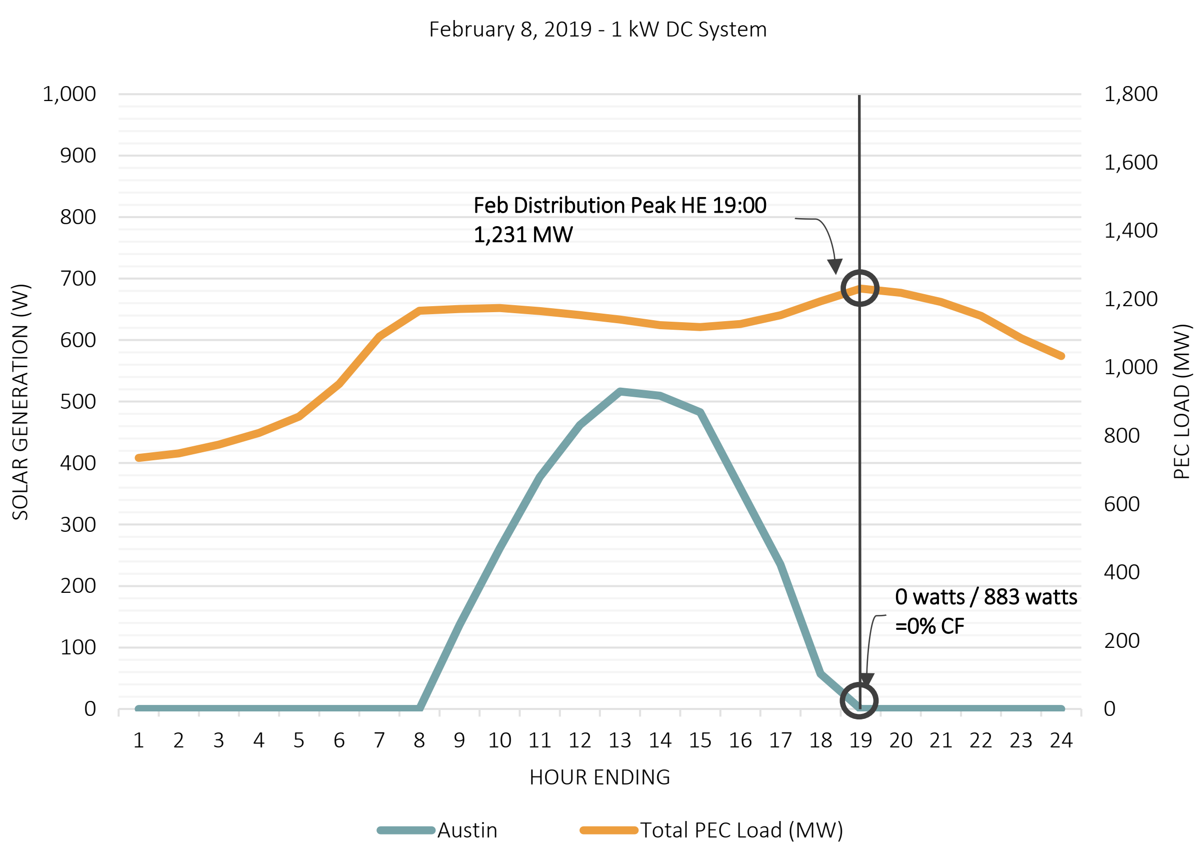


FIGURE 4-30 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – FREDERICKSBURG, TX

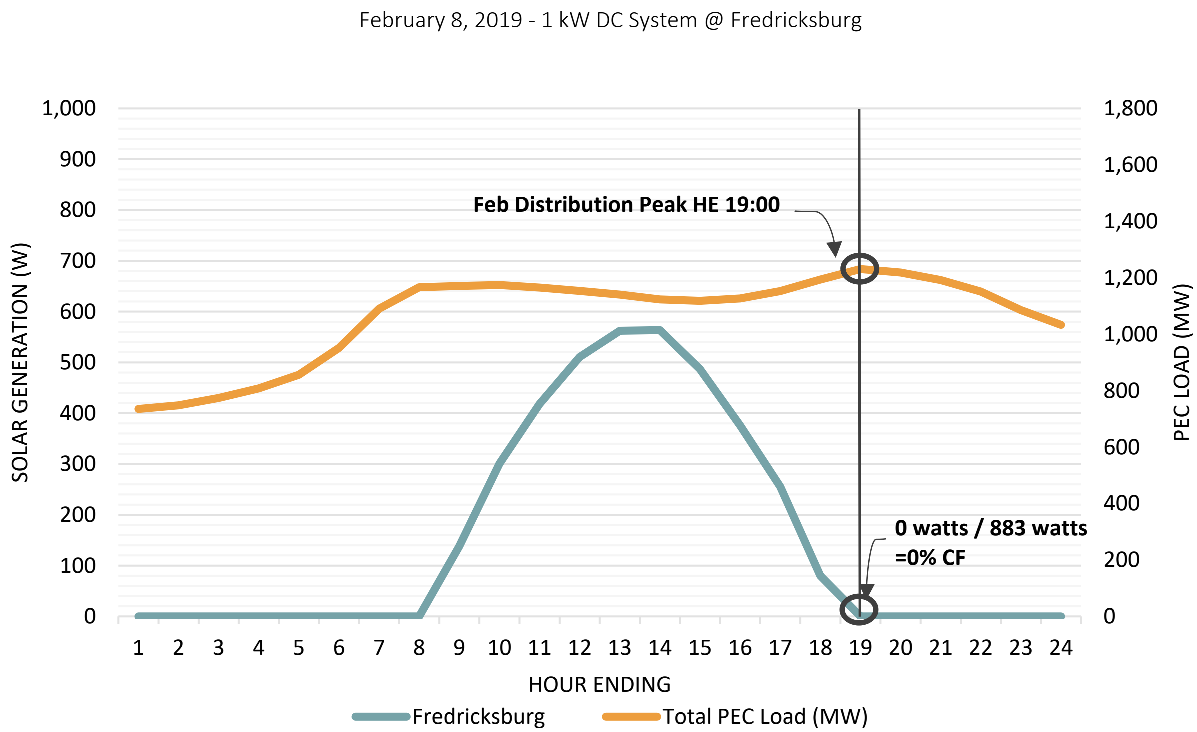


FIGURE 4-31 NCP SOLAR COINCIDENCE FACTOR EXAMPLE - JUNCTION, TX

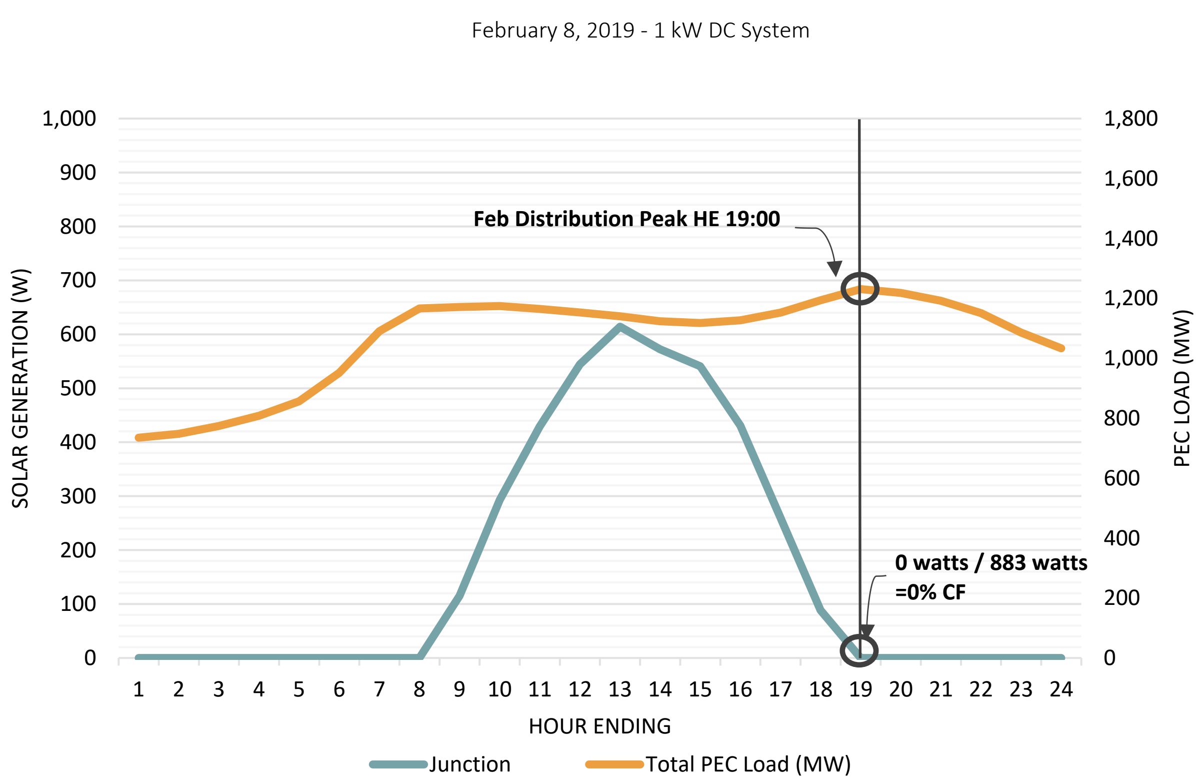


FIGURE 4-32 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – SAN ANTONIO, TX

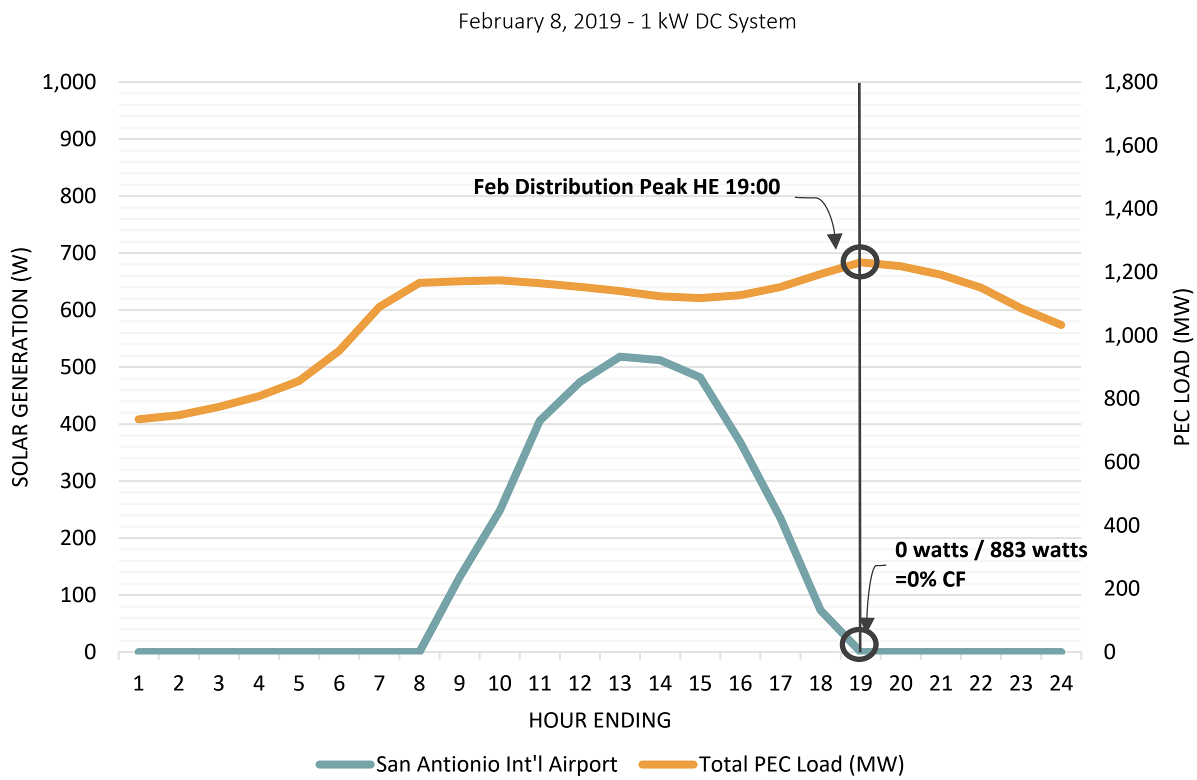


FIGURE 4-33 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – JOHNSON CITY, TX

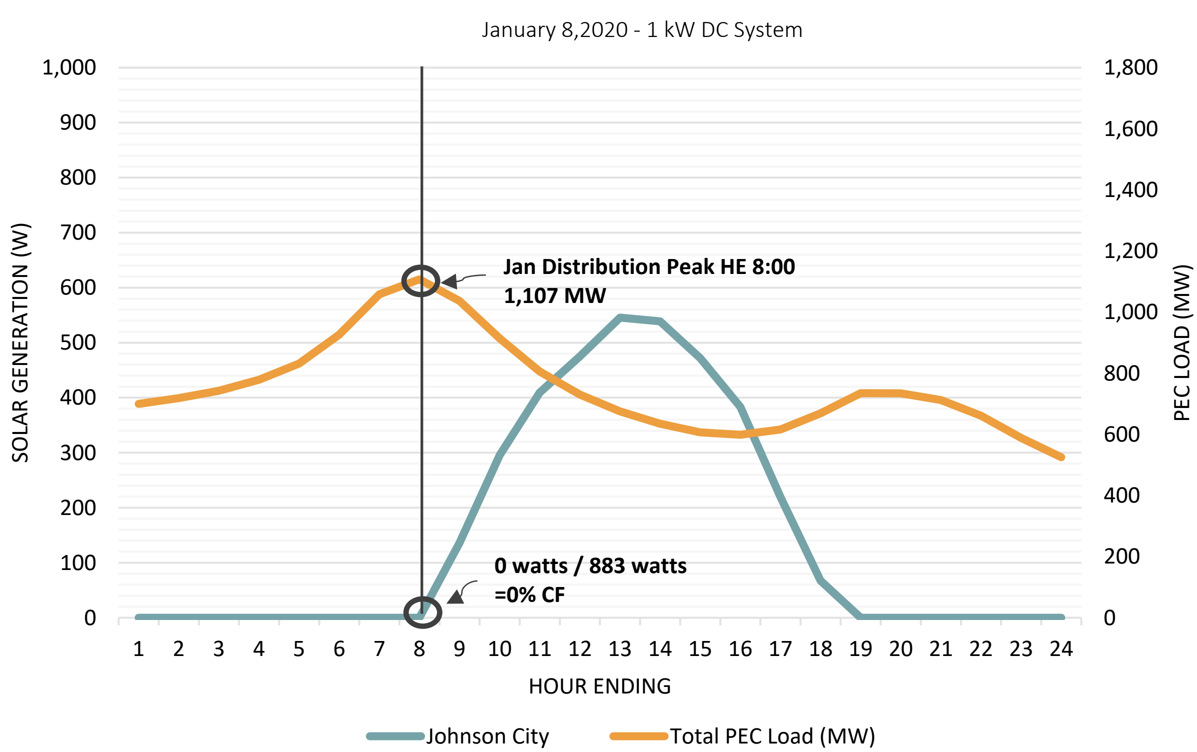


FIGURE 4-34 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – LAMPASAS, TX

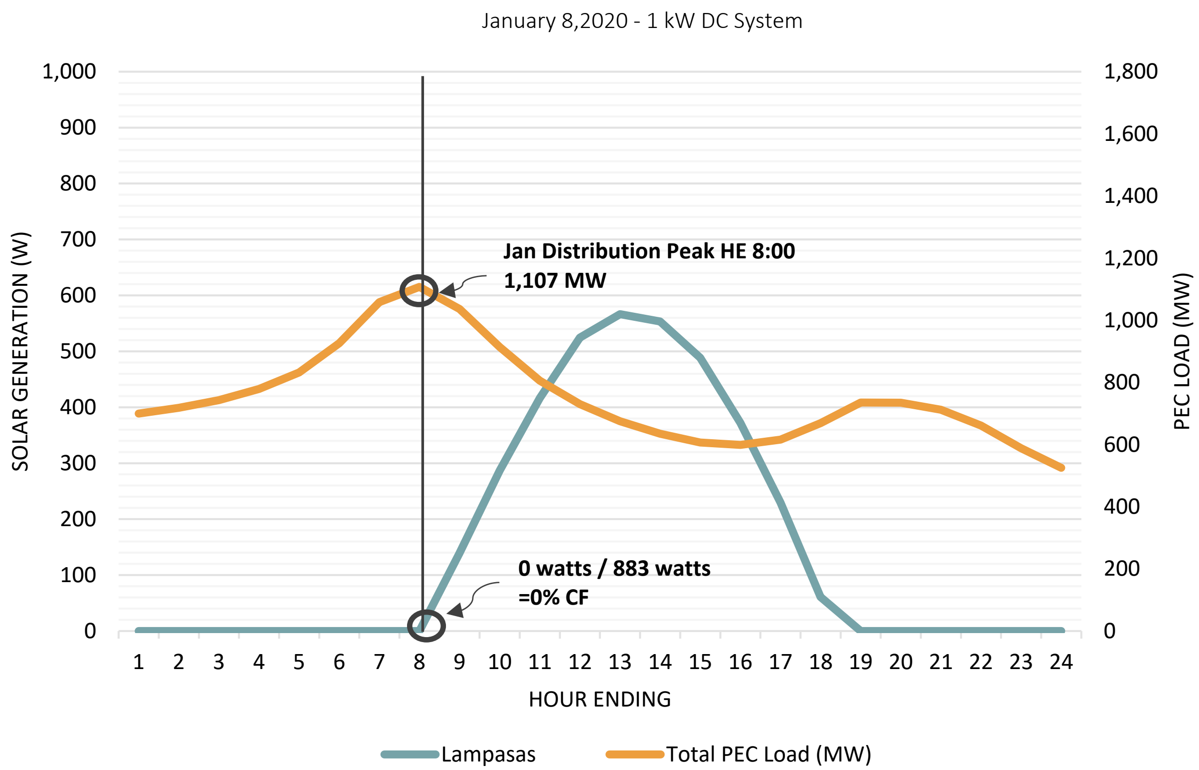


FIGURE 4-35 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – AUSTIN, TX

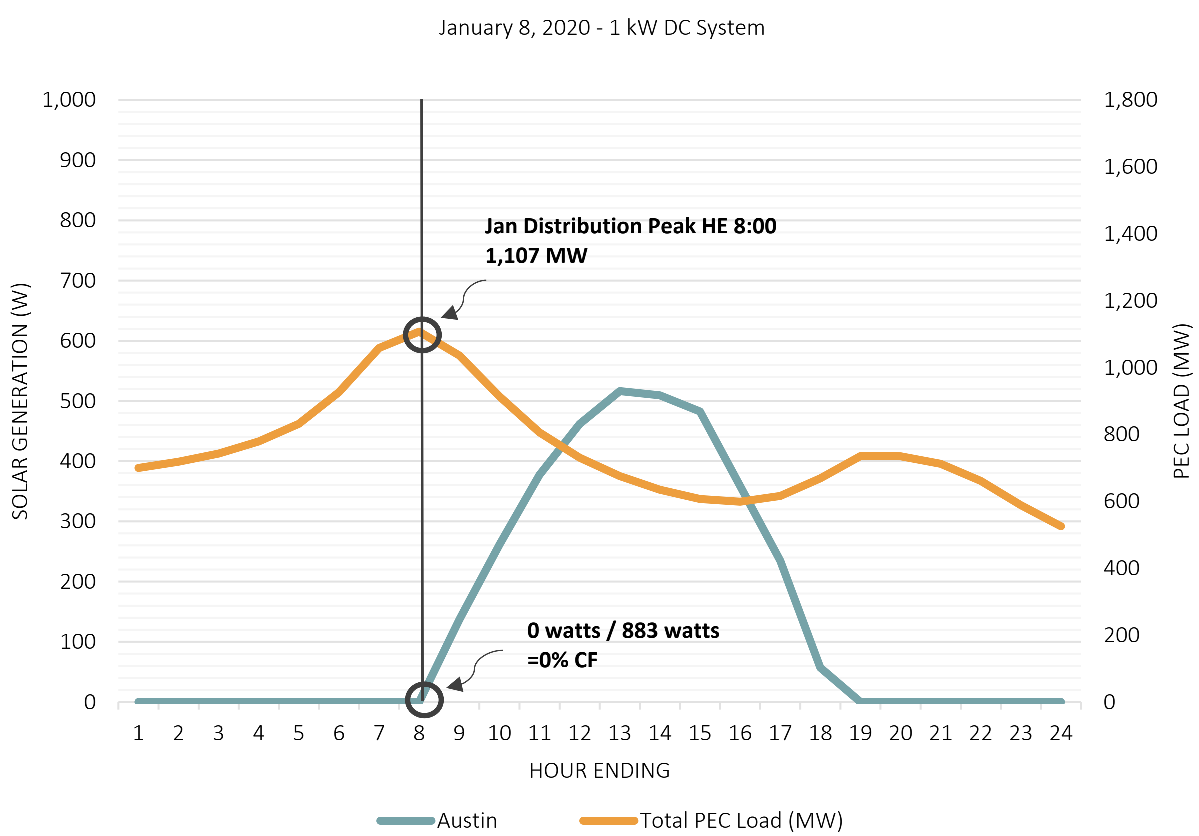


FIGURE 4-36 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – FREDERICKSBURG, TX

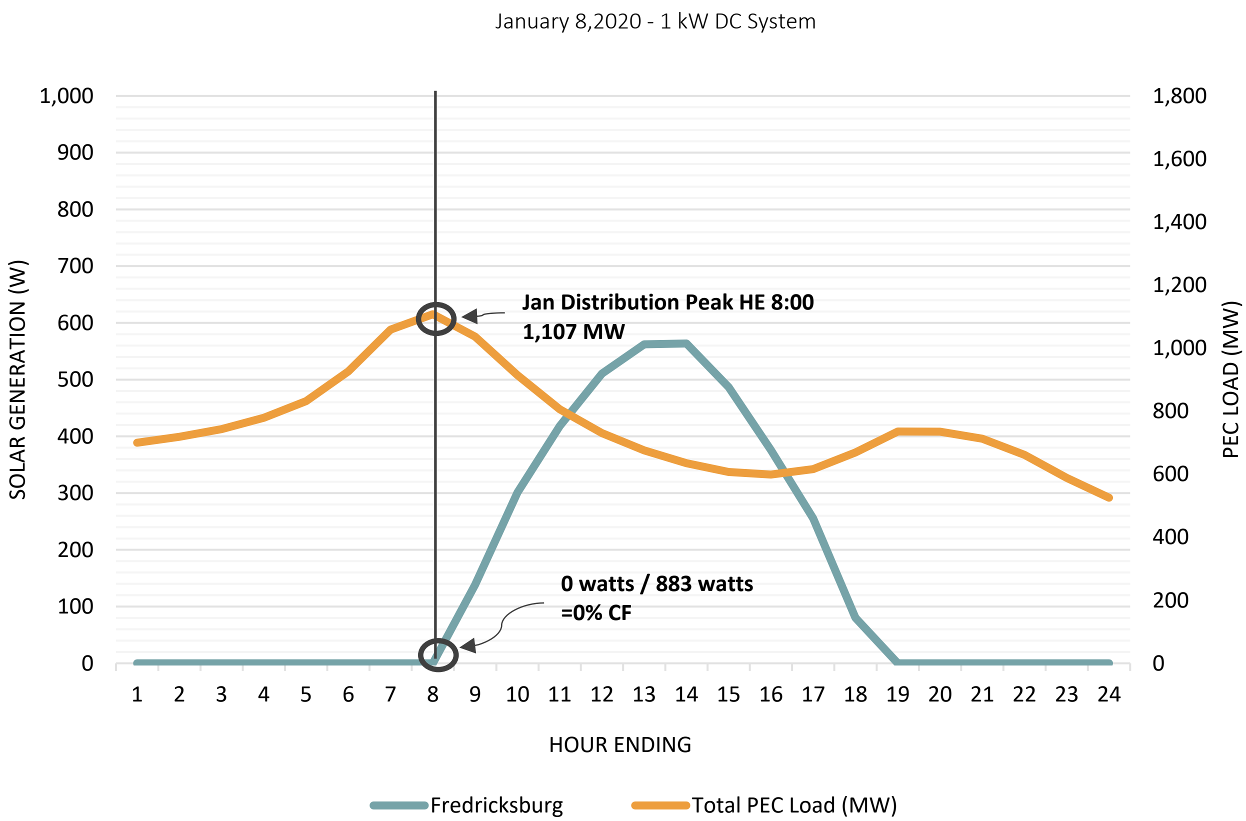


FIGURE 4-37 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – JUNCTION, TX

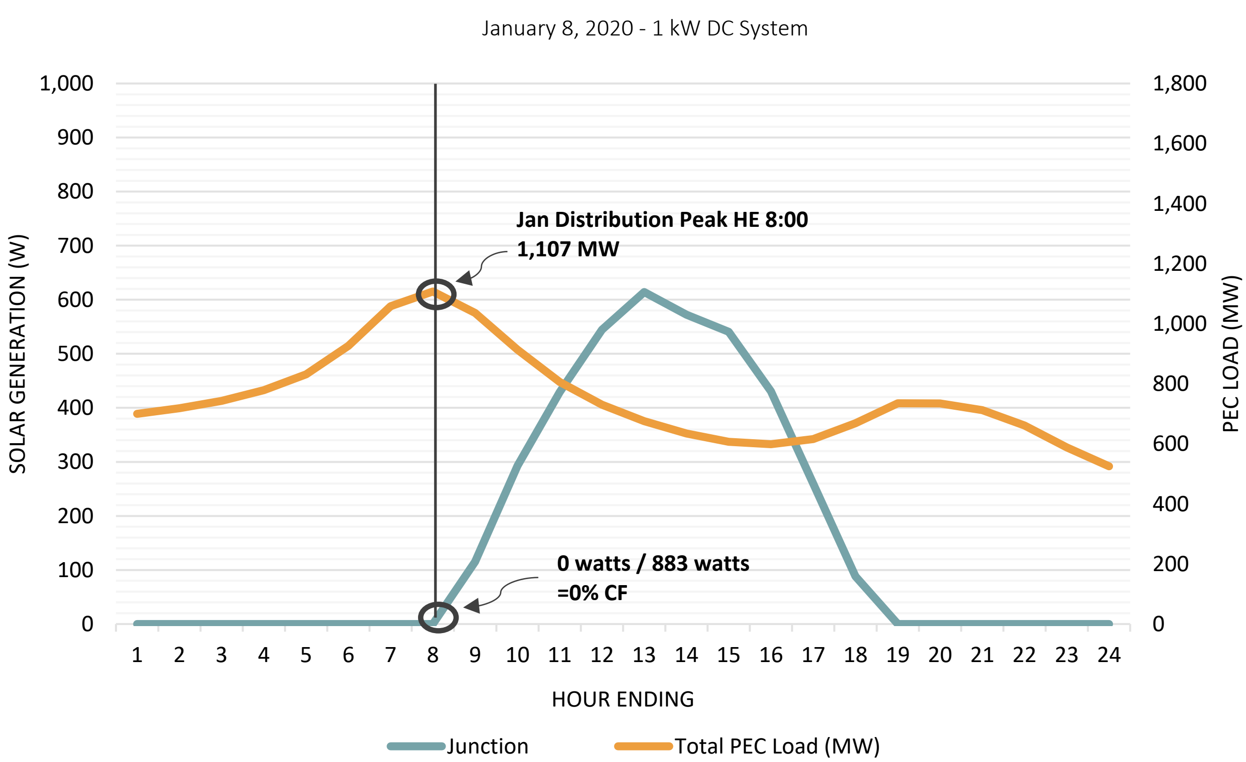


FIGURE 4-38 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – SAN ANTONIO, TX

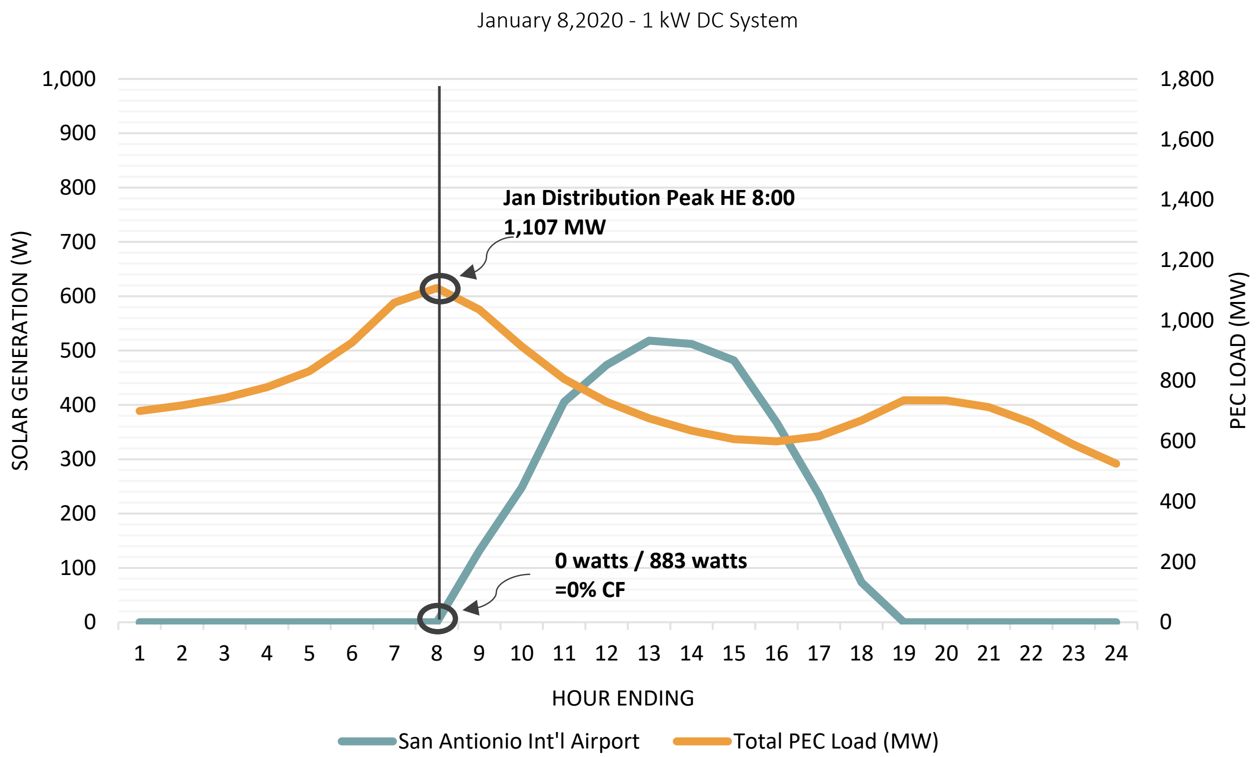


FIGURE 4-39 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – JOHNSON CITY, TX

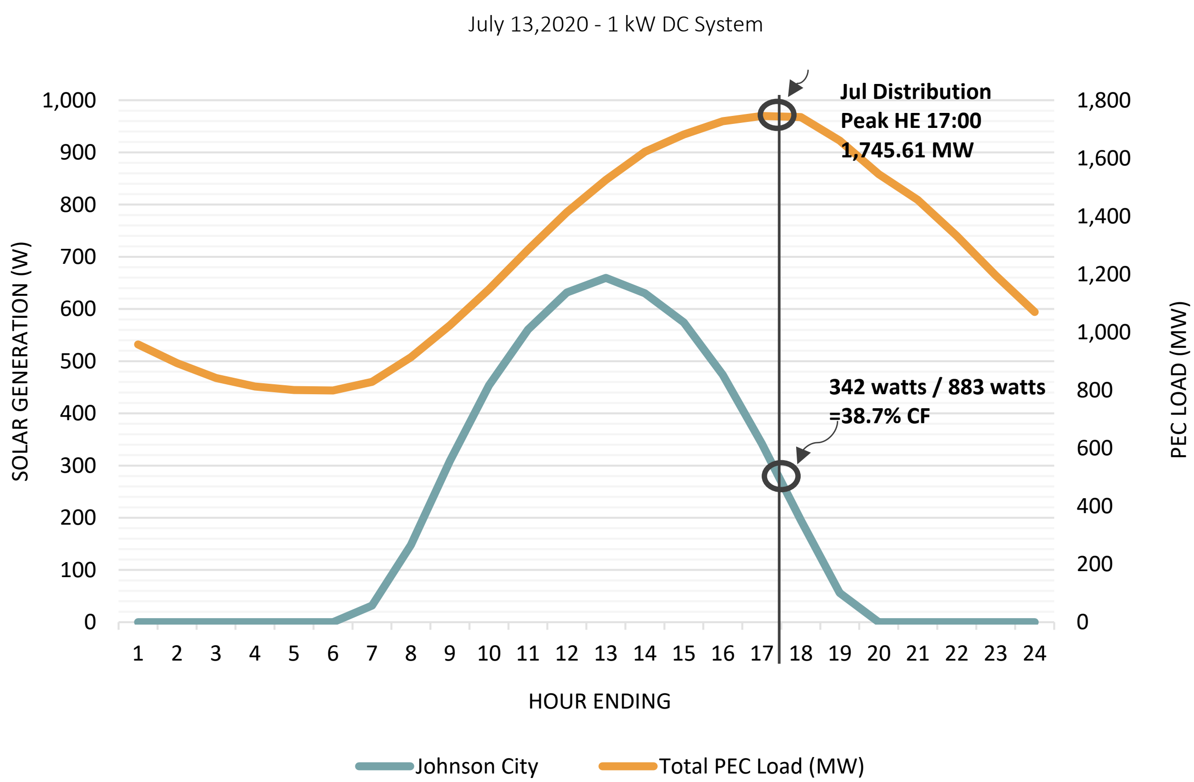


FIGURE 4-40 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – LAMPASAS, TX

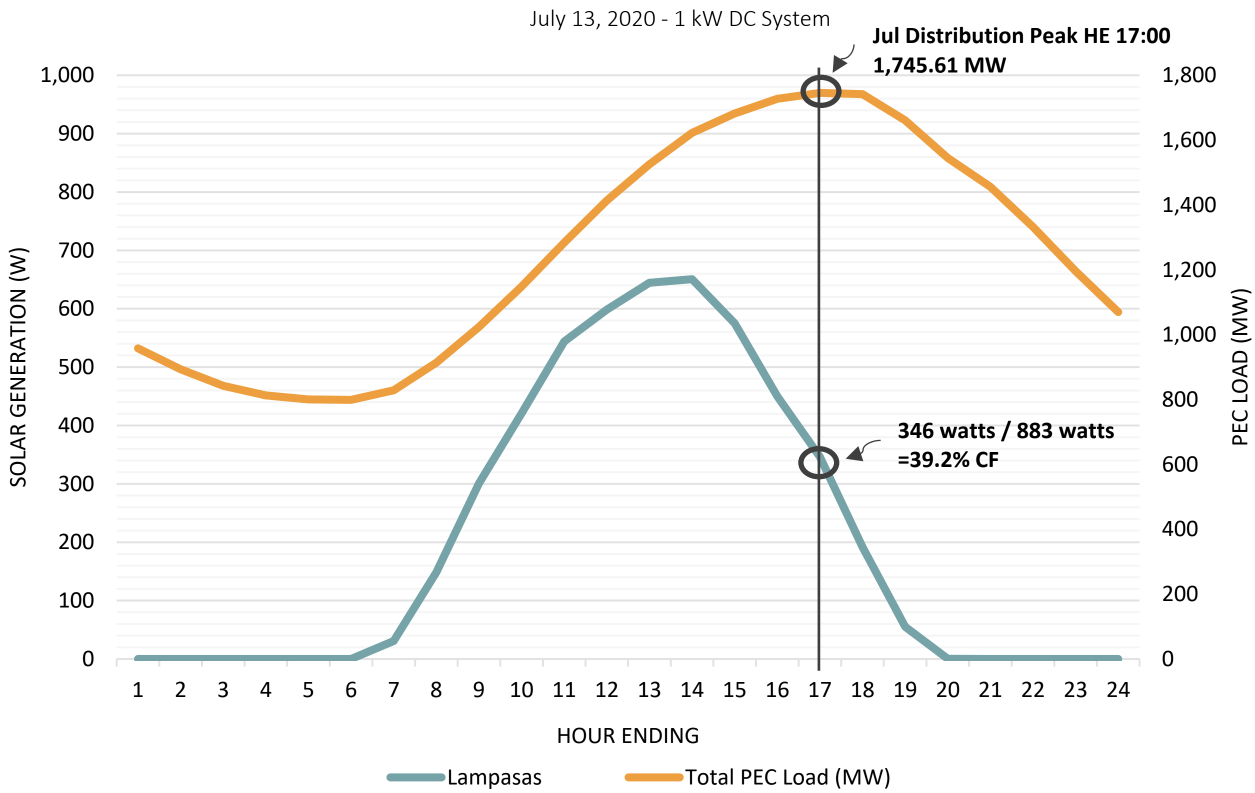


FIGURE 4-41 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – AUSTIN, TX

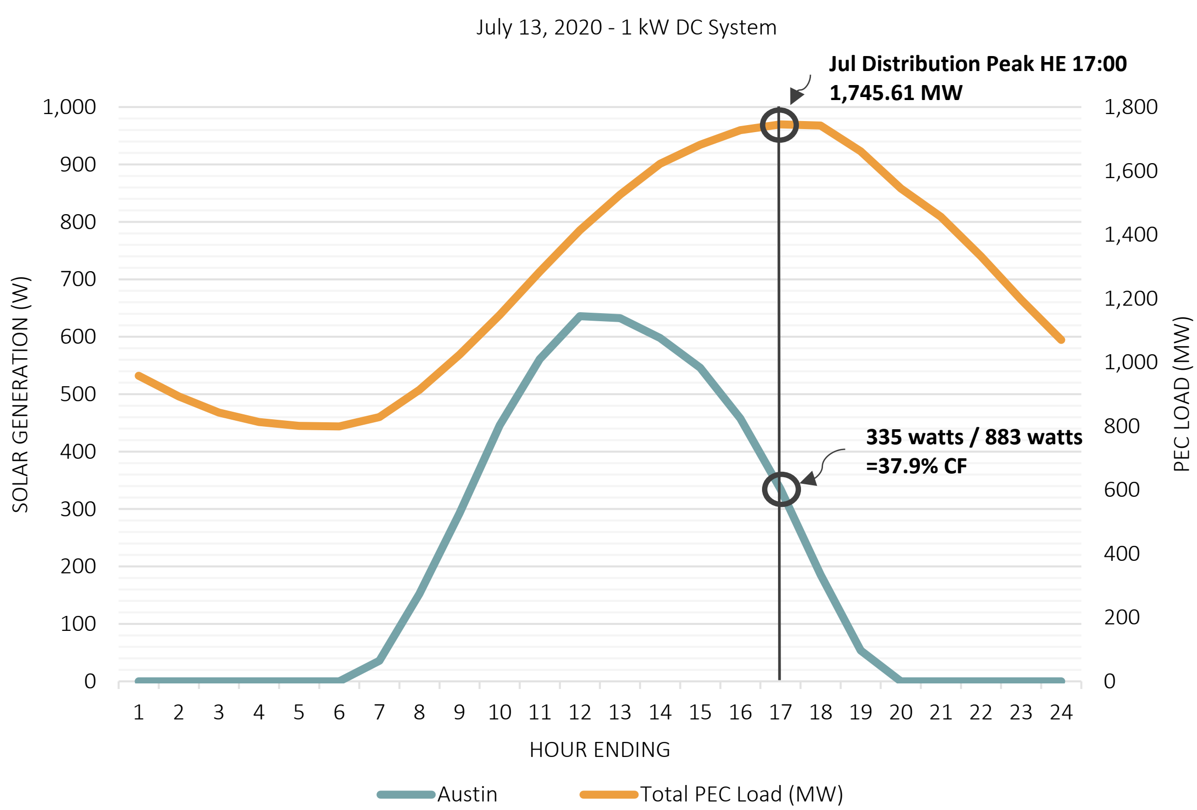


FIGURE 4-42 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – FREDERICKSBURG, TX

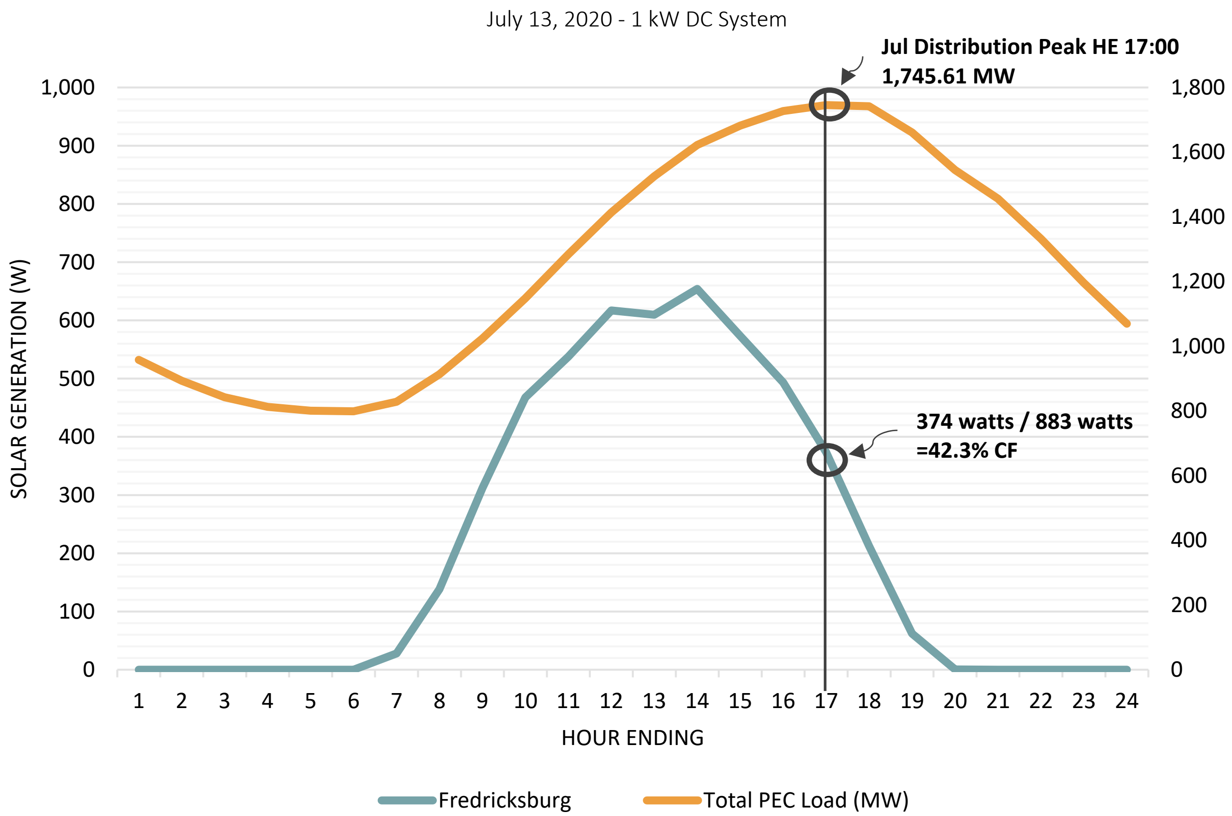


FIGURE 4-43 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – JUNCTION, TX

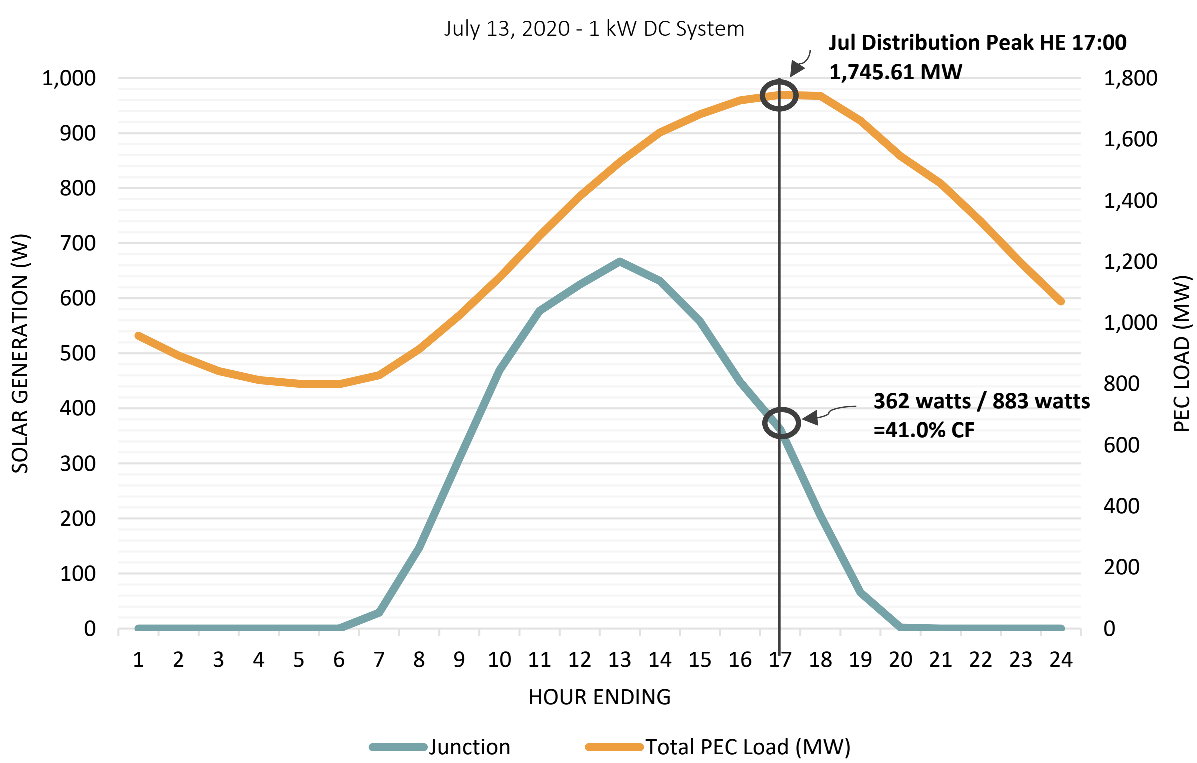
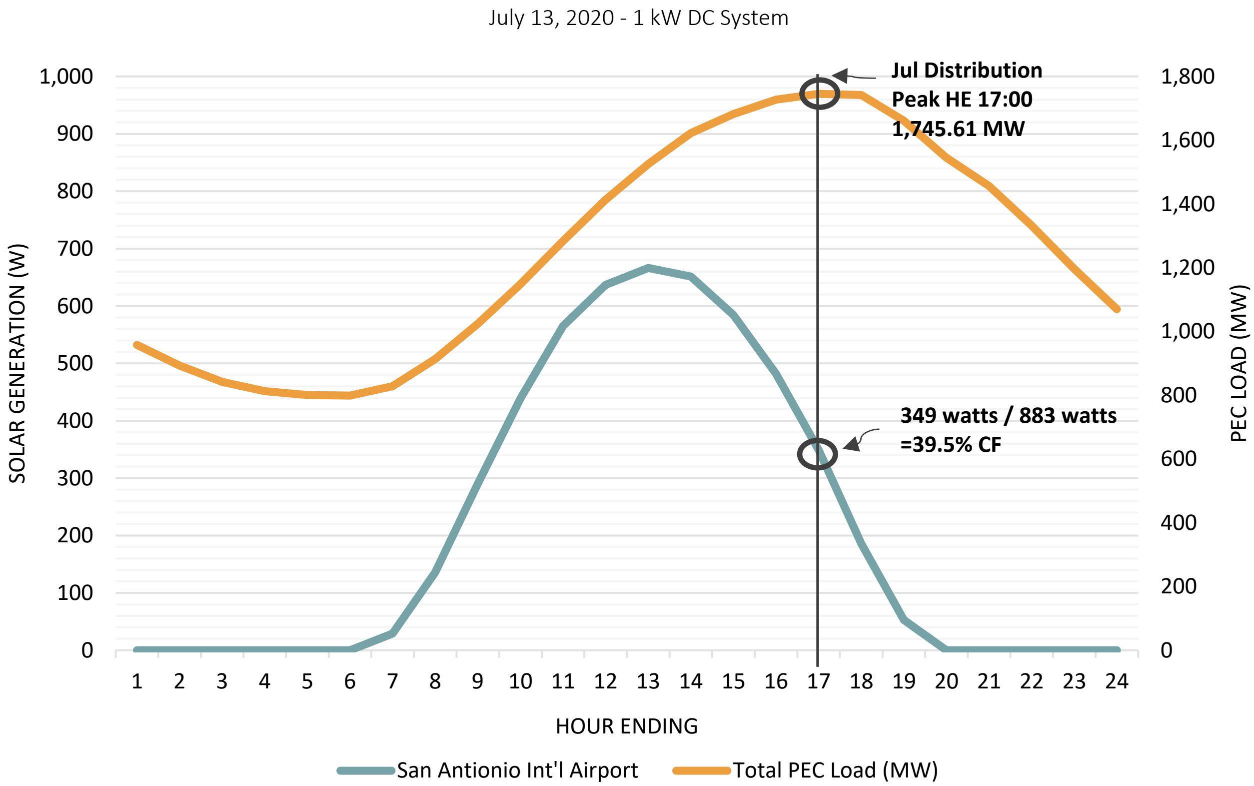


FIGURE 4-44 NCP SOLAR COINCIDENCE FACTOR EXAMPLE – SAN ANTONIO, TX



4.9 AVOIDED ANCILLARY SERVICES COSTS

Ancillary services represent functions that help grid operators, such as ERCOT, maintain a reliable and functioning electricity system every hour of the day. ERCOT defines ancillary service as a service necessary to support the transmission of energy to Loads while maintaining reliable operation of the Transmission Service Provider's (TSP's) transmission system using Good Utility Practice.

