Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System

Study Report in Response to Colorado Public Utilities Commission Decision No. C09-1223

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Executive Summary

Public Service Company of Colorado's objective in this study was to investigate and document the costs and benefits of distributed solar generation on its electric power supply system at current penetration levels and projections for near-term penetration levels. The study was initiated in response to Colorado Public Utilities Commission Decision No. C09-1223. The study examined the first 59 MW of distributed solar generation ("DSG") installed on the Public Service of Colorado ("Public Service" or the "Company") system as of 9/30/12 along with a projection of an additional 81 MW of DSG being installed by 12/31/2014 for a total of 140 MW. The study did not attempt to estimate costs and benefits of high penetration rates of DSG in part because the industry does not adequately understand the operational and reliability impacts to distribution systems at high penetration levels nor does it have sufficient historical solar generation data through which to model these impacts.

In this study the Company has utilized an avoided cost methodology to quantify costs and benefits; that is, the study is forward looking and examines electric <u>system</u> costs that might be deferred or avoided as a result of adding solar generation at distribution voltages. Given its focus on system costs, this study does not attempt to quantify any purported non-energy societal benefits (such as net economic growth or reduced healthcare costs) that might be attributed to the installation or operation of solar generation at distribution voltages. Nor does the study assign the quantified system costs and benefits to participant or non-participant customer sub-classes that result from the ability of the Company's customers to net-meter their solar generation under Colorado statute.

As the study focused on <u>system</u> costs and benefits, it does not include the costs of customer-funded incentives paid to the Company's customers who choose to install DSG systems on their premises or those customers' out-of-pocket costs. Nor does it quantify any customer cross-subsidization that might occur between customers who choose to install DSG and net-meter their generation and those that do not. As such, costs and benefits in this study are an estimate of the net avoided costs of DSG to the electrical system and the study results should be read with that concept in mind.

Part of the study effort was to conduct a review of previously published solar generation cost and benefit studies performed by others. This review found that the quantification of costs and benefits of DSG installed on other utility systems in the United States are not directly applicable to the Public Service system at this time given significant differences between the Company's electric power supply system and those of the other utility systems studied.

<u>Initial Observations</u>

Federal Energy Regulatory Commission orders require the Company to carry planning reserves for the full extent of a customer's load whether they have installed behind-the-meter generation or not. Thus behind-the-meter DSG is correctly analyzed as generation and not as load reduction.

Given the diurnal and intermittent nature of the solar resource and the resulting poor correlation of solar generation to an individual customer's load, customers who install DSG use the Company's transmission, distribution, and generation systems more than non-DSG customers. That is, DSG customers not only rely on these systems for the delivery of energy and capacity from the Company when the solar generation is less than their load (for example, during night or other times when the solar resource is insufficient or when the customer's generation equipment is non-functional) but they also rely on the distribution system to take away the excess solar generation produced (that is, the amount of solar generation that exceeds their load). Customers with DSG are also dependent upon the Company's generation, transmission and distribution systems to maintain sufficient line voltage such that their generation equipment may function pursuant to industry safety standards.

Although not quantified in this study for the Public Service system, previous studies have documented that the Law of Diminishing Returns applies to the incremental additions of solar generation to a utility's portfolio. That is, the quantification of electric system benefits from DSG on an installed capacity basis will be highest for the very first tranches of generation and will decline as more DSG is installed. Conversely, marginal integration costs for incremental DSG are expected to increase given the non-dispatchable and intermittent nature of the solar resource. Thus, all else equal, the avoided cost values quantified in this study represent the highest levels that solar on the distribution system are likely to provide for the benefits examined.

Major Findings of the Study

A review of prior studies was helpful in identifying the types of benefits examined and the quantification methods utilized. As with most prior studies, the Company discusses DSG benefits as they relate to the three major components of its electric power supply system:

- generation,
- distribution, and
- transmission.