ERCOT makes use of and charges for four different ancillary services:

1. **Regulation Up Service.** An Ancillary Service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes in system frequency. Such capacity is the amount available above any Base Point but below the High Sustained Limit (HSL) of a Generation Resource and may be called on to change output as necessary throughout the range of capacity available to maintain proper system frequency. A Load Resource providing Reg-Up must be able to increase and decrease Load as deployed within its Ancillary Service Schedule for Reg-Up above the Load Resource's Low Power Consumption (LPC) limit.

2. **Regulation Down Service.** An Ancillary Service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes in system frequency. Such capacity is the amount available below any Base Point but above the Low Sustained Limit (LSL) of a Generation Resource and may be called on to change output as necessary throughout the range of capacity available to maintain proper system frequency. A Load Resource providing Reg-Down must be able to increase and decrease Load as deployed within its Ancillary Service Schedule for Reg-Down below the Load Resource's Maximum Power Consumption (MPC) limit.

3. **Responsive Reserve.** An Ancillary Service that provides operating reserves that is intended to:
    - ***a.*** Arrest frequency decay within the first few seconds of a significant frequency deviation on the ERCOT Transmission Grid using Primary Frequency Response and interruptible Load;
    - ***b.*** After the first few seconds of a significant frequency deviation, help restore frequency to its scheduled value to return the system to normal;
    - ***c.*** Provide energy or continued Load interruption during the implementation of the Energy Emergency Alert (EEA); and
    - ***d.*** Provide backup regulation.
4. **Non-Spinning Reserve.** An Ancillary Service that is provided through use of the part of Off-Line Generation Resources that can be synchronized and ramped to a specified output level within 30 minutes (or Load Resources that can be interrupted within 30 minutes) and that can operate (or Load Resources that can be interrupted) at a specified output level for at least one hour. Non-Spin may also be provided from unloaded On-Line capacity that meets the 30-minute response requirements and that is reserved exclusively for use for this service. [30]

Each of the reserve categories are independently priced on an hourly basis. The following formulas provide the basis for ERCOT's pricing methodology under the most recently established nodal protocols. The formulas for each of the day-ahead ancillary service prices are found in Section 4.6.4.2[31]. The adjustments made to get to the real-time settlement of each ancillary service price are found in Section 6.7.4. [32]

Equation 4-4 provides the computation used by GDS to determine the avoidec cost of ancillary services:

EQUATION 4-4

$$AS_{ERCOT,y} = \sum_{h} kWh_{PV,h} \times RegUp_h + \sum_{h} kWh_{PV,h} \times RegDn_h + \sum_{h} kWh_{PV,h} \times RR_h + \sum_{h} kWh_{PV,h} \times NSR_h$$

Where:

$AS_{ERCOT,y}$	Avoided Ancillary Services Cost at ERCOT in Year y
y	Year
h	Hour in Year y
$kWh_{PV,h}$	Generation Output in Hour h in Year y
$RegUp_h$	Price of Regulation Up Service in Hour h in Year y
$RegDn_h$	Price of Regulation Down Service in Hour h in Year y
RRh	Price of Responsive Reserve Service in Hour h in Year y
$NSP_{\boldsymbol{h}}$	Price of Non-Spinning Reserve Service in Hour h in Year y

[30] ERCOT Nodal Protocols, *Section 2: Definitions and Acronyms*.

[31] ERCOT Nodal Protocols, *Section 4: Day Ahead Operation*.

[32] ERCOT Nodal Protocols, Section 6: Adjustment Period and Real Time Operations.

4.9.1 ERCOT Pricing Formulas for Regulation Service – Up

4.9.1.1 Charges in the Day-Ahead Market

Each QSE shall pay to ERCOT or be paid by ERCOT a Reg-Up Service charge for each hour as follows:

$$DARUAMT_{q} = DARUPR * DARUQ_{q}$$

Where:

$$DARUPR = (-1) * PCRUAMTTOT / DARUQTOT$$

$$PCRUAMTTOT = \sum_{q} PCRUAMT_{q}$$

$$DARUQTOT = \sum_{q} DARUQ_{q}$$

$$DARUQ_{q} = DARUO_{q} - DASARUQ_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
$DARUAMT_{q}$	$	*Day-Ahead Reg-Up Amount per QSE*—QSE *q*'s share of the DAM cost for Reg-Up, for the hour.
DARUPR	$/MW per hour	*Day-Ahead Reg-Up Price*—The Day-Ahead Reg-Up price for the hour.
$DARUQ_{q}$	MW	*Day-Ahead Reg-Up Quantity per QSE*—The QSE *q*'s Day-Ahead Ancillary Service Obligation minus its self-arranged Reg-Up quantity for the hour.
PCRUAMTTOT	$	*Procured Capacity for Reg-Up Amount Total in DAM*—The total of the DAM Reg-Up payments for all QSEs for the hour.
$PCRUAMT_{q}$	$	*Procured Capacity for Reg-Up Amount per QSE in DAM*—The DAM Reg-Up payment for QSE *q* for the hour.
DARUQTOT	MW	*Day-Ahead Reg-Up Quantity Total*—The sum of every QSE's Day-Ahead Ancillary Service Obligation minus its self-arranged Reg-Up quantity for the hour.
$DARUO_{q}$	MW	*Day-Ahead Reg-Up Obligation per QSE*—The Reg-Up capacity obligation for QSE *q* for the DAM for the hour.
$DASARUQ_{q}$	MW	*Day-Ahead Self-Arranged Reg-Up Quantity per QSE*—The self-arranged Reg-Up quantity submitted by QSE *q* before 1000 in the Day-Ahead.
q	none	A QSE.

4.9.1.2 Adjustment to Cost Allocations for Procurement

For Reg-Up, if applicable:

(a) The net total costs for Reg-Up for a given Operating Hour is calculated as follows:

$$\mathbf{RUCOSTTOT = (-1) * (\sum_{m} (RTPCRUAMTTOT_{m}) + PCRUAMTTOT + RUFQAMTTOT + RUINFQAMTTOT)}$$

Where:

Total payment of SASM- and RSASM-procured capacity for Reg-Up by market

$$RTPCRUAMTTOT_{m} = \sum_{q} RTPCRUAMT_{q,m}$$

Total payment of DAM-procured capacity for Reg-Up

$$PCRUAMTTOT = \sum_{q} PCRUAMT_{q}$$

Total charge of failure on Ancillary Service Supply Responsibility for Reg-Up

$$RUFQAMTTOT = \sum_{q} RUFQAMTQSETOT_{q}$$

Total payment of SASM- and RSASM-procured capacity for Reg-Up by QSE

$$RTPCRUAMTQSETOT_{q} = \sum_{m} RTPCRUAMT_{q,m}$$

Total charge of infeasible Ancillary Service Supply Responsibility for Reg-Up

$$RUINFQAMTTOT = \sum_{q} RUINFQAMT_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RUCOSTTOT	$	*Reg-Up Cost Total*—The net total costs for Reg-Up for the hour.
$RTPCRUAMTTOT_{m}$	$	*Procured Capacity for Reg-Up Amount Total by market*—The total payments to all QSEs for the Ancillary Service Offers cleared in the market *m* for Reg-Up, for the hour.
$RTPCRUAMT_{q,m}$	$	*Procured Capacity for Reg-Up Amount per QSE by market*—The payment to QSE *q* for its Ancillary Service Offers cleared in the market *m* for Reg-Up, for the hour.
RUFQAMTTOT	$	*Reg-Up Failure Quantity Amount Total*—The total charges to all QSEs for their capacity associated with failures and reconfiguration reductions on their Ancillary Service Supply Responsibilities for Reg-Up, for the hour.
$RUFQAMTQSETOT_{q}$	$	*Reg-Up Failure Quantity Amount Total per QSE*—The charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
$RTPCRUAMTQSETOT_{q}$	$	*Procured Capacity for Reg-Up Amount Total per QSE*—The total payments to a QSE *q* in all SASMs and RSASMs for the Ancillary Service Offers cleared for Reg-Up, for the hour.
$PCRUAMT_{q}$	$	*Procured Capacity for Reg-Up Amount per QSE in DAM*—The DAM Reg-Up payment for QSE *q*, for the hour.

Variable	Unit	Description
RUINFQAMTTOT	$	*Reg-Up Infeasible Quantity Amount Total* — The charge to all QSEs for their total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for Reg-Up, for the hour.
RUINFQAMT $_q$	$	*Reg-Up Infeasible Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for Reg-Up, for the hour.
PCRUAMTTOT	$	*Procured Capacity for Reg-Up Amount Total in DAM*—The total of the DAM Reg-Up payments for all QSEs, for the hour.
q	none	A QSE.
m	none	An Ancillary Service market (SASM or RSASM) for the given Operating Hour.

Each QSE's share of the net total costs for Reg-Up for the Operating Hour is calculated as follows:

$$\textbf{RUCOST}_{q} = \textbf{RUPR} * \textbf{RUQ}_{q}$$

Where:

$$\text{RUPR} = \text{RUCOSTTOT} / \text{RUQTOT}$$

$$\text{RUQTOT} = \sum_{q} \text{RUQ}_{q}$$

$$\text{RUQ}_{q} = \text{RUO}_{q} - \text{SARUQ}_{q}$$

$$\text{RUO}_{q} = \sum_{q} (\text{SARUQ}_{q} + \sum_{m} (\text{RTPCRU}_{q,\,m}) + \text{PCRU}_{q} - \text{RUFQ}_{q} - \text{RRUFQ}_{q}) * \text{HLRS}_{q}$$

$$\text{SARUQ}_{q} = \text{DASARUQ}_{q} + \text{RTSARUQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RUCOST $_q$	$	*Reg-Up Cost per QSE*—QSE *q*'s share of the net total costs for Reg-Up, for the hour.
RUPR	$/MW per hour	*Reg-Up Price*—The price for Reg-Up calculated based on the net total costs for Reg-Up, for the hour.
RUCOSTTOT	$	*Reg-Up Cost Total*—The net total costs for Reg-Up, for the hour. See item (2)(a) above.

Variable	Unit	Description
RUQTOT	MW	*Reg-Up Quantity Total*—The sum of every QSE's Ancillary Service Obligation minus its self-arranged Reg-Up quantity in the DAM and any and all SASMs, for the hour.
RUQ $_{q}$	MW	*Reg-Up Quantity per QSE*—The QSE *q*'s Ancillary Service Obligation minus its self-arranged Reg-Up quantity in the DAM and any and all SASMs, for the hour.
RUO $_{q}$	MW	*Reg-Up Obligation per QSE*—The Ancillary Service Obligation of QSE *q*, for the hour.
DASARUQ $_{q}$	MW	*Day-Ahead Self-Arranged Reg-Up Quantity per QSE*—The self-arranged Reg-Up quantity submitted by QSE *q* before 1000 in the Day-Ahead.
RTSARUQ $_{q}$	MW	*Self-Arranged Reg-Up Quantity per QSE for all SASMs*—The sum of all self-arranged Reg-Up quantities submitted by QSE *q* for all SASMs due to an increase in the Ancillary Service Plan per Section 4.4.7.1, Self-Arranged Ancillary Service Quantities.
RTPCRU $_{q, m}$	MW	*Procured Capacity for Reg-Up per QSE by market*—The MW portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* to provide Reg-Up, for the hour.
RUFQ $_{q}$	MW	*Reg-Up Failure Quantity per QSE*—QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
RRUFQ $_{q}$	MW	*Reconfiguration Reg-Up Failure Quantity per QSE*—QSE *q* total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Up, for the hour.
HLRS $_{q}$	none	*The Hourly Load Ratio Share calculated for QSE q for the hour*. See Section 6.6.2.4, QSE Load Ratio Share for an Operating Hour.
PCRU $_{q}$	MW	*Procured Capacity for Reg-Up per QSE in DAM*—The total Reg-Up capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE, for the hour.
SARUQ $_{q}$	MW	*Total Self-Arranged Reg-Up Quantity per QSE for all markets*—The sum of all self-arranged Reg-Up quantities submitted by QSE *q* for DAM and all SASMs.
q	none	A QSE.

Variable	Unit	Description
m	none	A SASM for the given Operating Hour.

The adjustment to each QSE's DAM charge for the Reg-Up for the Operating Hour, due to changes during the Adjustment Period or Real-Time operations, is calculated as follows:

$$\mathbf{RTRUAMT}_{q} = \mathbf{RUCOST}_{q} - \mathbf{DARUAMT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RTRUAMT_{q}	$	*Real-Time Reg-Up Amount per QSE*—The adjustment to QSE *q*'s share of the costs for Reg-Up, for the hour.
RUCOST_{q}	$	*Reg-Up Cost per QSE*—QSE *q*'s share of the net total costs for Reg-Up, for the hour.
DARUAMT_{q}	$	*Day-Ahead Reg-Up Amount per QSE*—QSE *q*'s share of the DAM cost for Reg-Up, for the hour.
q	none	A QSE.

4.9.2 ERCOT Pricing Formulas for Regulation Service – Down

4.9.2.1 Charges in the Day-Ahead Market

Each QSE shall pay to ERCOT or be paid by ERCOT a Reg-Down Service charge for each hour as follows:

$$\text{DARDAMT}_{q} = \text{DARDPR} * \text{DARDQ}_{q}$$

Where:

$$\text{DARDPR} = (-1) * \text{PCRDAMTTOT} / \text{DARDQTOT}$$

$$\text{PCRDAMTTOT} = \sum_{q} \text{PCRDAMT}_{q}$$

$$\text{DARDQTOT} = \sum_{q} \text{DARDQ}_{q}$$

$$\text{DARDQ}_{q} = \text{DARDO}_{q} - \text{DASARDQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
DARDAMT_{q}	$	*Day-Ahead Reg-Down Amount per QSE*—QSE *q*'s share of the DAM cost for Reg-Down, for the hour.
DARDPR	$/MW per hour	*Day-Ahead Reg-Down Price*—The Day-Ahead Reg-Down price for the hour.
DARDQ_{q}	MW	*Day-Ahead Reg-Down Quantity per QSE*—The QSE *q*'s Day-Ahead Ancillary Service Obligation minus its self-arranged Reg-Down quantity for the hour.

Variable	Unit	Definition
PCRDAMTTOT	$	*Procured Capacity for Reg-Down Amount Total in DAM*—The total of the DAM Reg-Down payments for all QSEs for the hour.
PCRDAMT $_q$	$	*Procured Capacity for Reg-Down Amount per QSE in DAM*—The DAM Reg-Down payment for QSE *q* for the hour.
DARDQTOT	MW	*Day-Ahead Reg-Down Quantity Total*—The sum of every QSE's Day-Ahead Ancillary Service Obligation minus its self-arranged Reg-Down quantity for the hour.
DARDO $_q$	MW	*Day-Ahead Reg-Down Obligation per QSE*—The Reg-Down capacity obligation for QSE *q* for the DAM for the hour.
DASARDQ $_q$	MW	*Day-Ahead Self-Arranged Reg-Down Quantity per QSE*—The self-arranged Reg-Down quantity submitted by QSE *q* before 1000 in the Day-Ahead.
q	none	A QSE.

4.9.2.2 Adjustment to Cost Allocations for Procurement

The net total costs for Reg-Down for a given Operating Hour is calculated as follows:

$$\textbf{RDCOSTTOT} = (-1) * (\sum_{m} (\textbf{RTPCRDAMTTOT}_{m}) + \textbf{PCRDAMTTOT} + \textbf{RDFQAMTTOT} + \textbf{RDINFQAMTTOT})$$

Where:

Total payment of SASM- and RSASM-procured capacity for Reg-Down by market

$$\text{RTPCRDAMTTOT}_{m} = \sum_{q} \text{RTPCRDAMT}_{q,\,m}$$

Total payment of DAM-procured capacity for Reg-Down

$$\text{PCRDAMTTOT} = \sum_{q} \text{PCRDAMT}_{q}$$

Total charge of failure on Ancillary Service Supply Responsibility for Reg-Down

$$\text{RDFQAMTTOT} = \sum_{q} \text{RDFQAMTQSETOT}_{q}$$

Total payment of SASM- and RSASM-procured capacity for Reg-Down by QSE

$$\text{RTPCRDAMTQSETOT}_{q} = \sum_{m} \text{RTPCRDAMT}_{q,\,m}$$

Total charge of infeasible Ancillary Service Supply Responsibility for Reg-Down

$$\text{RDINFQAMTTOT} = \sum_{q} \text{RDINFQAMT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RDCOSTTOT	$	*Reg-Down Cost Total*—The net total costs for Reg-Down, for the hour.
RTPCRDAMTTOT $_{m}$	$	*Procured Capacity for Reg-Down Amount Total by market*—The total payments to all QSEs for the Ancillary Service Offers cleared in the market *m* for Reg-Down, for the hour.
RTPCRDAMT $_{q,\ m}$	$	*Procured Capacity for Reg-Down Amount per QSE by market*—The payment to QSE *q* for its Ancillary Service Offers cleared in the market *m* for Reg-Down, for the hour.
RDFQAMTTOT	$	*Reg-Down Failure Quantity Amount Total*—The total charges to all QSEs for their capacity associated with failures on their Ancillary Service Supply Responsibilities for Reg-Down, for the hour.
RDFQAMTQSETOT $_{q}$	$	*Reg-Down Failure Quantity Amount Total per QSE*—The charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
RTPCRDAMTQSETOT $_{q}$	$	*Procured Capacity for Reg-Down Amount Total per QSE*—The total payments to a QSE *q* in all SASMs and RSASMs for the Ancillary Service Offers cleared for Reg-Down, for the hour.
PCRDAMT $_{q}$	$	*Procured Capacity for Reg-Down Amount per QSE for DAM*—The DAM Reg-Down payment for QSE *q*, for the hour.
PCRDAMTTOT	$	*Procured Capacity for Reg-Down Amount Total in DAM*—The total of the DAM Reg-Down payments for all QSEs for the hour.
RDINFQAMTTOT	$	*Reg-Down Infeasible Quantity Amount Total* — The charge to all QSEs for their total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for Reg-Down, for the hour.
RDINFQAMT $_{q}$	$	*Reg-Down Infeasible Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with infeasible deployment of its Ancillary Service Supply Responsibilities for Reg-Down, for the hour.
q	none	A QSE.
m	none	An Ancillary Service market (SASM or RSASM) for the given Operating Hour.

Each QSE's share of the net total costs for Reg-Down for the Operating Hour is calculated as follows:

$$\mathbf{RDCOST}_{q} \quad = \quad \mathbf{RDPR * RDQ}_{q}$$

Where:

$$\text{RDPR} \quad = \quad \text{RDCOSTTOT / RDQTOT}$$

$$\text{RDQTOT} = \sum_{q} \text{RDQ}_{q}$$

$$\text{RDQ}_{q} = \text{RDO}_{q} - \text{SARDQ}_{q}$$

$$\text{RDO}_{q} = \sum_{q} (\text{SARDQ}_{q} + \sum_{m} (\text{RTPCRD}_{q,m}) + \text{PCRD}_{q} - \text{RDFQ}_{q} - \text{RRDFQ}_{q}) * \text{HLRS}_{q}$$

$$\text{SARDQ}_{q} = \text{DASARDQ}_{q} + \text{RTSARDQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RDCOST_{q}	$	*Reg-Down Cost per QSE*—QSE *q*'s share of the net total costs for Reg-Down, for the hour.
RDPR	$/MW per hour	*Reg-Down Price*—The price for Reg-Down calculated based on the net total costs for Reg-Down, for the hour.
RDCOSTTOT	$	*Reg-Down Cost Total*—The net total costs for Reg-Down, for the hour. See item (3)(a) above.
RDQTOT	MW	*Reg-Down Quantity Total*—The sum of every QSE's Ancillary Service Obligation minus its self-arranged Reg-Down quantity in the DAM and any and all SASMs for the hour.
RDQ_{q}	MW	*Reg-Down Quantity per QSE*—The QSE *q*'s Ancillary Service Obligation minus its self-arranged Reg-Down quantity in the DAM and any and all SASMs, for the hour.
RDO_{q}	MW	*Reg-Down Obligation per QSE*—The Ancillary Service Obligation of QSE *q*, for the hour.
DASARDQ_{q}	MW	*Self-Arranged Reg-Down Quantity per QSE for DAM*—The self-arranged Reg-Down quantity submitted by QSE *q* before 1000 in the Day-Ahead.
RTSARDQ_{q}	MW	*Self-Arranged Reg-Down Quantity per QSE for all SASMs*—The sum of all self-arranged Reg-Down quantities submitted by QSE *q* for all SASMs due to an increase in the Ancillary Service Plan per Section 4.4.7.1.
$\text{RTPCRD}_{q,m}$	MW	*Procured Capacity for Reg-Down per QSE by market*—The MW portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* to provide Reg-Down, for the hour.
RDFQ_{q}	MW	*Reg-Down Failure Quantity per QSE*—QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
RRDFQ_{q}	MW	*Reconfiguration Reg-Down Failure Quantity per QSE*—QSE *q*'s total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Reg-Down, for the hour.
HLRS_{q}		*The Hourly Load Ratio Share calculated for QSE q for the hour*. See Section 6.6.2.4.
PCRD_{q}	MW	*Procured Capacity for Reg-Down per QSE in DAM*—The total Reg-Down capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE, for the hour.

Variable	Unit	Description
SARDQ $_q$	MW	*Total Self-Arranged Reg-Down Quantity per QSE for all markets*—The sum of all self-arranged Reg-Down quantities submitted by QSE *q* for DAM and all SASMs.
q	none	A QSE.
m	none	An Ancillary Service market (SASM or RSASM) for the given Operating Hour.

(c) The adjustment to each QSE's DAM charge for the Reg-Down for the Operating Hour, due to changes during the Adjustment Period or Real-Time operations, is calculated as follows:

$$\mathbf{RTRDAMT}_q = \mathbf{RDCOST}_q - \mathbf{DARDAMT}_q$$

The above variables are defined as follows:

Variable	Unit	Description
RTRDAMT $_q$	$	*Real-Time Reg-Down Amount per QSE*—The adjustment to QSE *q*'s share of the costs for Reg-Down, for the hour.
RDCOST $_q$	$	*Reg-Down Cost per QSE*—QSE *q*'s share of the net total costs for Reg-Down, for the hour.
DARDAMT $_q$	$	*Day-Ahead Reg-Down Amount per QSE*—QSE *q*'s share of the DAM cost for Reg-Down, for the hour.
q	none	A QSE.

4.9.3 ERCOT Pricing Formulas for Responsive Reserves

4.9.3.1 Charges in the Day-Ahead Market

Each QSE shall pay to ERCOT or be paid by ERCOT an RRS charge for each hour as follows:

$$\text{DARRAMT}_q = \text{DARRPR} * \text{DARRQ}_q$$

Where:

$$\text{DARRPR} = (-1) * \text{PCRRAMTTOT} / \text{DARRQTOT}$$

$$\text{PCRRAMTTOT} = \sum_q \text{PCRRAMT}_q$$

$$\text{DARRQTOT} = \sum_q \text{DARRQ}_q$$

$$\text{DARRQ}_q = \text{DARRO}_q - \text{DASARRQ}_q$$

The above variables are defined as follows:

Variable	Unit	Definition
DARRAMT $_q$	$	*Day-Ahead Responsive Reserve Amount per QSE*—QSE *q*'s share of the DAM cost for RRS, for the hour.
DARRPR	$/MW per hour	*Day-Ahead Responsive Reserve Price*—The Day-Ahead RRS price for the hour.
DARRQ $_q$	MW	*Day-Ahead Responsive Reserve Quantity per QSE*—The QSE *q*'s Day-Ahead Ancillary Service Obligation minus its self-arranged RRS quantity for the hour.
PCRRAMTTOT	$	*Procured Capacity for Responsive Reserve Amount Total in DAM*—The total of the DAM RRS payments for all QSEs for the hour.
PCRRAMT $_q$	$	*Procured Capacity for Responsive Reserve Amount per QSE for DAM*—The DAM RRS payment for QSE *q* for the hour.
DARRQTOT	MW	*Day-Ahead Responsive Reserve Quantity Total*—The sum of every QSE's Day-Ahead Ancillary Service Obligation minus its self-arranged RRS quantity for the hour.
DARRO $_q$	MW	*Day-Ahead Responsive Reserve Obligation per QSE*—The RRS capacity obligation for QSE *q* for the DAM for the hour.
DASARRQ $_q$	MW	*Day-Ahead Self-Arranged Responsive Reserve Quantity per QSE*—The self-arranged RRS quantity submitted by QSE *q* before 1000 in the Day-Ahead.
q	none	A QSE.

4.9.3.2 Adjustment to Cost Allocations for Procurement

The net total costs for RRS for a given Operating Hour is calculated as follows:

$$\mathbf{RRCOSTTOT} = (-1) * \left(\sum_m (\mathbf{RTPCRRAMTTOT}_m) + \mathbf{PCRRAMTTOT} + \mathbf{RRFQAMTTOT} + \mathbf{RRINFQAMTTOT}\right)$$

Where:

Total payment of SASM- and RSASM-procured capacity for RRS by market

$$\text{RTPCRRAMTTOT}_m = \sum_q \text{RTPCRRAMT}_{q,\,m}$$

Total payment of DAM-procured capacity for RRS

$$\text{PCRRAMTTOT} = \sum_q \text{PCRRAMT}_q$$

Total charge of failure on Ancillary Service Supply Responsibility for RRS

$$\text{RRFQAMTTOT} = \sum_q \text{RRFQAMTQSETOT}_q$$

Total payment of SASM- and RSASM-procured capacity RRS Service by QSE

$$\text{RTPCRRAMTQSETOT}_{q} \quad = \quad \sum_{m} \text{RTPCRRAMT}_{q,\,m}$$

Total charge of infeasible Ancillary Service Supply Responsibility for RRS

$$\text{RRINFQAMTTOT} \quad = \quad \sum_{q} \text{RRINFQAMT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RRCOSTTOT	$	*Responsive Reserve Cost Total*—The net total costs for RRS, for the hour.
RTPCRRAMTTOT $_{m}$	$	*Procured Capacity for Responsive Reserve Amount Total by market*—The total payments to all QSEs for the Ancillary Service Offers cleared in the market *m* for RRS, for the hour.
RTPCRRAMT $_{q,\,m}$	$	*Procured Capacity for Responsive Reserve Amount per QSE by market*—The payment to QSE *q* for its Ancillary Service Offers cleared in the market *m* for RRS, for the hour.
RRFQAMTTOT	$	*Responsive Reserve Failure Quantity Amount Total*—The total charges to all QSEs for their capacity associated with failures and reconfiguration reductions on their Ancillary Service Supply Responsibilities for RRS, for the hour.
RRFQAMTQSETOT $_{q}$	$	*Responsive Reserve Failure Quantity Amount Total per QSE*—The charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for RRS, for the hour.
RTPCRRAMTQSETOT $_{q}$	$	*Procured Capacity for Responsive Reserve Amount Total per QSE*—The total payments to a QSE *q* in all SASMs and RSASMs for the Ancillary Service Offers cleared for RRS, for the hour.
PCRRAMT $_{q}$	$	*Procured Capacity for Responsive Reserve Amount per QSE for DAM*—The DAM RRS payment for QSE *q*, for the hour.
PCRRAMTTOT	$	*Procured Capacity for Responsive Reserve Amount Total in DAM*—The total of the DAM RRS payments for all QSEs, for the hour.
RRINFQAMTTOT	$	*Responsive Reserve Infeasible Quantity Amount Total* — The charge to all QSEs for their total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for RRS, for the hour.
RRINFQAMT $_{q}$	$	*Responsive Reserve Infeasible Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for RRS, for the hour.

Variable	Unit	Description
q	none	A QSE.
m	none	An Ancillary Service market (SASM or RSASM) for the given Operating Hour.

Each QSE's share of the net total costs for RRS for the Operating Hour is calculated as follows:

$$\mathbf{RRCOST}_{q} = \mathbf{RRPR} * \mathbf{RRQ}_{q}$$

Where:

$$\text{RRPR} = \text{RRCOSTTOT} / \text{RRQTOT}$$

$$\text{RRQTOT} = \sum_{q} \text{RRQ}_{q}$$

$$\text{RRQ}_{q} = \text{RRO}_{q} - \text{SARRQ}_{q}$$

$$\text{RRO}_{q} = \sum_{q} (\text{SARRQ}_{q} + \sum_{m} (\text{RTPCRR}_{q,m}) + \text{PCRR}_{q} - \text{RRFQ}_{q} - \text{RRRFQ}_{q}) * \text{HLRS}_{q}$$

$$\text{SARRQ}_{q} = \text{DASARRQ}_{q} + \text{RTSARRQ}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RRCOST $_{q}$	$	*Responsive Reserve Cost per QSE*—QSE q's share of the net total costs for RRS, for the hour.
RRPR	$/MW per hour	*Responsive Reserve Price*—The price for RRS calculated based on the net total costs for RRS, for the hour.
RRCOSTTOT	$	*Responsive Reserve Cost Total*—The net total costs for RRS, for the hour. See item (4)(a) above.
RRQTOT	MW	*Responsive Reserve Quantity Total*—The sum of every QSE's Ancillary Service Obligation minus its self-arranged RRS quantity in the DAM and any and all SASMs for the hour.
RRQ $_{q}$	MW	*Responsive Reserve Quantity per QSE*—The QSE q's Ancillary Service Obligation minus its self-arranged RRS quantity in the DAM and any and all SASMs, for the hour.
RRO $_{q}$	MW	*Responsive Reserve Obligation per QSE*—The Ancillary Service Obligation of QSE q, for the hour.
DASARRQ $_{q}$	MW	*Day-Ahead Self-Arranged Responsive Reserve Quantity per QSE*—The self-arranged RRS quantity submitted by QSE q before 1000 in the Day-Ahead.
RTSARRQ $_{q}$	MW	*Self-Arranged Responsive Reserve Quantity per QSE for all SASMs*—The sum of all self-arranged RRS quantities submitted by QSE q for all SASMs due to an increase in the Ancillary Service Plan per Section 4.4.7.1.

Variable	Unit	Description
RTPCRR $_{q,\,m}$	MW	*Procured Capacity for Responsive Reserve per QSE by market*—The MW portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* to provide RRS, for the hour.
RRFQ $_{q}$	MW	*Responsive Reserve Failure Quantity per QSE*—QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for RRS, for the hour.
RRRFQ $_{q}$	MW	*Reconfiguration Responsive Reserve Failure Quantity per QSE*—QSE *q*'s total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for RRS, for the hour.
HLRS $_{q}$	none	*The Hourly Load Ratio Share calculated for QSE q for the hour*. See Section 6.6.2.4.
PCRR $_{q}$	MW	*Procured Capacity for Responsive Reserve per QSE in DAM*—The total RRS capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE, for the hour.
SARRQ $_{q}$	MW	*Total Self-Arranged Responsive Reserve Quantity per QSE for all markets*—The sum of all self-arranged RRS quantities submitted by QSE *q* for DAM and all SASMs.
q	none	A QSE.
m	none	An Ancillary Service market (SASM or RSASM) for the given Operating Hour.

The adjustment to each QSE's DAM charge for the RRS for the Operating Hour, due to changes during the Adjustment Period or Real-Time operations, is calculated as follows:

$$\textbf{RTRRAMT}_{q} \quad = \quad \textbf{RRCOST}_{q} - \textbf{DARRAMT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RTRRAMT $_{q}$	$	*Real-Time Responsive Reserve Amount per QSE*—The adjustment to QSE *q*'s share of the costs for RRS, for the hour.
RRCOST $_{q}$	$	*Responsive Reserve Cost per QSE*—QSE *q*'s share of the net total costs for RRS, for the hour.
DARRAMT $_{q}$	$	*Day-Ahead Responsive Reserve Amount per QSE*—QSE *q*'s share of the DAM cost for RRS, for the hour.
q	none	A QSE.

4.9.4 ERCOT Pricing Formulas for Non-Spinning Reserves

4.9.4.1 Charges in the Day-Ahead Market

Each QSE shall pay to ERCOT or be paid by ERCOT a Non-Spin Service charge for each hour as follows:

$$\text{DANSAMT}_{q} \quad = \quad \text{DANSPR} * \text{DANSQ}_{q}$$

Where:

$$\text{DANSPR} = (-1) * \text{PCNSAMTTOT} / \text{DANSQTOT}$$

$$\text{PCNSAMTTOT} = \sum_q \text{PCNSAMT}_q$$

$$\text{DANSQTOT} = \sum_q \text{DANSQ}_q$$

$$\text{DANSQ}_q = \text{DANSO}_q - \text{DASANSQ}_q$$

The above variables are defined as follows:

Variable	Unit	Definition
DANSAMT_q	\$	*Day-Ahead Non-Spin Amount per QSE*—QSE *q*'s share of the DAM cost for Non-Spin, for the hour.
DANSPR	\$/MW per hour	*Day-Ahead Non-Spin Price*—The Day-Ahead Non-Spin price for the hour.
DANSQ_q	MW	*Day-Ahead Non-Spin Quantity per QSE*—The QSE *q*'s Day-Ahead Ancillary Service Obligation minus its self-arranged Non-Spin quantity for the hour.
PCNSAMTTOT	\$	*Procured Capacity for Non-Spin Amount Total in DAM*—The total of the DAM Non-Spin payments for all QSEs for the hour.
PCNSAMT_q	\$	*Procured Capacity for Non-Spin Amount per QSE in DAM*—The DAM Non-Spin payment for QSE *q* for the hour.
DANSQTOT	MW	*Day-Ahead Non-Spin Quantity Total*—The sum of every QSE's Day-Ahead Ancillary Service Obligation minus its self-arranged Non-Spin quantity for the hour.
DANSO_q	MW	*Day-Ahead Non-Spin Obligation per QSE*—The Non-Spin capacity obligation for QSE *q* for the DAM for the hour.
DASANSQ_q	MW	*Day-Ahead Self-Arranged Non-Spin Quantity per QSE*—The self-arranged Non-Spin quantity submitted by QSE *q* before 1000 in the Day-Ahead.
q	none	A QSE.

4.9.5 Adjustment to Cost Allocations for Procurement

The net total costs for Non-Spin for a given Operating Hour is calculated as follows:

$$\textbf{NSCOSTTOT} = (-1) * \left(\sum_m (\textbf{RTPCNSAMTTOT}_m) + \textbf{PCNSAMTTOT} + \textbf{NSFQAMTTOT} + \textbf{NSINFQAMTTOT}\right)$$

Where:

Total payment of SASM- and RSASM-procured capacity for Non-Spin by market

$$\text{RTPCNSAMTTOT}_m = \sum_q \text{RTPCNSAMT}_{q,\,m}$$

Total payment of DAM-procured capacity for Non-Spin

$$\text{PCNSAMTTOT} = \sum_q \text{PCNSAMT}_q$$

Total charge of failure on Ancillary Service Supply Responsibility for Non-Spin

$$NSFQAMTTOT = \sum_{q} NSFQAMTQSETOT_{q}$$

Total payment of SASM- and RSASM-procured capacity for Non-Spin by QSE

$$RTPCNSAMTQSETOT_{q} = \sum_{m} RTPCNSAMT_{q,\,m}$$

Total charge of infeasible Ancillary Service Supply Responsibility for Non-Spin

$$NSINFQAMTTOT = \sum_{q} NSINFQAMT_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
NSCOSTTOT	$	*Non-Spin Cost Total*—The net total costs for Non-Spin, for the hour.
$RTPCNSAMTTOT_{m}$	$	*Procured Capacity for Non-Spin Amount Total by market*—The total payments to all QSEs for the Ancillary Service Offers cleared in the market *m* for Non-Spin, for the hour.
$RTPCNSAMT_{q,\,m}$	$	*Procured Capacity for Non-Spin Amount per QSE by market*—The payment to QSE *q* for its Ancillary Service Offers cleared in the market *m* for Non-Spin, for the hour.
NSFQAMTTOT	$	*Non-Spin Failure Quantity Amount Total*—The total charges to all QSEs for their capacity associated with failures and reconfiguration reductions on their Ancillary Service Supply Responsibilities for Non-Spin, for the hour.
$NSFQAMTQSETOT_{q}$	$	*Non-Spin Failure Quantity Amount Total per QSE*—The charge to QSE *q* for its total capacity associated with failures and reconfiguration reductions on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
$RTPCNSAMTQSETOT_{q}$	$	*Procured Capacity for Non-Spin Amount Total per QSE*—The total payments to a QSE *q* in all SASMs and RSASMs for the Ancillary Service Offers cleared for Non-Spin, for the hour.
$PCNSAMT_{q}$	$	*Procured Capacity for Non-Spin Amount per QSE in DAM*—The DAM Non-Spin payment for QSE *q*, for the hour.
PCNSAMTTOT	$	*Procured Capacity for Non-Spin Amount Total in DAM*—The total of the DAM Non-Spin payments for all QSEs, for the hour.
NSINFQAMTTOT	$	*Non-Spin Infeasible Quantity Amount Total* — The charge to all QSEs for their total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for Non-Spin, for the hour.
$NSINFQAMT_{q}$	$	*Non-Spin Infeasible Quantity Amount per QSE*—The total charge to QSE *q* for its total capacity associated with infeasible deployment of Ancillary Service Supply Responsibilities for Non-Spin, for the hour.
q	none	A QSE.
m	none	An Ancillary Service market (SASM or RSASM) for the given Operating Hour.

Each QSE's share of the net total costs for Non-Spin for the Operating Hour is calculated as follows:

$$\mathbf{NSCOST}_{q} = \mathbf{NSPR} * \mathbf{NSQ}_{q}$$

Where:

$$NSPR = NSCOSTTOT / NSQTOT$$

$$NSQTOT = \sum_{q} NSQ_{q}$$

$$NSQ_{q} = NSO_{q} - SANSQ_{q}$$

$$NSO_{q} = \sum_{q} (SANSQ_{q} + \sum_{m} (RTPCNS_{q,m}) + PCNS_{q} - NSFQ_{q} - RNSFQ_{q}) * HLRS_{q}$$

$$SANSQ_{q} = DASANSQ_{q} + RTSANSQ_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
$NSCOST_{q}$	$	*Non-Spin Cost per QSE*—QSE *q*'s share of the net total costs for Non-Spin, for the hour.
NSPR	$/MW per hour	*Non-Spin Price*—The price for Non-Spin calculated based on the net total costs for Non-Spin, for the hour.
NSCOSTTOT	$	*Non-Spin Cost Total*—The net total costs for Non-Spin for the hour. See item (5)(a) above.
NSQTOT	MW	*Non-Spin Quantity Total*—The sum of every QSE's Ancillary Service Obligation minus its self-arranged Non-Spin quantity in the DAM and any and all SASMs, for the hour.
NSQ_{q}	MW	*Non-Spin Quantity per QSE*—The difference in QSE *q*'s Ancillary Service Obligation minus its self-arranged Non-Spin quantity in the DAM and any and all SASMs, for the hour.
NSO_{q}	MW	*Non-Spin Obligation per QSE*—The Ancillary Service Obligation of QSE *q*, for the hour.
$DASANSQ_{q}$	MW	*Day-Ahead Self-Arranged Non-Spin Quantity per QSE for DAM*—The self-arranged Non-Spin quantity submitted by QSE *q* before 1000 in the Day-Ahead.
$RTSANSQ_{q}$	MW	*Self-Arranged Non-Spin Quantity per QSE for all SASMs*—The sum of all self-arranged Non-Spin quantities submitted by QSE *q* for all SASMs due to an increase in the Ancillary Service Plan per Section 4.4.7.1.
$RTPCNS_{q,m}$	MW	*Procured Capacity for Non-Spin per QSE by market*—The MW portion of QSE *q*'s Ancillary Service Offers cleared in the market *m* to provide Non-Spin, for the hour.
$NSFQ_{q}$	MW	*Non-Spin Failure Quantity per QSE*—QSE *q*'s total capacity associated with failures on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.

Variable	Unit	Description
RNSFQ $_q$	MW	*Reconfiguration Non-Spin Failure Quantity per QSE*—QSE *q*'s total capacity associated with reconfiguration reductions on its Ancillary Service Supply Responsibility for Non-Spin, for the hour.
HLRS $_q$	none	*The Hourly Load Ratio Share calculated for QSE q for the hour*. See Section 6.6.2.4.
PCNS $_q$	MW	*Procured Capacity for Non-Spin Service per QSE in DAM*—The total Non-Spin capacity quantity awarded to QSE *q* in the DAM for all the Resources represented by the QSE, for the hour.
SANSQ $_q$	MW	*Total Self-Arranged Non-Spin Supplied Quantity per QSE for all markets*—The sum of all self-arranged Non-Spin quantities submitted by QSE *q* for DAM and all SASMs.
q	none	A QSE.
m	none	An Ancillary Service market (SASM or RSASM) for the given Operating Hour.

The adjustment to each QSE's DAM charge for the Non-Spin for the Operating Hour, due to changes during the Adjustment Period or Real-Time operations, is calculated as follows:

$$\textbf{RTNSAMT}_{q} = \textbf{NSCOST}_{q} - \textbf{DANSAMT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Description
RTNSAMT $_q$	$	*Real-Time Non-Spin Amount per QSE*—The adjustment to QSE *q*'s share of the costs for Non-Spin, for the hour.
NSCOST $_q$	$	*Non-Spin Cost per QSE*—QSE *q*'s share of the net total costs for Non-Spin, for the hour.
DANSAMT $_q$	$	*Day-Ahead Non-Spin Amount per QSE*—QSE *q*'s share of the DAM cost for Non-Spin, for the hour.
q	none	A QSE.

The above formulae refer to the QSE, which is a Qualified Scheduling Entity. PEC is a LSE and is not a QSE. LCRA, as a QSE, completes settlement transactions in ERCOT on behalf of PEC. The final settlement is based on the real-time data and is therefore the appropriate data set for valuing the avoided cost of ancillary services for a DG unit's generation output.

4.9.6 Calculation of Avoided Ancillary Services

To determine the avoided cost of ancillary services, GDS computed the effective cost per MWh that LCRA settled as PEC's QSE representative incurred for each of the four services over the three-year period of 2018-2020. The real-time price of each service is determined based on the day-ahead formulas and real time adjustment formulas as provided earlier. The effective price to PEC for these services in any hour is based on a load share ratio of the ERCOT hourly MW associated with each service.

Table 4-8 shows the details of the hourly avoided cost per MWh computation, for July 14, 2020 at hour ending 1:00 PM. In that hour, ERCOT load was 68,529 MWh and PEC's QSE had a total load of 1,152 MWh, representing a 1.681% load share of the ERCOT load. In the real time settlement, ERCOT had 390 MWh of regulation up service in that hour and the nodal market formulas produced a cost of $11.94 per MWh for regulation up service. At that rate and given LCRA's 1.681% load share of the ERCOT load, PEC's QSE incurred a cost of $78.27 for regulation up service in that hour (390 MWh x 1.681% x $11.94 = $78.27). Expressed as a cost per total MWh for the LCRA region, PEC would be subject to $0.068 per MWh for regulation up service in Hour ending 1:00 PM on July 14, 2020. A similar computation can be completed for regulation down, responsive reserves, and non-spinning reserves, resulting in a cost of $0.658 per MWh for all ancillary services in that hour for PEC.

TABLE 4-8 COMPUTATION OF EFFECTIVE ANCILLARY SERVICE RATE FOR PEC (JULY 14, 2020, HOUR ENDING 1:00 PM)

Computation of Effective Ancillary Service Rate for PEC (July 14, 2020, Hour Ending 1:00PM)			
Line	**Item**	**Formula**	**Value**
[1]	ERCOT MWh in the Hour		68,529
[2]	LCRA MWh in the Hour		1,152
[3]	LCRA Share of ERCOT Load	[2] ÷ [1]	1.681%
[4]	ERCOT Regulation Up MWh		390
[5]	Price of Regulation Up ($/MWh)		$11.94
[6]	LCRA Cost of Regulation Up	[3] x [4] x [5]	$78.27
[7]	Regulation Up Cost at LCRA ($/MWh)	[6] ÷ [2]	$0.068
[8]	ERCOT Regulation Down MWh		173
[9]	Price of Regulation Down ($/MWh)		$1.49
[10]	LCRA Cost of Regulation Down	[3] x [8] x [9]	$4.33
[11]	Regulation Down Cost at LCRA ($/MWh)	[10] ÷ [2]	$0.004
[12]	ERCOT Non-Spin Reserve MWh		1,574
[13]	Price of Non-Spin Reserves ($/MWh)		$9.25
[14]	LCRA Cost of Non-Spin Reserves	[3] x [12] x [13]	$244.73
[15]	Non-Spin Reserves Cost at LCRA ($/MWh)	[14] ÷ [2]	$0.212
[16]	ERCOT Responsive Reserve MWh		2,300
[17]	Price of Responsive Reserves ($/MWh)		$11.14
[18]	LCRA Cost of Responsive Reserves	[3] x [16] x [17]	$430.67
[19]	Responsive Reserves Cost at LCRA ($/MWh)	[19] ÷ [2]	$0.374
[20]	**Hourly Avoided Cost of Ancillary Service ($/MWh)**	**[7] + [11] + [15] + [19]**	**$0.658**

A similar computation was completed for every hour of 2018-2020 to produce a series of hourly prices to which PEC would be subject on a load-share basis and with LCRA completing settlements in the ERCOT market on their behalf.

Ancillary services costs on average track market energy prices and ERCOT load curves, tending to increase during afternoons in the summer and early in the morning and again in early evening in the winter. Just a few hours of the year can really drive costs for LCRA and ultimately PEC. Just 5% of hours resulted in between 35% and 67% of annual costs for LCRA in 2018-2020.

FIGURE 4-45 AVERAGE LCRA ANCILLARY SERVICES COSTS – SUMMER (2018-2020)

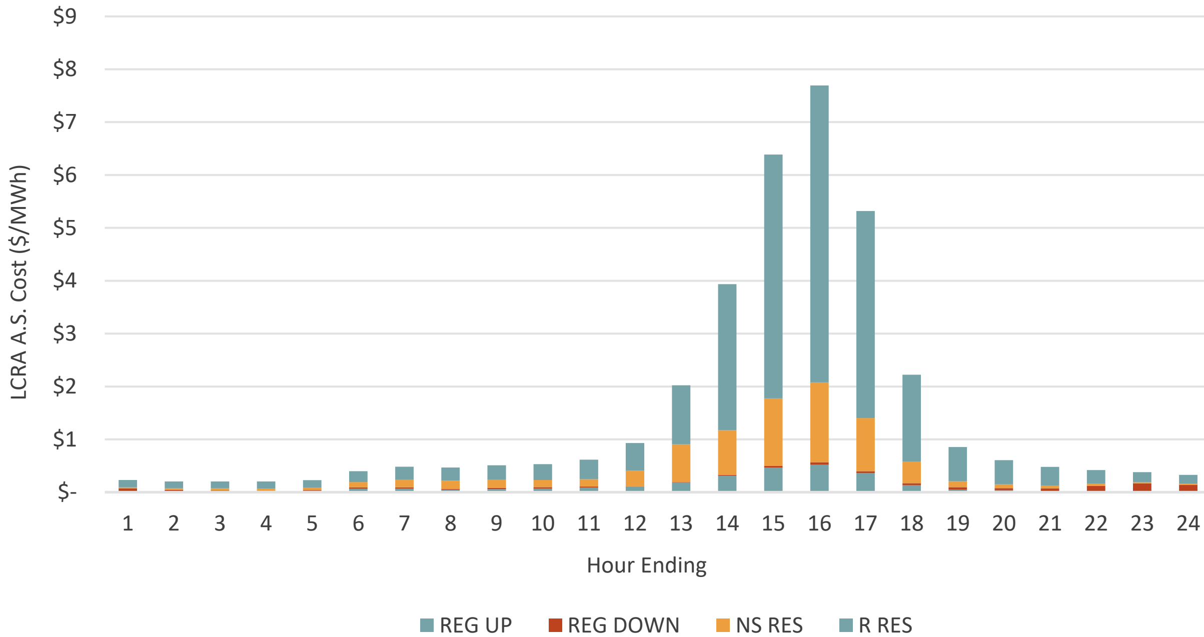


FIGURE 4-46 AVERAGE LCRA ANCILLARY SERVICES COSTS – WINTER (2018-2020)

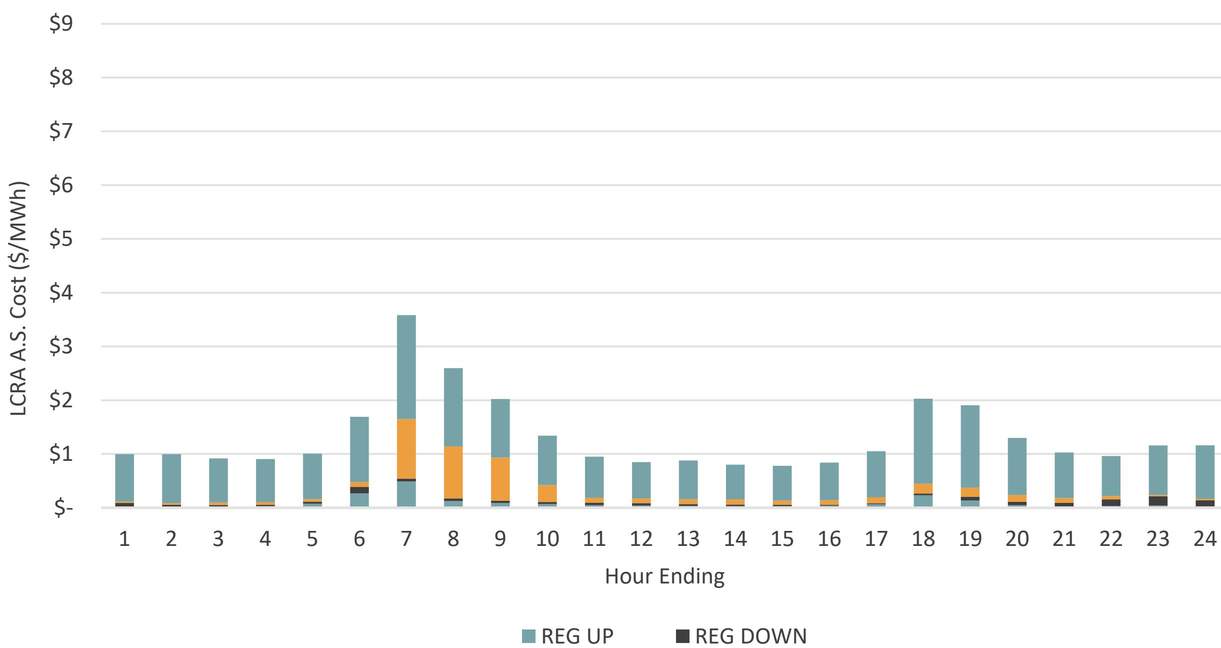


Table 4-9 through Table 4-13 provides the avoided cost computation for a single day (July 14, 2020). The avoided costs of the real time prices range from $0.09 per MWh at 3 AM to a high of $1.18 at 3 PM.

Overlaying these hourly prices with the output from the generation unit and assuming 1,000 1 kW units, results in avoided costs of $3.00 for PEC on July 14, 2020 for 1,000 1 kW solar units.

TABLE 4-9 AVOIDED COST COMPUTATION FOR JULY 14, 2020 - REGULATION UP

Date & Time	ERCOT MWh	LCRA MWh	Load Share	ERCOT MWh2	LCRA Share	RT Price ($/MWh)	LCRA Cost ($)	PEC Price ($/MWh)
7/14/20 12:00 AM	52,704	701	1.3308%	231	3.1	$2.26	$6.95	$0.01
7/14/20 1:00 AM	49,813	637	1.2778%	203	2.6	$1.80	$4.67	$0.01
7/14/20 2:00 AM	47,544	600	1.2611%	160	2.0	$1.01	$2.04	$0.00
7/14/20 3:00 AM	45,840	597	1.3032%	141	1.8	$1.00	$1.84	$0.00
7/14/20 4:00 AM	44,841	570	1.2708%	229	2.9	$1.60	$4.66	$0.01
7/14/20 5:00 AM	44,905	557	1.2398%	320	4.0	$3.00	$11.90	$0.02
7/14/20 6:00 AM	45,354	562	1.2393%	445	5.5	$4.00	$22.06	$0.04
7/14/20 7:00 AM	46,200	608	1.3165%	404	5.3	$3.34	$17.76	$0.03
7/14/20 8:00 AM	48,876	680	1.3916%	461	6.4	$4.00	$25.66	$0.04
7/14/20 9:00 AM	52,687	769	1.4594%	549	8.0	$8.42	$67.46	$0.09
7/14/20 10:00 AM	56,869	862	1.5151%	579	8.8	$9.90	$86.85	$0.10
7/14/20 11:00 AM	61,169	963	1.5749%	547	8.6	$6.02	$51.86	$0.05
7/14/20 12:00 PM	65,044	1,065	1.6367%	455	7.4	$7.20	$53.62	$0.05
7/14/20 1:00 PM	68,529	1,152	1.6809%	390	6.6	$11.94	$78.27	$0.07
7/14/20 2:00 PM	71,078	1,218	1.7133%	342	5.9	$20.98	$122.93	$0.10
7/14/20 3:00 PM	72,481	1,252	1.7270%	289	5.0	$28.42	$141.84	$0.11
7/14/20 4:00 PM	73,060	1,278	1.7487%	245	4.3	$25.07	$107.41	$0.08
7/14/20 5:00 PM	72,632	1,263	1.7389%	187	3.3	$13.19	$42.89	$0.03
7/14/20 6:00 PM	71,123	1,212	1.7040%	205	3.5	$8.43	$29.45	$0.02
7/14/20 7:00 PM	68,625	1,136	1.6549%	197	3.3	$6.11	$19.92	$0.02
7/14/20 8:00 PM	65,721	1,063	1.6171%	198	3.2	$4.00	$12.81	$0.01
7/14/20 9:00 PM	63,686	952	1.4948%	160	2.4	$3.00	$7.17	$0.01
7/14/20 10:00 PM	59,797	837	1.4004%	216	3.0	$2.84	$8.59	$0.01
7/14/20 11:00 PM	55,627	745	1.3391%	137	1.8	$2.06	$3.78	$0.01

TABLE 4-10 AVOIDED COST COMPUTATION FOR JULY 14, 2020 - REGULATION DOWN

Date & Time	ERCOT MWh	LCRA MWh	Load Share	ERCOT MWh2	LCRA Share	RT Price ($/MWh)	LCRA Cost ($)	PEC Price ($/MWh)
7/14/20 12:00 AM	52,704	701	1.3308%	438	5.8	$6.00	$34.97	$0.05
7/14/20 1:00 AM	49,813	637	1.2778%	337	4.3	$5.00	$21.53	$0.03
7/14/20 2:00 AM	47,544	600	1.2611%	276	3.5	$4.00	$13.92	$0.02
7/14/20 3:00 AM	45,840	597	1.3032%	195	2.5	$3.00	$7.62	$0.01
7/14/20 4:00 AM	44,841	570	1.2708%	159	2.0	$3.00	$6.06	$0.01
7/14/20 5:00 AM	44,905	557	1.2398%	161	2.0	$3.00	$5.99	$0.01
7/14/20 6:00 AM	45,354	562	1.2393%	206	2.6	$6.11	$15.60	$0.03
7/14/20 7:00 AM	46,200	608	1.3165%	157	2.1	$4.00	$8.27	$0.01
7/14/20 8:00 AM	48,876	680	1.3916%	255	3.5	$8.00	$28.39	$0.04
7/14/20 9:00 AM	52,687	769	1.4594%	220	3.2	$6.43	$20.64	$0.03
7/14/20 10:00 AM	56,869	862	1.5151%	153	2.3	$3.20	$7.42	$0.01
7/14/20 11:00 AM	61,169	963	1.5749%	227	3.6	$0.77	$2.75	$0.00
7/14/20 12:00 PM	65,044	1,065	1.6367%	138	2.3	$1.03	$2.33	$0.00
7/14/20 1:00 PM	68,529	1,152	1.6809%	173	2.9	$1.49	$4.33	$0.00
7/14/20 2:00 PM	71,078	1,218	1.7133%	222	3.8	$1.97	$7.49	$0.01
7/14/20 3:00 PM	72,481	1,252	1.7270%	227	3.9	$2.83	$11.09	$0.01
7/14/20 4:00 PM	73,060	1,278	1.7487%	269	4.7	$2.67	$12.56	$0.01
7/14/20 5:00 PM	72,632	1,263	1.7389%	321	5.6	$1.51	$8.43	$0.01
7/14/20 6:00 PM	71,123	1,212	1.7040%	427	7.3	$5.11	$37.18	$0.03
7/14/20 7:00 PM	68,625	1,136	1.6549%	424	7.0	$4.00	$28.07	$0.02
7/14/20 8:00 PM	65,721	1,063	1.6171%	375	6.1	$3.01	$18.25	$0.02
7/14/20 9:00 PM	63,686	952	1.4948%	526	7.9	$8.00	$62.90	$0.07
7/14/20 10:00 PM	59,797	837	1.4004%	617	8.6	$16.09	$139.03	$0.17
7/14/20 11:00 PM	55,627	745	1.3391%	548	7.3	$13.86	$101.71	$0.14

TABLE 4-11 AVOIDED COST COMPUTATION FOR JULY 14, 2020 - RESPONSIVE RESERVES

Date & Time	ERCOT MWh	LCRA MWh	Load Share	ERCOT MWh2	LCRA Share	RT Price ($/MWh)	LCRA Cost ($)	PEC Price ($/MWh)
7/14/20 12:00 AM	52,704	701	1.3308%	2,440	32.5	$1.45	$47.08	$0.07
7/14/20 1:00 AM	49,813	637	1.2778%	2,440	31.2	$1.45	$45.21	$0.07
7/14/20 2:00 AM	47,544	600	1.2611%	2,486	31.4	$1.01	$31.66	$0.05
7/14/20 3:00 AM	45,840	597	1.3032%	2,486	32.4	$1.00	$32.40	$0.05
7/14/20 4:00 AM	44,841	570	1.2708%	2,486	31.6	$1.20	$37.91	$0.07
7/14/20 5:00 AM	44,905	557	1.2398%	2,486	30.8	$1.20	$36.99	$0.07
7/14/20 6:00 AM	45,354	562	1.2393%	2,409	29.9	$2.20	$65.68	$0.12
7/14/20 7:00 AM	46,200	608	1.3165%	2,409	31.7	$1.95	$61.85	$0.10
7/14/20 8:00 AM	48,876	680	1.3916%	2,409	33.5	$3.01	$100.90	$0.15
7/14/20 9:00 AM	52,687	769	1.4594%	2,409	35.2	$3.01	$105.82	$0.14
7/14/20 10:00 AM	56,869	862	1.5151%	2,300	34.8	$4.16	$144.96	$0.17
7/14/20 11:00 AM	61,169	963	1.5749%	2,300	36.2	$5.02	$181.84	$0.19
7/14/20 12:00 PM	65,044	1,065	1.6367%	2,300	37.6	$6.20	$233.39	$0.22
7/14/20 1:00 PM	68,529	1,152	1.6809%	2,300	38.7	$11.14	$430.67	$0.37
7/14/20 2:00 PM	71,078	1,218	1.7133%	2,300	39.4	$20.35	$801.89	$0.66
7/14/20 3:00 PM	72,481	1,252	1.7270%	2,300	39.7	$28.22	$1,120.92	$0.90
7/14/20 4:00 PM	73,060	1,278	1.7487%	2,300	40.2	$24.87	$1,000.29	$0.78
7/14/20 5:00 PM	72,632	1,263	1.7389%	2,300	40.0	$16.50	$659.92	$0.52
7/14/20 6:00 PM	71,123	1,212	1.7040%	2,300	39.2	$9.03	$353.90	$0.29
7/14/20 7:00 PM	68,625	1,136	1.6549%	2,300	38.1	$7.11	$270.63	$0.24
7/14/20 8:00 PM	65,721	1,063	1.6171%	2,300	37.2	$5.29	$196.75	$0.19
7/14/20 9:00 PM	63,686	952	1.4948%	2,300	34.4	$3.75	$128.92	$0.14
7/14/20 10:00 PM	59,797	837	1.4004%	2,440	34.2	$2.69	$91.92	$0.11
7/14/20 11:00 PM	55,627	745	1.3391%	2,440	32.7	$2.25	$73.52	$0.10

TABLE 4-12 AVOIDED COST COMPUTATION FOR JULY 14, 2020 - NON-SPINNING RESERVES

Date & Time	ERCOT MWh	LCRA MWh	Load Share	ERCOT MWh2	LCRA Share	RT Price ($/MWh)	LCRA Cost ($)	PEC Price ($/MWh)
7/14/20 12:00 AM	52,704	701	1.3308%	1,238	16.5	$0.71	$11.70	$0.02
7/14/20 1:00 AM	49,813	637	1.2778%	1,238	15.8	$0.68	$10.76	$0.02
7/14/20 2:00 AM	47,544	600	1.2611%	1,313	16.6	$0.75	$12.42	$0.02
7/14/20 3:00 AM	45,840	597	1.3032%	1,313	17.1	$0.75	$12.83	$0.02
7/14/20 4:00 AM	44,841	570	1.2708%	1,313	16.7	$0.75	$12.51	$0.02
7/14/20 5:00 AM	44,905	557	1.2398%	1,313	16.3	$0.75	$12.21	$0.02
7/14/20 6:00 AM	45,354	562	1.2393%	1,533	19.0	$1.08	$20.52	$0.04
7/14/20 7:00 AM	46,200	608	1.3165%	1,533	20.2	$1.22	$24.62	$0.04
7/14/20 8:00 AM	48,876	680	1.3916%	1,533	21.3	$1.01	$21.55	$0.03
7/14/20 9:00 AM	52,687	769	1.4594%	1,533	22.4	$1.25	$27.97	$0.04
7/14/20 10:00 AM	56,869	862	1.5151%	1,574	23.8	$1.50	$35.77	$0.04
7/14/20 11:00 AM	61,169	963	1.5749%	1,574	24.8	$3.00	$74.37	$0.08
7/14/20 12:00 PM	65,044	1,065	1.6367%	1,574	25.8	$5.00	$128.81	$0.12
7/14/20 1:00 PM	68,529	1,152	1.6809%	1,574	26.5	$9.25	$244.73	$0.21
7/14/20 2:00 PM	71,078	1,218	1.7133%	1,150	19.7	$9.25	$182.25	$0.15
7/14/20 3:00 PM	72,481	1,252	1.7270%	1,150	19.9	$10.05	$199.60	$0.16
7/14/20 4:00 PM	73,060	1,278	1.7487%	1,150	20.1	$10.55	$212.16	$0.17
7/14/20 5:00 PM	72,632	1,263	1.7389%	1,150	20.0	$5.85	$116.99	$0.09
7/14/20 6:00 PM	71,123	1,212	1.7040%	1,117	19.0	$5.00	$95.17	$0.08
7/14/20 7:00 PM	68,625	1,136	1.6549%	1,117	18.5	$3.33	$61.56	$0.05
7/14/20 8:00 PM	65,721	1,063	1.6171%	1,117	18.1	$1.50	$27.09	$0.03
7/14/20 9:00 PM	63,686	952	1.4948%	1,117	16.7	$0.99	$16.53	$0.02
7/14/20 10:00 PM	59,797	837	1.4004%	1,238	17.3	$0.91	$15.78	$0.02
7/14/20 11:00 PM	55,627	745	1.3391%	1,238	16.6	$0.89	$14.75	$0.02

TABLE 4-13 AVOIDED COST COMPUTATION FOR JULY 14, 2020 - ANCILLARY SERVICES TOTALS

Date & Time	ERCOT MWh	LCRA MWh	Load Share	Ancillary Services ($/MWh)	Generator Output (kWh)	Avoided Cost Value of 1,000 Units ($)
7/14/20 12:00 AM	52,704	701	1.3308%	$0.14	-	$0.00
7/14/20 1:00 AM	49,813	637	1.2778%	$0.13	-	$0.00
7/14/20 2:00 AM	47,544	600	1.2611%	$0.10	-	$0.00
7/14/20 3:00 AM	45,840	597	1.3032%	$0.09	-	$0.00
7/14/20 4:00 AM	44,841	570	1.2708%	$0.11	-	$0.00
7/14/20 5:00 AM	44,905	557	1.2398%	$0.12	-	$0.00
7/14/20 6:00 AM	45,354	562	1.2393%	$0.22	0.03	$0.01
7/14/20 7:00 AM	46,200	608	1.3165%	$0.18	0.15	$0.03
7/14/20 8:00 AM	48,876	680	1.3916%	$0.26	0.30	$0.08
7/14/20 9:00 AM	52,687	769	1.4594%	$0.29	0.45	$0.13
7/14/20 10:00 AM	56,869	862	1.5151%	$0.32	0.56	$0.18
7/14/20 11:00 AM	61,169	963	1.5749%	$0.32	0.63	$0.20
7/14/20 12:00 PM	65,044	1,065	1.6367%	$0.39	0.64	$0.25
7/14/20 1:00 PM	68,529	1,152	1.6809%	$0.66	0.62	$0.40
7/14/20 2:00 PM	71,078	1,218	1.7133%	$0.92	0.56	$0.51
7/14/20 3:00 PM	72,481	1,252	1.7270%	$1.18	0.46	$0.55
7/14/20 4:00 PM	73,060	1,278	1.7487%	$1.04	0.34	$0.35
7/14/20 5:00 PM	72,632	1,263	1.7389%	$0.66	0.19	$0.12
7/14/20 6:00 PM	71,123	1,212	1.7040%	$0.43	0.05	$0.02
7/14/20 7:00 PM	68,625	1,136	1.6549%	$0.33	0.00	$0.00
7/14/20 8:00 PM	65,721	1,063	1.6171%	$0.24	-	$0.00
7/14/20 9:00 PM	63,686	952	1.4948%	$0.23	-	$0.00
7/14/20 10:00 PM	59,797	837	1.4004%	$0.30	-	$0.00
7/14/20 11:00 PM	55,627	745	1.3391%	$0.26	-	$0.00
Total						$2.84

Applying the same approach to every hour of 2018-2020 results in avoided costs of ancillary services for a single 1 kW unit of $3.25 on average per year.

TABLE 4-14 AVOIDED ANCILLARY SERVICES COSTS

Line No.	Item	3-Year Average	2018	2019	2020
1	Total Cost of Ancillary Services	$3.17	$2.49	$5.36	$1.66
2	Installed Capacity (kW_{DC})	1	1	1	1
3	Avoided Ancillary Services Costs ($/kW-year)	$3.17	$2.49	$5.36	$1.66

4.10 AVOIDED REGULATORY COSTS – $REG_{AVOID\ COST}$

As discussed earlier, there is no avoided cost value for the regulatory component since PEC currently does not incur costs related to regulation or environmental compliance. However, should a regulatory body enact a regulatory requirement that would be impacted by a member-owned DG system it would become appropriate at that time for PEC to update its Value Of Distributed Generation model and incorporate the avoided cost impacts. For that reason, GDS has chosen to include this element in the Value Of Distributed Generation formula but show it as having no value in PEC's current situation.

4.11 TOTAL VALUE OF DISTRIBUTED GENERATION

Given each of the avoided cost elements, the aggregate value of DG for PEC ranges from $77 to $112 per kW-year in the 2018-2020 period. The three-year average is $84 per kW-year. This is the value that PEC can use to determine the appropriate credit for excess generation for members with DG.

TABLE 4-15 VALUE OF DISTRIBUTED GENERATION

Line No.	Item	3-Year Average	2018	2019	2020
1	Avoided Energy Costs	$62.31	$56.85	$88.78	$41.31
2	Avoided Capacity or Demand Costs	$0.00	$0.00	$0.00	$0.00
3	Avoided Transmission Costs	$18.63	$18.14	$18.14	$19.61
4	Avoided Ancillary Services Costs	$3.17	$2.49	$5.36	$1.66
5	Avoided Distribution Costs	$0.00	$0.00	$0.00	$0.00
6	Avoided Regulatory Costs	$0.00	$0.00	$0.00	$0.00
7	Value of Distributed Generation ($/year)	$84.11	$77.48	$112.28	$62.58
8	Installed Capacity (kW_{DC})	1	1	1	1
9	Value of Distributed Generation ($/kW-year)	$84.11	$77.48	$112.28	$62.58

APPENDIX A . Comments on Avoided Distribution Cost Component of the Value of Solar

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August 23rd, 2019

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, MN 55101

RE: Reply Comments on Xcel Energy's May 1, 2019 Filing on the Calculation of the Avoided Distribution Cost Component of the Value of Solar (Docket No. M-13-867)

Dear Mr. Wolf,

Assistant Professor **Gabriel Chan** (Center for Science, Technology, and Environmental Policy and the Humphrey School of Public Affairs, University of Minnesota), hereby provides comments regarding PUC Docket No. M-13-867, which involve considerations for the avoided distribution cost component of the Value of Solar (VOS). These comments are in reference to the notice of extended reply comment period published on August 9, 2019. **Matthew Grimley** and **Bixuan Sun** (Research Fellows at the Center for Science, Technology, and Environmental Policy, University of Minnesota) join as co-signers of these comments.

These comments are submitted with the intention of broadening the set of considerations and eventual decision options that can be considered by the Commission. In preparing this submission, we have reviewed relevant academic peer-reviewed literature, proceedings in other Minnesota dockets, and reviewed public documents and consulted with expert stakeholders in other U.S. states. Through this review, we have come to deeply appreciate the complexity of the estimation of avoided distribution costs. Such calculations require many specific and untestable assumptions. Therefore, the context in which an avoided distribution cost calculation is applied matters significantly for the choice of methodological approach that best serves the public interest.

For example, while an approach to calculating avoided distribution costs may be the most accurate in theory (i.e. it would come closest to the true avoided costs on average if applied year after year), the same methodology could occasionally yield unreasonable results due to large estimation errors. This situation is a plausible explanation for the outcomes of the status quo methodology. The general dissatisfaction among all parties with the current methodology suggests that a way forward for calculating avoided distribution costs that serves the public interest need do more than simply yield outcomes that are on-average **accurate**. The methodology must also guarantee that outcomes are **fair** and **reasonable**, as reflected in the Commission's May 20, 2019 request for comments asking if Xcel Energy's proposed methodology "yield[s] accurate results that are fair and reasonable for all VOS stakeholders?"

To meet the multiple objectives of **accuracy**, **fairness**, and **reasonableness**, we propose a set of criteria for evaluating possible methodologies for avoided distribution costs that is derived from a parallel discussion in other dockets (see Section 2.3). Based on applying these criteria to the current and proposed methods and surveying alternative approaches, we reached the following three conclusions about the calculation of avoided distribution costs in Section 3:

1) *Section 3.1*: The avoided distribution cost component is more likely to yield **reasonable** and **accurate** results if based on historic and planned distribution system costs (as in Xcel Energy's proposed method) instead of aggregate proxy measures derived from peak load growth (as is done in the current method);

2) *Section 3.2*: The utilization of historic and planned distribution system costs in calculating the distribution cost component could be made more **fair** and **accurate** (than Xcel Energy's proposed method) by drawing lessons from other Minnesota proceedings and the methodologies used in other states; and

3) *Section 3.3*: Introducing locational differentiation in the avoided distribution cost component could be done in a **fair** and **reasonable** manner by adopting methods for "de-averaging" system-wide estimates instead of independently calculating estimates at different locations (as in Xcel Energy's proposed method).

1. Context and Complexity of the VOS: An Overview

The current issue before the Minnesota PUC goes to the heart of one of the most pressing challenges for the transition of the electricity system: how to fairly integrate distributed energy resources (DERs) in the context of an electricity system whose rules, processes, and organizations developed to support centralized generation and infrastructure.

The analytic task of establishing the VOS is fundamentally at tension with itself and requires compromises that balance the competing goals of accuracy and benefit/practicality. In reviewing possible VOS approaches, the National Renewable Energy Laboratory illustrated potential tradeoffs with a schematic (replicated in Figure 1)[1]. This report illustrated this tension in a similar context to the one currently under consideration by the Minnesota PUC:

> Location-specific VOS rates could be designed to represent a greater or lesser VOS across an individual utility's service territory, which would manifest in utility cost savings at the distribution or transmission level. While it is more accurate to reflect each individual solar system's value to the utility system, the question remains whether this level of accuracy yields sufficient benefit or practicality. When put into practice, the VOS rate could vary across hundreds of individual distribution circuits or in several larger geographic areas. But this accuracy needs to be balanced against the simplicity of a single VOS rate across an entire utility's territory. Limiting the number of different VOS rates will likely facilitate calculations, rate updates, customer marketing and communications with customers, the industry and other stakeholders. Just as utilities set electricity rates based on an average customer consumption profile per customer class, a single VOS rate,

[1] See https://www.nrel.gov/docs/fy15osti/62361.pdf

representing the average value that solar provides across the system may be easier to set and implement than multiple rates.

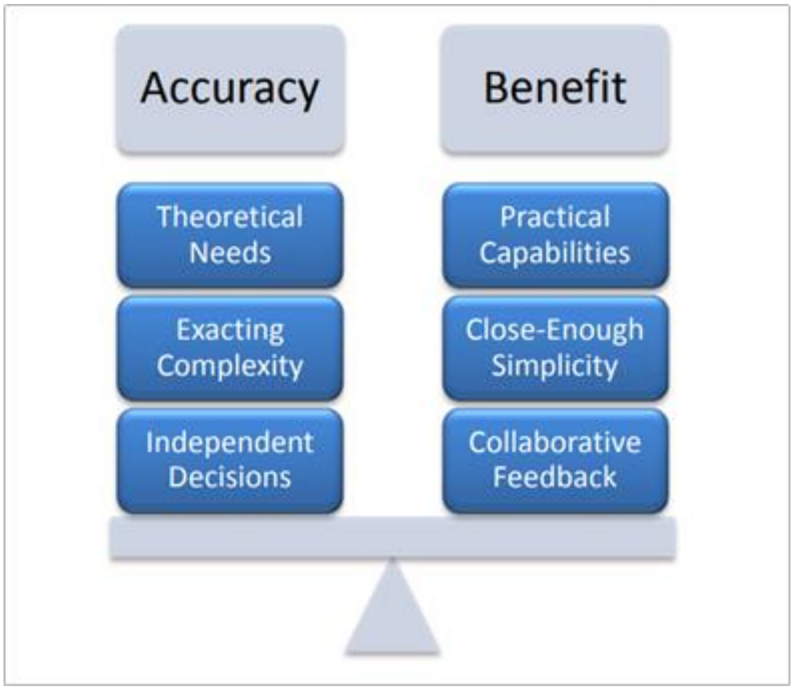

Figure 1. Schematic Representation of the Value of Solar Balancing Act (NREL, 2015)

While the VOS aspires to fairly compensate solar generators only for the social value they create, that the VOS was considered too low before for some developers, and that it is now (in the 2020 vintage) considered too high to the utility, is evidence of the VOS's role as a negotiated financial instrument that acts as an incentive for third parties to provide the best approximation of socially optimal outcomes. Note that *an incentive is not a subsidy*, and in this context, the incentive that the VOS tariff provides is designed explicitly to not subsidize any party by rewarding third-party solar developers only for the social value they create[2]. The balancing act that the VOS methodology must play between accuracy and benefit/practicality is compounded by the irreducible uncertainty in many of the fundamental drivers of the system-value that solar provides (e.g. long-run avoided costs of volatile natural gas purchases).

Further, the VOS must also take definitive positions on complex philosophical questions of fair attribution of costs. Avoided costs are estimated ex-ante: they avoid future costs (in the short- and long-run). But in reality, costs that were ex-ante anticipated to be avoidable may not be avoided at all, as the electric grid's composition changes from what had been a planned counterfactual. The possibility of a

[2] Here we use the term "incentive" as is commonly used in public policy and economics. For example, the U.S. Environmental Protection Agency states, "incentive-based policies influence rather than dictate the actions of the targeted parties. Incentive-based policies leave the ultimate choice of action to the affected parties, based on their own evaluation of the costs and benefits of the action. By correcting the incentives faced by private parties to reflect important social costs as well as private costs, incentives policies encourage private decisions that more closely approximate socially optimal outcomes." Retrieved from: https://www.epa.gov/environmental-economics/economic-incentives-options-environmental-protection-1991

substantial difference between the ex-ante anticipated avoided costs and the ex-post realized avoided costs could be particularly challenging for avoided distribution system costs. As the electricity system continues to deploy an increasing amount of distributed energy resources (DERs), the demand and the capacity to integrate DERs is rapidly changing.

2. Avoided Distribution Costs: An Overview of Methods and Specific State Proceedings

Against this theoretical and philosophical background, existing methods to calculate avoided distribution costs have been developed in the academic literature, other Minnesota proceedings, and in other states. These methods rely on either sophisticated system-wide simulation tools or complicated forecasts.

Across all extant studies for calculating avoided distribution costs, we observed an implicit or explicit reckoning with the difficulty of this analytic task. Coordinating growing distribution capacity with growing generation capacity (of either centralized or distributed facilities) is an unsolved problem of markets and utility modeling in general[3,4].

Perhaps for these tensions between accuracy, fairness, and reasonableness, there is a wide range of methods to estimate avoided distribution costs. They include system planning approaches, using combinations of historical and forecast information, marginal cost of service studies, and simple distribution cost sampling (see Section 2.3 for a list of proposed methods for avoided transmission and distribution costs in the context of energy efficiency programs).[5] A 2014 survey of these methods (in the context of energy efficiency) found that 24 utilities had avoided distribution costs between $0 and $171 per kW-year, with an average avoided distribution cost of $48.37 kW-year. While indicative of the variety of methods and the variety of estimated avoided costs, this survey says nothing of the validity of those methods.

2.1. Distribution System Simulation Models

In an academic example, Cohen et al (2016) use a simulation tool developed by the Pacific Northwest National Laboratories called GridLAB-D[6] to study distribution feeder replacement[7]. They used the simulation tool to identify which distribution capacity projects would occur in the next 10 years in the baseline scenario and then compute the number of years the same project would be deferred in different PV penetration scenarios. The avoided distribution cost is then taken as the capital depreciation value during the deferred period. The use of a sophisticated simulation tool allows this study to provide a realistic "counterfactual" for the calculation of those distribution-system costs that could be avoided with non-wires alternatives. This approach also takes into account the broad system impacts of solar

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[3] Cramton, P. (2017). Electricity market design. *Oxford Review of Economic Policy*, *33*(4), 589-612

[4] Trabish, H. (Nov. 13, 2018.) Location value of DER is essential to grid planning. So why hasn't anyone found it? *Utility Dive*. Retrieved from https://www.utilitydive.com/news/locational-value-of-der-is-essential-to-grid-planning-so-why-hasnt-anyone/541946/

[5] The Mendota Group, LLC. (Oct. 23, 2014). Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments for the Public Service Company of Colorado. Retrieved from https://mendotagroup.com/wp-content/uploads/2018/01/PSCo-Benchmarking-Avoided-TD-Costs.pdf.

[6] See https://www.gridlabd.org/

[7] Cohen, M. A., Kauzmann, P. A., & Callaway, D. S. (2016). Effects of distributed PV generation on California's distribution system, part 2: Economic analysis. *Solar Energy*, *128*, 139-152.

deployment on the distribution system and can be updated easily with different inputs and assumptions. However, applying this approach as part of the VOS tariff would reduce transparency, as the model includes many complex assumptions.

2.2. Lessons from New York

New York is a leading state in developing valuation approaches for DERs for the purposes of tariff design[8]. Though their overall methods appear to fall short of assured accuracy, they incorporate reasonable and fair standards of avoided distribution costs. The following is our attempt at a summary of recent developments in New York, but we note that their approach may still evolve.

In New York, where Reforming the Energy Vision (REV) is attempting to reconstruct locational values for DERs, most utilities use a deterministic forecast based on historical trends to help inform avoided distribution costs. Central Hudson Gas & Electric, however, uses probabilistic methods to forecast future load growth trajectories given different load reduction measures, including DERs. The timing on infrastructure upgrades is simulated to occur after the forecasted load exceeds the designed ratings for two consecutive years. The avoided costs are the difference between the costs with and without the load reduction necessary to avoid or defer the upgrade. This method does not use complicated simulation tools, hence increasing transparency of the calculations, at the cost of reduced accuracy in obtaining proper "counterfactual" load growth profiles in baseline and load-reduction scenarios. In addition, the load forecast model is applied separately and independently for each substation. The results can be sensitive to outliers and compounding errors.

New York proposed the Value Stack Compensation approach in 2016 to "de-average" Marginal Cost of Service (MCOS), which is submitted by utilities and takes into account overall system avoided distribution costs, such as savings from deferred feeder upgrades. The Value Stack approach de-averages utility level MCOS into two components based on peak demand reduction from distributed generators: "Demand Reduction Value (DRV)" that applies across the service territory and an additional "Locational System Relief Value (LSRV)" that applies to high-value areas for a limited number of MWs. Specifically, DRV assigns avoided distribution costs based on the amount of electricity generated by a DER project during the top 10 peak demand hours in a year. LSRV is applied on top of DRV to DERs in "high-value areas" where the impending system needs are high according to utilities. It is based on a DER project's capacity to inject energy during the top 10 peak demand hours in a year. DER projects receive lump sum monthly credit in the following year and these rates are updated annually.

The Value Stack compensation scheme was implemented in November 2017, and received critical feedback from stakeholders. The main criticism was that the DRV and LSRV mechanisms are too complicated and highly unpredictable and volatile because they depend only on the top 10 peak demand hours in a year, which are difficult to predict in advance and are sensitive to weather shocks. In addition, the method for determining "high-value areas" for LSRV calculation is not sufficiently transparent.

[8] Hall, J., Kallay, J., Napoleon, A., Takahasi, K., Whited, M. (2018). Locational and Temporal Values of Energy Efficiency and other DERs to Transmission and Distribution Systems. ACEEE Summary Study on Energy Efficiency in Buildings. Retrieved from https://www.synapse-energy.com/sites/default/files/ACEEE-Paper-Values-EE-DER.pdf. See also NY PSC docket 15-E-0751

Overall, although the DRV and LSRV mechanisms achieved a high level of granularity in reflecting avoided distribution costs, they make it difficult for developers to make investment decisions and for utilities to make long-term planning decisions and hence do not provide proper price signals and incentives for the expansion of DERs.

Taking into account these criticisms, the New York Department of Public Service revised the method in April 2019. The updated approach replaced the base value MCOS with existing system-wide marginal cost estimates for energy efficiency (EE) resources, citing similar contributions to the distribution system between DERs and EE resources. Specifically, they take the $/kW-year marginal cost for EE resources and assign it as $/kWh to the power generated during the 240 peak summer hours in the afternoons (1 pm to 6 pm) of non-holiday weekdays from June 24 through August 31 each year. The resulting amount is then divided by 12 and provided as a monthly lump-sum credit to monthly bills of DER system owners. This revision reduces the complexity and increases the transparency of the compensation scheme. Spreading the base value across many more peak summer hours instead of just 10 hours seems to address the uncertainty and volatility issues. In addition, DRV values will be updated every two years instead of annually, and the changes are bounded within 5% in either direction. Finally, LSRV will be phased out due to the lack of transparency in its calculation.

The complicated proceedings of New York demonstrate the push-and-pull between accuracy, fairness, and reasonableness that occur within a marginal costing debate. The issues are obscure but important as they represent a fundamental tension of leveraging finance, planning, and interest to create value for users of the electric grid. In New York, in particular, it appears that more accurate planning tools were eschewed in favor of more reasonable methods to third-party developers and their financiers.

We note that in addition to New York, California is also engaging in a multi-year stakeholder process to study approaches for calculating avoided distribution system costs (among other issues) through the California Integrated Distributed Energy Resources (IDER) and Distribution Resource Planning (DRP) Working Groups[9].

2.3. Lessons from Energy Efficiency Programs

In the Minnesota CIP docket 16-541, on July 1, 2016, DOC cited a 2014 report by the Mendota Group prepared for Xcel Energy's Colorado subsidiary[10] that outlined a number of alternative approaches to calculating avoided transmission and distribution (T&D) costs[11]. Appendix A of the Mendota Group report and Table 1 below outlines eight alternative methods for calculating avoided T&D costs with associated examples in practice and strengths and weaknesses. We have replicated this table below:

[9] See https://drpwg.org/sample-page/drp/

[10] https://mendotagroup.com/wp-content/uploads/2018/01/PSCo-Benchmarking-Avoided-TD-Costs.pdf

[11] https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B1B9FAB57-3FD6-483C-92FA-C4C2686710D5%7D&documentTitle=20167-122923-01

Table 1. Approaches to Calculating Avoided T&D Costs, adopted from Mendota Group

Table 1: Approaches to Calculating Avoided T&D Costs[7]

Method	Brief Description	Examples	Strengths	Weaknesses
System Planning Approach	• Uses costs and load growth for specific T&D projects based on a system planning study	• Vermont Electric Company (2003) - focused on specific transmission upgrade	• Potentially more accurate • Uses specific project data to develop estimates • Forces consideration of DER effects on project-by-project basis	• Costly and time consuming • May not be appreciably more accurate than other approaches • Dependent upon individual projects included in analysis
Mix of Historical and Forecast Information	• Uses data on historical and forecast T&D investments, determines what's related to load growth, and weighs the historical and forecast contributions	• ICF Tool used in the Northeast, Vermont DPS variation	• Uses publicly available FERC Form 1 data • Easily calculated and updated • Uses a form of marginal costs • Addresses "lumpiness" of T&D investments • Used by multiple other states • Relies upon historical as well as forecast information	• Assumes it's possible to differentiate amount of T&D investment that corresponds to load growth rather than maintenance, reliability and customer growth • Does not incorporate variability associated with time/location differences • Can't readily handle low forecast growth
Current Values	• Develops average cost to serve existing load by dividing each system's net cost	• MidAmerican Energy (IA, IL, SD), Commonwealth Edison (IL)	• Uses publicly available FERC Form 1 data • Easily calculated and updated	• May tend to undervalue • Does not incorporate variability associated with time/location differences
Rate case marginal cost data with allocators	• Uses T&D marginal cost of service data from utility rate cases and apply time and locational factors related to weather or specific substation loadings	• California IOUs	• Uses publicly available data (rate case portion) • Uses approach consistent with ratemaking • Uses time and location differentiated data • Uses marginal cost information	• Potentially costly and time consuming • May not be appreciably more accurate than other approaches • Somewhat assumes use of hourly avoided costs for Generation • Requires estimation of investments deferred by EE
Rate case marginal cost data	• Use T&D marginal cost of service data from most recent rate case	• Ameren (MO), PacifiCorp (OR, UT, WA), Nevada Energy, Consolidated Edison (NY)	• Uses publicly available data • Is approach consistent with ratemaking • Uses marginal cost information	• May not be appreciably more accurate than other approaches • Requires estimation of investments deferred by EE
IRP Method	• Uses with and without EE runs to determine avoided transmission costs	• Tucson Electric Power	• Is consistent with integrated resource plan	• Is highly dependent on IRP's model ability to calculate transmission costs • Requires integrated resource plan • Only updated as frequently as resource plan • Typically can only provide transmission

Averaging method	• Take simple average of a selection of similar jurisdictions	• Wisconsin Focus on Energy Market Potential Study (used Iowa) • Northwest Conservation and Electric Power Plan (used 8 utilities)	• Uses publicly available data • Very easily calculated	• Must pick appropriate proxy utilities for Averaging • Not specific to one utility
Simple Method	• Take representative sample of recent T&D upgrade projects, divide by increased capacity and annualize	• Unknown	• Very simple • Provides real information from specific example • Can be done for transmission, distribution and sub-transmission	• Project may not be system representative • Must still determine what portion of increased capacity relates to load growth

This table provides a helpful framework for developing criteria for evaluating proposed avoided distribution cost estimates. We suggest the following criteria for a proposed methodology building on the evaluations from the "strengths" and "weaknesses" columns of the table:

- Take an approach appreciably more accurate than other approaches
- Incorporate specific project data to develop estimates without being detrimentally dependent on individual projects; incorporates forecast information together with historic data
- Utilize publicly available data (e.g. from FERC Form 1)
- Allow for easy calculation and updating; maintain consistency with ratemaking and integrated resource planning
- Incorporate notions of marginality (rather than average) avoided costs
- Address the lumpiness of investments
- Incorporate variability associated with time/location differences

3.1. The Current Method: Unreasonable Because of Discrete Inputs of Peak Load

The current method uses historical cost information of the distribution system over the past 10 years in conjunction with the difference in peak load over a 10 year period. The performance of the current method is volatile due to the reliance on just two data points of peak load. We also note that the 2017 and 2018 VOS calculations relied on different datasets of historic peak load than the 2019 and 2020 calculations, as demonstrated in Figure 2. Figure 2 displays how the current method incorporates peak load as the difference between only two data points 10 years apart. The method ignores the changes in peak load in the interim period between the two end points, and we note that for each of the calculations from 2017-2020, the maximum peak load over the full 10-year period was greater between the endpoints than at the endpoints used in the calculations. This suggests that the current methodology fails to capture the system-wide need for distribution infrastructure to meet peak load over the 10-year period.

The most recent calculation of the avoided distribution cost under the current method demonstrates how relying on just two data points of peak load can yield volatile results. The fundamental statistical rationale is that the maximum of a distribution (in this case, the maximum of total annual load) has a high variance. Peaks are highly variable from year to year, as demonstrated in Figure 2, and therefore the difference between two peaks is not a statistically reasonable approximation for peak growth rates.

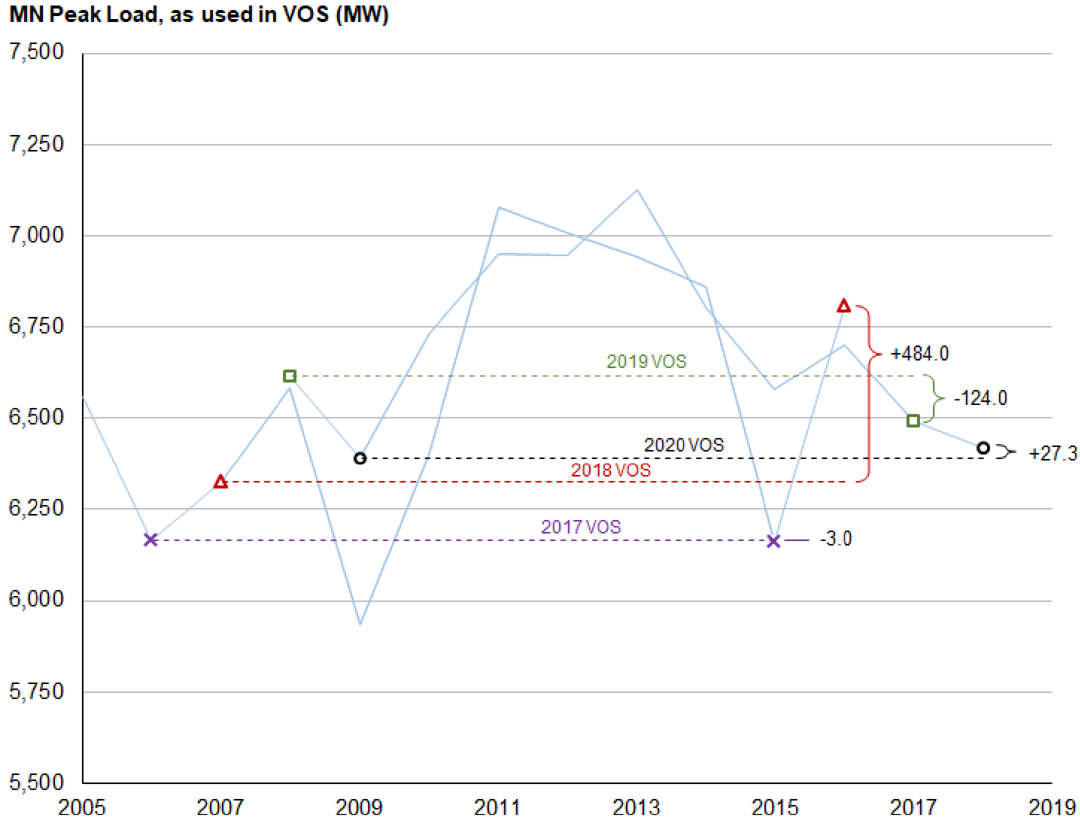

Figure 2. Weather-adjusted peak load, as represented in the Value of Solar calculations for 2017-2020 under the current methodology in Docket 13-867. Peak load varies substantially from year to year, but the current methodology only takes the difference in peak load over a 10-year span as the input to the methodology. Because of the large variability in peak load, this simple difference does not actually represent changes in distribution system needs. The difference in peaks is also highly volatile, and because this difference enters the formula in the denominator, the VOS component is highly volatile. (Note: It is unclear why historic peak load data included in the VOS calculations differs for 2008 - 2016 for the 2019/2020 VOS calculation and the 2017/2018 VOS calculation.)

A more reasonable approach to incorporating notions of peak load growth would be to utilize assumed fixed growth rates, as is done in the Integrated Resource Plan (IRP). Figure 3 below replicates a figure from the 2019 Xcel Energy IRP that shows an average ~0.2% annual peak load growth rate. This growth rate is net of energy efficiency, but it is conceptually unclear if energy efficiency should be included or excluded in the determination of peak load for the purposes of the VOS[12].

[12] It is unclear because future energy efficiency investment is incentivized under the CIP based on its role in reducing marginal system costs but the VOS makes the same assumption about marginality. Only one resource can technically be the marginal resource, but it is unclear whether that should be an energy efficiency resource or a solar resource.