Generation System Costs and Benefits of DSG:

- The bulk of the avoided costs from DSG (>90%) derives from impacts on the Company's generation system, in particular, avoided energy costs. These forecast avoided energy costs are directly related to the forecast of natural gas prices.
- The value of DSG to the generation system is heavily dependent on the correlation between solar generation and the Public Service system electric load. In general, solar generation does not correlate well with the Company's system load or with its residential customer load. The correlation to commercial customer load is better. Figures 1 and 2 below illustrate these concepts for peak load days in January and July.
- Electric system production cost models indicate that DSG displaces a blend of coal-fired and gas-fired generation on the Company's system until roughly 2017 at which point over 1,300 MW of coal-fired generation is removed from the Company's generation portfolio as a result of the Company's long-term resource planning activities. After 2017 DSG was found to displace mostly efficient, gas-fired generation.

- The avoided generation capacity credit attributable to DSG for generation resource planning purposes is greatly impacted by the geographic location of the DSG in Colorado and the tracking capabilities of the DSG system.
- The use of actual solar generation meter data in an updated electrical load carrying capability resulted in significantly lower generation capacity credit values than the Company's prior study which utilized satellite-derived solar resource data and generic PV generation models.

Distribution System Costs and Benefits of DSG:

- The value of DSG to the distribution system is heavily dependent on the correlation between solar generation and feeder load.
- The potential for DSG to defer capital investment in the distribution system is more likely on distribution feeders with a high level of commercial customer load as opposed to distribution feeders with a high level of residential customer load. However, any capital deferral potential would apply in very limited circumstances, few of which currently exist on the Company's distribution system.
- Given the relatively low correlation between solar generation and feeder load across an entire calendar year, annual <u>avoided</u> distribution line losses are no greater than annual <u>average</u> distribution line losses.
- On distribution feeders with high levels of DSG penetration at secondary voltage levels, total line losses with DSG might be expected to be higher than total line losses that would occur in the absence of DSG. This effect is caused by higher electrical current flows across sections of the Company's 120-volt secondary delivery system than would exist without 120-volt interconnected generation.

Transmission System Costs and Benefits of DSG:

- Given the relatively low correlation between solar generation and system load across the entire calendar year, annual <u>avoided</u> transmission line losses are no greater than annual <u>average</u> line losses.
- The majority of the transmission system benefits quantified in this study are not tied to the avoidance of incremental bulk transmission additions but instead to the potential deferral/avoidance of a generation capacity resource and the assumed incremental transmission costs associated with that new generation resource.

Figures 1 and 2 below show residential and commercial loads and solar generation data on peak load days during July and January 2010. These figures (along with similar plots provided in Appendix V) help illustrate the differences in customer class load profiles (and, thus, feeders predominately serving a single customer class) and the ability of solar generation to help meet the customer class peak loads.