Figure 3-2: Forecasted Peak Load, After Energy Efficiency Adjustments (MW)[1]

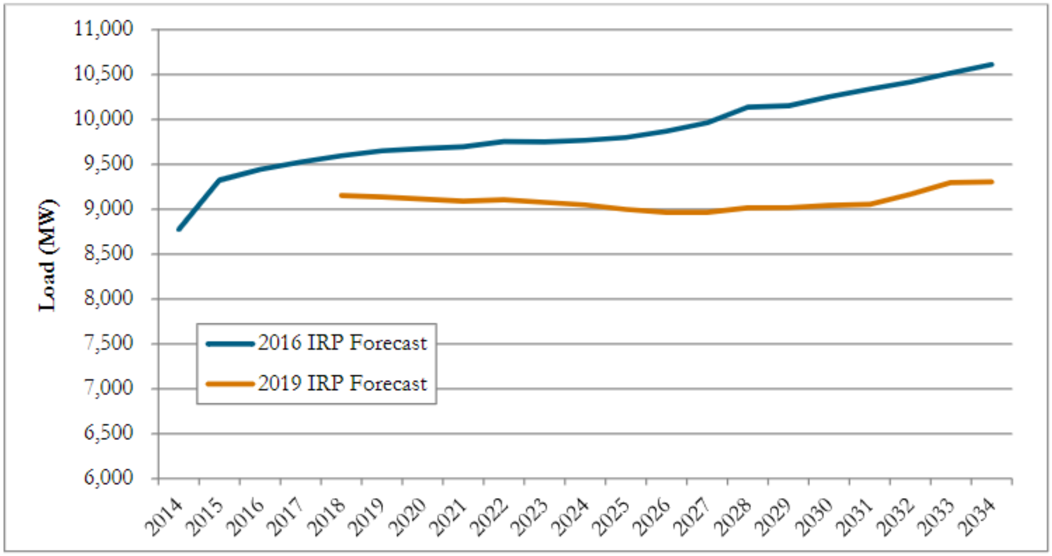

Figure 2. Forecasted peak load, replicated from Xcel Energy's 2020-2034 Upper Midwest Integrated Resource Plan (IRP). The figure shows that in the most recent IRP (shown in orange), Xcel forecasts average annual growth of peak load of less than 0.2% (after accounting for energy efficiency). This is a significant reduction in peak load compared to the previous IRP forecast (shown in blue).

In addition to the concerns about peak load, there are other concerns about the current methodology that we raise in Table 2. Table 2 applies the evaluation criteria introduced in Section 2.3 to assess the current methodology.

Table 2. Evaluation of the Current Method for Avoided Distribution Costs

Does the method…	2014 Approved Method
… take an approach appreciably more accurate than other approaches?	As the first-of-its-kind methodology applied in Minnesota, the accuracy of the method relative to other methods available at the time is difficult to discern.
… incorporate specific project data to develop estimates without being detrimentally dependent on individual projects; incorporate forecast information together with historic data?	Specific project data is not explicitly incorporated and the methodology is entirely backward looking without any notion of forecasting.

… utilize publicly available data (e.g. from FERC Form 1)	The methodology does rely mostly on publicly available data, although the designation of some investments as capacity-related is opaque.
… allow for easy calculation and updating; maintain consistency with ratemaking and integrated resource planning	The methodology has been relatively easy to calculate and update but relies on assumptions that are wholly inconsistent with ratemaking and integrated resource planning. In particular, the assumption in the methodology that the 10-year difference in peak load is a fair approximation for the driver of distribution-system investments is inconsistent with how the IRP justifies new investments (based on load forecasts).
… incorporate notions of marginality (rather than average) avoided costs	Theoretically, by focusing just on peak load growth, there is an attempt to only account for distribution investments to serve additional load; however, changes in peak load are not a fair approximation.
… address the lumpiness of investments	The 10-year window attempts to smooth over the lumpiness of distribution-system investments.
… incorporate variability associated with time/location differences	No, the current methodology provides no such differentiation.

3.2. Xcel Energy's Proposed Method: An Improvement that Could be Made More Fair and Accurate

Xcel's proposed method for calculating avoided distribution costs represents a conceptual break from the current method. Rather than relying on peak load growth and total capacity-related investments made historically, the method looks at actual and planned distribution system investments and the associated capacity that those investments support. In this way, Xcel's proposed methodology represents a conceptual approach similar to that used in the Conservation Improvement Program for avoided distribution costs.

While we believe Xcel's proposal to be a significant conceptual improvement to the current method (primarily because it does not rely on peak load growth and instead relies on actual and planned costs), there is still room for improvement. This improvement can be identified by re-examining some of the untestable assumptions and opaque data sources relied on in the proposed method. As other commenters have identified, the use of a 50% reduction factor is an untestable assumption that warrants additional justification. Further, the identification of some distribution system investments as capacity-related could be made more transparent. Finally, the choice of a limited number of historic and forecast years seems arbitrary and additional sensitivity could be conducted to limit the volatility of the resultant values from year to year. We provide an evaluation of Xcel Energy's alternative methodology in Table 3.

Table 3. Evaluation of Xcel's Alternative Method for Avoided Distribution Costs

Does the method…	Xcel's Alternative Method
… take an approach appreciably more accurate than other approaches?	The volatility of the method appears to be reduced compared to the current method, reflecting the long lifetime of distribution-system equipment, but accuracy with respect to true avoided costs is uncertain. Solar's value in reducing the volatility of net system peak demand is not incorporated.
… incorporate specific project data to develop estimates without being detrimentally dependent on individual projects; incorporate forecast information together with historic data?	Specific project data is not explicitly incorporated, but the method incorporates two historic and three forecasted years of data on capacity spending and capacity additions in aggregate and in planning areas. However, Attachment B of Xcel's May 1, 2019 filing does not appear to use the two years of historic data in calculating individual planning area estimates, basing those instead only on three years of anticipated costs and capacity needs.
… utilize publicly available data (e.g. from FERC Form 1)	No, data inputs are largely proprietary. For example, several commenters have noted the opaqueness of the designation of which distribution-system investments are "capacity related."
… allow for easy calculation and updating; maintain consistency with ratemaking and integrated resource planning	Appears to be easy to update but not consistent with other proceedings.
… incorporate notions of marginality (rather than average) avoided costs	No notions of marginality incorporated except in the ad-hoc 50% reduction factor. Justification for the 50% reduction factor has been questioned by several other commenters.
… address the lumpiness of investments	The five-year data-input to capacity spending and additions partially smooths out the volatility of lumpy investments, although longer time horizons may more accurately reflect the lifetime of solar projects and distribution-system infrastructure.

… incorporate variability associated with time/location differences	Differences in location are established at the planning-area level. Time differences are only incorporated through the peak load reduction factor in the VOS method.

Potential improvements to Xcel Energy's methodology could also be made by seeking greater consistency with other Minnesota dockets. We highlight three dockets, Xcel Energy's Integrated Distribution Plan (IDP) (docket 18-251), Conservation Improvement Program (CIP) (dockets 16-541, 16-115, and 18-783), and Integrated Resource Plan (IRP) (docket 19-368) where consideration of avoiding distribution costs is deliberated. This comparison is done to highlight the ways in which avoided distribution costs are considered internally at the utility and how they are considered with external programs such as CIP.

In its IDP, Xcel Energy considers avoided distribution costs mostly in potential non-wires alternative procurements[13,14]. Its distribution budget is "an ongoing and iterative process" composed within 5-year cycles. Xcel Energy acknowledges that planning tools for its distribution system are in development across the industry and will eventually incorporate more granular and probabilistic approaches than the utility uses now. For now, the utility considers that NWAs are best suited for deferring specific capacity-related distribution investments as they occur. Each NWA must be rated against traditional capacity solutions through a "cost/benefit basis" to be judged as sufficiently cost-competitive. The PUC ordered Xcel to provide more granular information at the distribution for its next IDP update in 2019.[15]

Within its IDP, Xcel Energy also notes its efforts through CIP to allocate energy efficiency impacts to each distribution substation and feeder on a proportional basis of percentage of system load share. A summer peak analysis determines if specific projects can be deferred, and then using that deferral value, the cost/benefit of particular technologies are judged to be cost effective through CIP.[16] The utility's discrete method of calculating avoided T&D was selected by the Department of Commerce over its continuous method.

Xcel Energy's current CIP calculations estimate that energy efficiency defers $7/kW-year in distribution costs. With deferred transmission added in, the total avoided cost of T&D amounts to $9.88/kW-year. This number is lower than Xcel Energy's prior avoided transmission and distribution costs of $36.23/kW-

13 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={D0117164-0000-C716-B2CA-4BE90B5EF708}&documentTitle=20187-144590-01

14 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={E098D466-0000-C319-8EF6-08D47888D999}&documentTitle=201811-147534-01

15 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={5072FC6B-0000-C715-8B8F-F971D67B302B}&documentTitle=20197-154416-01

16 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BD0549A5D-0000-CE15-BEF1-9B48DB00A554%7D&documentTitle=20177-134393-01

year for 2017.[17] Each of the current and prior avoided costs were determined on a system-wide basis, as energy efficiency was judged to be broadly implemented enough to result in a single value even though specific avoided T&D costs were acknowledged but not calculated.[18]

In both the CIP dockets and its current IRP, Xcel Energy seems to determine that geo-targeted demand-side management is the best solution to avoiding distribution investments. In the IRP, in particular, the utility says that demand response can help defer both systemwide and specific distribution investments.[19] In the IRP's appendix G2, a utility-commissioned Brattle report uses CIP-adapted avoided T&D cost numbers to judge demand response's ability to avoid T&D costs. The utility also states it is also working with the Center for Energy and Environment to pilot a geotargeting study aimed at increasing residential demand response to defer distribution upgrades.

The differences between the dockets shows organizational change (and some barriers) within the electricity sector and opportunities for learning across these proceedings. There are also discrepancies in the values of avoided distribution costs between these dockets. For instance, within the IRP and IDP, values of geo-targeted avoided costs for distribution upgrades appear to be determined internally at the utility and/or forthcoming in upcoming filings. With CIP, those numbers and calculations are more transparent. Despite the increased transparency of CIP, in all cases between these dockets, complete visibility into the state of the distribution system is limited.

Some commenters in the dockets have suggested linking these proceedings in a more formal way. Other commenters, including those from the state, have suggested more opportunities for learning across these initiatives. At the least, with an understanding that grid modernization is a slow-moving and developing process, we suggest increased transparency and collaboration between these different planning processes can create a more uniform vision of the differentiated value of DERs to the public.

3.3. A New Proposed Method: De-Averaging to Add Locational Differentiation that is Fair and Reasonable

The estimation of avoided distribution costs is inherently uncertain. Any methodology may yield estimates that are unreasonable. Xcel's proposed methodology has the potential to yield unreasonable results if there are idiosyncratic periods with higher (or lower) distribution system investments. As described above, one approach to reducing the probability of unreasonable results is to average over longer periods of historical and forecasted costs. However, the probability of yielding at least one unreasonable cost is multiplied when the same methodology is repeated independently in multiple jurisdictions. This is exactly what could happen in the proposed methodology's approach to calculating

17 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={09A3CF6C-CC72-42A1-A867-E449BAC71BAF}&documentTitle=20162-118355-02

18 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B4E448E54-2E17-4890-9067-10534F918A48%7D&documentTitle=20169-124805-01

19 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B10FBAE6B-0000-C040-8C1D-CC55491FE76D%7D&documentTitle=20197-154051-03

spatially disaggregated estimates. The potential for the current methodology to yield at least one unreasonable spatially disaggregated result is explained with statistical reasoning in Box 1.

Box 1. How the "Multiple Comparisons Problem" can create unreasonable results

The proposed methodology independently estimates the avoided distribution costs in nine planning areas. Each estimate is based on data unique to each planning area and a similar set of assumptions about the relationship between past investments and future avoided costs. This approach amounts to multiple independent avoided distribution cost estimates in each planning area. Theoretically, this increases the precision of each individual estimate (because deferred distribution costs should not have a material impact on distribution costs in other planning areas, it follows that the avoided distribution costs in one planning area should only be based on information from that one planning area—although there may be marginal spillover effects around planning area boundaries). However, independent estimates of avoided distribution costs raise the specter of yielding occasional severe outliers in individual planning areas.

To illustrate, suppose that the current methodology imperfectly estimates true avoided distribution costs due to random statistical noise due to the difficulty in estimating avoided distribution costs. Incorrectly high estimates can yield an unreasonably high public cost (e.g. by directing solar investment to areas where more generation isn't needed—or not directing solar investment to the areas where it is most needed—and therefore requiring new distribution system upgrades at a cost borne by all ratepayers). Again, for illustration, suppose that unreasonable high public costs are produced by a methodology in 5% of cases. In other words, when the methodology is applied in a single planning area, an unreasonably erroneous estimate would only occur in 5% of cases. Yet if this methodology is applied independently in 10 planning areas, the probability that at least one estimate would be unreasonably high would be 40% ($1 - (1 - 0.05)^{10}$). This general phenomenon is known in statistics as the "Multiple Comparisons Problem."

Stated simply, as the number of independent forecasts increases, the more likely it is that there will be forecasts that exhibit an undesired level of statistical noise. This statistical problem is relevant in this context because just a single unreasonable statistical mis-forecast can yield an avoided distribution cost estimate that would drive too much development in a single planning area at the determinant of other valuable development opportunities. This exact outcome is manifest in the estimates of the current method which show avoided distribution costs in the Minnetonka planning area of 27.72 cents per kWh. The Minnetonka value is 39-times greater than the median of the nine planning areas. This phenomenon is apparent to a lesser--but potentially still important--degree in the proposed alternative methodology. The alternative method gives an estimate for the Newport planning area that is 4.5-times greater than the median of the nine planning areas. Is a factor of 450% above the median for an entire planning area's avoided distribution cost reasonable? Perhaps, but more information on whether this is a realistic degree of variability across Xcel's planning areas is difficult to discern without further justification. Protecting the public interest should imply directly interrogating whether or not this degree of variability is in fact "reasonable."

With this in mind, we propose a new method to create locationally specific differentiation in the avoided distribution cost estimate. Our proposal is based on the methodology developed in New York to first calculate a system-wide average avoided distribution cost and then to apply a set of multipliers that "de-average" the system-wide avoided cost estimate to locationally specific values. Our proposed method has three steps:

Step 1: Estimate total system avoided distribution cost

The first step of this approach calculates the system-wide avoided distribution cost. This step can be accomplished through the cost-based approach that Xcel Energy has proposed, although the modifications raised in other comments and the questions we raise in Section 3.2 should also be considered.

Step 2: Establish location-specific multipliers (de-averaging weights)

The second step of this approach is to establish geographic units (such as planning areas) and create weights that correspond to the relative potential for solar installed in the geographic unit to avoid distribution system costs. These weights could take as inputs location-specific variables, such as:

- Peak load growth
- Anticipated load growth (e.g. from anticipated beneficial electrification, large public/private energy-consuming projects--such as the Light Rail expansion or housing developments)
- Anticipated generation growth, particularly other distributed energy resources with similar generation profiles as projects under the VOS (e.g. rooftop solar)
- Demand profiles (incorporated in the weights in a sophisticated manner or through specific peak load reduction (PLR) factors)

We do not propose a specific methodology for calculating location-specific multipliers; however, once developed, it would be possible to set some constraints around the multipliers so that they remain reasonable (for example, multipliers could be constrained to be between 0.5 and 2). Multipliers could also be smoothed over time through moving averages.

Multipliers would then be multiplied by the system-wide average to de-average the avoided distribution cost component to yield location-specific tariffs.

Step 3 (optional): True-up avoided distribution cost bill credits to equal total cost

By creating locationally differentiated weights, the intention would be to appropriately reward solar development that takes place in areas with greater VOS tariffs. If the locational incentive is great enough, development may shift significantly to areas with higher tariffs. Therefore, the realized average avoided distribution cost component may not equal the ex-ante estimated average that formed the basis of the tariff. This could be addressed by trueing up the distribution cost components of the tariff to equal the ex-ante total. This complexity may not be necessary if the total bill credit uncertainty is not significant.

The key advantage of this proposed methodology is that it avoids the possibility of individual unreasonable avoided cost estimates. A single system-wide average forms the basis of all location-specific tariffs and regulators would be able to set limits on the degree of spread between the multipliers so that no one location is subject to an unreasonably high or low tariff. This approach would also allow for more dynamic management of the program by allowing continuous refinement of the size of the geographic units over which tariffs are differentiated (i.e. future iterations could introduce differentiation within planning areas). This approach also separates the analytic exercise of estimating total avoided distribution costs (and the associated issues described in Section 3.2) from the analytic task of incorporating locational differentiation. Table 4 provides an evaluation of our proposed methodology.

Table 4. Evaluation of Our Proposed Method for Avoided Distribution Costs

Does the method…	Our Proposed Method
… take an approach appreciably more accurate than other approaches?	Can be equivalently accurate to other methodologies for total system avoided distribution costs. Location-specific avoided costs may be more or less accurate due to the less direct approach to incorporating historic data but a possibility to incorporate a wider range of forward-looking information.
… incorporate specific project data to develop estimates without being detrimentally dependent on individual projects; incorporate forecast information together with historic data?	Can incorporate specific project data in the multipliers and can avoid dependence on individual projects by developing procedures to smooth over anomalies.
… utilize publicly available data (e.g. from FERC Form 1)	Flexible. Multipliers could be developed based on publicly available data while total system avoided distribution costs could rely on proprietary data.
… allow for easy calculation and updating; maintain consistency with ratemaking and integrated resource planning	Multipliers can be incrementally updated to increase (or decrease) sophistication to balance accuracy with close-enough simplicity. Not necessarily consistent with other proceedings but multipliers can be informed by other proceedings that develop location-differentiated distribution-system cost information.
… incorporate notions of marginality (rather than average) avoided costs	Possible to include notions of marginality in development of multipliers. Marginality can be reinforced through the application of the optional third step to true-up total avoided distribution costs to reward more distributed deployment.
… address the lumpiness of investments	Multipliers can address lumpiness by intentionally constraining variability
… incorporate variability associated with time/location differences	Locational variation can be established flexibly through the multipliers. Time variation can be incorporated through multipliers that take into account differentiation in peak load reduction (PLR).

4. Open Questions

The complexity of establishing a VOS begs the question, "Is this framework worth it?"

Our impression is that the PUC, Xcel Energy, and other stakeholders have spent a disproportionate amount of time and effort establishing the VOS relative to the scope of the electricity system and customers affected by solar investments under the VOS to date. We acknowledge other complementary frameworks to prudently bring new energy resources online, such as running competitive procurements and running programmatic solicitations for fixed quantities of resources.[20,21]

Looking to the long-run transition of the energy system, however, the complexity of the VOS (and other such avoided cost calculations) may be necessary to create an environment for distributed resources to be deployed in a manner that recognizes the full system-value these resources can provide.

The VOS acts as a boundary object--a point of negotiation and a neutral incentive--for third-party investment on the grid.[22] Negotiating the complexity of the VOS is a problem that is inherent to other boundary objects that are integral to other distributed energy resource proceedings, such as CIP, the IDP, and the IRP. Complexity is necessary, however, especially for distributed resources that are to be deployed in an electricity system where even the smallest resources, if deployed over and over, can have ripple effects throughout the system.

As noted before, we recognize that the VOS is not the only domain in which the complexity of valuing DERs arises. Several key dockets before the PUC grapple with the same fundamental issues. CIP has long-established procedures for recognizing the system impact of end-use energy efficiency measures (e.g. the cost tests for CIP include methodologies for estimating avoided distribution and transmission costs attributable to efficiency measures). The IDP and IRP processes both take a systems-level perspective on investment planning and seek to model how DERs affect the value of alternative investment strategies (e.g. the IRP establishes effective load carrying capacities for DERs so that their system-value can be compared to dispatchable centralized generation resources). These dockets also touch on issues related to concepts that are related to the value that solar provides but that are excluded in

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[20] While introducing a bidding process for developers could lower costs in the short run, the level of the cap set is an unprincipled approach for our state's energy system in the long run because the cap is not based on the value of the resource to the system. The cap risks leaving significant amounts of beneficial new solar development on the table at a time when the economics of solar resources is rapidly changing. In contrast, while the VOS is flawed, it represents a principled approach for establishing an incentive for third parties to invest in any available solar project that creates more social value than it costs.

[21] New York Public Service Commission staff. (Dec. 12, 2018.) Whitepaper Regarding Future Value Stack Compensation, Including for Avoided Distribution Costs. Case 15-E-0751. Retrieved from: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B5DE69B8A-D3FB-44BA-95C0-7B4EB4FFCAAF%7D

[22] Carlile, P. R. (2002). A pragmatic view of knowledge and boundaries: Boundary objects in new product development. Organization science, 13(4), 442-455.

the current VOS, such as reliability, resiliency, avoided distribution O&M, voltage support, and power quality support. Other studies have attempted to quantify these values.[23]

Given its potential impact in shaping a large amount of third-party investment in DERs, and its potential for linking together distinct proceedings, the VOS deserves specific attention. In our view, it is "worth it" to spend significant deliberative energy on continuously refining the VOS and other price signals so that investment in DERs can grow to meet system needs in a way that can be most beneficial to the public in the short- and long-run.

Thank you for this opportunity to comment. If you have any questions regarding the information or opinions provided in this filing, please contact me at 612-626-3292 or gabechan@umn.edu.

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[23] ICF. (May 2018). Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar. Prepared for: The U.S. Department of Energy. Retrieved from https://www.icf.com/-/media/files/icf/reports/2019/icf-nem-meta-analysis_formatted-final_revised-1-17-193.pdf

APPENDIX B . UNC Valuing DER Analysis

CENTER FOR CLIMATE, ENERGY, ENVIRONMENT AND ECONOMICS

Valuing Distributed Energy Resources: A Comparative Analysis

Heather Payne* and Jonas Monast**

June 4, 2018

The total capacity of installed solar in the United States continues to increase at a rapid pace.[1] To date, this growth has been primarily driven by policy choices at both the state and federal level, including: state renewable portfolio standards; state and federal tax incentives for renewable energy investments; net metering; and requirements that electric utilities purchase electricity from renewable energy facilities pursuant to the Public Utilities Regulatory Policy Act (PURPA).[2] While much of the growth in solar capacity – especially outside states with aggressive renewable energy goals (e.g., California) – has

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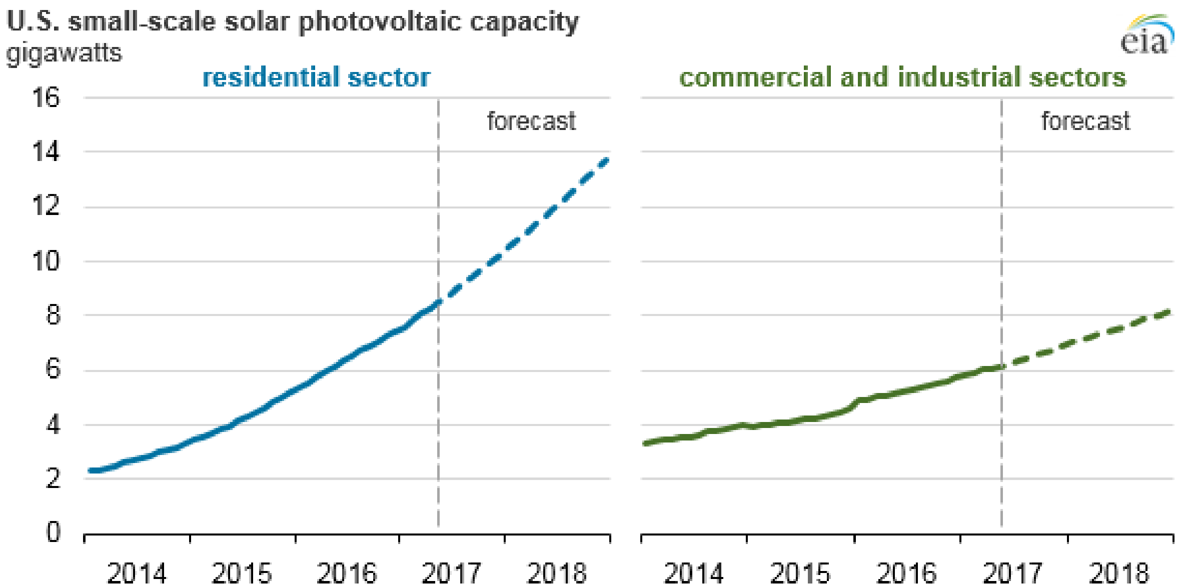
[1] For example, solar energy capacity in the Southeast increased from 200 MW in 2012 to 6 GW in 2017. Julia Pyper, *The Rise of Solar in the Southeast*, GREENTECH MEDIA (Mar. 9, 2018), https://www.greentechmedia.com/squared/read/the-rise-of-solar-in-the-southeast?utm_source=newsletter03.10&utm_medium=email&utm_campaign=gtm2#gs.wVovaEA. A cumulative 10.6 GW of solar PV was installed in the United States in 2017. Julia Pyper, *US Residential and Utility-Scale Solar Markets See Installations Fall for the First Time*, GREENTECH MEDIA (Mar. 15, 2018), https://www.greentechmedia.com/articles/read/us-residential-and-utility-scale-solar-see-installations-fall-first-time?utm_source=Daily&utm_medium=email&utm_campaign=GTMDaily#gs.4hx=F70.

[2] The Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§ 2601-2645 (2016), was meant to promote energy conservation and greater use of domestic and renewable energy. It established a new class of generating facilities, known as "qualifying facilities," which are either small power production facilities (generally under 20 MW in RTO territories and under 80 MW elsewhere) that has a renewable fuel as a primary source or cogeneration facilities. FED. ENERGY REG. COM'N, WHAT IS A QUALIFYING FACILITY (2017), https://www.ferc.gov/industries/electric/gen-info/qual-fac/what-is.asp These QFs have the right to sell energy and capacity to a utility at the utility's avoided cost; the utility must accept the generation. Avoided cost is "the incremental cost to an electric utility of electric energy or capacity which, but for the purchase from the QF, such utility would generate itself or purchase from another source." FED. ENERGY REG. COM'N, WHAT ARE THE BENEFITS OF QF STATUS? (2017), https://www.ferc.gov/industries/electric/gen-info/qual-fac/benefits.asp.

been large, utility-scale projects,[3] distributed solar capacity is also increasing due to falling prices, increased consumer interest, and favorable state policies.[4] The Energy Information Administration projects that renewable energy capacity, including small-scale solar, will continue to increase despite changes to federal and state policies.[5] This is true even with the imposition of the §201 tariffs in early 2018.[6]



Source: U.S. Energy Information Administration, *Short-Term Energy Outlook Supplement: Expanded Forecasts for Renewable Energy Capacity and Generation*, July 2017.

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[3] Larger projects allow for legal and other transactional costs to be spread over a larger base of energy output.
[4] About an eighth of installed solar in the Southeast is distributed. Herman K. Trabish, *In the New South, Customer Demand is Showing Utilities the Dollars and Sense in Solar*, UTILITY DIVE (Mar. 15, 2018), https://www.utilitydive.com/news/in-the-new-south-customer-demand-is-showing-utilities-the-dollars-and-sens/518857/?mc_cid=49b8c4dbed&mc_eid=7c8d730a3c; Julia Pyper, *The Rise of Solar in the Southeast*, GREENTECH MEDIA (Mar. 9, 2018), https://www.greentechmedia.com/squared/read/the-rise-of-solar-in-the-southeast?utm_source=newsletter03.10&utm_medium=email&utm_campaign=gtm2#gs.wVovaEA.
[5] U.S. Energy Information Admin., Annual Energy Outlook 2018, 13-14 (Feb. 6, 2018), https://www.eia.gov/outlooks/aeo/.
[6] Projected reductions are expected over the next five years of 7.6 GW from the tariffs, Lacey Johnson, *Forecast Shows How Trump Tariffs Will Hurt Solar Growth, State by State*, GREENTECH MEDIA (Feb. 1, 2018), https://www.greentechmedia.com/articles/read/forecast-shows-how-tariffs-will-hurt-solar-growth-state-by-state?utm_source=Daily&utm_medium=email&utm_campaign=GTMDaily#gs.JUW9ne8, or a reduction of around 11% from what was expected mostly coming from utility-scale installations, Julia Pyper, *New Tariffs to Curb US Solar Installations by 11% Through 2022*, GREENTECH MEDIA (Jan. 23, 2018), https://www.greentechmedia.com/articles/read/tariffs-to-curb-solar-installations-by-11-through-2022?utm_source=Daily&utm_medium=email&utm_campaign=section201#gs.JcS4rKg; "Total solar installations across the U.S. fell from 15 GW in 2016 to 10.6 GW in 2017, driven partly by uncertainty over tariffs on solar cells and modules that were eventually imposed in January by the Trump Administration." Trabish, *supra* note 4. The price increases could hurt solar expansion in the Southeast the hardest. Zack Coleman, *Traffic Could Fall Heaviest on Southeastern States*, CLIMATEWIRE (Jan. 18, 2018), https://www.eenews.net/climatewire/2018/01/18/stories/1060071271, although the Southeast is leading in new installations for 2018. E & E News, *South to Lead Solar Development in 2018*, ENERGYWIRE (Jan. 22, 2018), https://www.eenews.net/energywire/2018/01/22/stories/1060071481.

Growth in solar energy capacity is leading some states to reevaluate compensation for distributed energy resources. This is driven by a variety of factors, including increased distributed generation adoption, questions about how that may be impacting other electricity customers, and what benefits, such as decreased air pollution or resiliency, should be taken into account when looking at the value assigned to distributed energy resources. These valuation processes primarily focus on solar energy, but the choices may inform compensation for other distributed energy resources. In some states, this process is part of broader rate reform efforts.[7] In others, the focus on valuing solar energy arises specifically in the context of rooftop net metering and compensation provided to renewable energy facilities pursuant to PURPA. By one tally, more than 249 policy or rate design changes around solar policy occurred at the state level in 2017.[8] Despite the increasing focus on the role of renewable energy in the electricity system, there is no consensus regarding which factors states consider or the valuation methodologies states utilize.[9]

This paper compares recent solar valuation approaches in nine states that have explicitly engaged in actions to determine compensation for distributed energy resources, including distributed solar. The selected states represent a variety of political environments, regulatory structures, climate policies, sizes, and starting places for current compensation. The paper examines key factors that influence these states' solar valuation processes and, where possible based on the administrative record, factors that state policymakers explicitly declined to consider.

Starting with a general discussion of the current status of net metering, the paper then highlights seven key areas: how states started their DER valuation process, grandfathering, methods utilized to determine valuation of distributed resources, impacts on the distribution system, environmental consideration, resiliency, risk hedging, and each state's plan to revisit their valuation. The appendix summarizes key factors that each state considered as part of the valuation process.

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[7] Autumn Proudlove et al., N.C. CLEAN ENERGY TECH. CENTER, THE FIFTY STATES OF SOLAR: 2017 POLICY REVIEW AND Q4 2017 QUARTERLY REPORT (2018), https://nccleantech.ncsu.edu/wp-content/uploads/Q4-17_SolarExecSummary_Final.pdf ; Herman K. Trabish, *As Solar Matures, Rate Design and Incentive Debates Grow Ever More Complex*, UTILITY DIVE (May 23, 2017), https://www.utilitydive.com/news/as-solar-matures-rate-design-and-incentive-debates-grow-ever-more-complex/443185/?mc_cid=0b768eb51f&mc_eid=7c8d730a3c ; Herman K. Trabish, *In New Trend, Utilities Propose Separate Rate Classes for Solar Customers Without Rate Increase*, UTILITY DIVE (Nov. 2, 2017), https://www.utilitydive.com/news/in-new-trend-utilities-propose-separate-rate-classes-for-solar-customers-w/508393/.

[8] Proudlove, *supra* note 7.

[9] "While there is growing convergence toward the net billing framework, states are taking diverse approaches to credit rates for excess generation. The most common of these have been avoided cost and value-based crediting, although there are is a wide variety of methodologies in use or under consideration for calculating avoided cost and the value of distributed generation." Proudlove, *supra* note 7.

Status of Net Metering

Net metering currently exists in 38 states plus the District of Columbia.[10] The traditional concept of net metering is that a customer's electricity meter runs backwards – providing a direct offset between electricity used from the grid and electricity put back onto the grid.[11] While PURPA encourages states to adopt net metering, there are significant differences between how states have implemented net metering.

States have considered six main choices when implementing net metering and other valuation schemes which have led to differences in implementation.[12] The first is whether all electric utilities in the state must offer net metering, or if municipal utilities or electric cooperatives are exempt. In Arizona, for example, the Salt River Project and municipal utilities are exempt from the mandate to provide net metering. California specifically exempts Los Angeles Department of Water and Power (publicly-owned electric utilities with more than 750,000 customers who also provide water are exempt, and LADWP is the only entity which meets that criteria). Which sources can use net metering has also developed differently on a state-by-state basis. Solar PV and wind are the most commonly qualified sources, with biomass and hydroelectric also able to be net metered in a majority of states with net metering programs. Combined heat and power/co-generation systems can also be net metered in a variety of states, including Arizona, Minnesota, New York and South Carolina.

The size of systems allowed varies between 10kW and 80MW, depending on the technology and the state. While highly variable, a common size constraint is that the maximum size of the installation is tied to the monthly or annual average usage of the site with the generation. For example, in Arizona, the cap is 125% of a customer's total connected load. Other states set the limit at 100% of annual usage, including South Carolina.

The amount of net metering allowed in the state can also be capped based on utility average or peak load, with states setting caps between 0.2% and 20% of utility load. California, Hawaii, New York, and South Carolina all have caps based either on utility peak demand or annual average demand. The owner of the renewable energy credits (RECs) awarded for the net-metered power generation is also a point of difference. A number of states, including Minnesota, have decided that the customer owns the RECs. Other states, including California, fall into a hybrid system, where RECs are transferred under specific conditions but are kept with the customer under other scenarios.

One of the most contentious issues more recently is whether net metering customers are considered a separate rate class, which could lead to different fixed rates or the imposition

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[10] DSIRE, NET METERING (Nov. 2017), [http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2017/11/DSIRE_Net_Metering_November2017.pdf.](http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2017/11/DSIRE_Net_Metering_November2017.pdf) However, the number of states offering net metering has been declining over the last few years.

[11] *See* Richard L. Revesz and Burcin Unel, *Managing the Future of the Electricity Grid: Distributed Generation and Net Metering*, 41 Harv. Envtl. L. Rev. 43 (2017).

[12] Heather Payne, *A Tale of Two Solar Installations: How Electricity Regulations Impact Distributed Generation*, 38 U. Haw. L.R. 135 (2016).

of demand charges. Arizona and Hawaii have sorted customers with distributed energy generation into separate classes. In contrast, Nevada enacted a statute which specifically forbade classifying distributed energy generators as a separate rate class.

These considerations are independent of the primary question regarding direct compensation for electricity generated by the distributed energy resource but can have an impact on both valuation and adoption. Additionally, states continue to call some rate designs net metering when they actually provide valuations other than a one-for-one offset.

Origin and Oversight of the DER Valuation Processes

Some state legislatures have initiated inquiries into the value of distributed energy resources following the enactment of a statute requiring the action. In other states, the PUCs opened dockets on DER valuation on their own initiative. Of the states included in this study, legislatures in California, Massachusetts, Minnesota, New Hampshire, and South Carolina adopted statutes with varying degrees of specificity, while PUCs in Arizona, Hawaii, Mississippi, and New York initiated the valuation of distributed energy resources on their own. The legal circumstances underlying a state's decision to evaluate the value of distributed energy resources can influence the outcomes, as legislation may be more prescriptive regarding the factors to consider while PUC-initiated efforts may allow commissioners broader latitude regarding the factors to consider and the relative weight assigned to each. New legislation may also identify a broader range of societal interests to consider when assessing the value of distributed energy resources than may otherwise fall under the PUC.

For example, New Hampshire's legislature identified the following factors for the PUC to take into account when determining valuation: costs and benefits of customer generator facilities; avoidance of unjust and unreasonable cost shifting; rate effects on all customers; alternative rate structures, including time-based tariffs; whether there should be a limitation on the amount of generating capacity eligible for alternative net metering tariffs; the size of facilities eligible to receive net metering tariffs; timely recovery of lost revenue by the utility using an automatic rate adjustment mechanism; electric distribution utilities' administrative processes required to implement such tariffs and related regulatory mechanisms; continuance of reasonable opportunities for electric customers to invest in and interconnect customer generator facilities and receive fair compensation for such locally-produced power while ensuring costs and benefits are fairly and transparently allocated among all customers; and the promotion of a balanced energy policy that supports economic growth and energy diversity, independence, reliability, efficiency, regulatory predictability, environmental benefits and a modern and flexible grid.

Similarly, South Carolina's statute required the Public Service Commission to consider a number of factors when determining the value of distributed energy resources, including: avoided energy; energy losses/line losses (at generation, transmission and distribution); avoided capacity; ancillary services; transmission and distribution capacity; avoided criteria pollutants; avoided carbon dioxide emission cost; fuel hedge; utility integration and interconnection costs; utility administration costs; environmental costs; and other categories which cannot currently be quantified but which will be continuously updated. However, the statute also specified that the avoided carbon dioxide emission cost was to be set at zero monetary value until state or federal laws or regulations result in an avoidable cost on utility systems for these emissions, and environmental costs had to be quantifiable and not based on estimates.

Who conducts the valuation analysis also varies by jurisdiction. PUC staff conducted the analyses in Arizona, New Hampshire, and New York. South Carolina's valuation is currently pending, with the state's Office of Regulatory Staff conducting the analysis. Minnesota took a slightly different approach; rather than the analysis being performed by PUC staff, public staff of the Minnesota Department of Commerce undertook the analysis.

California based its decision on information presented by utilities and intervenors, rather than tasking regulatory staff with conducing an independent inquiry. While not of primary importance to final outcomes, both New Hampshire and New York also took into account valuation analyses presented by third parties in addition to having public staff provide an analysis to the PUC.

Massachusetts and Mississippi did not perform any specific valuation determinations in the dockets studied as part of this analysis. As states look to determine how to change distributed energy valuation, one of the first questions is how to handle existing net metering customers.

Treatment of Existing Net Metering Customers

Justifications for grandfathering in the net metering context are similar to other circumstances when policy changes impact the value of past infrastructure investments. Although the level of investment for a single rooftop solar installation pales in comparison to the costs of large-scale generation such as natural gas-fired power plants, the upfront costs of a rooftop solar installation may represent a significant investment for a homeowner or business owner. Changing compensation methodologies after the initial investments could impact the value of the rooftop system and thus the economic impacts for the owner, especially in light of payback periods of 10 years or more in certain jurisdictions. Some states have addressed this concern by exempting existing rooftop solar installations from any changes to net metering rates for a length of time deemed sufficient to recoup the initial capital investment.

Arizona and California both grandfathered existing customers for 20 years. New Hampshire grandfathered customers until 2040. New York adopted a slightly more complicated standard; the period is either 20 or 25 years, depending on the time of interconnection. However, developers can request a period longer than 20 years based on existing financial or contractual conditions.

While Nevada was not among the nine states included in this analysis, the state's experience in dramatically altering the value proposition for existing net metering customers may prove instructive. In December 2015, the Nevada PUC eliminated net metering for both new and existing customers, ramping down the valuation paid to existing net-metered customers over a short time span. With broad public support, the legislature passed new legislation in 2017 that reversed the net metering order and, additionally, prohibits customers with net metering from ever being considered in a separate rate class.[13] While not retaining full retail-rate net metering, the valuation currently will be 95% of the retail rate, slowly trending down as more solar is added to the grid. The minimum price will be 75% of the retail rate. The commissioners who made the original decision to reduce net metering were also replaced, and, for the first time in 30 years, an investor-owned utility in the state was forced to decrease rates as part of a general rate case (both fixed and volumetric rates went down).[14] While it was an uncertain situation for distributed energy valuation in Nevada for two years, the situation has now stabilized, with different commissioners, new legislation including a statutorily guaranteed right to self-generate electricity, and more consumer protections for those who adopt distributed generation.[15] The public outcry from the policy change being applied retrospectively is widely considered to have brought these changes about.[16]

Methods Utilized to Determine DER Compensation

The methods used to determine the value of distributed energy resources vary greatly. An initial decision for many states is whether to value distributed energy resources at retail electricity rates, or to determine another valuation, most often starting with the wholesale electricity rate. California, New York, and South Carolina currently have retail-rate net metering for at least residential distributed generation customers, although California requires the payment of non-bypassable charges. New York, additionally, has chosen a different path for non-residential customers, based on the "value stack" approach. The value stack attempts to value distributed resources based on the locational marginal value of the energy plus value to the distribution system and environmental benefits to maximize the system as a whole.[17] With this formula, New York takes into account energy value (day ahead hourly zonal locational-based marginal price, inclusive of transmission losses); capacity value (different methodologies for intermittent and dispatchable technologies); environmental value (based on latest Tier 1 REC published by NYSERDA or Social Cost of Carbon, whichever is higher); demand reduction value and locational system relief value

[13] Julia Pyper, *Nevada PUC Approves Net Metering Rules Expected to Reboot the State's Rooftop Solar Industry*, GREENTECH MEDIA (Sept. 5, 2017), https://www.greentechmedia.com/articles/read/nevada-puc-approves-net-metering-rules-expected-to-reboot-the-rooftop-solar#gs.tFEYAQE.
[14] Julia Pyper, *Regulators Deny NV Energy's Rate Increase, Garnering Cheers from Solar Advocates*, GREENTECH MEDIA (Jan. 4, 2017), https://www.greentechmedia.com/articles/read/regulators-deny-nv-energy-rate-increase-rooftop-solar#gs.YGSovVc.
[15] *Id.*; *see also* Julia Pyper, Nevada's New Solar Law Is About Much More Than Net Metering, GREENTECH MEDIA (Jun. 16, 2017), https://www.greentechmedia.com/articles/read/nevadas-new-solar-law-is-about-much-more-than-net-metering#gs.XQ91DIo.
[16] Pyper, *supra* note 15.
[17] Michael Kuser & Rich Heidorn Jr., *NYPSC Adopts 'Value Stack' Rate Structure for DER*, RTO INSIDER (Mar. 9, 2017), https://www.rtoinsider.com/nypsc-value-stack-rate-structure-der-39880/.

(determined every three years; projects that qualify for LSRV will receive that compensation for ten years, whereas DRV shall not be fixed but instead changes as updated by the utility on a three-year basis).

Other states start with the avoided cost and then determine what other values to include in the value associated with distributed energy resources. Arizona, for example, added a number of additional considerations: avoided generation (energy and capacity),[18] transmission and distribution capacity with line losses adjusted for geographic location; grid support services; financial risk, including fuel price hedging and market price responses; security risks; and environmental considerations. In addition to the changes in valuation, Arizona has implemented export credits based on short-term valuation methods, specifically basing value on a five-year average of utility-scale solar PPA pricing.[19]

Minnesota, similarly, started with avoided cost[20] and then added avoided fixed plant operations and maintenance (O&M) costs, avoided variable plant O&M, avoided generation capacity cost (based on natural gas facilities), avoided reserve capacity cost, avoided transmission capacity cost, avoided distribution capacity cost (based on location), and avoided environmental cost. New Hampshire (pending a more detailed valuation study to be developed) values distributed resources at the wholesale energy cost plus 100% of the transmission charges and 25% of the distribution charges, but still requires distributed energy generators to pay per kWh non-bypassable charges. Hawaii, on the other hand, set the value for exported generation at just the energy avoided cost.[21]

Mississippi adopted a "buy all, sell all" approach for compensating owners of distributed energy systems. In a "buy all, sell all" approach, a customer has two meters – one for electricity coming onto the site, and one for electricity leaving it. All electricity coming onto the site is purchased by the customer, and all electricity leaving the site is purchased by the utility. This allows PUCs to assign different values to the electricity depending on whether it is being purchased from the utility or sold back to it. With this change, usage from the

[18] The Arizona Corporation Commission adopted the Staff's proposed definition of avoided cost. Decision 75859, page 147-150. Staff defined avoided cost as the "costs of energy that would have been produced or purchased but for the existence of the DG." Decision 75859, page 103 FN 727, http://images.edocket.azcc.gov/docketpdf/0000176114.pdf. This is not limited to only renewable resources or distributed energy resources, as renewable resources or distributed generation would not be the only sources which could see to the utility to meet this need. For a discussion of where states can limit avoided cost to comparable resources, *see generally* Felix Mormann, *Regulatory Opportunities for State Climate Policy*, 41 Harv. Envtl. L. Rev. 189 (2017).

[19] Julia Pyper, *Arizona Vote Puts an End to Net Metering for Solar Customers*, GREENTECH MEDIA (Dec. 21, 2016), https://www.greentechmedia.com/articles/read/Arizona-Vote-Puts-an-End-to-Net-Metering-for-Solar-Customers?utm_source=Daily&utm_medium=Newsletter&utm_campaign=GTMDaily#gs.uR4WwT0.

[20] Minnesota similarly defined the avoided fuel cost based on energy market costs, which are not limited to a particular form of generation or are necessarily distributed. Benjamin L. Norris et al., Clean Power Res., Minnesota Value of Solar: Methodology (Jan. 30, 2014), https://www.cleanpower.com/wp-content/uploads/MN-VOS-Methodology-2014-01-30-FINAL.pdf.

[21] Hawaii continues to see solar adoption with this valuation, likely due to high electricity prices from the state's dependence on imported oil to generate electricity.

grid is billed at the retail rate and excess electricity exported back to the grid is paid at the avoided cost rate (energy only, not capacity) plus 2.5 cents/kWh for currently unquantifiable benefits. Michigan also recently decided to change how they approach net metering and changed to a "buy all, sell all" approach. Per Michigan's new rules, all electricity purchased by the customer will be paid for at retail rate, but the utility will only pay avoided cost for the electricity generated and put back onto the grid.[22]

Impacts on the Distribution System

One of the considerations when determining the value of solar is how distributed energy resources will impact the distribution grid. Many are in agreement that, at this point in time, distributed resources, especially rooftop solar, do not impact the transmission system. (California and Hawaii may be the exceptions, given the large penetration of rooftop systems in those states.) Therefore, it is generally agreed that distributed resources should be credited for the full amount of any avoided transmission charges. The calculation around the distribution system, however, is more nuanced and complicated.[23] At this point in time, no state has finalized a specific value, but some states are working on determining the methodology that they will use.

The distribution system was originally designed for one-way flows of electricity (i.e., from a power plant to a home). With two-way flows, several scenarios are possible. With certain scenarios, distributed generation can lead to decreased distribution spending (by avoiding the need for infrastructure upgrades, for example); with others, adding distributed generation on the system may lead to additional cost (where equipment needs to be updated to handle the additional generation coming into the system). The conditions will depend on circuit-level circumstances, potentially leading to difficulties in valuation. Other factors that could influence valuation include increases in the amount of distributed generation on a particular circuit, the amount of distributed generation consumed on-site, the location of the distributed generation on the circuit (in relation to the transformer), and changes to the timing of peak use on that distribution circuit.

Acknowledging that distributed energy resources, especially larger facilities, could have an impact on the distribution system, California ruled that systems larger than 1 MW can participate in net metering provided they have "no significant impact" on the distribution grid. Minnesota has not currently calculated a specific value, but has a placeholder for solar integration cost pending the ability for that value to be measurable in the future.

Other states have sought to specifically address the impact of distributed energy resources on the distribution grid. New York, for example, has opened a separate proceeding on the value of distributed generation to the distribution system (the "Value of D"), which is ongoing. New York's value stack for distributed energy resources provides compensation

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[22] Robert Walton, *Michigan Nixes Net Metering*, UTILITY DIVE (Apr. 19, 2018), https://www.utilitydive.com/news/michigan-nixes-net-metering/521755/.
[23] *See generally* Joel B. Eisen and Felix Mormann, *Free Trade in Electric Power*, 2018 Utah L. Rev. 48, https://dc.law.utah.edu/ulr/vol2018/iss1/2/.

for avoided distribution-level infrastructure costs (as mentioned above) through the demand reduction value (DRV) and locational system relief value (LSRV). "The DRV applies to all projects in a utility's territory and is based on the utility's average cost of service. The LSRV is specific to projects that, based on their location and characteristics, contribute to meeting a particular utility need and therefore provide a specific, higher value to the distribution system."[24] However, these are based on the utility's marginal cost of service, which ranges from a low of $15/kW to a high of $226/kW in New York based on utility methodologies and inputs.[25] This has led to uncertainty around what the value would be for any particular distributed project. New York has plans to further standardize and improve these calculations during the next phase of the value-stack proceeding.[26] Similarly, Arizona also tied the value provided to the distribution system to location, including distribution capacity with line losses adjusted for geographic location in the valuation calculation, as did Minnesota, including avoided distribution capacity cost based on location.

New Hampshire took a different approach. Given that, as a restructured state, transmission and distribution charges were already calculated separately, distributed generation received the full value for transmission costs, but only 25% of distribution costs.[27] This was to acknowledge that distributed generation would create some costs for the distribution network, but that there were also cases where it would be beneficial. Rather than attempt to calculate it specifically on a circuit-by-circuit and project-by-project basis, New Hampshire opted to use the 25% average until better data are available.[28] South Carolina was less specific, requiring energy, line losses, and capacity from the distribution system to be factored into the value of distributed resources.

Environmental Benefits

Based on 2017 data from the U.S. Energy Information Administration, about 63% of total U.S. electricity production was from fossil fuel sources, including coal, natural gas, and

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[24] Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matter at 5, 10, In the Matter of the Value of Distributed Energy Resources, No. 15-E-0751, and Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions For Implementing a Community Net Metering Program, No. 15-E-0082 (N.Y. Pub. Serv. Comm'n Sept. 14, 2017) [hereinafter Order on Phase One Value].

[25] Jeff St. John, *Why Solar Advocates Are Crying Foul Over New York's Latest REV Order*, GREENTECH MEDIA (Sept. 19, 2017), https://www.greentechmedia.com/articles/read/why-solar-advocates-are-crying-foul-over-new-yorks-latest-rev-order#gs.6rMsPnA.

[26] Order on Phase One Value, *supra* note 24, at 8, 12.

[27] The 25% value was part of a negotiated settlement; some parties to the proceeding wanted 0%, and some 100%.

[28] On April 30, 2018, the Commission directed parties to this proceeding to conduct a distribution-level locational DG valuation study to evaluate alternative study designs and methodologies to address the potential locational value of DG on the utility distribution system. Docket Development of New Alternative Net Metering Tariffs and/or Other Regulatory Mechanisms And Tariffs For Customer-Generators, Order No. 26,124 Addressing Non-Wires Alternatives Pilot Program, 30 April 2018.

petroleum.[29] Emissions from coal plants include varying amounts of carbon dioxide, carbon monoxide, sulfur dioxide, nitrogen oxides, particulate matter, and heavy metals such as mercury, whereas emissions considerations for natural gas focus mostly on carbon dioxide.[30] The degree to which these are released per unit of electricity produced depends on the source.[31] The emissions from fossil fuel plants can contribute to climate change, acid rain, respiratory problems, heart disease, asthma and bronchitis, or other health problems.[32] Which of these sources produce more electricity for a given area – or whether cleaner sources like hydropower, wind and solar supply more of the local electricity – will have an impact on what environmental benefits might be achieved through the adoption of distributed energy resources.

As with many of the attributes associated with distributed resources, state approaches to evaluating the potential environmental benefits vary greatly. In Arizona, for example, environmental benefits including carbon emissions, criteria pollutants, and water and land impacts can be factored into the valuation, but only if these are not already considered in operating costs. Minnesota was also specific, including the value of avoided environmental costs based on the federal government's metric for the social cost of carbon and Minnesota-specific externality costs within a specific utility service territory. Currently, Minnesota anticipates the likely cost of carbon regulations to be in the range of \$5 to \$25 per ton of CO_2.[33] New York included an environmental value in the value stack provided to distributed energy resources, based on the latest Tier 1 REC published by NYSERDA (which for 2017 was \$21.71[34]), or the social cost of carbon (which was around \$36 in 2016 with a suggested value of \$42 from the Interagency Working Group in 2017[35]), whichever is higher. New Hampshire's legislature included a mandate for the commission that the value was to factor in environmental benefits but was not more specific than that. South Carolina's legislative mandate also stated that environmental costs should be taken into account but mandated that those values must be quantifiable and not based on estimates.

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[29] U.S. ENERGY INFO. ADMIN., WHAT IS U.S. ELECTRICITY GENERATION BY ENERGY SOURCE? (2017), https://www.eia.gov/tools/faqs/faq.php?id=427&t=3.

[30] U.S. ENERGY INFO. ADMIN., ELECTRICITY EXPLAINED: ELECTRICITY AND THE ENVIRONMENT (2017), https://www.eia.gov/energyexplained/index.cfm?page=electricity_environment. *See also* U.S. Energy Info. Admin., Frequently Asked Questions: What are the greenhouse gas and air pollutant emissions factors for fuels and electricity?, https://www.eia.gov/tools/faqs/faq.php?id=76&t=11.

[31] U.S. Energy Info. Admin., Carbon Dioxide Emissions Coefficients (Feb. 2, 2016), https://www.eia.gov/environment/emissions/co2_vol_mass.php.

[32] U.S. ENERGY INFO. ADMIN., ELECTRICITY EXPLAINED: ELECTRICITY AND THE ENVIRONMENT (2017), https://www.eia.gov/energyexplained/index.cfm?page=electricity_environment.

[33] Jeffrey Tomich, *Minn. Tackles Timing, Cost of Carbon Regulations*, ENERGYWIRE (Apr. 23, 2018), https://www.eenews.net/energywire/2018/04/23/stories/1060079769.

[34] CLEAN ENERGY STANDARD, N.Y. STATE ENERGY RESEARCH & DEV. AUTHORITY, 2017 SOLICITATION (2017), https://www.nyserda.ny.gov/All-Programs/Programs/Clean-Energy-Standard/Renewable-Generators-and-Developers/RES-Tier-One-Eligibility/Solicitations-for-Long-term-Contracts/2017-Solicitation.

[35] NAT'L ACADS. OF SCI., ENG'G, & MED., VALUING CLIMATE DAMAGES: UPDATD ESTIMATION OF THE SOCIAL COST OF CARBON DIOXIDE 2 (2017), https://www.nap.edu/read/24651/chapter/2#2.

Resiliency Attributes

Grid resiliency – generally thought of as the ability of the grid to recover after disasters or other life-threatening emergencies, and different from grid reliability – is difficult to define and to qualify. While more utilities and PUCs are starting to consider grid resilience, few have attempted to quantify the benefits that distributed energy resources may have in relation to grid resilience, or even define exactly what they mean when they use the term grid resilience. Arizona included security risks (both resilience and reliability) in the state's valuation, although these were not quantified, but instead simply included in the list of criteria to be considered. While New Hampshire adopted a long list of state DER goals, including promoting independence and reliability, resiliency was not included among them. However, the state requires customers using net metering to pay non-bypassable charges that include a storm recovery surcharge—a cost that is otherwise incorporated into customers' regular billing, and arguably adds to the state's resiliency through ensuring sufficient funds for restoration.

Risk-Hedging Attributes

Renewable energy resources can help hedge against the financial and regulatory risks facing the electricity sector. For example, solar and wind generation do not require fuel purchases and thus avoid the risk of fuel price volatility that has historically affected natural gas-fired generation. Solar energy also has predictable construction costs and relatively short construction time frames compared to other electricity generation options. Because most distributed energy generation does not emit air pollutants or utilize water, the facilities can also help electric power generators manage regulatory uncertainty regarding climate policy and other environmental regulations.

Despite the risk-hedging attributes associated with renewable energy, few states explicitly consider this factor in their DER valuation processes. Arizona considers valuations for financial risk, including fuel price hedging, in its calculations. The South Carolina legislature also identified fuel hedging as a factor for regulators to consider when valuing distributed energy resources. To date, neither state has quantified the risk-hedging benefits of DER.

Plans to Revisit DER Valuation

A number of states have specifically noted that either more information is needed or that the solution being implemented at this point in time is an interim one. Arizona will determine in future rate cases if they are going to retain valuation based on the five-year average of utility-scale solar PPA pricing or move to an avoided-cost methodology that "uses five-year forecasting to evaluate the costs and values of energy, capacity and other services delivered to the grid from distributed generation."[36] California plans to revisit retail-rate net metering (with non-bypassable charges) in 2020. Minnesota's valuation methodology includes two placeholder values, pending available data in the future. Mississippi is conducting an independent consultant study to determine if the 2.5 cent/kWh adder is the right value, or if it should be changed, and what values should be

[36] Pyper, *supra* note 19.

included in that decision. New Hampshire will revisit after a working group determines the details of data collection for a distributed energy resources valuation study and that study is performed. New York, while adopting the value stack approach for distributed energy resources,[37] continues to evaluate the appropriate valuation overall for distributed resources within the "Value of D" proceeding.

Conclusion

The nine states analyzed for this project have each taken a different path to valuation of distributed energy resources, and that is likely to continue into the future. State-level policy choices will continue to impact the valuation determinations made. While outside of the specific categories looked at in this paper, states continue to make other policy choices which impact their valuation decisions. Arizona, for example, specifically decided not to include any social impacts, including economic development opportunities, as being too speculative. California is moving all customers to default time-of-use (TOU) rates with an opt-out, but net-metered customers will not be able to choose to move back out of a TOU rate. Massachusetts most specifically dealt with land use concerns, grouping projects into those where the land hosting the project is agricultural or non-agricultural, and allowing the base compensation rate to have the potential for both adders (for specific locations like brownfield and landfills or as solar canopies; for shared community solar, low income properties, or public entities; and for storage and solar trackers) and subtractors (for greenfield development). Mississippi has also made low-income customer adoption a priority by providing a specific 2 cents/kWh adder for low income customers. As distributed generation penetration increases, states will continue to make choices based on state policies and goals that impact distributed generation valuation and customer choice.

Summary Table

This table summarizes the above material, and only includes what was found in the particular orders or statutes described in the Appendix. It does not reflect other aspects of state policy, but rather is limited to the material directly researched for this paper.

	Initiated by	Grandfathering	Distribution Impacts	Environmental Benefits	Risk Hedging	Plans to Revisit
Arizona	PUC	Yes	Yes	Yes	Yes	Yes
California	Legislature	Yes	Yes			Yes
Hawaii	PUC					
Massachusetts	Legislature					
Minnesota	Legislature		Yes	Yes		Yes
Mississippi	PUC					Yes
New Hampshire	Legislature	Yes	Yes	Yes		Yes
New York	PUC	Yes	Yes	Yes		Yes
South Carolina	Legislature		Yes	Yes	Yes	

[37] *Briefing Notes: Value of DER— Phase I Order*, E9 INSIGHTS (Mar. 2017), https://gallery.mailchimp.com/3dcda9a0dee5aecdf43892999/files/47f317c5-0ce8-4d4b-9132-4ff26bb0e401/Briefing_Notes_Value_of_DER_Phase_I_Order.01.pdf.

ARIZONA[38]	
Factors chosen	**Factors identified but not adopted**
• 5- year timeframe • Avoided energy costs, including energy and system losses • Avoided generation, transmission and distribution capacity with line losses adjusted for geographic location • Grid support services • Financial risk, including fuel price hedging and market price responses • Security risks (reliability and resilience) • Environmental considerations, including carbon emissions, criteria pollutants, water and land impacts; but will not duplicate if these are already considered in operating costs • Existing net metered customers grandfathered for 20 years • Analysis on valuation performed by ACC staff, voluntarily undertaken as part of the ACC Renewables Initiatives[39]	• Longer timeframe (20 to 30 years) • Social impacts, including economic development opportunities

[38] In the Matter of the Commission's Investigation of Value & Cost of Distributed Generation., 334 P.U.R.4th 29, Decision No. 75859 (Jan. 3, 2017), at 106, 114, 134, 148, 150, 152– 54, 156, 157, http://images.edocket.azcc.gov/docketpdf/0000176114.pdf.
[39] In the Matter of the Commission's Investigation of Value & Cost of Distributed Generation., 334 P.U.R.4th 29, Decision No. 75859 (Jan. 3, 2017), at 5, http://images.edocket.azcc.gov/docketpdf/0000176114.pdf.

CALIFORNIA[40]	
Factors chosen	**Factors identified but not adopted**
• Continue basic net metering structure, including retail rate compensation • Adopt default time of use (TOU) rates for all residential customers; all new net metering customers have no option to opt out of a time-differentiated rate • Customers who opt into a TOU rate prior to default residential TOU rates going into effect can stay on that TOU rate for a period of five years • New net metering customers pay interconnection costs of $75-$150 (waived for low income households) • Net metering customers must pay non-bypassable charges on each kWh of electricity they consume from the grid, including the Public Purpose Program Charge, the Nuclear Decommissioning Charge, the Competition Transition Charge, and the Department of Water Resources Bond Charges • No change to standby charges • Systems larger than 1 MW can participate in net metering provided they have "no significant impact" on the distribution grid and pay all interconnection costs • Customers under current net metering standard grandfathered for 20 years from the date of the customer's interconnection • Customers under this current net metering order also grandfathered for 20 years • Customers may not restart the 20- year grandfathering period by switching to the new metering tariff, but they can elect to transfer if they choose • Valuation analyses performed by intervenors • Action required by state statute[41]	• Customers continue not to pay non-bypassable charges, or only pay for the Public Purpose Program Charge after the market recovers from the projected loss of the federal investment tax credit or another transition period • Allow systems larger than 1 MW to be exempt from interconnection fees, grid charges, standby charges and non-bypassable charges • Add demand charges, grid access charges, additional fixed charges, grid use charge, standby charges, or installed capacity charges, including for residential customers • Require systems larger than 1 MW to pass the Rule 21 Fast Track process to be eligible for net metering • Interconnection fees for residential up to $280, and higher for systems above 30kW • Compensate at less than full retail rate (energy generation rate, levelized avoided cost, levelized avoided cost plus renewable energy credit adder), retail system average commodity rate, or wholesale rate • Cap total eligible system size at 3 MW • Customers purchase all energy consumed and are credited on their bills at the utility's avoided cost for all energy they generate • Eliminate annual true up • Grandfather a specific rate for 10 years, based on levelized 10 year forecast of avoided cost, plus a distributed generation adder

[40] Order Instituting Rulemaking to Develop A Successor to Existing Net Energy Metering Tariffs Pursuant to Pub. Utilities Code Section 2827.1, & to Address Other Issues Related to Net Energy Metering., 327 P.U.R.4th 75, Decision 16-01-044 (Jan. 28, 2016), at 2–5, 23–36 86–89, 91– 96, 99–101, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf.
[41] Cal. Pub. Util. Code § 2827.1 (West); *see* PUBLIC UTILITIES—ENERGY—RATES AND CHARGES, 2013 Cal. Legis. Serv. Ch. 611 (A.B. 327) (West).

HAWAII[42]	
Factors chosen	**Factors identified but not adopted**
• Caps net metering program at existing levels, indicating that net metering is fully subscribed and closed to new participants • Customers who applied for interconnection up to the date of the order shall continue to be eligible for interconnection under the net metering program • Customers going forward can choose a self-supply tariff or a grid-supply tariff • All future interconnection applications will be treated as an application under the grid-supply tariff unless otherwise indicated by the customer • The self-supply tariff is a limited, non-export solution that requires customers to use their generation to meet their own energy needs; allows only a limited amount of inadvertent export to the grid, with no compensation provided for any exported energy • The grid-supply tariff provides customers with the option of exporting excess generation, compensated at the energy credit rate, calculated at 12-month average on-peak avoided cost ending June 2015 for each island grid, guaranteed for 2 years; but this is seen as a transitional option, and initially set a cap at 24 MW for HECO and 5 MW each for HELCO and MECO for this option; no carry-over of energy credits month to month • Minimum bill of $25 for residential customers and $50 for small commercial customers under either option • TOU rate available to any eligible customer, with three time periods: overall system peak period, mid-day period, and off-peak period • Valuation is pending as part of the Phase 2 analysis [43] • Adopted on HPUC's own initiative	• No minimum bill charges or minimum bill for all customers • Mandate a minimum interconnection fee • Grid-supply tariff rate should be fixed for a period of five years • Compensation rate for grid-supply option should use wholesale value of renewable energy provided to the grid rather than wholesale rate • Limit TOU options to pilot areas • Two-period TOU design (only on-peak and off-peak) • No TOU at this time, need further study

[42] In the Matter of Pub. Utilities, Comm'n, 325 P.U.R.4th 339, Order No. 33258, (Oct. 12, 2015), at 118–123, 126–34, 139–42, 146–52, 196–97, https://dms.puc.hawaii.gov/dms/OpenDocServlet?RT=&document_id=91+3+ICM4+LSDB15+PC_DocketReport59+26+A1001001A15J13B15422F9046418+A15J13B31859H489831+14+1960.

[43] *Id.* at 62.

MASSACHUSETTS[44]	
Factors chosen	**Factors identified but not adopted**
• Successor tariff to net metering as net metering has hit its full capacity of 15% of peak load; uses wholesale transactions as a base compensation rate • Developed specific land use, siting, and development criteria, including whether the land hosting the distributed generation is agricultural or non-agricultural and the size of the system • Systems are grouped into Class I, Class II, or Class III based on size (up to 60 kW, 60 kW – 1 MW, and 1 MW – 2 MW, respectively) • Systems under 10 kW on a single-phase circuit and systems under 25 kW and under on a three-phase circuit are exempt from capacity limits • All systems subject to capacity limits receive market net metering credits for excess generation • The base compensation rate will decrease with increasing solar generation, with the potential for both adders (for specific locations like brownfield and landfills or as solar canopies; for shared community solar, low income properties, or public entities; and for storage and solar trackers) and subtractors (for greenfield development) • There are limits as to which adders can be combined with different class facilities and size of generating unit • Compensation rates are in effect for 20 years for systems over 25kW and 10 years for systems under 25kW • No specific valuation yet accomplished; but changes were required by session law Chapter 75 Act of 2016[45]	• Information not available

[44] 225 Mass. Code Regs. 20.00, Solar Mass. Renewable Target (SMART) Program, https://www.mass.gov/files/documents/2017/11/14/225-cmr-20-00-draft.pdf, at *8–12, 15–24.
[45] Chapter 75 of the Acts of 2016, "An Act Relative to Solar Energy."

MINNESOTA[46]	
Factors chosen	**Factors identified but not adopted**
• Assumed 25-year lifespan for solar PV installations • New value for solar compensation based on: avoided fuel cost (based on energy market cost including the cost of long-term price risk), avoided fixed plant O&M, avoided variable plant O&M, avoided generation capacity cost (based on natural gas facilities), avoided reserve capacity cost, avoided transmission capacity cost, avoided distribution capacity cost (based on location), avoided environmental cost (based on the federal government's social cost of carbon and Minnesota-specific externality costs within a specific service territory) • Two other values are included but are currently placeholders pending the ability to be measurable in the future: avoided voltage control cost and solar integration cost • Formula looks at these components plus the load match factor, loss savings factors, discount/escalation factors, and solar penetration • Valuation calculations made by the Minnesota Department of Commerce • Changes required by statute[47]	• Component corresponding to the compliance value of solar renewable energy credits • Component representing the value of increased economic development • Any factor not based on known or measurable evidence • An assumption of a 20-year lifespan for solar PV installations • Other environmental externality values, including regulatory planning values • Other values than the social cost of carbon for CO2 emissions values • Utility-specific, substitute, or more complex avoided fuel costs • Corresponding avoided generation capacity cost to utility's next planned generation facility • Requested credit to be given for local manufacturing or assembly • Market price reduction • Adder for disaster recovery • Separate treatment of solar renewable energy credits

[46] In the Matter of Establishing A Distributed Solar Value Methodology Under Minn. Stat. S 216b.164, Subd. 10 (e) & (f), E-999/M-14-65, 2014 WL 1347985, at *4, 7–8, 10–14, 18, (Apr. 1, 2014).
[47] Minn. Stat. § 216B.164, subd. 10(e) (2017).

MISSISSIPPI[48]	
Factors chosen	**Factors proposed but not adopted**
• Excess generation sold to the utility at avoided cost plus a distributed generation benefits adder of 2.5 cents/kWh • Carryover of excess energy indefinitely but valued each month • All usage from grid billed at retail rate • Electricity exported to the grid will not offset customers' monthly electricity use • 2.5 cents/kWh is for presently non-quantifiable benefits; will be replaced with calculation of actual benefits based on independent consultant study • Credits for excess energy exported shall not reduce any fixed monthly charges or minimum bill provisions • First 1000 low-income customers receive an additional 2 cents/kWh adder for the first 15 years • Renewable energy credits transfer to utility for any excess generation sent back to the grid where 2.5 cent/kWh adder is paid • Avoided cost calculation includes the cost of fuel needed to produce that electricity and corresponding portion of plant's operation and maintenance costs; average line loss adjustment; no capacity credit. If within an RTO, is the locational marginal price for that load zone and may be adjusted to reflect daytime energy production of solar PV systems • No valuation specifically conducted • Action not required but specifically authorized by the Miss. Code Ann. § 77-3-45 and Mississippi Administrative Procedures Act, Miss. Code Ann §§ 25-43-1.101	• Carryover of energy credits in kWh for indefinite period • All usage billed at retail rate and all generated energy valued at avoided cost rate • Retail rate for excess generation • Separate determination of avoided cost for distributed generation assets • All renewable energy credits stay with the customer, regardless of whether that energy is supplied to the grid or used instantaneously by the customer • All renewable energy credits come to the utility, which monetizes them for the benefit of the entire customer base

[48] Mississippi Public Service Commission, *Order Adopting Net Metering Rule*, Docket No. 2011-AD-2, http://www.psc.state.ms.us/InSiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=362179, at 9–12, 14–20, A1–A7, B1, B6, B7–17, B20.

NEW HAMPSHIRE[49]	
Factors chosen	**Factors identified but not adopted**
• Alternative net metering tariff in effect while further data is collected, pilot programs are implemented, and a DER valuation study is conducted (details of data collection for DER study to be determined through a working group) • Systems of 100 kW or less will net meter with monthly monetary credits (rather than kWh credits) equal to the value of the kWh charges for energy service transmission at 100% and distribution service at 25%, pay non-bypassable charges (system benefits charge, stranded cost recovery charge, storm recovery surcharges, other surcharges, electricity consumption tax) on full amount of electricity imported from the grid without netting exports • Accumulated excess credits will receive a cash payment when customers move/discontinue service or on an annual basis if credit balance is above $100 • Net metering grandfathered until 2040 while the alternative tariff in place • Net metering customers will have bi-directional meters installed to record separately the quantities of electric imports from the grid and exports to the grid • Large customer generators receive export credits based on utility default service energy charge, also with monetary crediting instead of kWh banking; systems of between 100 kW and 1 MW are only eligible for new tariff if they consume greater than 20% of actual or estimated distributed generation system electric production behind the meter • Utilities have the opportunity to recover lost revenues attributable to customer net metering; approve utilities to install production meters behind the meter at no cost to those customers if the customer opts in to a production meter • Utilities permitted to recover prudently-incurred costs of required metering upgrades, study expenses, and pilot program • Approve utilities to facilitate REC program; utilities not obligated to purchase RECs, but may at reasonable market prices	• Separate rate classes for those with distributed generation • Mandatory demand charges for those with distributed generation • Mandatory time of use rates • Customers should pay 100% of distribution as well as 100% of transmission charges • Excess credited at energy service rate rather than retail rate • Excess credits at end of billing cycle paid at avoided cost rate • Install production meters so utilities could measure lost revenue from customer consumption of self-generated electricity behind the meter • Use of comprehensive list of benefits and costs to determine value of excess energy (to include avoided energy cost, avoided generation capacity, avoided line losses, avoided ancillary services, avoided transmission and distribution capacity, avoided environmental costs, avoided carbon emissions, avoided fuel hedging/fuel price uncertainty, market price mitigation, avoided renewables, and societal benefits) • If uncertainty in benefit value, consider range rather than saying it is unquantifiable and therefore assigning a zero cost • Increase system size available for net metering to 250 kW • Allow residential customers to monetize RECs by optionally selling RECs to an aggregator for a specific adder to their net metering credit • Approve specific adders for larger commercial systems (greater than 100 kW) including location benefits adder, directional benefits adder, environmental benefits adder, municipal or other public benefits adder, peak demand time of use adder, development adder, adder for storage or other ancillary services • 25-year grandfathering of rates • No cap on distributed generation

[49] Dev. of New Alternative Net Metering Tariffs and/or Other Regulatory Mechanisms & Tariffs for Customer-Generators, 25,972, 2016 WL 7433293, at *1–2, 6–13, 15–20, 48–51 (Dec. 21, 2016), http://www.puc.state.nh.us/Regulatory/Orders/2017orders/26029e.pdf.

• After completion of the DER study, commission will open a new proceeding to determine if changes are needed • Factors required by the legislature for the commission to take into account: costs and benefits of customer generator facilities; avoidance of unjust and unreasonable cost shifting; rate effects on all customers; alternative rate structures, including time-based tariffs; whether there should be a limitation on the amount of generating capacity eligible for alternative net metering tariffs; the size of facilities eligible to receive net metering tariffs; timely recovery of lost revenue by the utility using an automatic rate adjustment mechanism; electric distribution utilities' administrative processes required to implement such tariffs and related regulatory mechanisms; and continuance of reasonable opportunities for electric customers to invest in and interconnect customer generator facilities and receive fair compensation for such locally-produced power while ensuring costs and benefits are fairly and transparently allocated among all customers, and the promotion of a balanced energy policy that supports economic growth and energy diversity, independence, reliability, efficiency, regulatory predictability, environmental benefits and a modern and flexible grid • Valuations provided by both staff and 3rd parties • Action was required by statute[50]	• Set standard reviews of policy at specific percentages of utility peak load • Office of Consumer Advocate indicated benefits of solar range between 13 and 15 cents/kWh, not including different societal benefits which are hard to quantify • Larger systems use competitive bid/auction mechanism • Real time pricing on an opt-in basis, with credit based on load zone real-time locational marginal price with generation related ancillary services adjusted for avoided line losses and credited for capacity market prices for exported energy • Transmission charges charged or credited depending on customer's load during monthly coincident peak

[50] 2015 New Hampshire House Bill No. 1116.

NEW YORK[51]	
Factors chosen	**Factors identified but not adopted**
• Residential customers retain retail-rate net metering for 25 years after in-service date for projects under the transition plan and 20 years for projects developed under the Phase One NEM order • Grandfathering includes option for developers or customers able to file for a term longer than 20 years based on pre-existing financial or other contractual arrangements • Community Distributed Generation, Remote Net Metering, and large on-site projects compensated based on limited net metering or DER value stack depending on contractual obligations (systems with storage must use value stack) • For projects compensated under the value stack, the compensation term is 25 years from the in-service date • Value stack based on: energy value (day ahead hourly zonal locational-based marginal price, inclusive of losses); capacity value (different methodologies for intermittent and dispatchable technologies); environmental value (based on latest Tier 1 REC published by NYSERDA or Social Cost of Carbon, whichever is higher); demand reduction value and locational system relief value (adopted to maximize benefits to the system as a whole; determined every three years; projects that qualify for LSRV will receive that compensation for ten years, whereas DRV shall not be fixed by instead changes as updated by the utility on a three-year basis) • This value stack means the value of a kWh can vary greatly depending on where and when it is injected into or consumed from the grid • The costs associated with compensation under the value of DER will be collected proportionately from the same group of customers who benefit from the savings associated with the compensated DER • Valuations primarily made by PSC staff • Action taken voluntarily at PSC's initiative	• Grandfathering should be for 25 years after the in-service date for all projects • Grandfathering should be for 15 years to reduce long-term risks to non-participants • For energy value in value stack, should have additional study to understand how avoided losses are impacted with the increased use of distributed generation • For energy value in value stack, other components should be included, such as congestion and losses • For capacity value in value stack, value based on a single peak hour during the year presents too much uncertainty and variability, has the potential to unfairly favor solar over hydro, and another value should be chosen • CHP plants using non-renewable fuels should not be eligible for environmental value part of the value stack • There should be no compensation for environmental values in the value stack • The values for DRV and LSRV raises uncertainties about financing; need a long-term fixed rate for compensation for predictability • Values not taken into effect in the value stack include: distribution system values not reflected by the locational demand reduction value; reduced sulfur dioxide and nitrous oxide emissions; reductions in carbon dioxide emissions; land and water impacts; environmental justice impacts; wholesale price suppression; particulate reduction; reduced energy burden for low-income customers; local job creation; increased resiliency; and ensuring geographical equity.

[51] Case 15-E-0751 In the Matter of the Value of Distributed Energy Res, Case 15-E-0082 Proceeding on Motion of the Comm'n As to the Policies, Requirements & Conditions for Implementing A Cmty. Net Metering Program., 335 P.U.R.4th 178 (Mar. 9, 2017)), at *15–17, 46–49, 50, 52–56, 82, 86–88, 90, 93, 96, 97–100, 102–104, 106–109, 111, 119–121.

SOUTH CAROLINA[52]	
Factors chosen	**Factors identified but not adopted**
• Factors to be used to determine the value of net metered distributed energy resources: avoided energy; energy losses/line losses (at generation, transmission and distribution); avoided capacity; ancillary services; transmission and distribution capacity; avoided criteria pollutants; avoided carbon dioxide emission cost (zero monetary value until state or federal laws or regulations result in an avoidable cost on utility systems for these emissions); fuel hedge; utility integration and interconnection costs; utility administration costs; environmental costs (must be quantifiable and not based on estimates); and other categories which cannot currently be quantified but which will be continuously updated • Utilities allowed to recover costs related to DER programs to extent that costs are reasonably and prudently incurred to implement approved programs; will be recovered during annual fuel proceeding • Any difference between value of DER generation and retail rate paid to customer generators shall be treated as a DER program expense and collected through fuel clause; not recovered through base rates • Avoided costs calculated using less of rates negotiated pursuant to PURPA or electric utility's most recently approved/established avoided cost rates • Requires development by 1/1/2021 of renewable energy facilities equal to at least 2% of previous five-year retail peak demand for each utility, with at least 0.25% of that from small scale facilities (20 kW or less) • Net metering available for all 2% required under the program • Energy generated that exceeds energy supplied by the utility during the billing period not used to offset non-volumetric electricity charges • Any excess rolled over to future billing periods; but annually utility pays for any accrued excess at avoided cost • Utility to calculate whether it has under-recovered or over-recovered revenue from net metering customers	• Environmental benefits insufficiently calculated • Rate for excess energy should be based on net cost to serve customer generators, retail rate provides a subsidy to DER customers

[52] Distributed Energy Resource and Net Metering Implementation, SOUTH CAROLINA OFFICE OF REGULATORY STAFF, (July 21, 2016), https://www.scstatehouse.gov/CommitteeInfo/PublicUtilitiesReviewComm/Act236Reports/DER%20and%20Net%20Metering.ORS.2016.pdf, at 3–4, 8–10.

by: computing bill without consideration of DER production; subtracting actual bill with consideration of DER; subtracting amount net benefits delivered by DER; if final number positive, then under recovered, if negative, then over recovered from net metering customer. • Customer generator treated same as others in rate class for all other purposes (type of meter, rate) • Cap of adder to bills to pay for incremental utility costs to implement DER under the program ($12/year for residential customers; $120/year for commercial; $1200/year for industrial) • Valuation is pending in the office of regulatory staff • Actions were required by statute[53]	

[53] South Carolina Distributed Energy Resource Act, S.C. Code Ann. § 58-39-110.

APPENDIX C . Energy Division Staff Proposal for 2020 Avoided Cost Calculator Update

Energy Division Staff Proposal for 2020 Avoided Cost Calculator Update

Integrated Distributed Energy Resources Rulemaking (R.14-10-003)

Final April 16, 2020

Table of Contents

1. Introduction

The Integrated Distributed Energy Resources (IDER) proceeding, R.14-10-003, recently commenced a process, as outlined in Decision (D.)19-05-019, to determine major changes to be made to the Distributed Energy Resource (DER) Avoided Cost Calculator (ACC) in 2020. The ACC determines the benefits of DERs such as energy efficiency and demand response. Those programs that undergo cost-effectiveness analysis depend on the ACC to accurately determine the benefits they provide to the electric grid. The ACC determines several types of benefits including avoided generation capacity, energy, ancillary services, GHG emissions, and transmission and distribution capacity.

Historically, the value of the generation capacity and energy that a DER could avoid is determined by estimating the hourly marginal cost of a natural gas generator, for every hour of the year over a 30-year period. However, Renewable Portfolio Standard (RPS) requirements and greenhouse gas (GHG) reduction goals have resulted in profound changes to the electric grid, so that natural gas generators are less likely to represent the marginal unit of capacity (since they are unlikely to be built in California in the future) or energy (since renewable units are more and more likely to be the marginal unit during many hours of the day).

Therefore, Energy Division staff (Staff) believes that the Commission needs to change the basis of the ACC. One possible change would be to simply replace the natural gas generator with another technology (or technologies), such as a storage battery. This would more closely align the ACC with Integrated Resource Planning (IRP) modeling results.[1] In fact, the Joint IOUs, in their October 7, 2019 IDER testimony, have proposed this. However, Staff proposes that a better approach would be to align the ACC even more closely with IRP, by using IRP modeling outputs as inputs to the ACC.

The Commission has clearly expressed its intent that all electricity resource procurement be guided by the IRP process. Following this direction Staff proposes that in line with that effort, we align the data, models and methods used for IDER cost-effectiveness with the data, models and methods used in IRP. Staff sees alignment between the ACC and IRP as inevitable, with the main questions being timing and feasibility. Thus, the main question left regarding IRP-ACC alignment over the short term is whether it is feasible to implement this proposal in time for the 2020 Avoided Cost Calculator update.

Staff turned to its consultants, Energy + Environmental Economics (E3) to answer these questions. E3 and Staff have prepared this proposal to examine the details of aligning IDER and IRP, so that stakeholders and the Commission can judge whether it is reasonable to make the major changes to the Avoided Cost Calculator described in this proposal in 2020.

1.1. Overview of Proposed Avoided Cost Calculator Update

The existing Avoided Cost Calculator is a product of the time in which it was developed and the priorities that existed in the post-California Energy Crisis period of 2003 and 2004. At the time, the approach was innovative and led the nation in decomposing area- and time-specific avoided costs for the evaluation of California's robust energy efficiency program. Since the original avoided cost framework was developed,

[1] CPUC Integrated Resource Planning Proceeding (R.16-02-007)

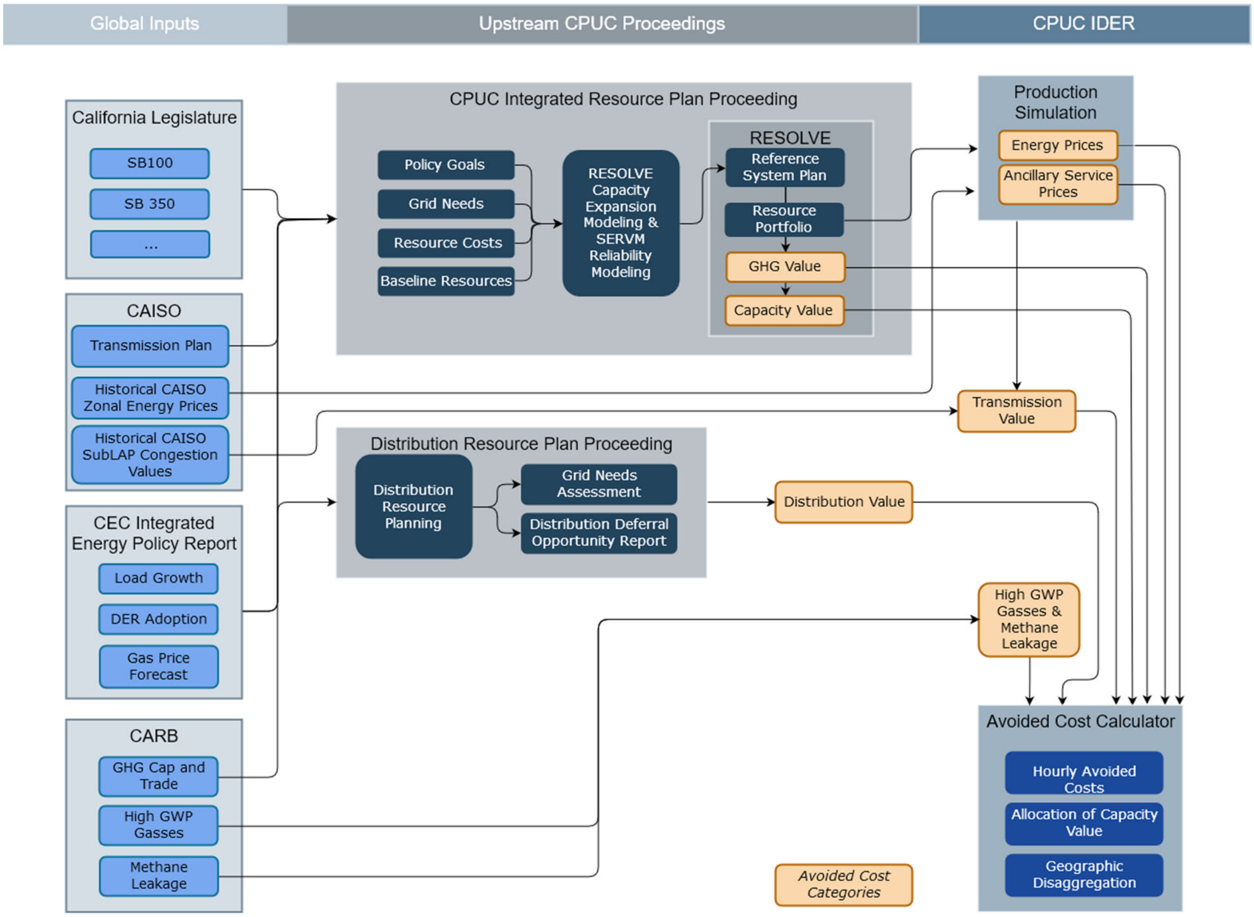
significant updates to the model to more closely reflect actual avoided costs have been adopted. The largest among these is the update to include avoided renewable generation and to incorporate the various GHG Adders, including the current one which was developed as part of the IRP process. In addition, many other smaller adjustments have been made as a response to evolving markets.

Nevertheless, the current approach does not reflect the value of DERs in this period of high renewable and clean generation capacity expansion in the state's plans required by SB 100, nor the wholly different operational regime of a highly intermittent renewable system, nor does it have a strong focus on GHG emission reductions. The "avoided" supply-side resource is now much more complicated than the fixed and fuel costs of a new combined cycle or combustion gas turbine. Therefore, to appropriately capture this value, Staff proposes a fully new approach that has a tight link to the IRP process where the costs and modeling of the avoided supply-side resources are being calculated and the least cost renewable portfolio is being selected for the system plan.

To appropriately value distributed energy resources a shift is needed, from avoided costs that are based on natural gas generation and utility transmission and distribution investment plans to a new framework focusing on avoided renewable generation, transmission and distribution planning with non-wires alternatives, flexibility, and resiliency. In addition, a central policy focus in California on reducing greenhouse gas (GHG) emissions will mean that it will be essential for any new framework to provide an accurate estimate of GHG impacts for all distributed energy resource types and include the value of reduced GHG emissions as a core component.

A high-level flow chart of the proposed 2020 ACC update process is shown in Figure 1. Policy directives are adopted by the state legislature and implemented through several state agencies, including the California Independent System Operator (CAISO), California Energy Commission (CEC) and California Air Resources Board (CARB) as well as the CPUC. A variety of information from these agencies provide inputs into the CPUC Integrated Resource Planning (IRP) and Distribution Resource Planning proceedings to guide electricity sector planning that supports the states policy objectives. For the 2020 ACC update Staff proposes to coordinate more closely with the IRP and DRP processes to support consistency in the evaluation of supply and demand side resources in the electric sector planning. The proposed process for translating CPUC IRP results into ACC inputs is covered in Sections 2-4 and for the DRP in Sections 5-6. The IRP will provide values for developing GHG and system capacity avoided costs, and the resource portfolio that will be used to develop energy and ancillary service avoided costs. The DRP will provide inputs for developing distribution avoided costs and Staff proposes to use CAISO congestion prices to develop transmission avoided costs. Finally, new avoided costs for high global warming potential (GWP) gas and methane leakage, using inputs from CARB.

Figure 1: Overview of Proposed 2020 ACC Update Process



2. IRP Coordination

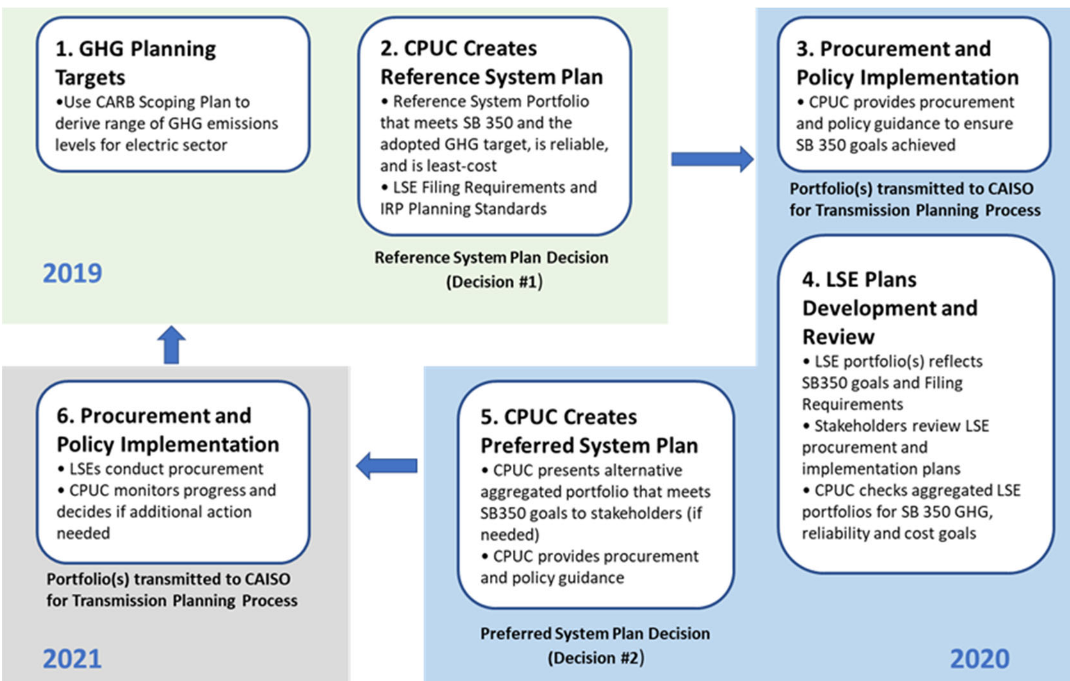
Generally speaking, the avoided costs developed for evaluating DER cost-effectiveness have always had a close relationship with supply-side resource planning. Utility resource planning typically involves lengthy and detailed modeling and stakeholder processes to develop a resource plan for investing in supply and demand side resources to meet anticipated needs. This resource plan represents the best thinking on how to reliably meet anticipated system needs at the lowest cost.

Avoided costs for DER are developed based on that resource plan to evaluate which DERs can meet system needs at a lower cost. System level planning over long time horizons necessarily requires that DERs be evaluated in aggregate with a high level of abstraction. Avoided costs provide a simpler and more transparent analysis and facilitate the evaluation of individual DER measures and programs in greater detail than is possible in supply side resource planning. This section describes the plan to more specifically coordinate the development of avoided costs with the CPUC IRP proceeding.

2.1. CPUC IRP Proceeding

The CPUC IRP proceeding (R.16-02-007) has established a biennial process to 1) Identify a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable energy in a cost-effective manner and 2) have LSEs file integrated resource plans with the CPUC that accomplish specific goals, including meeting GHG, RPS, and reliability targets at least cost[2]. CPUC staff and consultants have been working in 2019 to develop a Proposed Reference System Plan (RSP) that will provide a safe, reliable and cost-effective electricity portfolio that meets California's GHG emission goals. A Reference System Plan is expected to be adopted by the CPUC in early 2020. This RSP is then passed to Load Serving Entities (LSEs) for use in development of their individual integrated resource plans. LSEs will then submit their individual integrated resource plans to the CPUC, which CPUC staff will review, potentially amend, and aggregate into a final Preferred System Plan (PSP) that is expected to guide resource procurement in the state beginning in 2021.

Figure 2: 2019-2020 CPUC IRP Process



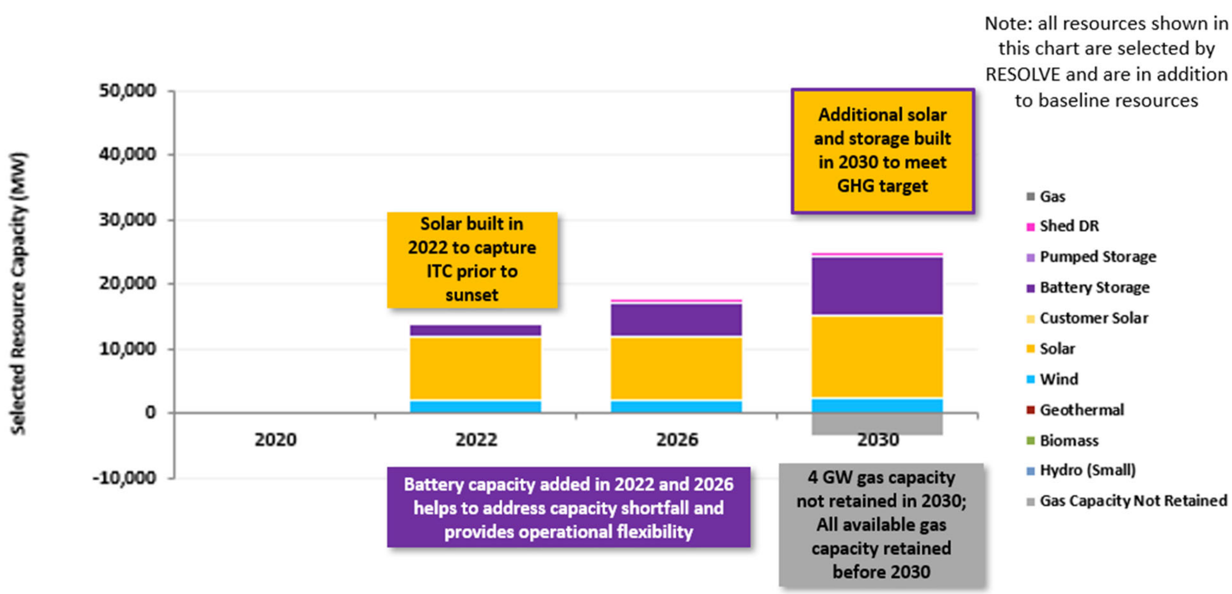
The 2019-2020 IRP Preliminary Results were presented at an informal workshop on October 8, 2019. They contained descriptions of the input and methodological updates from the previous IRP cycle, as well as preliminary results for the core policy cases and a variety several sensitivities.[3] The Preliminary Results will inform selection of the 2019 IRP Proposed RSP, expected to be issued in November 2019,

[2] For more information see the CPUC IRP webpage at: https://www.cpuc.ca.gov/irp/
[3] See CPUC 2019-20 IRP Events and Materials at: https://www.cpuc.ca.gov/General.aspx?id=6442459770 and the Preliminary Results Presentation at: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/2019%20IRP%20Preliminary%20Results%2020191004.pdf

which is proposed to serve as the basis for developing inputs for this proposed 2020 Avoided Cost Calculator update.

The IRP uses the RESOLVE and Strategic Energy Risk Valuation Model (SERVM) models to identify least-cost portfolios of resources to meet California's electricity sector GHG emission targets under different assumptions. The RESOLVE model, a capacity expansion model developed by Energy Division's consultant E3, is used to select a least-cost portfolio of generation resources to meet future grid needs. The SERVM model is a probabilistic reliability planning model developed by Astrape that evaluates the loss of load probability for portfolios of generation and transmission resources generated by RESOLVE. The resources included in the 2019 IRP Preliminary Results 46 MMT case are summarized in Figure 2. This case includes 2.4 GW of wind and 12.6 GW of solar PV with 9.3 GW of battery storage and 440 MW of shed demand response (DR) in 2030.[4] This portfolio is considered adopted policy in the IRP proceeding, as it most closely resembles the 2017-18 IRP Preferred System Plan (PSP) 42 MMT case adopted in D.19-04-040.