Figure 1 Customer Loads and Solar Generation - July 2010

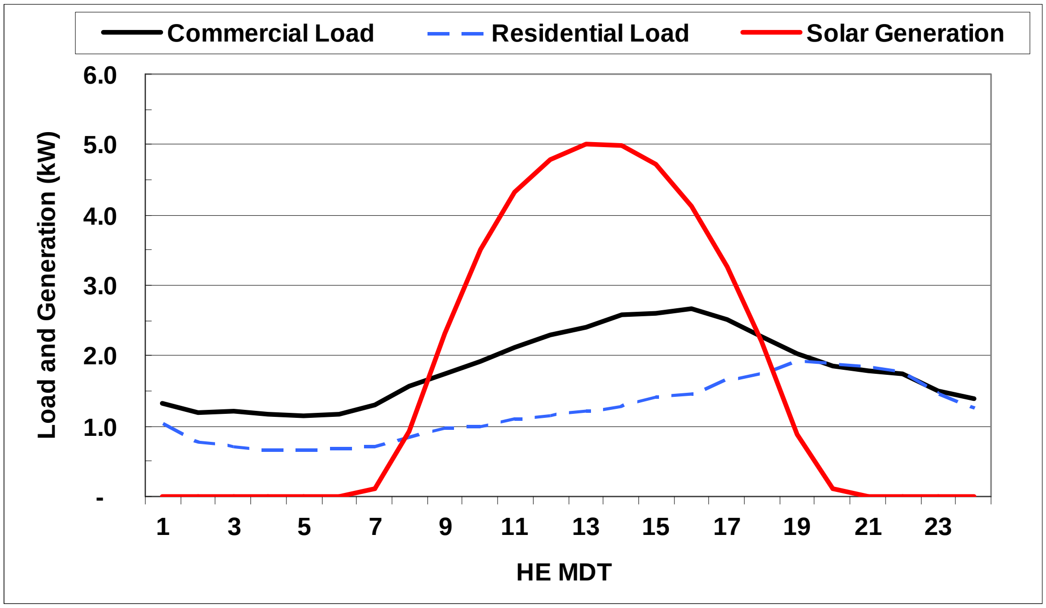
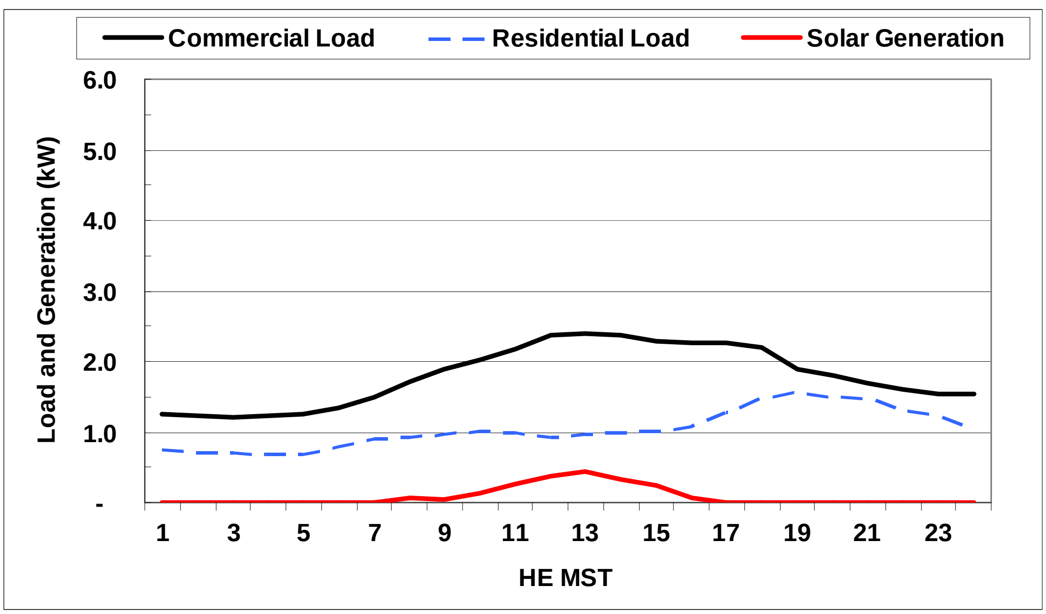


Figure 2 Customer Loads and Solar Generation - January 2010



As Figures 1 and 2 indicate, DSG is not an effective generation resource with which to meet residential customer class peak load; DSG is more effective at matching the load from the Company's commercial classes.

Table 1 below shows the 20-year levelized net avoided costs quantified in this study for Low Gas cost, Base Gas cost, and High Gas cost scenarios. As the tables in Appendix III indicate, given current natural gas costs, current net avoided costs of DSG (that is, net avoided costs in the earlier years of the study period) are roughly 50% of the Base Gas case levelized value.