Figure 3: New Resources Selected in 2019-20 Preliminary Results 46 MMT Case[5]



In the 2019-2020 IRP cycle, DERs are characterized by RESOLVE in two different ways. Generally, DER adoption is projected by California Energy Commission (CEC) Integrated Energy Policy Report (IEPR) demand forecast modeling and included as baseline resources in the Reference System Plan. A summary of the CEC IEPR mid case DER adoption projections for EE, PV, EVs and BTM storage are shown in Table 1. In addition to baseline resources, some DER are also provided to RESOLVE as candidate resources, including BTM PV, BTM storage, and shed DR, should the baseline resources in RESOLVE not be sufficient to meet future grid needs.

[4] Shed DR is the traditional type of DR that reduces load during peak system hours.
[5] From 2019-20 IRP Preliminary Results Presentation, October 8, 2019, slide 52.

Table 1: DER resources included in 2019 Preliminary Results 46 MMT case[6]

Planning Area	PG&E		SCE		SDG&E	
Electric Demand Component [1]	2020	2030	2020	2030	2020	2030
Consumption, MW peak	22,838	25,760	25,353	28,753	4,825	5,517
Consumption, GWh load	111,274	123,640	110,047	123,337	22,123	24,691
Light-duty electric vehicles, GWh load	2,528	7,531	1,851	5,398	562	1,662
Time of use rate effects, GWh load [2]	-	23	-	13	0.03	2
Additional Achievable EE, GWh savings	2,939	12,949	2,881	14,108	572	3,029
Committed BTM PV installed cap MW	5,493	10,269	3,476	7,292	1,504	2,458
Additional Achievable PV installed cap MW	63	720	67	740	14	168
BTM storage installed cap MW [3]	122	469	167	566	65	198

2.2. No New DER Case

To quantify the avoided cost value of the DERs that are included in the RSP, Staff proposes that the IRP modeling include a “No New DER” sensitivity case of the RSP. Without the planned DER, RESOLVE will select more supply side resources to meet reliability and GHG targets, which will result in higher capital investment and annual operating costs. The difference in total revenue requirement between the Proposed RSP and No New DER case will provide a measure of the costs avoided with the DER included in the RSP portfolio.

For the No New DER case, Staff proposes to remove from the RSP portfolio all DERs in the RSP that are associated with utility incentive programs and incremental to the DERs installed up until 2018. Thus, EE, PV, BTM storage and other resources would remain at the 2018 level. All DR, which requires ongoing annual incentive payments, will be assumed to be zero. The same DER categories would also not be available as candidate resources for RESOLVE to select. The energy (GWh) and capacity (MW) assumptions for the RSP and the proposed No New DER case are summarized in Table 2 and Table 3. Given the IRP timeline for issuing the RSP, only one No New DER case may be possible in the IRP proceeding. If time and resources permit, additional sensitivities, for example running RESOLVE cases with and without just one specific type of DER (e.g., BTM PV), could in the future potentially be performed in the IDER proceeding.

[6] From IRP Modeling Advisory Group June 17, 2019 webinar presentation, slide 40, available at: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/IRP_MAG_20190617_CoreInputs.pdf

Table 2: Proposed DER Energy (GWh) Assumptions for No New DER Case

CAISO Sales Forecast Buildup		2018	2020	2025	2030
	Energy Efficiency (GWh)				
	CEC 2018 IEPR - Mid Mid AAEE	1,906	5,930	17,322	27,940
	No New DER Case	1,906	1,906	1,906	1,906
	Commited BTM PV				
	CEC 2018 IEPR - Mid PV + Mid-Mid AAPV	12,439	16,797	25,446	32,466
	No New DER Case	12,439	12,439	12,439	12,439
	Additional Achievable BTM PV				
	CEC 2018 IEPR - Mid PV + Mid-Mid AAPV	-	134	1,441	2,657
	No New DER Case	-	-	-	-
	Behind-the-Meter CHP (GWh)				
	CEC 2018 IEPR - Mid Demand	13,594	13,637	13,648	13,595
	No New DER Case	13,594	13,594	13,594	13,594
	Non-PV Non-CHP Self Generation (includes storage losses) (GWh)				
	CEC 2018 IEPR - Mid Demand	764	751	716	681
	No New DER Case	764	751	716	681

Table 3: Proposed DER Capacity (MW) Assumptions for No New DER Case

BTM PV and BTM Storage Capacity from CEC 2018 IEPR		2018	2020	2025	2030
	Commited BTM PV				
	CEC 2018 IEPR - Mid PV + Mid-Mid AAPV	7,269	9,694	14,387	18,555
	No New DER Case	7,269	7,269	7,269	7,269
	AAPV (Additional Achievable BTM PV)				
	CEC 2018 IEPR - Mid PV + Mid-Mid AAPV	-	134	843	1,511
	No New DER Case	-	-	-	-
	BTM Storage (MW)				
	CEC 2018 IEPR - BTM Storage installed capacity	92	722	1,239	1,647
	CEC 2018 IEPR - BTM Storage peak impact	(81)	(641)	(1,072)	(1,390)
	No New DER Case	(81)	(81)	(81)	(81)
	Load Modifying Demand Response				
	Load-Modifying Demand Response: Mid Mid AAEE	(137)	(162)	(186)	(200)
	No New DER Case	-	-	-	-
Capacity Contribution of BTM Resources Modeled as Supply-Side in RESOLVE					
	BTM PV (MW peak reduction)				
	CEC 2018 IEPR - Mid PV + Mid-Mid AAPV	3,532	4,408	5,859	5,641
	No New DER Case	3,532	3,532	3,532	3,532
Baseline DR 1-in-2 Peak Load Impact (MW)					
	DR 1-in-2 Load Impact (MW)				
	Mid Case	1,617	1,617	1,617	1,617
	No New DER Case	-	-	-	-

The No New DER case has not yet been run, but a high load sensitivity included in the October 8, 2019 workshop presentation illustrates the concept. Removing DER will have the effect of increasing load. The high load sensitivity does not remove DER, but does show the additional costs that would be incurred if load growth is higher than the forecast used in the Reference System Plan. The High IEPR baseline load trajectory in place of the Mid IEPR case in the Preliminary Results 46 MMT high load case results in an increased total cost of $793 million dollars per year.

Table 4: 2019-20 IRP Preliminary Results: Sensitivity Results[7]

"Incremental TRC" calculated relative to 46MMT Reference case (highlighted in orange)

	Incremental Cost ($MM/yr)		
Sensitivity	**46 MMT**	**38 MMT**	**30 MMT**
Reference	**$0**	**$589**	**$1,621**
Low RA Imports	$294	$840	$1,833
High RA Imports	-$141	$563	$1,579
Paired Battery Cost	-$461	$88	$1,008
High Battery Cost	$602	$1,451	$2,634
PV ITC Extension	-$330	$297	$1,152
High PV Cost	$614	$1,351	$2,441
Low OOS Tx Cost	-$37	$362	$1,125
New OOS Tx	-$32	$478	$1,268
High OOS Tx Cost	-$30	$513	$1,412
High Load	$793	$1,533	$2,608

The proposed 2019 RSP will be used as the basis for calculating avoided costs as described in the following sections. The avoided costs based on the proposed 2019 RSP will provide the marginal value for DERs that are in addition to those already included in the RSP portfolio.

The No New DER Case will provide two different measures of the avoided costs of the DER included in the proposed RSP. The increased revenue requirement of the No New DER Case is a measure of the supply side costs avoided by the proposed RSP DER portfolio. Staff propose to also calculate avoided costs based on the No New DER Case as a sensitivity. This information is included as an appendix in the 2019-20 IRP Proposed Reference System Plan, released on November 6, 2019 by an ALJ Ruling in the IRP proceeding (R.16-02-007).

2.3. RESOLVE IRP outputs for the ACC

This section describes the key IRP RESOLVE modeling outputs that will be used as inputs for the ACC. The charts below show the values for the 2019 Preliminary Results 46 MMT compared to the 2017-18 42 MMT reference case, as well as the values in the 2019 ACC. Note that the IRP results are provided in 2016 dollars whereas the ACC values are in nominal dollars. For the charts below we have converted the IRP results to nominal dollars. The 2019 preliminary results shown here may change substantially prior to the release of the Proposed RSP.

[7] From 2019-20 IRP Preliminary Results Presentation, October 8, 2019, slide 85.

The 2019-20 IRP cycle includes several updates to inputs, models and methodology from the 2017-18 cycle. Energy Division's consultant E3 anticipates that in total, the 2019-2020 updates will result in lower modeled total system costs to achieve a given GHG emissions target, though the ultimate outcome will depend on final assumptions made for the proposed RSP. The primary updates resulting in lower costs are lower cost projections for solar and storage technologies. Other updates have increased the capacity value relative to the prior IRP cycle. The accelerated retirements of Once-through Cooling (OTC) plants as required by the State Water Resources Control Board to reduce the environmental impacts of high-volume water withdrawals has resulted in a need for new capacity. In addition, the quantity of imports allowed to count towards Resource Adequacy has been reduced from 10 to 5 GW in the preliminary 46 MMT case. Finally, the Effective Load Carrying Capacity (ELCC) for energy storage of a given duration is now modeled to decline over time as the quantity of solar generation increases.[8]

RESOLVE calculates a shadow price for GHG emissions, which reflects the incremental capital and operating cost per ton of GHG to procure the resources necessary to avoid an additional ton of emissions. As in the previous IRP cycle, the GHG shadow price for the 2019 Preliminary Results 46 MMT case remains relatively low until 2030 when it reaches $150/ton in nominal dollars ($109/ton in $2016). The 2030 GHG shadow price is lower than the $301/ton in nominal dollars ($219/ton in $2016) for the prior IRP cycle due primarily to lower capital costs for solar and storage and in part because renewable generation is procured earlier for reliability needs.

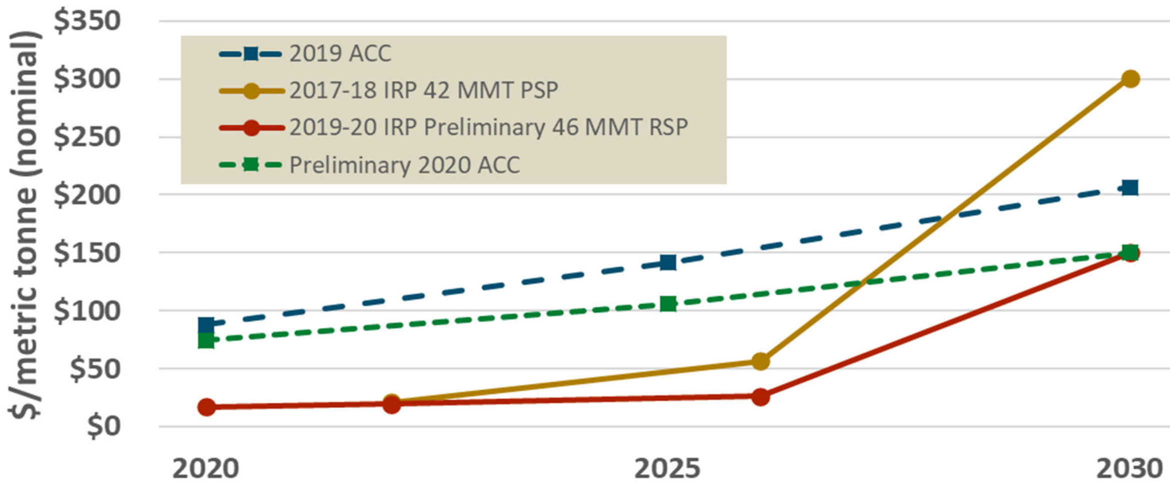
The 2019 ACC uses GHG costs set forth in Table 6 of D.18-02-018 (in $2016). These costs are developed from the RESOLVE GHG shadow price for the initial 42 MMT RSP trended back to a 2018 cap and trade price. The adopted 2017-18 42 MMT Preferred System Plan (PSP), however, incorporated an update to use forecasts from the 2017 CEC Integrated Energy Policy Report (IEPR) (whereas the Reference System Plan had used 2016 IEPR forecasts). This update changed the resulting GHG shadow prices in RESOLVE, as shown in Figure 4, below, in which the 2019 ACC (dashed blue line) and 2017-18 PSP (gold line) reflect different GHG cost trajectories and end points.

Figure 4 also reflects the GHG shadow price from the 2019 Preliminary Results 46 MMT case (red line), as well as preliminary 2020 ACC emissions costs (dashed green line). For the preliminary 2020 ACC trajectory, the Preliminary Results 46 MMT GHG shadow price in 2030 of $150/ton is discounted back to 2020 and 2025 using a nominal discount rate from the 2019 ACC (~7.3%). Note that this proposed 2019 Preliminary Results 46 MMT case may be updated prior to the adoption of the final RSP expected in early 2020. The 2020 ACC update proposes to use values from the final RSP to reflect emissions costs in the 2020 ACC.

The 2017-18 42 MMT PSP showed excess reserve margin for the full planning cycle, resulting in zero value for additional capacity resources. The 2019 ACC employs the current resource balance year approach for DER, assuming a capacity value at the Cost of New Entry for a combustion turbine starting at $112/kW-yr in 2020 and increasing to just over $150/kW-yr in 2030.

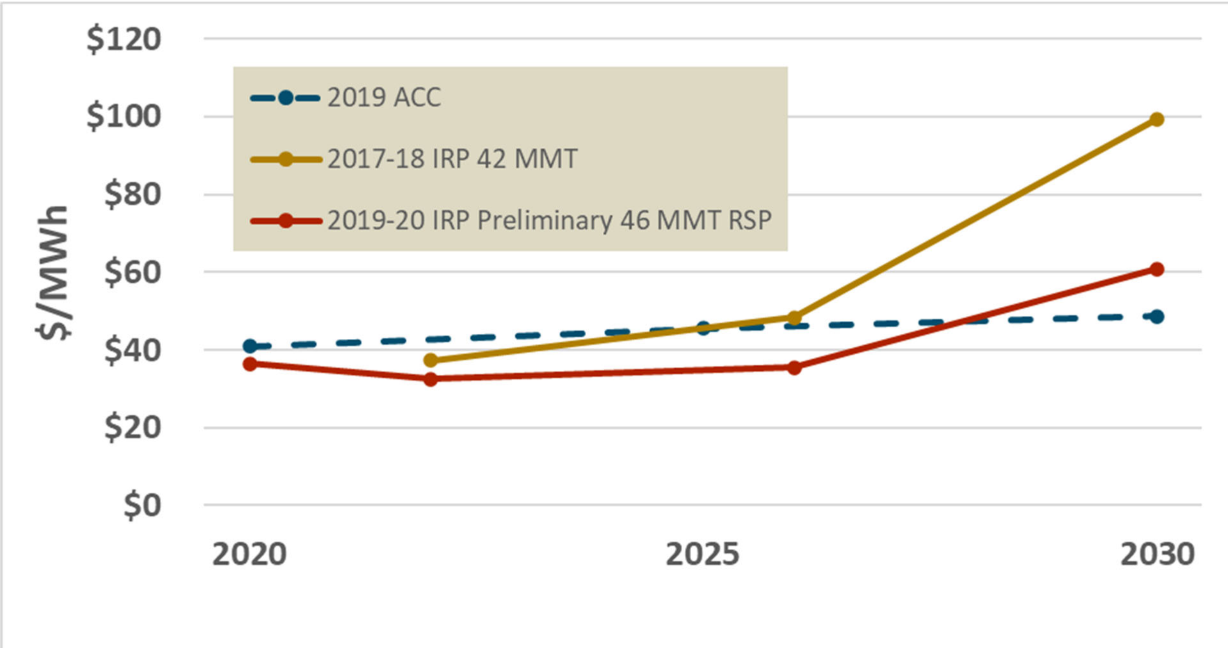
[8] See the IRP documentation referenced above for more detail on these and other IRP updates.

Figure 4: GHG Value ($ nominal)



The proposed energy value in the ACC is not a direct input from the IRP. Rather, Energy Division's consultant E3 recommends performing production simulation with the resource portfolio from the RSP to quantify energy values for DER (described in the next section). For purposes of comparison only, Figure 5 shows indicative annual energy values from 2017-18 and 2019-20 IRP modeling. Figure 5 shows the average annual energy value from RESOLVE, which are calculated as the hourly energy prices weighted by total load in each year. In 2022 the average annual energy price in RESOLVE modeling has decreased from $37/MWh to $32/MWh. In 2030 the reduction is much larger, from $99/MWh to $61/MWh. For comparison, the chart includes the average annual energy value from the 2019 ACC, which increases from $41/MWh in 2020 to $49/MWh in 2030. These preliminary RESOLVE results suggest that the energy prices produced with production simulation of the 2019 Preliminary Results 46 MMT case as described in the next section may be lower than those of the 2019 ACC, at least through 2026, and likely higher thereafter.

Figure 5: Energy Value ($ nominal)



Staff recognizes that implementing this proposal, which is a market-based approach to estimating avoided costs, is conceptually similar to returning to an older method of calculating avoided generation capacity costs, where the ACC included both short-run, market-based values, and long-run values, based on future construction costs. In 2016, the Commission decided to change to use only long-run avoided generation capacity costs in the Avoided Cost Calculator, thus eliminating the use of short-run avoided generation capacity costs. This means that the Resource Balance Year (RBY), which is defined as the point in time in which we switch from short-run to long-run avoided generation capacity costs, is currently always set at the current year. D.16-06-007 states:

> *We find that the current system omits Commission clean energy policies, such as the loading order and ignores grid planning processes. As discussed in detail below, this omission places distributed energy resources at a disadvantage to fossil fueled generation .*

Section 2.4 of the Decision goes on to explain in more detail why the generation capacity that DERs avoid is more appropriately represented by long-run, rather than short-run, capacity values.

Since that time, the question of alignment with other valuation methods, such as the Least Cost Best Fit (LCBF) method used for supply-side procurement and IRP models, has come up. Both IRP and LCBF consider both the short-run cost of generation, which is based on the current market price for capacity, and the long-run "cost of new entry (CONE)," which is based on the cost of building new generation facilities. If the Commission does decide to reconsider using only long-run costs it is important to consider the impact of any change in method on DERs and consider what can be done to alleviate the concerns raised in D.16-06-007. Staff welcomes party comment on this issue.

One of those concerns is that use of a valuation method which compares DERs to the short run value of capacity unfairly impacts demand response programs. Demand response cost-effectiveness analysis is done only over the lifetime of a demand response program, typically 3 years, which is generally well within the short-run timespan. Even the recent change from 3 to 5 years for demand response programs would not be likely to move much of the demand response value into the long-run period. Use of only short-run avoided capacity costs to value DR programs underestimates the value to the electric grid of having customers who are willing and able to reduce demand when needed, because once those customers are enrolled they are likely to continue in the program for more than 3 years, particularly if they invest in enabling technologies (which also will persist for more than 3 years).

Hence, this proposal requires a discussion of possible modifications to demand response cost-effectiveness analysis. For example, the Commission could consider if it is possible to develop a method for estimating demand response cost-effectiveness over an extended time period, such as the expected useful lifetime of enabling technologies. Questions that will be considered in a future update of the Demand Response Cost-effectiveness Protocols include:

- In the 10 or so years since the demand response cost-effectiveness methods were first developed, how have demand response programs, practices, and technologies changed?
- In that same time period, how much has the percentage of demand response participants using enabling technologies changed?
- Do technological changes require that we reconsider how we calculate demand response participant costs?
- Can we use the long-run supply costs of demand response developed in the demand response potential study and IRP modeling in the cost-effectiveness framework?

This will be taken up in the appropriate demand response proceeding.

2.4. RESOLVE Resource Portfolio for Production Simulation

RESOLVE selects a least-cost portfolio for the 2019 RSP. That portfolio would be used as an input in production simulation to generate hourly energy and ancillary services prices (described in next section). The resource portfolio from the 2019 Preliminary Results 46 MMT case is summarized below in

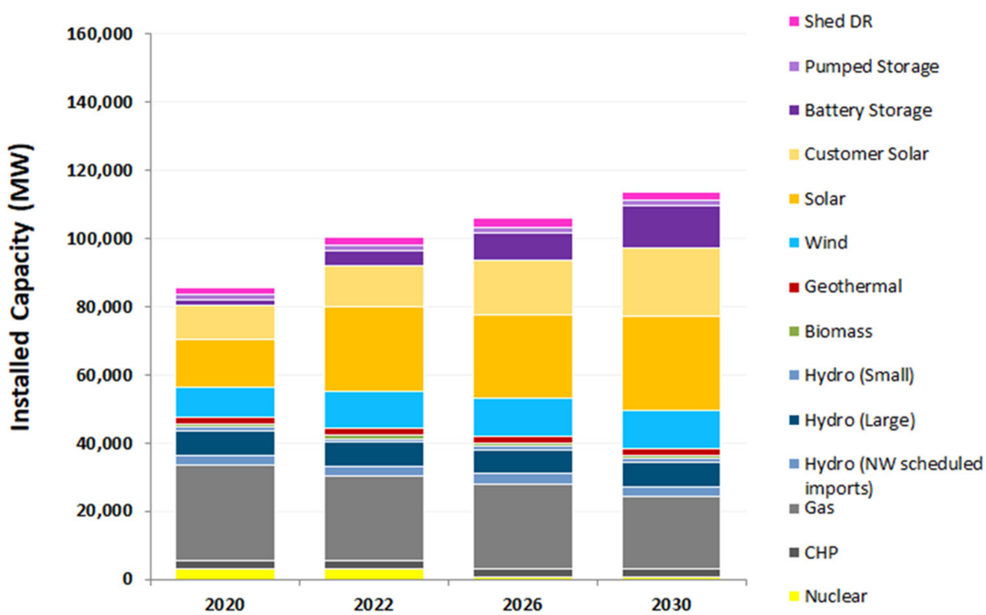
Table 5 and Figure 6. The energy balance from that resource portfolio is shown in Figure 7.

Table 5: Summary of 2030 Portfolio for 2018 Preferred System Plan and 2019 Preliminary Results 46 MMT case[9]

[9] From 2019-20 IRP Preliminary Results Presentation, October 8, 2019, slide 82.

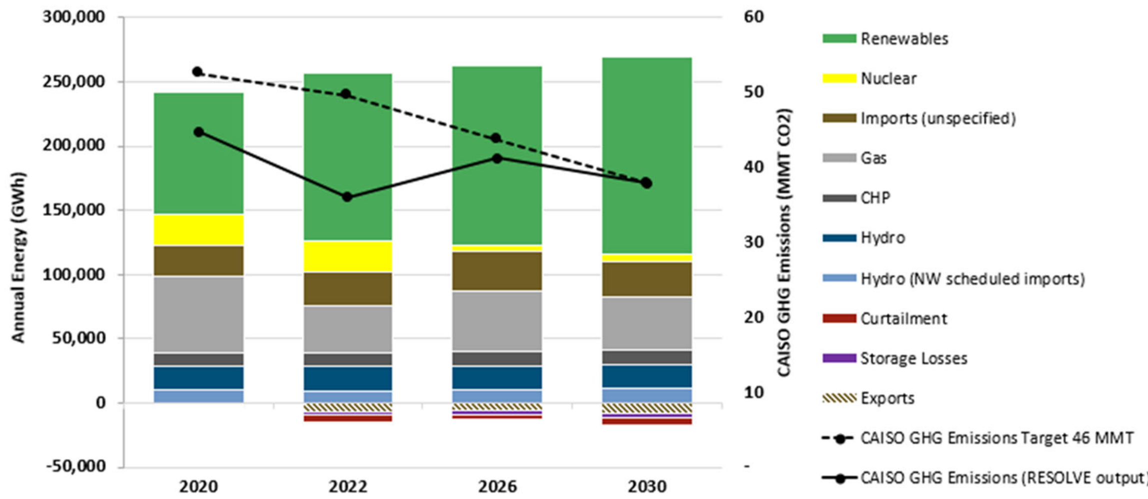
Metric	2017-18 IRP Preferred System Plan	2019 Preliminary Results 46 MMT
CAISO GHGs	34 MMT	37.9 MMT
Selected Resources (by 2030)	2.2 GW wind 5.9 GW solar PV 2.1 GW battery storage 1.7 GW geothermal	2.4 GW wind 12.6 GW solar PV 9.3 GW battery storage 440 MW shed DR
Selected Renewables *(on existing Tx)*	9.8 GW	15 GW
Levelized Total Resource Cost	$44.5 billion/yr	$46.3 billion/yr
Marginal GHG Abatement Cost	$219/metric ton ($2016) $301/metric ton (2030 nominal)	$109/metric ton ($2016) $150/metric ton (2030 nominal)
Planning Reserve Margin	22%	15%

Figure 6: Total Resource Portfolio for 2019 Preliminary Results 46 MMT case[10]



[10] From 2019-20 IRP Preliminary Results Presentation, October 8, 2019, slide 61.

Figure 7: CAISO Energy Balance for Preliminary Results 46 MMT case[11]



3. Production Simulation

Prior ACC cycles have relied upon historical CAISO day-ahead hourly energy prices to provide shapes for forecasted 8,760 hourly energy prices. With the forecasted increase of renewable generation in California, historical prices are no longer a reliable indicator of future price shapes. Staff therefore recommend shifting to production simulation to develop forecasts of energy prices and hourly energy price shapes.

Production simulation is a widely used method of modeling the operation and associated costs of the power system, including the interaction between generators and transmission constraints. Users specify different combinations of assumptions and inputs that describe the electric grid and power needs, such as generator characteristics, fuel prices, load forecasts, weather, and dispatch constraints. Based on these inputs, production simulation models produce the least-cost operational outcomes that ensure sufficient supply to meet demand for all modeled time periods, while satisfying all constraints. Different scenarios and sensitivities can be designed to investigate the impact of different input assumptions on system operation and prices.

The CEC uses production simulation in developing time-dependent valuation (TDV) for evaluating cost-effective energy efficiency for California Title 24 building standards (Section 3.1). The process is quite similar in intent, though different in approach, to this proposed update to the ACC. In both cases, state policy makers are developing a set of avoided costs to evaluate and implementing programs to require/promote DER measures that are found cost-effective. Using production simulation for the 2020 ACC update will facilitate alignment and consistency in these two processes.

To highlight the importance of updating the ACC methodology to better reflect expectations of future price shapes, Figure 8 below shows the increase in spring solar generation on the CAISO system, and the impact on system operations. Years 2017-2019 show pronounced changes in system operation and price shapes with increased solar generation. Each dot represents a single hour for each day in March, April

[11] From 2019-20 IRP Preliminary Results Presentation, October 8, 2019, slide 65.

and May across hours of the day (from left to right). As solar generation increases, the 'duck curve' shape emerges in the net loads for 2017-2019. Thermal generation decreases overall, with a dual morning and evening peak in 2018 and 2019. Imports are significantly reduced mid-day, with exports of excess solar out of the state in 2018 and 2019. Most importantly, for purposes of developing avoided costs, the price shapes are dramatically different beginning in 2017. These changes illustrate the importance of capturing anticipated changes in the generation resource mix over time when developing avoided costs.

An additional advantage of employing production simulation is that it can also provide real-time energy and ancillary service prices, which have not been outputs of previous ACCs. Real-time energy and ancillary service values will reflect the value that dispatchable DERs can have in providing grid services.

There are a variety of production simulation models available, each with advantages and disadvantages. The CEC uses the PLEXOS model for its IEPR and Title 24 building standards. The CAISO is also using PLEXOS in developing transmission plans, so use of the PLEXOS model could provide some consistency across state agencies, although due to difference in the timing and purpose of each proceeding, it is not necessarily feasible for the Commission to use precisely the same PLEXOS model and cases as the CEC and CAISO. Energy Division staff use the SERVM production simulation model as part of the IRP process. Using the SERVM model would have the advantage that it is already fully integrated with the IRP modeling. Staff and its consultants E3, will determine in the near future which production simulation model is the most appropriate and feasible to use.

Note, while the proposed ACC would leverage RESOLVE outputs and assumptions to remain aligned and consistent with the IRP, RESOLVE is not a production simulation model and therefore does not directly produce the data needed to develop forecasts of future energy prices and hourly price shapes. A production simulation model will provide a useful complement to the resource portfolio outputs from RESOLVE.

Figure 8: CAISO Spring Solar Generation with Impacts on Net Load, Thermal Generation, Imports and Prices (X axis represents average of hours 01 – 24 for the months of March-May in each year)

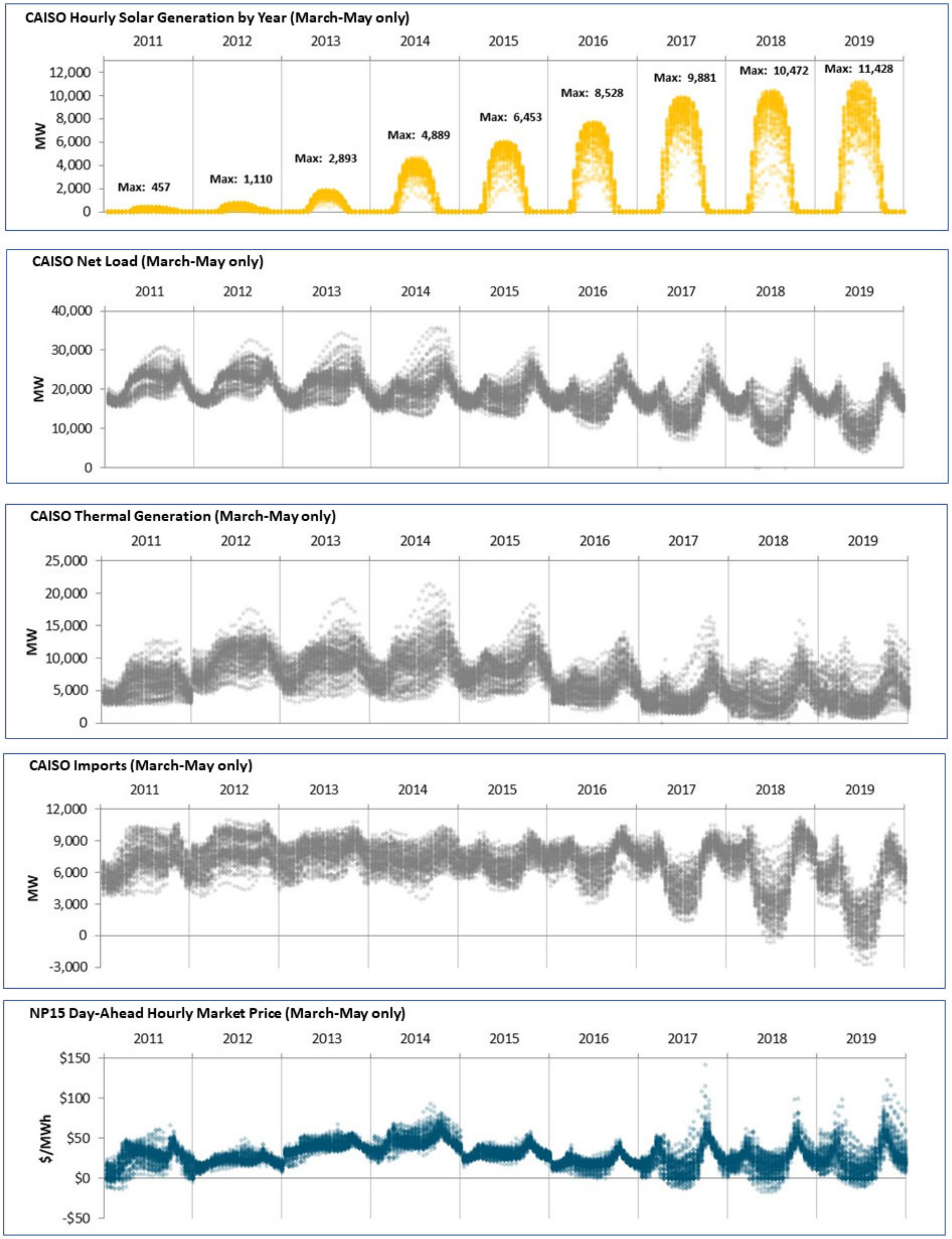
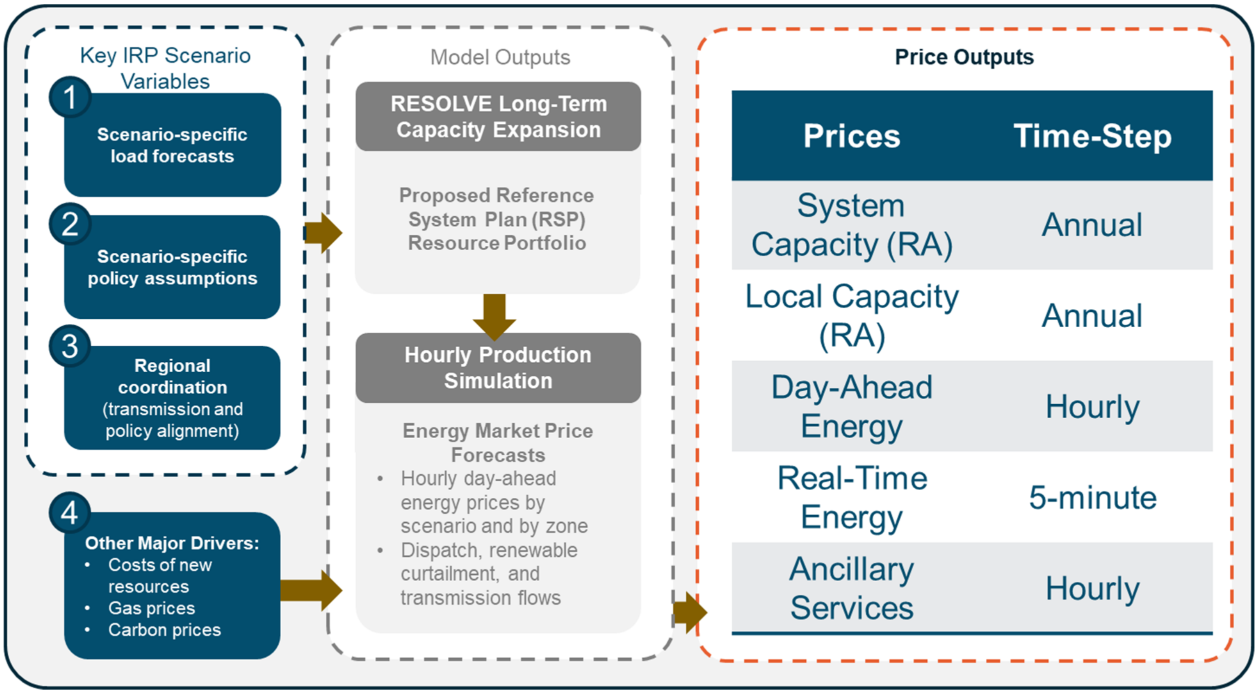


Figure 9: Overview of Proposed Production Simulation Process



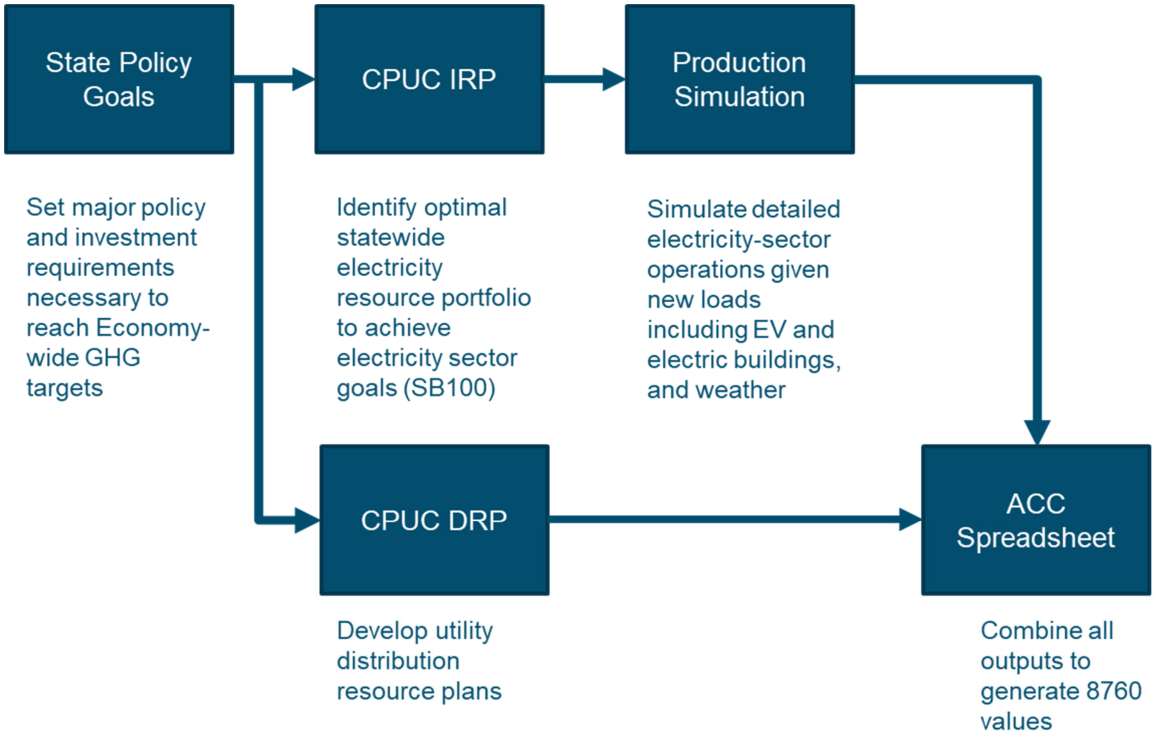
3.1. Example Production Simulation for Title 24 Building Standards

Every three years the CEC undertakes an update to the cost-effectiveness methods and calculator for time-dependent valuation (TDV) that is used to evaluate cost-effective energy efficiency for California Title 24 building. Both the CEC and CPUC are focused on developing policies to update their respective analytical approaches to appropriately and consistently evaluate load increasing (such as building and transportation electrification) and load reducing DER. Staff proposes that aligning the inputs, assumptions and approaches of the CEC ACC and the CEC Title 24 TDV proceedings will promote consistency in cost-effectiveness evaluation and efficient allocation of public funds to the most effective DER programs and measures. This alignment can be achieved while fully supporting the goals and policies adopted in the CPUC IDER proceeding.

Figure 10 shows the proposed CPUC avoided cost process, which is similar in concept to the CEC TDV process:

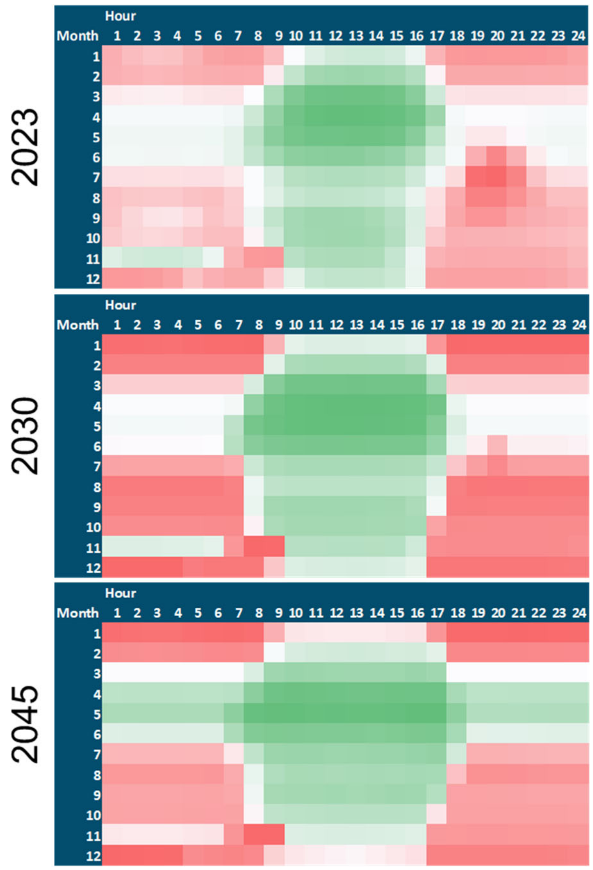
1. California state level policy goals guide the development of electricity sector resource plans.
2. RESOLVE capacity expansion modeling identifies least-cost resource portfolios for the electric section.
3. The selected resource plans are uses as the basis for production simulation modeling.
4. Production simulation modeling results feed into an Excel based TDV/ACC model that provides hourly values for DER for multiple categories.

Figure 10: Proposed CPUC Process for Developing Avoided Costs



Illustrative results from the CEC production simulation modeling are presented below for reference. The CEC ran production simulation for 2023-2030 and for 2045, interpolating results in between for the years 2023 – 2052. Illustrative heat maps of average hourly prices are shown in Figure 11 with lower priced hours in green and higher prices hours in red. This heat map shows how production simulation can produce price shapes base on changing electric generation portfolios over time.

Figure 11: CEC Production Simulation Modeling Energy Price Shapes Evolve with Changing Loads and Generation Mix



3.2. CEC Weather Year Matching

In this update of the ACC, Energy Division's consultant E3 recommends another step towards aligning California evaluation of DER cost-effectiveness, namely using the CEC's new California Thermal Zone 2022 (CTZ22) typical meteorological year (TMY) as the weather underlying the Avoided Costs. This CTZ22 TMY weather, adopted for the 2022 TDVs, will be used for the avoided cost components for which weather-driven load or generation affects the hourly variation of electricity costs.

The CTZ22 weather year was developed by Whitebox Technologies and Bruce Wilcox for the 2022 Title 24 Building Codes update.[12] The development of this weather year shares much of the same methodology as the typical weather year used in previous code cycles. For each month, the year whose weather is most "typical" for California is selected. This selection is done for the state as a whole, instead of by climate zone so that weather is consistent across climate zones. The defining difference between CTZ22 and previous weather years is that the historical weather is sampled from more recent years to reflect impacts of climate change. For areas outside of California, historical weather data from

[12] See presentations from Oct 17, 2019 CEC Workshop and methodology reports (forthcoming) under Dockets #19-BSTD-03 and #19-BSTD-04: https://ww2.energy.ca.gov/title24/2022standards/prerulemaking/documents/

the same month-years in CTZ22 are used to maintain simultaneous, consistent weather across the entire WECC footprint.

Using CTZ22 TMY weather matching and production simulation will align three key components that impact the shape and magnitude of energy prices: weather, load and DER impact shapes, and long-term forecasts. Several of the data sources developed with a significant, CEC-funded effort that can be consistently aligned with this process include:

- System Load Balancing Authority Area (BAA) data for WECC[13]
- Annual hourly electricity consumption for all-electric residential and commercial building prototypes and for selected electric water heating, space heating, cooking, and clothes drying end use shapes generated in CBECC-Res[14] and CBECC-Com[15] building simulation software
- Hourly wind generation profiles from multiple sources including NREL Western Wind[16], NREL Wind Toolkit[17], and Renewables Ninja[18]
- Simulated utility-scale PV generation profiles and historical NREL National Solar Radiation Database (NSRDB) data[19]
- Constructed database of Distributed Generation (DG) Solar PV for every county in the WECC using LBNL's Tracking the Sun dataset[20]

Energy Division's consultant E3 recommends continued examination of how assumptions, inputs and methods from the CEC TDV update process can be productively used in the CPUC 2020 ACC update process, erring on the side of maintaining consistency with the CPUC IRP as a first preference.

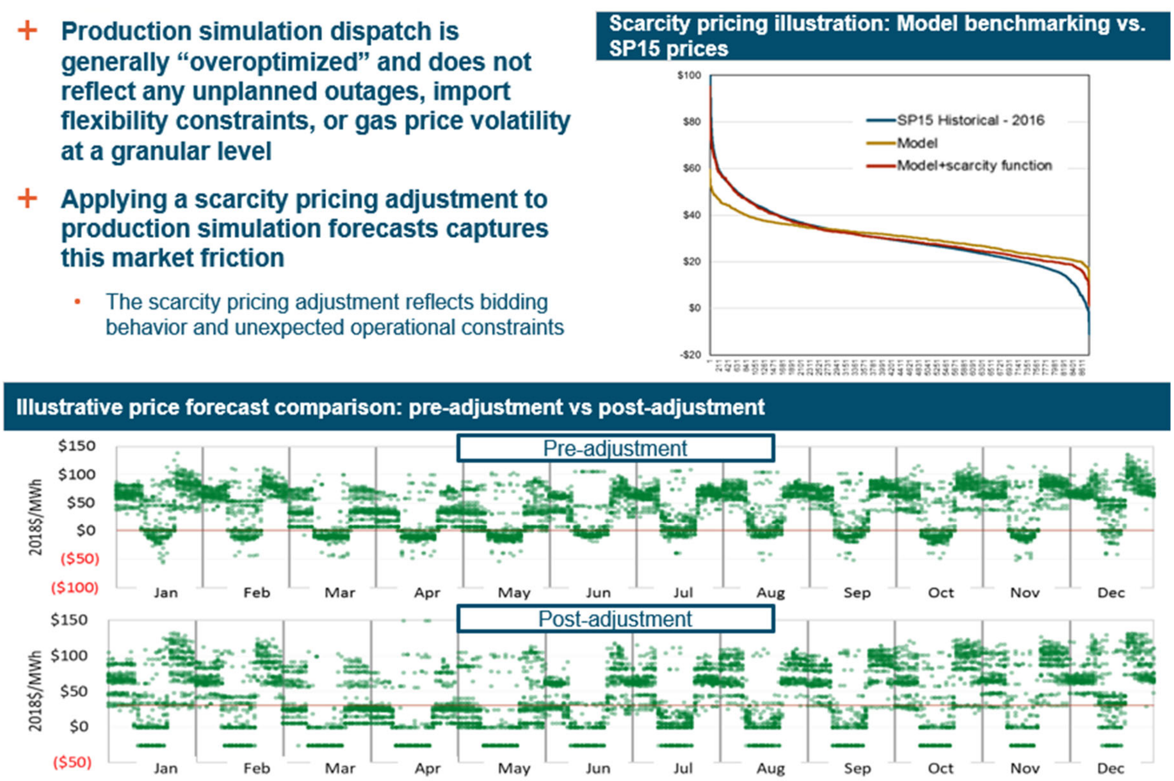
Other weather year files are available that could be used if parties suggest they are more appropriate. White Box Technologies also developed the CALEE2018 weather year.[21] However, CALEE2018 is more similar to the old CZ2010 TMY in that historical weather was sampled to be typical by climate zone instead of statewide as in the CTZ22. This results in the use of different years for different climate zones, which complicates production simulation modeling. In contrast CTZ22 year was designed to maintain historically consistent weather across the entire state, while representing typical weather as best as possible. The advantage of the CAL EE2018 weather year is that it uses the most recent 12 years of data, rather than the 20 years used for CTZ22, which may be a better basis for future changes in weather due to climate change.

[13] Data requested from WECC: https://www.wecc.org/Pages/Contacts.aspx
[14] http://www.bwilcox.com/BEES/BEES.html
[15] http://bees.archenergy.com/index.html
[16] https://www.nrel.gov/grid/western-wind-data.html
[17] https://www.nrel.gov/grid/wind-toolkit.html
[18] https://www.renewables.ninja/
[19] https://nsrdb.nrel.gov/
[20] https://emp.lbl.gov/tracking-the-sun
[21] For more information on the differences between CTZ22 and CALEE2018 see: https://pda.energydataweb.com/api/view/2280/Weather webinar CALEE2018 7-12-2019.pptx

3.3. Introducing Volatility in Production Simulation

Production simulation tends to produce unrealistically smooth price shapes and the optimization does not reflect real-world market friction, imperfect information or operating constraints. Energy Division's consultant E3 therefore recommends introducing volatility with a scarcity pricing function. Incorporating volatility that better matches real-world prices will be important for valuing dispatchable and flexible DER that can respond to market conditions. The scarcity pricing function is designed to capture real-world bidding behavior and operational constraints, which mostly apply to extreme price hours. The first step is calculating the implied marginal heat rate for each hour based on prices generated through production simulation. Then a set of multipliers will be applied to implied heat rates that are on both high and low bookends and recalculate the corresponding energy prices based on the adjusted implied heat rates. The multipliers are derived through benchmarking simulated prices to actual prices for selected historical years. Although hourly price shapes will change with the evolving grid as described above, historical price volatility and day-ahead vs. real-time relationships are the best model we have for producing similarly volatile prices from production simulation.

Figure 12: Illustration of Introducing Volatility to Production Simulation with a Scarcity Pricing Function



4. GHG Emissions and Avoided Cost Value

4.1. GHG Emissions

Staff proposes to update the GHG emissions methodology used in the ACC to better reflect the evolution of California's electric grid as the state progresses towards its emissions reduction goals. The current GHG avoided cost approach does not incorporate the declining GHG intensity of the electric grid as planned in the IRP. The proposed new method will accurately account for the decreasing emissions intensity of the electric grid when considering the increasing adoption of electrification measures. Without an accurate reflection of their electric sector impact the emissions attributable to these technologies will be grossly overstated. For the 2020 ACC update, Staff proposes to use production simulation (described is Section 3) to calculate short run hourly marginal emissions in place of the current implied market heat rate method. With the proposed RSP portfolio from the IRP modeling, marginal GHG emissions from production simulation will accurately reflect the declining emissions intensity of the grid going forward.

In the current ACC, GHG impacts are based on hourly short run marginal emissions, calculated using an implied heat rate methodology that incorporates market price forecasts for electricity and natural gas, as well as gas generator operational characteristics.[22] The future market price shapes are currently adjusted using the RPS calculator to reflect increased renewable generation. This approach does result in lower implied market heat rates during periods of higher solar generation, but it does not account for the declining annual average GHG emissions intensity of the grid.

Measuring GHGs based on the short run marginal emissions rate, however, does not accurately account for the supply-side response that will need to be procured due to changes in load. Given the GHG emissions reduction goals that California has adopted, the carbon intensity of the state's electric sector will need to decrease significantly in the coming years, even as the state adds considerable new load through building and transportation electrification. Thus, as demand-side actions modify load, load serving entities will rebalance the supply portfolio to meet the required emissions targets.

Staff proposes to account for this supply-side response in the updated ACC through a methodological shift to using long run marginal emissions in evaluating the GHG impacts of demand-side load modifications. Given that California plans to meet the SB100 goal of 100% decarbonized electricity (as measured by retail sales) by 2045, long run marginal emissions can be calculated based on an assumed GHG reduction target aligned with the SB100 goal.[23] Staff believe it is most appropriate to structure the long run emissions calculations based on this electric sector emissions reduction target. To do so Staff

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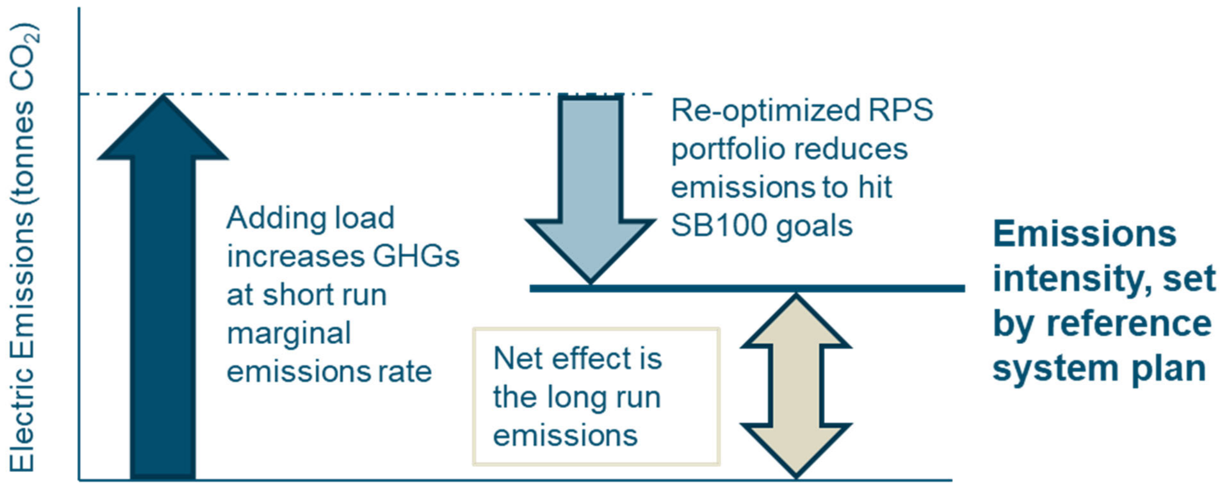
[22] See 2019 Avoided Cost Update Documentation available at: https://www.cpuc.ca.gov/General.aspx?id=5267

[23] A joint agency report process to assess an interpret SB 100 requirements is underway. Among the issues is an interpretation of how to define SB 100-eligible zero carbon resources. CPUC IRP inputs in the 2019 RSP modeling analysis were developed, of necessity, based on one possible interpretation of the SB100 goals. However, assumptions used for IRP modeling purposes by CPUC staff do not represent the Commission's dispositive view on SB 100 interpretation.

proposes to use the annual emissions intensity values derived from the IRP to reflect the emissions attributed to load-modifying demand-side actions.[24]

Figure 13 below provides an illustrative example of how long run emissions based on annual emissions intensity targets would be derived, and their relationship to the existing short run emissions calculated in the ACC.

Figure 13: Illustrative Long Run Emissions Calculation



The annual emissions intensity factors are calculated as follows, for year *t*:

$$Emissions\ Intensity_t(\frac{tCO_2}{MWh}) = \frac{Total\ CAISO\ Emissions_t(tCO_2)}{Total\ Retails\ Sales_t\ (MWh)}$$

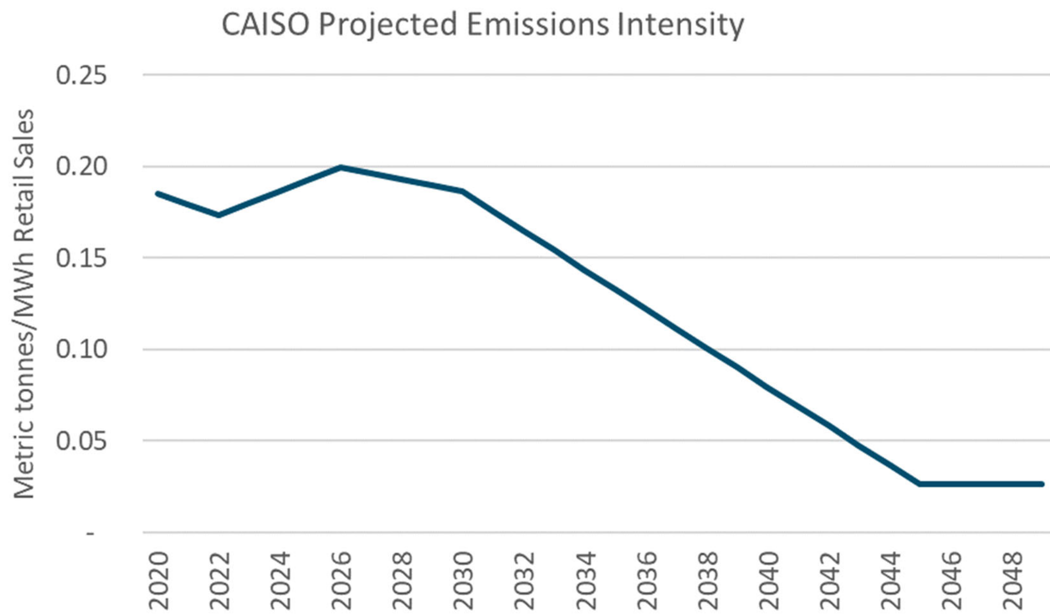
Table 6: and Figure 14 below depict the annual emissions intensity trajectory derived from the 2017-2018 Reference System Plan. Note that the rebound in emissions intensity between 2022 and 2026 is due to the planned retirement of Diablo Canyon. Emissions intensity is calculated as tonnes of GHG per MWh of retail sales to be consistent with SB100 language that zero-carbon resources supply 100% of retail sales of electricity to end-use customers in 2030.

Table 6: 2019 IRP Preliminary Results 46 MMT Case Load and Emissions

	Units	2020	2022	2026	2030
Load	*GWh*	242,188	247,401	253,790	257,010
Total Retail Sales	*GWh*	207,468	208,040	207,212	203,359
Total CAISO Emissions	*MMtCO2/Yr*	45	36	41	38
Emissions Intensity	*tCO2/MWh*	0.22	0.17	0.20	0.19

[24] The 2017-18 Reference System Plan adopted an electric sector goal of 42 MMt CO_2e by 2030, reflective of specific scenario assumptions. Energy Division's consultant E3 recommends using the implied annual emissions intensity – rather than the 42 MMt emissions goal itself or the updated 46 MMt goal in the proposed 2019-20 Reference System Plan – to reflect the electric sector target for that year.

Figure 14: CAISO Projected Emissions Intensity, 2019 IRP Preliminary Results 46 MMT Case



As the adopted 2017-2018 Reference System Plan provides retail sales and GHG emissions through 2030, a linear progression was assumed between these 2030 values and the 2045 SB100 goals to estimate emissions intensity at that end-year.[25] However, as the IRP process progresses it will be possible to more directly leverage outputs from that proceeding to inform annual emissions intensity values beyond 2030.

4.2. Avoided Cost Value

In addition to updating GHG accounting from short run marginal to long run marginal emissions, Staff further proposes to modify the valuation of these emissions to better align with the updated accounting approach.

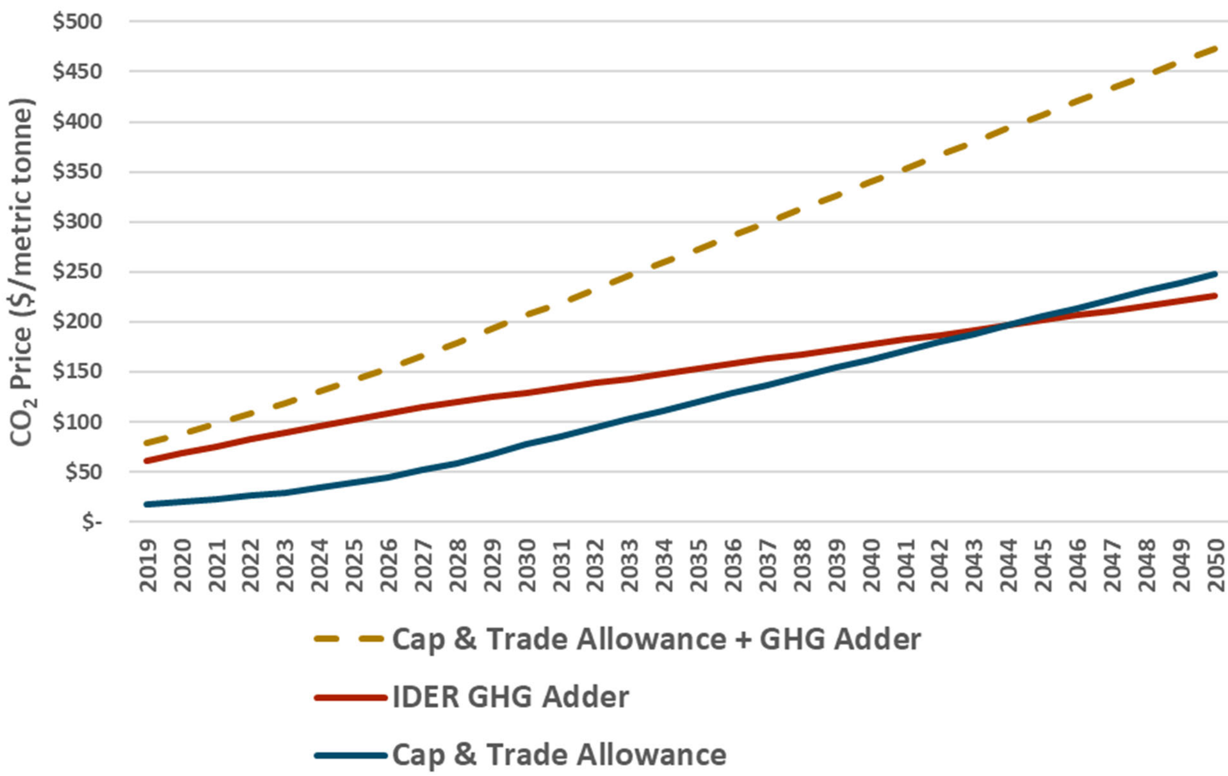
In the current ACC, the avoided cost of GHG emissions is represented by the sum of two values, 1) the monetized carbon cap and trade allowance cost embedded in energy prices, and 2) the non-monetized carbon price beyond the cost of cap and trade allowances (represented by the GHG Adder, as adopted

[25] To estimate the emissions intensity in 2045 it is assumed that SB100 goals will be met, requiring a minimum level of decarbonized generation equal to 100% of retail sales. With this assumption, up to approximately 7.25% of electric generation could be from natural gas generation (based on loss factor assumptions from the 2019 ACC v1b). Sector emissions in 2045 can be calculated using an assumption of the emissions intensity of a combined cycle gas turbine (with a heat rate of 7,000 Btu/kWh) and an assumed volume of fossil energy that could be used while still allowing the state to meet the SB100 target. The remaining energy on the system is assumed to have zero emissions.

by the CPUC).[26] The second of these values reflects the cost of further reducing carbon emissions from electricity supply, rather than the compliance cost represented by the cap and trade allowance price.

Figure 15 below depicts the price forecasts for the cap and trade allowance price (solid blue line), the IDER GHG Adder (solid red line) and the allowance price plus the GHG Adder (dashed gold line) from the 2019 ACC v1b.

Figure 15: CO_2 Cap & Trade and GHG Adder Price Series



The proposal is to continue to calculate a GHG avoided cost value based on the shadow price of GHG emission reductions from RESOLVE modeling in the IRP. As described in Section 2 above, the GHG value in the 2019 proposed RSP is expected to be lower than the 2017-18 PSP. However, using the GHG valued developed in the most recent IRP provides consistency in the evaluation of supply and demand side cost-effectiveness. The GHG avoided cost value will continue to be used in total, but separated into a monetized cap and trade value and the residual non-monetized value that is the difference between the GHG shadow price and the cap and trade value.

A proposed change to the 2019 ACC methodology and the D. 18-02-018 GHG avoided cost value is to discount the 2030 GHG shadow price from the IRP at the utility WACC to calculate GHG avoided cost values for 2020 – 2029. This would be in place of trending the value back to the current cap and trade price. RESOLVE modeling for the IRP results in relatively low GHG shadow prices in earlier years. This is

[26] D.18-02-018, Table 6. Note that in Table 6 of this IRP Decision, the term "GHG Adder" is used, inconsistent with the usage in IDER, to represent the combined value of the monetized cap and trade allowance price and the non-monetized residual value (rather than only the residual, non-monetized value).

for a variety of reasons, but in part because renewable generation is procured prior to 2022 for reliability and to take advantage of the ITC before it steps down from 30% to 10%. This results in a generation portfolio that exceeds the GHG targets for 2022 and 2026, resulting in a low GHG shadow price for GHG. Energy Division's consultant E3 recommends that the long-term value of GHG reductions from DER is better reflected by discounting the 2030 value back to 2020 to calculate the annual GHG avoided cost value.

In current cost-effectiveness calculations, the direct, hourly short run marginal emissions for a given year are multiplied by the load shape (the hourly load increase or reduction) of a given DER program or measure, and the annual product of that multiplication represents that year's GHG emissions. This annual emissions figure is then multiplied by that year's total carbon value (cap and trade allowance value plus GHG Adder) to derive the avoided emissions cost (either positive or negative) of a given program or measure, which represents the value of additional supply-side investments to reduce emissions.

To be consistent with the methodological change to using an annual emissions intensity target the emissions valuation must also be updated. Rather than assuming *all* demand-side changes in emissions must be entirely offset by supply-side resources, the *difference* between the direct short run marginal emissions and the intensity target must be calculated. When multiplied by the GHG Adder this value reflects the avoided electric sector emissions cost of maintaining the annual intensity target, rather than the cost of completely offsetting the change in emissions due to the measure's load impact.

The remaining emissions – that is, the additional emissions which would need to be offset to result in a given measure having zero net emissions impact – should be valued differently, as these emissions no longer represent GHG that should only be valued at costs specific to the electric sector (as represented by the GHG Adder). Instead, it is more consistent with the state's economy-wide GHG reduction goals to value these residual emissions as emissions from other sectors are valued at the CARB cap and trade price.

The following equations illustrate the difference between the existing GHG calculation in the 2019 ACC and the proposed GHG calculation for the 2020 ACC. These equations reflect the net present value of the emissions attributable to a given measure or program, over its expected useful life.

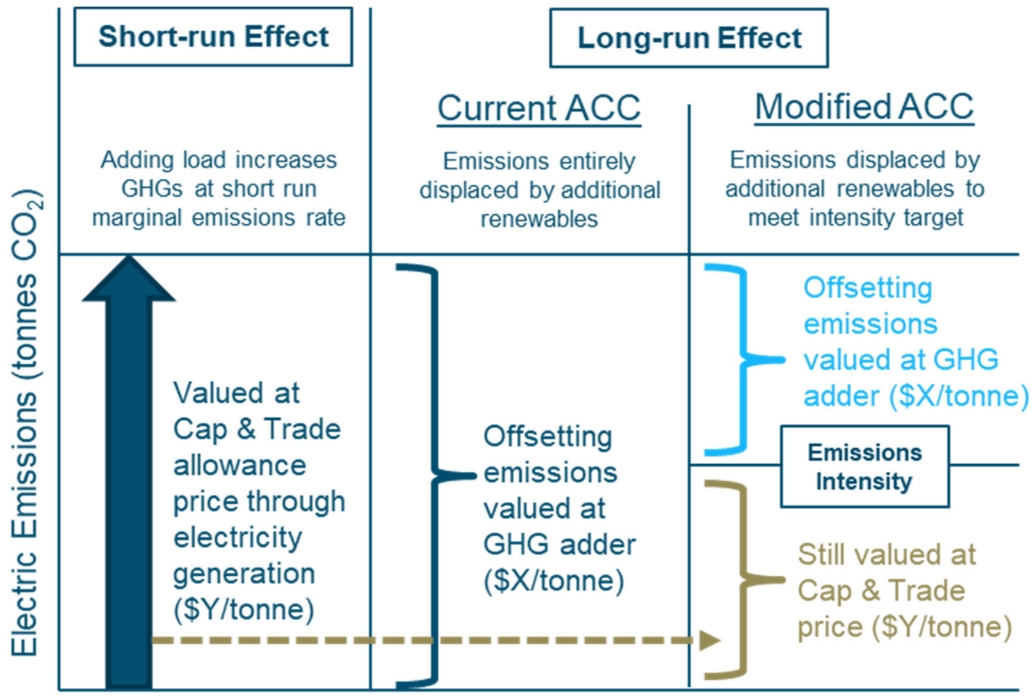
$$
\begin{aligned}
&GHG\ Calculation_{2019\ ACC} \\
&\qquad = Load\ Shape\ (kWh)_h * Marginal\ Emissions\ (tCO_2e/kWh)_h \\
&\qquad * \ GHG\ Adder(\$/tCO_2e)_y
\end{aligned}
$$

$$
\begin{aligned}
&GHG\ Calculation_{2020\ ACC} \\
&\qquad = Load\ Shape\ (kWh)_h * [Marginal\ Emissions\ (tCO_2e/kWh)_h \\
&\qquad - Annual\ Emissions\ Intensity\ (tCO_2e/kWh)_y] \ * \ GHG\ Adder(\$/tCO_2e)_y \\
&\qquad + [Annual\ Load\ (kWh)_y * Annual\ Emissions\ Intensity\ (tCO_2e/kWh)_y \\
&\qquad * Cap\ and\ Trade\ Price\ (\$/tCO_2e)_y]
\end{aligned}
$$

Note, in the above equations *h* represents an hourly dimension, while *y* represents a yearly dimension.

Figure 16 provides an illustrative example of the current ACC emissions valuation and the proposed update based on the long run emissions calculation. This example illustrates increased emissions due to a load-building measure, but the inverse relationship would hold true for a measure which instead reduces load.

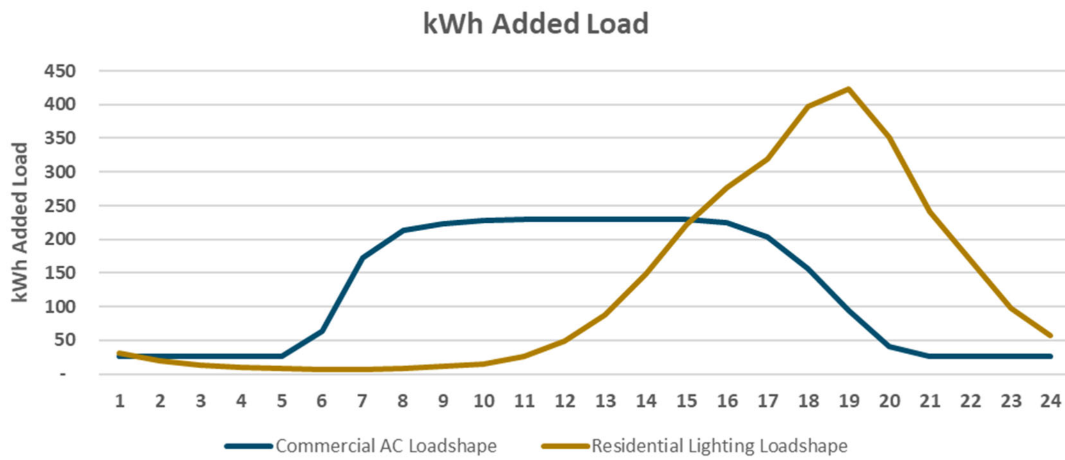
Figure 16: Current ACC GHG Valuation and Proposed Update (illustrative load increase example)



4.3. Example Calculation

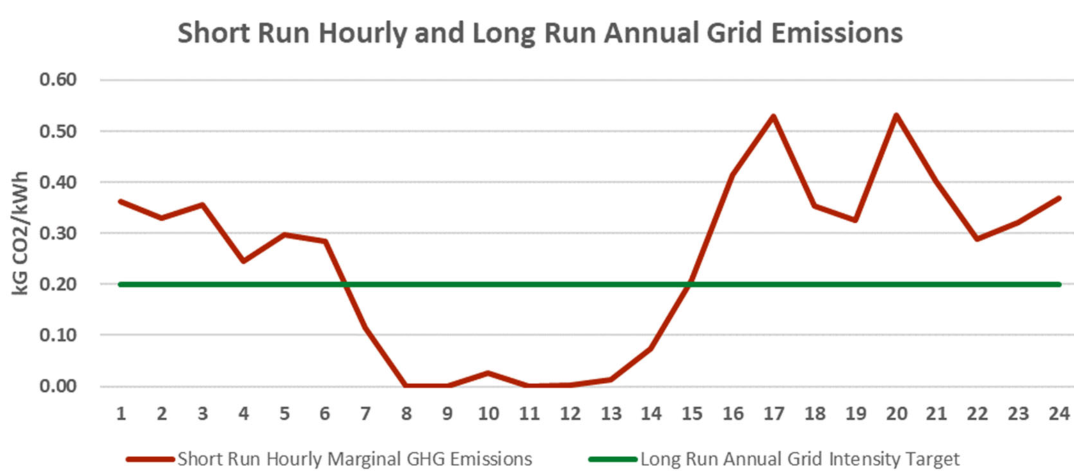
This section presents an example calculation for the GHG emissions impact and associated avoided costs. Using the methods described above, the example adds load to the electric grid and calculates the resulting increase in GHG emissions costs. To illustrate the combination of short run hourly and long run annual emissions, the example shows one day with two load shapes. The two load shapes are commercial air conditioning with load added predominately in the middle of the day, and residential lighting with load added predominately in the evening (Figure 17).

Figure 17: Illustrative Load Shapes for Example Day



For this example, a target long run annual grid intensity of 0.2 kg C02/kWh is assumed. The short-run hourly marginal emissions for the example day are higher than the long run intensity in the morning and the evening, but lower during the middle of the day, as shown in Figure 18. The commercial AC load shape adds load predominately during the middle of the day when the short run hourly marginal emissions are lower than the annual intensity, whereas the residential lighting measure adds load during evening hours when the short run emissions are higher.

Figure 18: Illustrative Short Run Hourly Marginal Emissions and Long Run Annual Grid Emissions Intensity



The hourly load shapes and GHG emissions illustrated in the above charts are shown below in Table 7. The first two columns list the hourly kWh load shape for the commercial AC and residential lighting load, both totaling 3,000 kWh for the day. At the long run annual grid emissions intensity of 0.2 kg/kWh both measures will each increase GHG emissions by 600 kg for this example day. Both the short run and the long run marginal GHG emissions are displayed for each measure, as is the difference between these values.

The commercial AC load is adding load during the middle of the day with lower marginal emissions such that the emissions intensity of the added load is lower than the 0.2 kg/kWh annual average. This additional load at lower emissions intensity creates headroom of 103 kg of CO2 in grid emissions that can be added while still meeting the 0.2 kg/kWh intensity target. For residential lighting the additional load is well above the annual average intensity, such that 435 kg of CO2 must be removed from the grid to meet the 0.2 kg/kWh intensity target. The differences between the short-run emissions intensity and the long-run emissions intensity target are valued at the GHG Adder which reflects the marginal cost of supply-side GHG reductions in RESOLVE and includes the costs of renewable generation and integration.

Table 7: Illustrative Short and Long Run GHG Emissions Calculations for an Example Day

	Added Load		GHG Emissions Rates		Short-run GHG Emissions		Long-run GHG Emissions		Marginal GHG Impact Relative to Intensity Target	
	Commercial AC Loadshape	Residential Lighting Loadshape	Short Run Hourly Marginal GHG Emissions	Long Run Annual Grid Intensity Target	AC	Lighting	AC	Lighting	AC	Lighting
Hour	kWh	kWh	kg/kWh	kg/kWh	kg	kg	kg	kg	kg	kg
1	26	32	0.36	0.2	9	12	5	6	4	5
2	26	19	0.33	0.2	9	6	5	4	3	2
3	26	14	0.35	0.2	9	5	5	3	4	2
4	26	10	0.25	0.2	6	2	5	2	1	0
5	27	8	0.30	0.2	8	2	5	2	3	1
6	64	7	0.28	0.2	18	2	13	1	5	1
7	173	7	0.12	0.2	20	1	35	1	(15)	(1)
8	213	8	0.00	0.2	-	-	43	2	(43)	(2)
9	224	12	0.00	0.2	-	-	45	2	(45)	(2)
10	229	15	0.03	0.2	6	0	46	3	(40)	(3)
11	229	27	0.00	0.2	-	-	46	5	(46)	(5)
12	229	50	0.00	0.2	0	0	46	10	(45)	(10)
13	229	89	0.01	0.2	3	1	46	18	(43)	(17)
14	229	148	0.07	0.2	17	11	46	30	(29)	(19)
15	229	222	0.21	0.2	48	46	46	44	2	2
16	224	277	0.41	0.2	93	115	45	55	48	59
17	203	318	0.53	0.2	107	168	41	64	67	105
18	156	397	0.35	0.2	55	140	31	79	24	61
19	95	423	0.32	0.2	31	137	19	85	12	53
20	42	351	0.53	0.2	22	186	8	70	14	116
21	26	241	0.40	0.2	10	97	5	48	5	49
22	26	169	0.29	0.2	7	49	5	34	2	15
23	26	98	0.32	0.2	8	32	5	20	3	12
24	26	57	0.37	0.2	10	21	5	11	4	10
Total	**3,000**	**3,000**			**497**	**1,035**	**600**	**600**	**(103)**	**435**
				Allowable kg/kWh of additional generation >>					**0.23**	**0.06**

The resulting sum of the short and long run GHG value calculations are shown in Table 7. In both cases the total added long run GHG emissions, after changes in the supply portfolio, for the illustrative day are the same at 600 kg CO2.

The short run emissions are valued at the cap and trade allowance price, in this case assumed to be $90/tonne. This results in a $45 cost for the commercial AC measure, and a $93 cost for the lighting measure given it adds load in hours with higher emissions. In addition to these values, the difference between each measures' short run emissions and the long run emissions calculated assuming an annual intensity target of 0.2 kg/kWh is multiplied by the GHG adder, here assumed to be $110/tonne. This results in a credit of $11 for the AC measure, given it is adding load in relatively low-emission hours, and a cost of $48 for the lighting measure given it is adding load in relatively high-emissions hours.

Table 8: Illustrative GHG Value Calculation

GHG Emissions Value ($/Tonne)			Commercial AC Load Shape		Residential Lighting Load Shape	
			kg GHG Impact	$ GHG Value	kg GHG Impact	$ GHG Value
Short run Emissions	Cap and Trade Value	$90	497	$45	1,035	$93
Incremental Emissions beyond Intensity Target	IRP GHG Shadow Price	$110	(103)	($11)	435	$48
		Total		**$33**		**$141**

kWh Added	$/MWH GHG Value	kWh Added	$/MWH GHG Value
3,000	$11.17	3,000	$46.97

For the sake of brevity, a similar example for load reductions is not included. However, the method and logic applies exactly the same in the opposite direction for load reductions. If the above examples of commercial AC and residential lighting were efficiency measures rather than load additions, they would result in GHG costs of -$33 and -$141, respectively. In that scenario, the residential lighting measure is more valuable from an emissions standpoint than the commercial AC measure, given that it is reducing load during hours with relatively high emissions rates.

5. Distribution Avoided Costs

Distribution avoided costs represent the value of deferring or avoiding investments in distribution infrastructure through reductions in distribution peak capacity needs. The ACC currently uses marginal cost values from IOU filings in their General Rate Case Phase II proceedings. Recently the Distributed Resources Planning (DRP) proceeding (R.14-06-013) has developed considerable insight and data related to the impact of DERs on the distribution system. Specifically, the Energy Division White paper attached to the DRP June 13, 2019 ALJ Ruling[27] (DRP Staff Paper) defines two types of avoided costs (Specified and Unspecified), and proposes to leverage information from utility Distribution Deferral Opportunity Report (DDOR) and Grid Needs Assessment (GNA) filings that contain detailed information about utility needs and investment plans. Therefore, for the 2020 update, Energy Division has asked our consultants E3 to examine how to use the DRP information to derive avoided costs that are more applicable to cost-effectiveness evaluations than the extant GRC marginal costs. The following section proposes a method for developing avoided distribution costs that is based on the recommendations in the DRP Staff Paper. The CPUC will determine in the DRP proceeding how to use the DRP Staff Paper's recommendations.

5.1. Distribution avoided costs from the DRP

5.1.1. Specified Deferrals

The utilities calculate distribution avoided costs as part of the annual DDOR process. These avoided costs are specific to a small number of utility capacity projects that could potentially be deferred via DER adoptions in the project areas. The DDOR avoided costs represent the value of deferring distribution investment projects through the addition of DER or other load reducing measures that are *above and beyond* the DER growth the utility expects to be adopted in the project area because of current DER policies, incentives and programs. The DRP report defines these DDOR costs as "**Specified deferrals**".

The Specified deferral costs are not included directly in the avoided costs for the ACC because new incremental DER in these areas would be implemented through a separate DDIF process. The Specified deferral avoided costs and underlying information, however, are used as inputs into the calculation of Unspecified deferrals discussed below.

5.1.2. Unspecified Deferrals

The second set of avoided costs, which will be used in the ACC, is derived using data from the DRP, but not a direct output of that process. Defined as "**Unspecified deferrals**" in the DRP Staff Paper, these avoided costs reflect the increased need for capacity projects that would have occurred if there were less DER growth embedded in the utility base forecasts. With less DER growth, the forecasted demand would be higher on each circuit which could lead to a circuit overloads that trigger the need for upgrade projects not identified in the GNA filings.

Unspecified deferrals are represented in Figure 19 as the lower right quadrant. The table summarizes the differences between the Specified and Unspecified deferrals. Specifically, the Specified deferrals are for a limited set of utility projects and based on load forecasts that reflect all projected new DER growth, while the Unspecified deferrals are based on the rest of the utility system and reflect capacity needs under a counterfactual load forecast.

[27] ADMINISTRATIVE LAW JUDGE'S AMENDED RULING REQUESTING COMMENTS ON THE ENERGY DIVISION WHITE PAPER ON AVOIDED COSTS AND LOCATIONAL GRANULARITY OF TRANSMISSION AND DISTRIBUTION DEFERRAL VALUES, June 13, 2019

Figure 19: Distribution avoided costs

	Base Load Forecast (reflects expected new DER)	Counterfactual Load Forecast (reflects limited new DER)
DDOR Subset of Projects	**Specified** Deferrals (Not included in ACC)	
Rest of System **(GNA data)**		**Unspecified** Deferrals (Included in ACC)

5.1.3. Counterfactual Load Forecast

To estimate the Unspecified deferrals, a counterfactual load forecast is developed for each circuit. The counterfactual forecast is conceptually similar to the No New DER case discussed above, in that it a method of forecasting how the future would be different without new DERs, so as to determine the impact of DERs on load (in the case of the counterfactual forecast) or system costs (in the case of the No New DER case).

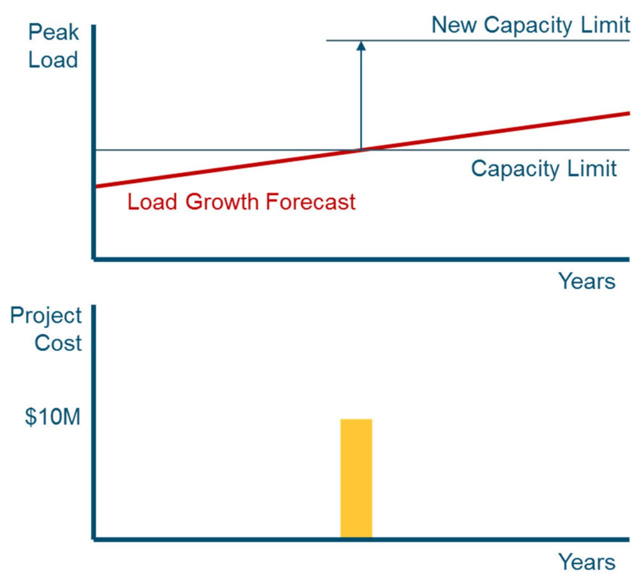
The counterfactual forecast, as defined in the DRP Staff Paper, is the load forecast from which forecasts of the adoption of load-modifying distributed energy resources, such as energy efficiency, demand response, battery storage, rooftop photovoltaic (PV), and electric vehicles, have been removed, for the most part. This counterfactual forecast reflects the removal of those DER load impacts that are the result of Commission policies, including tariffs like Net Energy Metering (NEM). As the CPUC does not have jurisdiction over Federal or State Codes and Standards, such as the California Title-24 Building Energy Efficiency Standards, those load reductions are not removed from the counterfactual load forecasts. The difference between the utility base forecast and the counterfactual forecast is also referred to as the **embedded DER**.

5.2. Distribution Deferral Background

The Specified deferral value calculates avoided costs using the Distribution Deferral methodology. Similarly, the Unspecified deferral value seeks to calculate what the Distribution Deferral avoided costs would have been under the counterfactual load forecasts. The essence of the Deferral Value is the present value revenue requirement cost savings from deferring a local expansion plan for a specific period of time. More details on the methodology can be found at the California IDER and DRP Working Group site.[28]

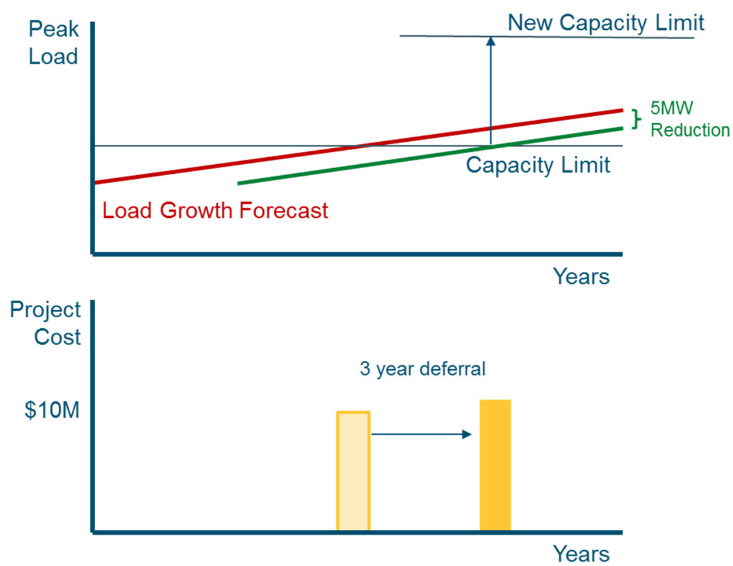
Figure 20 illustrates a situation where a network T&D investment is needed and the project cost. The project is needed to prevent the load growth (net of naturally occurring DER) from exceeding the T&D facility's load carrying capability and allows time for project deployment prior to the actual overload. In Figure 21, the utility is targeting incremental load reduction from the red line to the green line to allow the investment to be deferred by 3 years. The deferred project's cost is slightly higher due to equipment and labor inflation costs, but this would be more than offset by the financial savings from being able to defer the project.

Figure 20: Investment in a typical distribution project due to load growth



[28] https://drpwg.org/sample-page/drp/ and http://drpwg.org/wp-content/uploads/2016/07/R1408013-PGE-Demo-Projects-A-B-Final-Reports.pdf

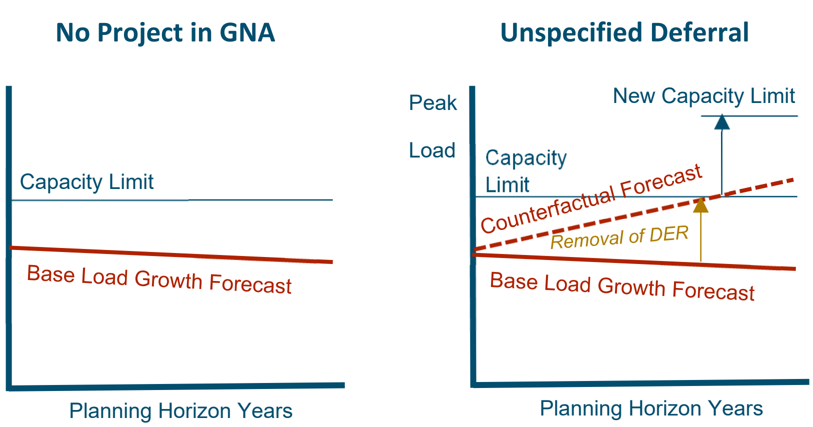
Figure 21. Project deferral of a typical distribution investment



5.3. Unspecified Deferral Value Method

As shown in the prior figures, the need for a capacity-driven distribution project is determined by the intersection of the capacity limit with the load growth forecast. In some cases, the load growth forecast may not intersect the capacity limit because of the expected peak load reductions from new DER. However, if that new DER were removed from the forecast, there could have been a need for a capacity project. This is illustrated in Figure 22 where the chart on the left represents the GNA analysis for a circuit that shows no need for a capacity project within the five-year planning horizon. The chart on the right shows the effect of the removal of the new DER growth from the load forecast. The counterfactual forecast is higher than the utility's base forecast and indicates the need for a capacity project within the five-year planning horizon.

Figure 22: Project need from counterfactual forecast



The Unspecified deferral avoided cost represents the potential capacity benefits for those circuits where there is no identified need for a project in the GNA's five-year planning horizon, but there is an indicated need if the utility base load forecast is replaced with the higher counterfactual forecast.

Below is a summary of the five-step process to calculate unspecified deferral avoided costs. For a more detailed description, please refer to pg. 11 of the DRP White Paper[29].

1. *Calculate the counterfactual forecast from the GNA:* For each listed circuit, the counterfactual load can be derived by removing the circuit level DER forecast from the circuit level load.

2. *Identify potential new capacity projects under the counterfactual forecast:* Circuits overloaded in the counterfactual forecast and not overloaded in the actual planning GNA forecast are considered deferrable. Projects that showed an overload in the GNA are not included.

3. *Estimate the percentage of distribution capacity overloads that lead to a deferred distribution upgrade:* Calculate a system level quantity for deferred distribution capacity by using a ratio between capacity overloads identified in the GNA to capacity overloads deferrable in the DDOR. The resulting percentage is a proxy for the percentage of distribution capacity upgrades that can be deferred by DER. Multiplying this percentage with the number of deferrable projects from Step 2 determines the subset of counterfactual capacity projects that could potentially be deferred via DER.

4. *Calculate the average marginal cost of the deferred distribution upgrades:* The average DDOR marginal cost is the sum of the DDOR avoided distribution cost ($/kW-yr) for each project from the DDOR filing, multiplied by its total deficiency need over the planning horizon, and the sum then divided by the total deficiency need for all DDOR projects.

5. *Calculate system level avoided costs:* Multiply the average DDOR marginal cost found in step 4 by the total quantity of deferred capacity by DERs for each circuit. This product is then divided by the sum of forecasted level of DERs for all areas (not just DDOR areas) to obtain a single, system level distribution deferral value in $/kW-yr.

5.4. Near-term and long-term avoided distribution costs

As stated in the DRP Staff Paper, "the impact of DERs to defer distribution upgrades accrue over the long term, while the GNA is limited to the forecast horizon that is necessary for distribution planning." The avoided costs estimates discussed above are based on DDOR and GNA filings that use a 5 year planning horizon. To extrapolate these estimates into long-term forecasts, Energy Division's consultant E3 recommends two options:

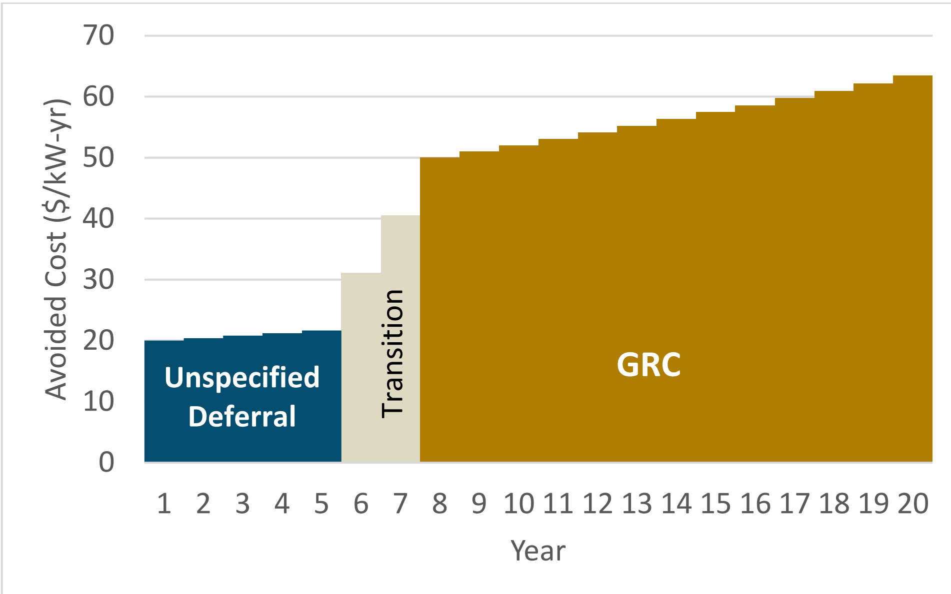
A. Escalate the short-term avoided cost estimates at a deemed rate per year.
B. Transition to marginal costs from each utility's most recent GRC Phase II proceeding

Of the two options, Energy Division' consultant E3 recommends transitioning to the GRC levels over a three-year period. The avoided costs in years 1-5 would be the Unspecified deferral values held constant on a real dollar basis. Years 8 and beyond would be the GRC level held constant on a real dollar

[29] ADMINISTRATIVE LAW JUDGE'S AMENDED RULING REQUESTING COMMENTS ON THE ENERGY DIVISION WHITE PAPER ON AVOIDED COSTS AND LOCATIONAL GRANULARITY OF TRANSMISSION AND DISTRIBUTION DEFERRAL VALUES, June 2019, Attachment A, p. 11

basis. Years 6 and 7 would linearly transition between the two end points of years 5 and 8. This method is depicted in the figure below.

Figure 23: Illustrative Distribution Avoided Cost Transition



5.4.1. Distribution avoided cost area granularity

PG&E estimates marginal distribution costs by area (division). Therefore, the extrapolation of the marginal costs into the future requires an assumption of if and when the area-specific distribution avoided costs should revert to a utility-wide average or continue to escalate separately. We recommend that the area differences be maintained in the forecasts, based on detailed work originally conducted as part of the 2004 avoided cost methodology prepared by Energy Division's consultant E3 and adopted for use in the cost effectiveness evaluation of California IOU energy efficiency programs[30]. Staff welcomes input from PG&E to update and amend these assumptions as needed.

5.5. GRC-based marginal costs

The California IOUs have used a wide variety of methods for estimating distribution marginal costs in their GRC filings[31]. The long-standing purpose of the marginal costs in a GRC filing is to guide the allocation of the utility revenue requirement to customer classes and the design of marginal-cost based rates. The GRC filing therefore provides a useful source for marginal costs that are estimated on regular three-year cycle. However, the GRC marginal costs might not be completely appropriate for use in DER

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[30] PG&E's territory in 2004 comprised 18 planning areas across 9 climate zones. Given such diversity, the utility indicated to E3 that fundamental differences in population density and climate imply that its area-specific avoided T&D costs should not converge to the system average over the long run. Rather, high density areas with mild temperatures such as San Francisco, the Peninsula and the coastal East Bay would remain low cost due to economies of scale and flatter peak demand. On the other hand, hotter and less populated planning divisions such as North Valley, Stockton and Sacramento would retain relatively high avoided T&D costs.

[31] Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs, Prepared for the CPUC, October 2004, p. 102

cost effectiveness evaluations. They are not location-specific, and they are not necessarily avoidable costs. Therefore, Staff recommends that the GRC values be the source for long-run marginal costs, with the recognition that they may need to be modified for DER cost effectiveness and the ACC.

Specifically, this proposal uses GRC total distribution capacity costs for all utilities and does not make a distinction between peak and grid distribution capacity. Energy Division's consultant E3 has examined SCE's proposed separation of peak and grid-related distribution marginal costs, and has concluded that it was not supported by sufficient estimation rigor. Use of the total distribution capacity cost as estimated by SCE's regression analysis of cumulative distribution capacity-related investments and cumulative peak loads is consistent with avoided distribution capacity costs that have been used for SCE in prior avoided cost updates.

Should SCE adequately revise its methods in a subsequent GRC proceeding, those revisions should be evaluated on their merits and not rejected based on the current findings herein.

5.5.1. GRC Data Hierarchy

In selecting data to use for the long term avoided costs, Staff proposes the following hierarchy of GRC Phase II data sources, presented in descending order of preference.

1. Values adopted for revenue allocation from most recently completed proceeding.
2. Values adopted for rate design purposes from most recently completed proceeding.
3. Values agreed to by majority of parties for revenue allocation in settlement agreement from most recently completed proceeding.
4. Values agreed to by majority of parties for rate design purposes in settlement agreement from most recently completed proceeding.
5. Utility-proposed values for revenue allocation from most recently completed proceeding.

Note that some parties have recommended using averages of party positions when there are no adopted or settlement values. Staff has concerns that such an approach would encourage the gaming of party positions in order to skew the resulting averages. Given that GRC Phase II issues have been largely managed through settlement agreements rather than hearings, the risk of gaming is particularly high for California.

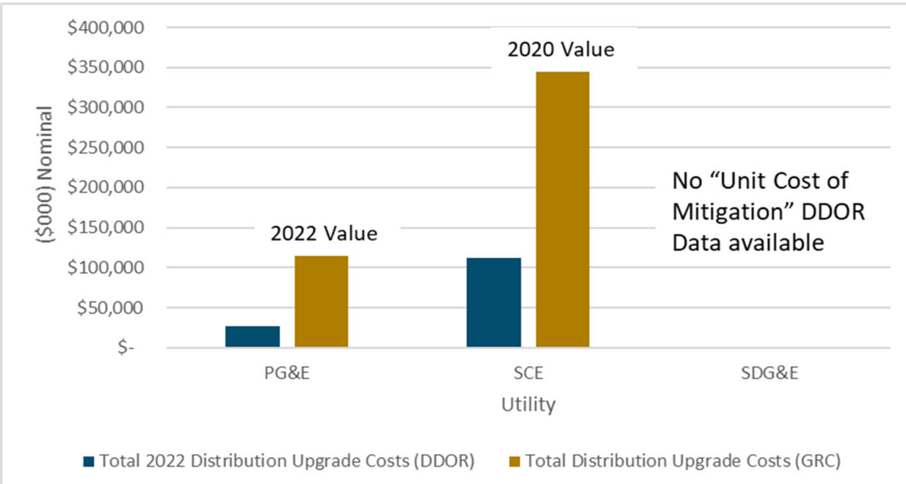
5.5.2. Gap Analysis

Using the GNA filing as the basis for distribution avoided costs is a new untested approach. Because of this, there is value in comparing the DDOR and GNA information that use the utility base load forecasts to the information that utilities have traditionally used in their GRC estimations of distribution avoided costs.