Table 1 Categorization of Levelized Net Avoided Costs

	Low Gas		Base Gas		High Gas	
	$/MWh	%	$/MWh	%	$/MWh	%
Avoided Energy Costs	$ 35.80	55%	$ 52.10	63%	$ 76.10	69%
Fuel Hedge Value	6.60	10%	6.60	8%	6.60	6%
Avoided Emissions Costs	5.10	8%	5.10	6%	5.10	5%
Avoided Capacity & FOM Costs	11.50	18%	11.50	14%	11.50	11%
Avoided Distribution Upgrades	0.50	1%	0.50	1%	0.50	0%
Avoided Transmission Upgrades	0.20	0%	0.20	0%	0.20	0%
Avoided Line Losses	4.70	7%	6.20	8%	8.30	8%
Solar Integration Costs	(0.50)		(1.80)		(4.40)	
Net Avoided Cost	$ 63.90	100%	$ 80.40	100%	$ 103.90	100%
Generation	$ 58.50	92%	$ 73.40	92%	$ 94.90	91%
Transmission	2.50	4%	3.20	4%	4.30	4%
Distribution	2.90	5%	3.60	4%	4.60	4%
Net Avoided Cost	$ 63.90	100%	$ 80.20	100%	$ 103.80	100%

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Acknowledgements

Technical Review Committee

Several individuals served as members of the Technical Review Committee:

- Bill Bennett, Sangre de Cristo Electric, representing the Colorado Rural Electric Association
- Annie Carmichael, Solar Alliance
- William Dalton, Colorado Public Utility Commission Staff
- Easan Drury, National Renewable Energy Laboratory
- Gwen Farnsworth, Western Resource Advocates
- Matt Futch, Governor's Energy Office
- Rick Gilliam, Solar Alliance/Solar Energy Industries Association
- R.J. Harrington, Colorado Solar Electric Industries Association
- Rebecca Lim, Colorado Public Utility Commission Staff
- Susan Lovejoy, Colorado Springs Utilities, representing the Colorado Association of Municipal Utilities
- Jeff Lyng, Governor's Energy Office
- Jonathan Miller, Governor's Energy Office
- James Newcomb, Rocky Mountain Institute
- Meghan Nutting, Solar Energy Industries Association
- Kevin Pratt, Black Hills Energy
- Dr. P.B. Schechter, Office of Consumer Counsel
- Warren Wendling, representing the Colorado Harvesting Energy Network
- Dr. Chris Worley, Colorado Energy Office

The Company is grateful to these individuals for their participation in this study.

Other Parties

Estimates of hourly generation from photovoltaic systems located in the Southern Front Range area (near Pueblo, Colorado) were developed by Lincoln Renewable Energy, LLC based on historical, meteorological data acquired from Public Service's weather monitoring facility located at its Comanche generating facility in Pueblo. The modeled systems were based on typical, utility-scale design parameters for fixed and 1-axis tracking systems utilizing the PVSyst simulation software.

SolarCity Corp. provided the Company with hourly, cumulative generation rates from approximately 100 residential facilities it owns on the Company's system. SolarCity provided meter data beginning in July 2010 and ending in December 2011.

The Company is grateful to these companies for their support of this study.

Background

On May 1, 2009, Public Service Company of Colorado ("Public Service" or "Company") filed Advice Letter No.1535-Electric with the Colorado Public Utilities Commission ("PUC" or "Commission"), along with pre-filed testimony and exhibits seeking to set new rates for electric customers (i.e., a rate case); the Commission opened docket 09AL-299E. On August 4, 2009, Public Service filed a motion to withdraw certain sections of its rate case dealing with a Transmission and Distribution Capacity Charge it sought to assess on net-metered residential and small commercial customers with solar photovoltaic ("PV") system installations. The Company stated in its motion that issues related to the recovery of transmission and distribution charges would be better addressed through a stakeholder process outside of a rate case. In Decision No. C09-0923, the Commission allowed the Company to withdraw those sections of the advice letter and testimony related to the proposed Transmission and Distribution Capacity Charge and directed the Company to provide further details regarding its proposed stakeholder process. In Decision No. C09-1223, the Commission found that a cost/benefit study of distributed solar generation ("DSG") on the Public Service system would be a worthwhile and an important tool in evaluating the impact of distributed solar generation resources.