Initial investigations show that there is a large gap between the amount of annual investment represented by the DDOR projects and the annual capacity-related investments used to derive distribution marginal capacity costs in the utility GRC filings.

Figure 24 shows the difference between distribution upgrade costs from the utility DDOR and the forecasted distribution upgrade costs listed in the utility GRC. The total distribution upgrade costs from the PG&E and SCE DDORs were calculated by summing the "Unit Cost of Traditional Mitigation" for all Distribution Service projects coming online in 2022. The year selection was based on the fact that most distribution upgrade projects in SCE and PG&E came online in 2022. SDG&E did not report a unit cost of traditional mitigation in it's DDOR filing. The forecasted GRC Distribution Upgrade Costs from were taken from the 2018 SCE Workpapers[32] and the 2020 PG&E Workpapers[33].

Figure 24: Total Forecasted Utility Distribution Upgrade Costs



The gap analysis looks to identify and quantify the causes of the differences. For example, one cause would be that only a subset of capacity projects are included in the DDOR due to unlikely DER deferral success. Another cause could be the inclusion of projects in the GRC filings that are not captured in the GNA process. For example, PG&E had traditionally developed marginal costs for distribution as a sum of marginal costs for a) large identified projects over $1M and b) smaller capacity-related projects that are needed every year but are not specifically forecast by planners. If there were a large number of capacity-related projects that are not captured in the GNA process, then the distribution avoided costs based on the GNA would be incomplete.

The gap analysis would be useful from an information perspective, but could also affect the avoided distribution costs included in the ACC. For example, some of the reasons for excluding projects from DDOR, such as minimum project lead times, may not be applicable to Unspecified deferral values. Unlike DDOR projects that would require a minimum amount of load reduction by a specific date to allow deferral or avoidance of a specific project, the Unspecified deferral values are meant to be more general, and not tied to the amount of load reduction that could be provided.

For example, if it were determined that there were $30/kW-yr of missing non-GNA avoided distribution costs, then it might be appropriate to add $30/kW-yr to the unspecified avoided costs in the ACC.

Staff looks to the utilities for their insights on the reasons for the differences in investment levels from the two sources and will welcome recommendations for any avoided costs adders accordingly.

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32 Southern California Edison 2018 General Rate Case - Transmission & Distribution (T&D) Volume 3 – System Planning

33 PACIFIC GAS AND ELECTRIC COMPANY 2020 GENERAL RATE CASE EXHIBIT (PG&E-4) ELECTRIC DISTRIBUTION WORKPAPERS SUPPORTING CHAPTERS 11-19

5.6. Determining DER measure coincidence with distribution peak load hours

In evaluating the capacity value provided by a resource, there are five basic approaches for estimating the coincidence of the resource with the timing of the capacity need:

1. Simple Peak Method. Peak reduction is calculated as the resource output or load reduction at the time of the defined system peak. Typically a single hour is deemed to the peak, although in some cases a small number of hours are designated as peak hours and the peak reduction contribution is the simple average of resource performance across those hours.

2. Peak Clipping Method. Hourly loads for a project area are examined before and after installation of the resource(s). The change in the annual maximum net demand is the peak reduction provided by the resource(s).

3. Peak Capacity Allocation Factor (PCAF) Method. Peak reduction is the weighted average resource performance across hours in the peak period. The weights are relative to the project area demand in excess of a "peak threshold." The higher the demand, the higher the weight assigned to the hour to approximate higher need for capacity in the higher demand hours.

4. Peak Load Reduction Factors (PLRF). Statistical representation of the timing of equipment peaks across the utility service territory

5. Convolution Methods. Peak capacity needs are based on both variations and uncertainty of customer demands as well as supply resources. These methods are typical of generation methods such as Loss of Load Expectation studies.

The distribution allocation factors should reflect current and future grid loadings, be flexible enough to allow modeling of alternate scenarios of DER and electrification penetration, match the underlying weather conditions assumed for the modeling of weather sensitive resources (which also entails modeling at the climate zone or finer geographic differentiation), and be applicable to cost effectiveness evaluations for individual resources (as opposed to being applicable only to entire portfolios).

Of the five methods, Energy Division's consultant E3 recommends rejecting the Simple Peak method for being overly simplistic and dependent on a limited number of peak hours (often one). The limited hours are problematic because of the inherent uncertainty of when actual future peaks would occur. E3 also recommends rejecting the Peak Clipping method as its results are too dependent on the entire portfolio of DER that could be implemented in an area. While the method is useful for analysis of non-wires alternatives for a specific project, the method is not compatible with the use cases of the ACC model. Finally, E3 sees the Convolution methods as being overly complex and not well suited to the distribution capacity issue at this time. As customer generation continues to increase on the distribution system, it may be worthwhile to revisit convolution methods.

The two remaining methods, PCAF and PLRF, both are well matched to develop avoided costs for cost effectiveness evaluations. PCAF is used in the current ACC and by PG&E, and PLRF is used by SCE. Energy Division's consultant E3 recommends the use of allocation factors developed by the utilities using their up-to-date demand information, provided that the allocation factors be estimated using both near term and future DER adoption levels, be performed at the climate zone or finer geographic level, and have accompanying weather information to allow mapping to the Typical Meteorological Year (TMY) data used to model efficiency measures in the Database for Energy Efficiency Resources (DEER).

As reliance on the utility allocation factors may require additional work by those utilities, Staff welcomes comments on this topic. Absent the utility allocation factors that reflect the needed conditions of 1) variation over years due to increased DER, and 2) geographic variation by climate zones or finer disaggregation, Energy Division's consultant E3 recommends that the current allocation method based on temperature-based hourly load estimates be continued.

5.6.1. Peak capacity allocation factors

Hourly allocation factors represent the relative need for capacity reductions during the peak periods specific to each distribution area. The concept is based on the Peak Capacity Allocation Factor (PCAF) method first developed by PG&E in their 1993 General Rate Case that has since been used in many applications in California planning[34].

The peak hours could be defined in three ways:

1. Specification of months and hours. For example, peak period is July and August hours between 4pm and 7pm on weekdays.
2. Specification of area peak threshold. The peak period would consist of all hours with forecasted demand above the specified threshold MW. The forecasted demand would be net of all existing and forecast naturally occurring generation (both behind the meter and in-front of the meter) located downstream from the planned distribution investment.
3. Statistical specification. The peak period would consist of all hours with demand within one standard deviation of the single hour maximum peak demand for the area. In other words, the area peak threshold is calculated by the LNBA Tool based on the variability of the area loads.

The relative importance of each hour is determined using weights assigned to each peak hour either 1) in proportion to their level above the threshold, or 2) on a uniform basis. Hours outside the peak period are assigned zero weight and zero value.

The formula for peak capacity allocation factors (PCAFs) using proportional weights is shown below.

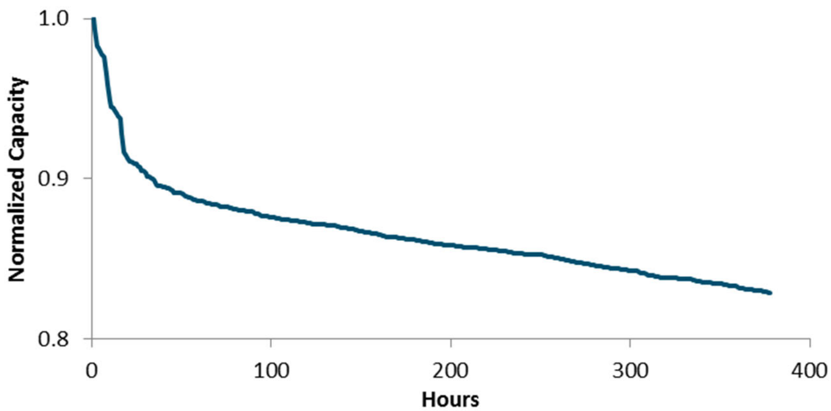
$$PCAF[yr][hr] = \frac{Max(0, Load[yr][hr] - Thresh[yr])}{\sum_{hr=1}^{8760} Max(0, Load[yr][hr] - Thresh[yr])}$$

Where *Thresh[yr]* is the load in the threshold hour or the highest load outside of the peak period.

Once the PCAFs have been determined for each hour of the year, these are multiplied by the dependable output of each DER shape to determine the dependable MW contribution to peak load reductions. The following series of figures show an example of this process using the statistical peak period definition. One standard deviation from the top of the load duration curve above leaves the following hours with higher load than the threshold.

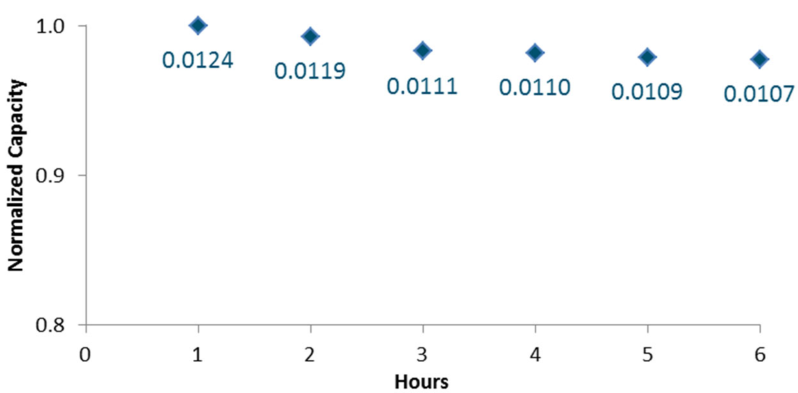
[34] For example, PCAfs were used recently in a CPUC report quantifying distributed PV potential in California: http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf

Figure25. Example of PCAF calculation



This relatively flat load duration curve has more hours above the threshold than other peakier load duration curves – in this case, there are 378 hours. A PCAF is assigned to each one of these hours using the formula above. The following chart shows the PCAFs for the top 6 hours of the load duration curve as an example. The number below each plotted hour's normalized load represents the PCAF relative importance to peak load reductions. They are unitless, sum to one over the hours above the threshold, and can be thought of as the weights in a weighted average calculation of a particular resource's capacity contribution.

Figure26. PCAFs for top 6 hours of load duration curve



5.6.2. Peak Load Reduction Factors (PLRF)

SCE uses a PLRF method to derive its distribution peak capacity factors. The method is similar in concept to the PCAF method, and is an equally valid method for use in DER valuation because, like the PCAF method, it allocates capacity value in proportion to the peak loadings in an area. In the recent GRC Phase II proceeding, SCE included a forecast of DER in 2021 to adjust the net circuit loads used for the PLRF, so in concept alternate forecasts could be incorporated to reflect DER forecasts farther in the future.

5.6.3. Effective Demand Factors (EDF)

SCE also developed Effective Demand Factors (EDF) that it uses as a measurement of peak load diversity and customer group contributions to gird-related costs. Should grid-related costs be separated out from peak-related costs for SCE, the EDF concept could be leveraged to quantify the contribution of DER to reducing grid-related costs. The EDF factors themselves would not be useful, but the distribution of the timing of the grid-related peaks could be used to create hourly allocation factors that equal that distribution. This would require the cooperation and assistance of SCE, but would not be needed for the 2020 update, given that this proposal has not accepted the use of their Grid-related costs as currently estimated.

6. Transmission Avoided Costs

For a long-term transmission value Staff proposes to use GRC transmission costs, as has been done in prior ACCs. This approach, similar to distribution value, would use annual $/kW-yr values developed from GRC (or other sourced deemed appropriate), which is then allocated to individual hours using the PCAF method.

7. High GWP Gases

In 2017, the IDER proceeding issued an Energy Division Staff Proposal[35] that contained a proposal for a new avoided cost to estimate the value of DERs which decrease refrigerant leakage. This section expands upon that proposal by proposing a new avoided cost that encompasses a broader category of high Global Warming Potential (GWP) gasses, including refrigerants and methane. This new avoided cost would primarily apply to DER programs designed to replace natural gas appliances with electric appliances. However, it can also be used for DERs which results in changes in natural gas consumption, such as natural gas energy efficiency measures, and any future programs which focus on refrigerant replacement.

7.1. Background: Refrigerant leakage

As California pursues higher levels of building electrification, through SB 1477 programs, changes in building codes, energy efficiency measures, and other efforts, many more heat pumps will be purchased and used in the state. All heat pumps use refrigerants, and most refrigerants used today are very strong greenhouse gases— as much as 2,000 times stronger than CO_2. The ratio of global warming impact relative to that of CO_2 is known as Global Warming Potential, or GWP. Refrigerants only contribute to global warming when they leak, but leakage is inevitable given current practices. Emissions from refrigerant leakage in all-electric buildings can be a significant portion of a building's lifecycle GHG emissions.

[35] *Distributed Energy Resources Cost Effectiveness Evaluation: Societal Test, Greenhouse Gas Adder, and Greenhouse Gas Co-Benefits*. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M175/K295/175295886.PDF

Figure 27: Annual emissions from a mixed fuel and all-electric building modeled as part of the CEC Title 24 2022 building code update.[36]

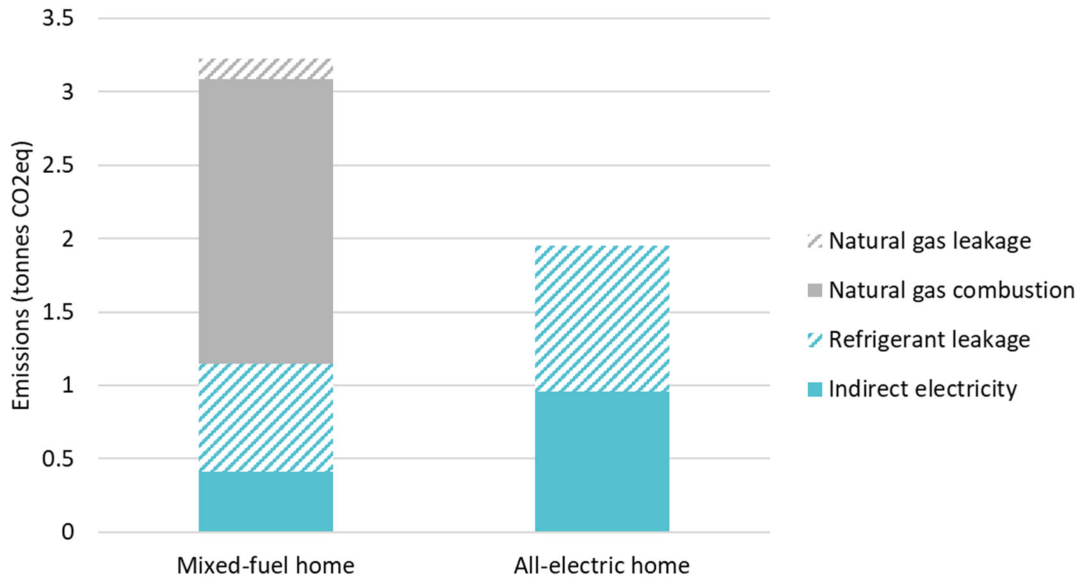
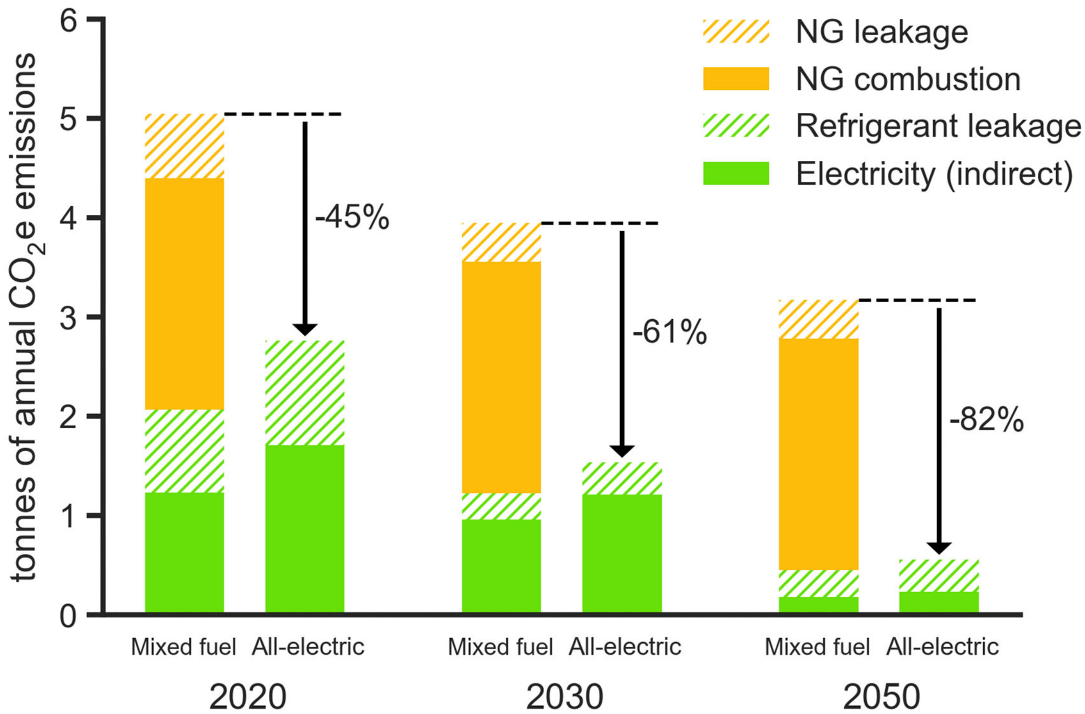


Figure 27 shows that when switching from a mixed fuel to an all-electric home, GHG emissions related to natural gas decrease, but GHG emissions from refrigerants *increase*. Also, switching from a device that uses a high-GWP refrigerant to one that uses a low-GWP refrigerant decreases refrigerant emissions. These types of equipment changes represent a significant change in avoided cost that has not yet been quantified in the IDER framework. This avoided cost also applies to a number of similar situations, such as where the alternative technology is a standard air conditioner. Air conditioners are very similar to heat pumps, and often use the same (high-GWP) refrigerants.

Figure 28 shows the CO2 equivalent emissions by source for a mixed fuel and electric home in 2020, 2030 and 2050 from the linked report on building electrification in California. This chart illustrates how declining GHG emission intensity of the electric grid over time will increase the proportion of global warming impacts attributed to refrigerant leakage, natural gas leakage and natural gas combustion. It will also increase over time the net GHG impact of electrification measures relative to the example shown above. Including an avoided cost category for GWP gasses will thus be increasingly important for DER cost-effectiveness evaluation.

[36] Energy and Environmental Economics (E3), "Title 24 2022 TDV Factors Background and Updates" presentation at the Lead Commissioner Workshop for the California Energy Commission 2022 Energy Code Pre-Rulemaking, October 17, 2019. https://ww2.energy.ca.gov/title24/2022standards/prerulemaking/documents/2019-10-17_workshop/2019-10-17_presentations.php

Figure 28: Annual GHG Emissions from a Mixed-fuel and All-electric 1990's Vintage Home in Sacramento[37]



The most common refrigerants found in new HVAC heat pumps and heat pump water heaters available today have GWPs in the range of 1,400-2,000. Lower GWP refrigerants are available and are actively being developed by refrigerant and heat pump manufacturers, but they often have slightly lower performance, require specially designed heat pumps that might be more expensive, and/or require special installation and maintenance practices to account for their mild flammability. With refrigerants trade-offs are inevitable. **However, it is important to account for the potential reduction in emissions from using low-GWP refrigerants, so that the benefits of using these refrigerants can be compared to their costs, and so that their use can be incentivized.**

[37] Energy and Environmental Economics (E3), "Residential Building Electrification in California: Consumer Economics, Greenhouse Gases and Grid Impacts". April 2019. Developed for Southern California Edison (SCE), Sacramento Municipal Utility District (SMUD), and the Los Angeles Department of Water and Power (LADWP)

Table 9: Common refrigerants in use today

Refrigerant	100-year Global Warming Potential (GWP)[38]	Common Uses
R-410A	2,088	New heat pumps and air conditioners
R-134A	1,430	New heat pump water heaters
R-22	1,810	Existing air conditioners (R-22 is mildly ozone-depleting and is being phased out in the US)

Table 10: Low-GWP refrigerant alternatives

Refrigerant	100-year Global Warming Potential (GWP)	Common Uses
R-32	675	Most promising near-term replacement for R-410A in residential HVAC heat pumps
R-1234yf	4	One of the more promising near-term replacements for R-134A in heat pump water heaters and clothes dryers
Propane (R-290)	4	Can be used in any heat pump, but high flammability means special installation and maintenance practices are required.
CO2 (R-744)	1	Some automobile air conditioners in Europe, some heat pump water heaters in Japan.

7.2. Background: Methane leakage

Another potentially significant avoided cost that has not yet been reflected in the IDER framework is the potential for avoided methane leakage when displacing a natural gas device. Global Warming Potential (GWP) is a measure of how much energy the emissions of 1 ton of a gas will absorb over a given period of time, usually 100 years, relative to the emissions of 1 ton of CO2. The larger the GWP, the more that a given gas warms the Earth compared to CO2 over that time period. Methane, the primary component of natural gas, has a 100-year GWP of 25[39], meaning it is 25 times stronger than CO2 over a 100-year time horizon, so any leakage of uncombusted methane has a disproportionately high impact on global

[38] GWPs listed are the same as those used by the CARB Refrigerant Management Program, which are IPCC AR4 (2007). See https://ww2.arb.ca.gov/resources/documents/high-gwp-refrigerants

[39] GWP is from IPCC AR4 (2017), and is the same as that used in the CARB GHG Inventory. See https://ww2.arb.ca.gov/ghg-gwps

warming compared to burning that same methane and emitting CO2 instead.[40] Methane has an even higher GWP if a shorter time horizon is used[41], as its lifetime in the atmosphere is only about 12 years, but a 100-year time horizon is assumed here to maintain consistency with refrigerant leakage GWPs and the CARB GHG inventory.

Methane leakage is inherently difficult to quantify, given that much of the leakage that occurs is due to abnormal, infrequent events, and even more difficult to quantify is the amount of methane leakage that is possible to avoid by displacing a natural gas device. California will continue to have a pressurized natural gas system for the foreseeable future, so any leakage associated with simply keeping this system pressurized is not likely to be avoided by decreasing throughput. However, there is certainly a nonzero quantity of methane leakage that will be avoided by displacing natural gas devices. At the least, behind-the-meter leakage will go to zero when switching from a mixed-fuel home to an all-electric home. At the most, leakage that happens during production and storage will also be reduced as a result of decreased throughput.

Methane leakage is quantified in official GHG inventories, such as the US EPA and California Air Resources Board inventories, but the leakage rates reported in these are widely accepted in the academic community to be significant underestimates[42] [43]. The leakage rate implied by the EPA GHG Inventory is 1.4%, but national leakage rates reported in academic literature range from 2.3% (see Alvarez 2018, previously cited) to 12% for certain shale gas developments[44]. These numbers all include lifecycle leakage emissions from well-to-meter, but not behind-the-meter leakage.

These academic studies reporting higher leakage rates than inventories generally note that the reasons for this discrepancy are likely to include abnormal events due to equipment malfunction (e.g., Aliso Canyon), and older emission factors that have since been updated. The distribution of methane leakage rates has a long “tail” (i.e., most facilities have low leakage, but a select few occasionally have very high leakage). Therefore, accounting for average leakage rates from normal usage, as is generally done in inventories, can lead to a significant underestimate of total leakage (see Alvarez 2018).

[40] Note that, when calculating GHG impacts from methane leakage (compared to burning the same methane), a factor of 9, not 25, must be used to account for the difference in molar mass between methane and CO2. For example, a 1% leakage rate for a home that consumes 100 tons of natural gas per year would result in 1 ton of leaked natural gas, leading to 25 tons of CO2-equivalent emissions. However, if that 1 ton of natural gas had been burned instead, it would lead to 44/16 = 2.75 tons of CO2 emissions (the ratio between the molar masses of CO2 and CH4). Thus it is the ratio between 25 and 2.75 that matters (25/2.75 = 9.1) in calculating the increased warming effect from leaking natural gas.

[41] https://unfccc.int/process/transparency-and-reporting/greenhouse-gas-data/greenhouse-gas-data-unfccc/global-warming-potentials

[42] Brandt, A. R., et al. “Methane Leaks from North American Natural Gas Systems.” Science, vol. 343, no. 6172, 2014, pp. 733–735., doi:10.1126/science.1247045.

[43] Alvarez, Ramón A., et al. “Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain.” Science, vol. 361, no. 6398, 13 July 2018, doi:10.1126/science.aar7204.

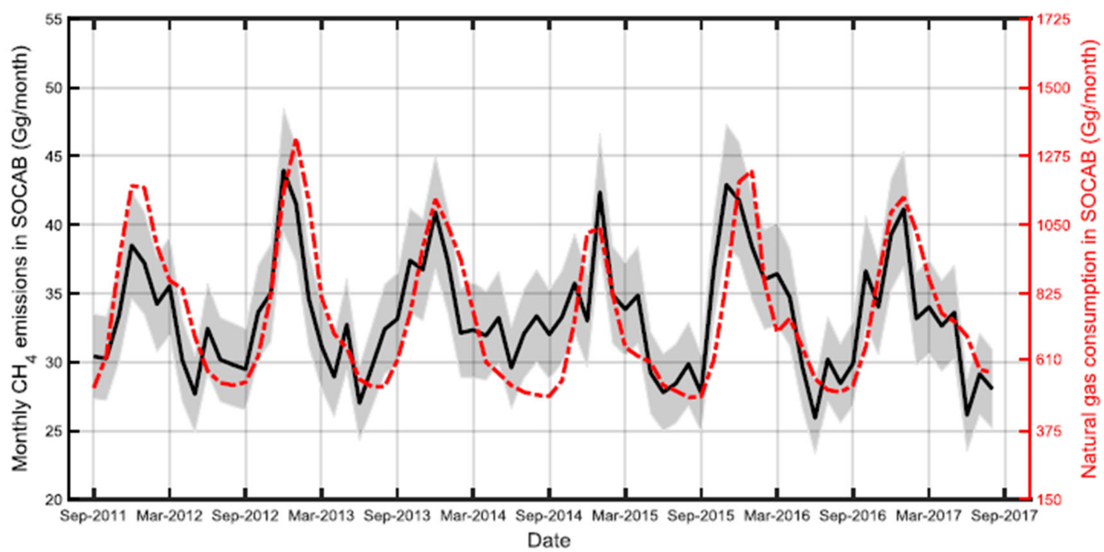
[44] Howarth, Robert. “Methane Emissions and Climatic Warming Risk from Hydraulic Fracturing and Shale Gas Development: Implications for Policy.” Energy and Emission Control Technologies, vol. 3, 8 Oct. 2015, pp. 45–54., doi:10.2147/eect.s61539.

The CARB inventory reports an even lower implied leakage rate of 0.7%[45], since it only quantifies in-state emissions, with the exception of electricity. California imports about 95% of its natural gas, so the leakage emissions that happen due to out-of-state production and storage are not included. Therefore, Staff proposes to not include these impacts in CPUC avoided costs. These emissions are likely significant, as production and storage is generally considered to be the leakiest part of the natural gas system (see Alvarez 2018). The CARB inventory includes behind-the-meter (BTM) leakage, a new addition for the 2017 inventory.

Also of note is that if the leakage rate were actually closer to 12%, as is reported by Howarth (2015, previously cited) for shale gas, then burning natural gas for electricity would be significantly worse for climate change than burning coal (see Howarth 2015).

As mentioned above, since at least for the near term the natural gas system will remain in place and stay pressurized, the key question for IDER is -- How much leakage could be avoided through displacing a natural gas device? Recent research attempted to quantify the degree to which natural gas throughput is correlated with methane leakage in the LA basin[46]. The study found that the two are highly correlated, meaning it is reasonable to assume that decreased throughput would result in decreased leakage, at least in the LA basin and likely in California more generally.

Figure 29: Methane emissions and natural gas consumption in the LA basin between 2011 and 2017.



7.3. Proposed methodology: Refrigerant leakage emissions

Staff proposes to quantify avoided refrigerant leakage emissions using detailed leakage data compiled by the California Air Resources Board (CARB). CARB maintains a database of typical refrigerant charge,

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[45] This number is obtained by dividing the total methane leakage reported in the ARB inventory for 2017 by the total natural gas consumption in CA in 2017, as reported by EIA.

[46] He, Liyin, et al. "Atmospheric Methane Emissions Correlate With Natural Gas Consumption From Residential and Commercial Sectors in Los Angeles." Geophysical Research Letters, vol. 46, no. 14, 2019, pp. 8563–8571., doi:10.1029/2019gl083400.

annual leakage rates, and end-of-life leakage rates for all major types of residential and non-residential equipment that uses refrigerants. The table below shows leakage data available from CARB for common residential equipment types.

Table 11: Refrigerant leakage data compiled by the California Air Resources Board.[47]

Appliance	Typical refrigerant	Refrigerant GWP	Average refrigerant charge	Average annual leakage	Average end-of-life leakage
Central A/C	R410A	2088	7.5 lbs	5%	80%
Air-source ducted heat pump	R410A	2088	8.2 lbs	5.3%	80%
Heat pump water heater	R134A	1430	2.4 lbs	1%	95%
Heat pump clothes dryer	R134A	1430	0.88 lbs	1%	100%

This leakage data can be converted into annualized leakage rates by adding the end-of-life leakage divided by the expected equipment lifetime, and subsequently to annualized emissions by multiplying by refrigerant charge and GWP:

$$\text{Annualized emissions} = \text{Refrigerant charge} * \text{GWP} * (\text{Annual leakage rate} + \frac{\text{End-of-life leakage rate}}{\text{lifetime}})$$

This equation in combination with the CARB data represents the proposed methodology for estimating refrigerant leakage emissions for IDER. This framework allows for the reduction in emissions from using lower-GWP refrigerants to be appropriately accounted for.

7.4. Proposed methodology: Methane leakage emissions

Energy Division's consultant E3 proposes to investigate and develop a methodology for calculating avoided costs for methane leakage. Proceedings at CARB on methane leakage are ongoing and final recommendations have not been adopted. Staff expects further direction from CARB to be finalized prior to the issuance of the 2020 ACC and will incorporate methane leakage rates accordingly into the new version of the ACC when it is proposed in 2020.

[47] Data obtained via email from CARB staff. Similar (but not exactly the same) data is available in the latest technical support document for the CARB HFC Inventory.

For the IDER workshop held in August 2019, Energy Division's consultant E3 presented two possible leakage rates (the CARB leakage rate of 0.7% and the Alvarez 2018 leakage rate of 2.4%, which reflects T&D emissions subtracted out but BTM added). Note that both of these leakage rates include behind-the-meter emissions (estimated at 0.5% of consumption[48]), which are the most certain to be eliminated through electrification. These two estimates represent likely bounds for any leakage rate that could be adopted. Energy Division's consultant E3 will perform a literature review to further examine the potential for decreased natural gas throughput to reduce methane leakage, including any values formally adopted in CEC or CARB proceedings. Avoided methane leakage emissions for natural gas devices will be quantified by multiplying lifetime natural gas consumption by the leakage rate which will be determined later. The proposed methodology for incorporating these emissions into the IDER framework is described further in the next section.

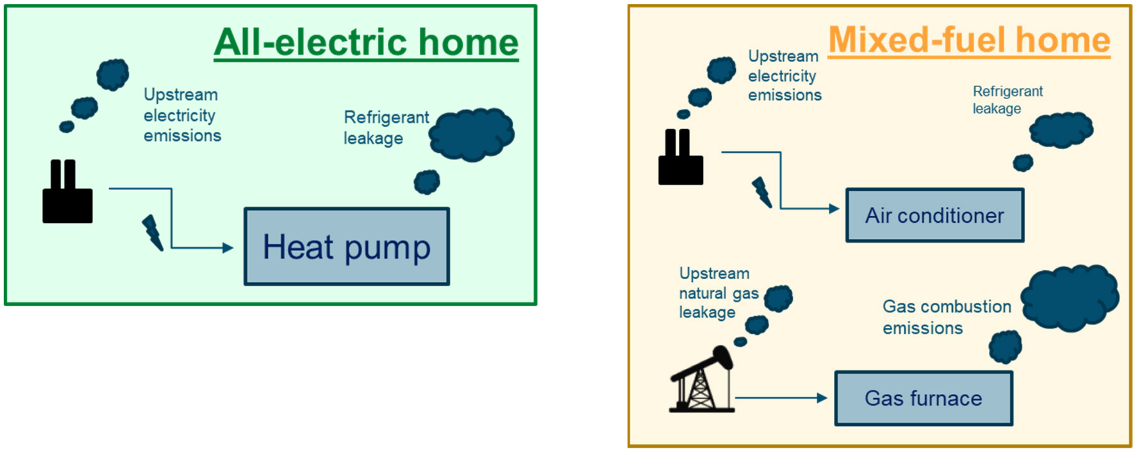
7.5. Example Calculation

To summarize, this section describes the method for calculating avoided costs for refrigerant gas and methane leakage, as shown in Figure 30. Staff anticipates that proceedings at CARB will produce additional findings and eventually adopt recommendations on refrigerant and methane leakage. We propose to determine the appropriate upstream leakage factors from the appropriate CARB findings for use in the 2020 ACC update. Upstream methane leakage factors will be multiplied by the annual volume of natural gas usage that is reduced to calculate CO_2-equivalent GHG impacts. Those impacts will be multiplied by the annual GHG value, in dollars, for the ACC. This methane leakage avoided cost will be applied to all measures increasing or decreasing natural gas consumption. The BTM leakage will be calculated in a similar manner, with annual leakage factors and annual natural gas impacts. BTM natural gas combustion emissions will be calculated as is currently done for natural gas measures in the 2019 ACC. The upstream and BTM methane leakage and BTM combustion avoided cost values will apply to all DER measures impacting natural gas consumption.

In addition, avoided costs for the global warming impacts of BTM refrigerant leakage will be calculated using the average annual leakage factor adopted for the appliance as described above. The BTM refrigerant leakage does not vary with annual electric or natural gas loads. Hourly load shapes are not a factor in calculating methane or refrigerant leakage.

[48] Estimated by a 2018 CEC study. The results of this study were included in the latest CARB inventory.

Figure 30: Comparison of All Electric and Mixed Fuel Home Leakage.



8. Geographic Resolution of the ACC

The proposed approached described above reference a range of possible geographic resolutions for the source data and for the resulting ACC categories. Distribution values are based on distribution planning areas for PG&E and the DDOR data could provide potentially finer resolution for PG&E and the other utilities. Transmission values refer to CAISO Sub-LAPs and CEC Title 24 TDV values, like CPUC avoided costs historically refer to climate zones. As part of the 2020 ACC update process Staff proposes to evaluate and propose a geographic resolution for avoided costs and for mapping inputs from different geographies consistently. Staff welcomes party input on the needed level of granularity.

9. Natural Gas Avoided Cost Calculator

Energy Division's consultant E3 recommends simplifying the current approach to developing natural gas price forecasts. The current method for natural gas price forecasts in the ACC evolved from a now obsolete Market Price Reference (MPR) methodology first established in 2004 to determine 'above-market prices' for renewable generation.[49] That the MPR methodology evolved over several years with stakeholder proposals and CPUC decisions made in the context of renewable procurement when prices for renewables were significantly higher than fossil generation. The core of the current MPR based method is using natural gas forward prices for the near-term (~5 years) and then transitioning to a long-term natural gas fundamentals price forecast. Energy Division consultant E3 proposes to retain this core concept, but simplify the approach. Whereas the current MPR based approach used Henry Hub fundamental forecasts, the proposed approach would instead transition to the long-term gas price forecasts used in the CPUC IRP, the CEC IEPR natural gas forecast.

As in the current ACC, the natural gas commodity avoided cost will be based on natural gas forward prices for NYMEX Henry Hub, and for and basis swaps for PG&E Citygate and the Southern California Border. Henry Hub forward prices typically trade for a future period of up to ten years whereas the basis

[49] D.04-06-015

prices for California typically trade for up to 5 years. Staff proposes using forward based prices for 5 years and then transitioning to the CEC IEPR mid gas price forecast that is used in the CPUC IRP.

Whereas the current MPR based method transitions to the *escalation rate* of the Energy Information Administration (EIA) fundamentals forecast over a period of three years, we propose instead to transition to the actual *nominal $/MMBtu price* of the CEC IEPR forecast over the same three year period.

The MPR based method averaged forward prices for the prior 22 business days to avoid basing a long-term price forecast on a short-term aberration in market prices. In practice prices have varied by less than $0.10/MMBtu over the 22-day period. Furthermore, as the proposal is to transition to the nominal price forecast rather than the escalation rate, the impact of the last year of market price data is limited to that year and the 3 year transition period. That is, the last year of market price data is not escalated 25 years into the future. Instead, the proposal is to use an average of 5 business days of forward price data rather than 22.

In addition Energy Division's consultant E3 recommends continuing the approach of adding the relevant in-state transportation charges for PG&E, SoCal Gas and SDG&E, municipal franchise fees and an adder for natural gas hedging costs. The natural gas transportation cost allocation across seasons and customer classes has not been updated for some time. Staff proposes to direct its consultant E3 to continue investigating and implementing appropriate updates to those allocations.

Finally, given policy discussions on the future of natural gas in California, there is a question of how to forecast in-state natural gas transportation rates in an era of declining throughput. For the 2020 ACC update, the proposal is to continue to use a trend-based escalation of recent and currently proposed natural gas transportation rates. This would involve evaluating new methods or new transportation rate forecasts as may be adopted by the CEC or CPUC for the next ACC update cycle in 2021.

9.1. Natural Gas GHG Avoided Costs

For electricity sector GHG emissions below the grid intensity target, the proposal described in Section 4 is to use the projected cap and trade value for short run GHG avoided costs. Energy Division's consultants E3 recommend using the same cap and trade value for natural gas GHG emissions. This would provide a consistent metric for fuel substitution measures, so that the same value would apply for avoided GHG of both natural gas at the powerplant and at the customer premise.

Staff recognizes that there has been little research on this issue, and proposes that as an alternative, the current natural gas GHG adder could be retained until such time as additional research becomes available. In the future, targets for low carbon fuels in the natural gas system may drive sector specific investment and associated GHG emissions costs (analogous to the GHG shadow prices from IRP RESOLVE modeling). If specific targets are adopted by natural gas utilities for low carbon fuels in the portfolio, Staff recommends considering development of additional methods to reflect those costs in future ACC updates.

However, Staff also recognizes that either of the options above result in inconsistent valuation for DERs that reduce natural gas consumption and DERs that reduce electricity consumption, and in the extreme case would use different values for avoided GHGs resulting from dual fuel equipment or between fuels in a fuel substitution project. Therefore, Staff proposes as a third option to consider using the electric sector, IRP-based GHG Adder for natural gas, as a proxy value that indicates the approximate cost to ratepayers of the State's building decarbonization efforts. This would avoid what seems to be a problematic outcome of applying different avoided GHG values to the same avoided cost for projects or equipment that happen to involve two different fuels.

Staff welcomes party comment on these options.

10. Minor Updates to the ACC

This section proposes several minor updates to the ACC that do not entail substantial changes to methodology or results of the model. Note that the above major updates will entail significant changes and updates to the structure of the ACC that will need to be developed and implemented over several months. This section does not enumerate all possible changes that are proposed for the Avoided Cost Calculator. Rather, this section describes additional changes that are not related to the major updates described above.

One minor error has been found in 2019 Natural Gas Avoided Cost Calculator, which does not affect the 2019 ACC results. Staff proposes that this error be resolved in the next update. The issue was a mismatch in the start year, between the "Settings + Results" tab and the "Emissions" tab. The NOx and CO2 costs from the former were being pulled in beginning with 2019 data from the latter, regardless of the user-input "First year" value on the "Settings + results" tab. The same issue took place for the "Average T&D Cost" output on the "Settings + results" tab. Both issues have been resolved and will be incorporated in the next public version released."

Additional updates that are proposed to for development and incorporation in the 2020 ACC update are:

- **Expanding the Avoided Cost Calculator outputs used for demand response**: include 8760 values to value additional DR types. The DR outputs were designed to evaluate Shed DR that reduces load during peak load hours. More dynamic forms of DR are proposed to better support renewable generation. These include Shift DR to reduce load in some hours and increase load in hours, and Shimmy DR to provide flexible ramping and ancillary services like frequency regulation. Staff proposes expanding the ACC to provide the data needed to value these additional DR types.
- **Remove any remaining separate Avoided Cost Calculator outputs used for Permanent Load Shifting.** With the expansion of the DR evaluation described above, it will include all the results necessary to evaluate any load shifting programs.
- **One-year ACC back cast.** Evaluation, Measurement and Verification studies for DER in some cases want to perform ex-post cost-effectiveness or GHG impact evaluation of DER installed in prior years. For example, the Self-Generation Incentive Program evaluation reports include and evaluation of GHG impacts for the previous year. Staff proposes including one or more historical years in the ACC so such evaluations can be performed on a consistent basis, with aligned historical weather, loads and prices.

APPENDIX D. Glossary

1-Axis	A single-axis solar tracking system uses a tilted PV panel mount and an electric motor to move the panel from east to west tracking the sun during the day.
2 Axis	A dual-axis tracking system capable of tiling the PV panel on two axes. These systems can move the panel from east to west and north to south, allowing the panel to track the sun during the day and the change of seasons.
Ancillary Services	A service necessary to support the transmission of energy to loads while maintaining reliable operation of the transmission system. *
Azimuth	An arc of the horizon measured between a fixed point (such as true north) and the vertical circle passing through the center of an object usually in astronomy and navigation clockwise from the north point through 360°. For photovoltaic systems, an azimuth of 90° means the module is facing due east, an azimuth of 180° is due south, and 270° is due west.
Backtracked 1-Axis	Backtracking is a tracking control program used when the installed system consists of more than one array and minimizes production loss to panel shading.
Capacity	The maximum generation output of a power plant. Capacity of photovoltaic systems may be measured by either their alternating current (AC) or direct current (DC) capacity. PV modules produce DC voltage, which is converted to AC by an inverter. The AC rating is always lower than the DC rating because of losses associated with the conversion of the energy.
Coincidence Factor	A factor representing the ratio of the output of a power plant at a specific hour to the capacity of the power plant. Likewise, coincidence factor can represent the ratio of the demand of an electricity consumer in a specific hour to the maximum demand of that consumer. For example, if a photovoltaic module produces 300 watts at 5 PM and has a maximum alternating current capacity of 830 watts, the coincidence factor for 5PM is 300/830 = 36.1%.
Distribution System Backbone	The main three-phase feeders originating from substations in a distribution system and leading to lower voltage lines.
ERCOT	The interconnected power system that is under the jurisdiction of the Public Utility Commission of Texas and that is not synchronously interconnected with either the Eastern Interconnection or the Western Electricity Coordinating Council.*
Fixed open rack	Solar PV system that is normally ground-mounted and allows air to flow freely around the array to help cool the modules and reduce cell operating temperatures.
Fixed roof mount	Solar PV system that are attached to the roof surface and do not track or move with the movement of the sun. These systems provide limited air flow between the module back and roof surface.

Light-Induced Degradation	Phenomenon in which the power output of a photovoltaic module decreases after the first few hours it is exposed to sunlight.
Load Serving Entity	An entity that sells electricity to individual or wholesale customers.
Locational Marginal Price	The offer and/or bid-based marginal cost of serving the next increment of Load at an Electrical Bus *
Non-Spinning Reserves	An Ancillary Service that is provided through use of the part of Off-Line Generation Resources that can be synchronized and ramped to a specified output level within 30 minutes (or Load Resources that can be interrupted within 30 minutes) and that can operate (or Load Resources that can be interrupted) at a specified output level for at least one hour. Non-Spin may also be provided from unloaded On-Line capacity that meets the 30-minute response requirements and that is reserved exclusively for use for this service. *
Postage Stamp Rate	Postage stamp pricing sets a transmission-owning utility's transmission rate based on the ERCOT utilities' combined annual costs of transmission divided by the total demand placed on the combined transmission systems of all transmission-owning utilities within ERCOT.
PVWatts	PVWatts is an interactive web application developed by the NREL that estimates the performance of PV installations at specific locations.
Qualified Scheduling Entity	A Market Participant that is qualified by ERCOT in accordance with Section 16, Registration and Qualification of Market Participants, for communication with ERCOT for Resource Entities and LSEs and for settling payments and charges with ERCOT. *
Radial Feeders	Distribution lines from the substation to the end-use that have only one path for power to flow.
Regulation Down Service	An Ancillary Service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes in system frequency. Such capacity is the amount available below any Base Point but above the LSL of a Generation Resource and may be called on to change output as necessary throughout the range of capacity available to maintain proper system frequency. A Load Resource providing Reg-Down must be able to increase and decrease Load as deployed within its Ancillary Service Schedule for Reg-Down below the Load Resource's MPC limit. *
Regulation Up Service	An Ancillary Service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes in system frequency. Such capacity is the amount available above any Base Point but below the HSL of a Generation Resource and may be called on to change output as necessary throughout the range of capacity available to maintain proper system frequency. A Load Resource providing Reg-Up must be able to increase and decrease* Load as deployed within its Ancillary Service Schedule for Reg-Up above the Load Resource's LPC limit. *

Responsive Reserves	An Ancillary Service that provides operating reserves that is intended to: – Arrest frequency decay within the first few seconds of a significant frequency deviation on the ERCOT Transmission Grid using Primary Frequency Response and interruptible Load; – After the first few seconds of a significant frequency deviation, help restore frequency to its scheduled value to return the system to normal; – Provide energy or continued Load interruption during the implementation of the EEA; and – Provide backup regulation. *
Roof pitch	The slope ratio of a roof that defines how many inches the roof rises for every 12 inches of depth. A 4/12 roof pitch is a roof that rises 4 inches for every 12 inches of run.
Settlement Point Price	A price calculated for a Settlement Point for each Settlement Interval using LMP data and the Settlement Calculations for the Real-Time Energy Operations. *
Solar Zenith	The solar zenith is the angle between the sun and the 90° vertical. The zenith angle is 90° minus the elevation.
Tilt Angle	Angle from horizontal of a photovoltaic module's array. For a fixed array, 0° is horizontal and 90° is vertical.

**ERCOT Glossary of Terms - http://www.ercot.com/glossary*

APPENDIX E. Acronyms

AC:	Alternating Current
COSS:	Cost of Service Study
CP:	Coincident Peak
DC:	Direct Current
DG:	Distributed Generation
EEA:	Energy Emergency Alert
ERCOT:	Electric Reliability Council of Texas
GDS:	GDS Associates, Inc.
HSL:	High Sustainable Limit
kW:	Kilowatts
kWh:	Kilowatt-hours
LCRA:	Lower Colorado River Authority
LPC:	Low Power Consumption
LSE:	Load Serving Entity
LSL:	Low Sustainable Limit
MPC:	Maximum Power Consumption
MW:	Megawatts
MWh:	Megawatt-hours
NCP:	Non-Coincident Peak
NREL:	National Renewable Energy Laboratory
PEC:	Pedernales Electric Cooperative, Inc.
QSE:	Qualified Scheduling Entity
SPP:	Settlement Point Price
TSP:	Transmission Service Provider

PREPARED BY GDS ASSOCIATES, INC.

PEDERNALES ELECTRIC COOPERATIVE, INC.

Value of Solar Study

November, 15, 2021

GDS Associates, Inc.
ENGINEERS & CONSULTANTS