At a Commissioner's Information Meeting held on August 18, 2010, the Company and the Governor's Energy Office presented an outline of a joint study to be conducted in response to Decision No C09-1223.[1] At the Commission Information Meeting, the Company outlined a study methodology based on avoided/incremental cost principles. Following the information meeting, the Commission indicated that it was satisfied with the proposed scope and directed the parties to begin the study.

The Governor's Energy Office did not conduct its section of the joint study as originally proposed to the PUC.

Avoided Cost Methodology

Study Objectives

Public Service's objective in this study was to investigate and document the costs and benefits of distributed solar generation on its electric supply system at current penetration levels and projections for near-term penetration levels. It was expected that the results of the study could be used to inform future rate designs and perhaps guide implementation of current and future Public Service solar generation acquisition programs (e.g., Solar*Rewards and programs developed to acquire solar generation resulting from Colorado HB10-1342, "Solar Gardens").

Study Scope

Public Service proposed—and the TRC agreed—that "current" penetration levels of installed DSG capacity should be defined as those systems installed as of 9/30/2010. A near-term

[1] Copies of the draft Study Plan and presentation are available on the PUC website; Search for "Meetings" with a Title of "08/18/2010*"; https://www.dora.state.co.us/pls/efi/EFI_Search_UI.Search

penetration level was selected by the Company as the installed capacity expected by the end of 2014 (approximately 140 MW_{DC}).[2,3] Public Service selected a future date of 2014 since this comports with CRS 40-2-124(1)(e)(2)[4] and since dates farther into the future have higher levels of uncertainty around expected installed DSG capacity. Costs and benefits associated with both current DSG levels and expected 2014 levels were to be examined over a twenty (20) year life for installed DSG systems, which corresponds to the current Renewable Energy Credit ("REC") purchase terms of Public Service's Solar*Rewards program.

For purposes of this study, DSG is defined as any solar photovoltaic generation system interconnected to Public Service's distribution system at primary voltage or lower (typically < 44 kV). Employing this definition of DSG, photovoltaic systems may be physically net-metered or not. The study did not contemplate the addition of any solar thermal electric generation systems on the Company's distribution system by 2014.

Benefits are defined in this study as those quantifiable, solar generation attributes that tend to reduce or displace the cost of electric utility service. Benefits are driven by the correlations between the solar generation profile and the Company's electricity load profiles. Depending upon the specific benefit, the load in question might consist of customer, distribution feeder, substation, or system load. Potential benefits outlined during the Commissioner's Information Meeting included:

- avoided utility bill payments,
- avoided electric system energy costs,
- avoided electric generation capacity costs,
- reduced electric transmission and distribution line losses,
- avoided or deferred electric transmission and distribution capital expenditures, and,
- avoided ancillary services.

At the time of the Commissioner's Information Meeting, costs were identified as the quantifiable, solar generation attributes and solar acquisition program charges that tend to increase participant and/or non-participant costs for electric utility service.[5] Potential costs outlined during the Commissioner's Information Meeting included:

- participant's installed system and ongoing costs,
- rebate and REC payments made by the utility to program participants, and
- increased utility system costs resulting from the intermittent and non-dispatchable nature of the solar generation resource (e.g., increased ancillary costs and power quality issues).

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[2] Expected 2014 levels of installed DSG were based on Exhibit PJN-2 provided in Public Service's 2010 RES Compliance Plan, which was filed with the Commission on October 27, 2009; Docket 09A-772E.

[3] Unless otherwise indicated, all references to MW should be interpreted as MW_{DC} and all references to MWh should be interpreted as MWh_{AC}.

[4] HB10-1001 amended CRS 40-2-124 (1)(e)(2) with the addition of paragraph (c) which reads, in part, "Distributed generation amounts in the Electric Resource Standard for the years 2015 and thereafter may be changed by the Commission for the period after December 31, 2014, if the Commission finds, upon application by a Qualifying Retail Utility, that these percentage requirements are no longer in the public interest."

[5] Here, "participants" refers to those Company customers who install DSG.

Costs and benefits were initially proposed to be examined from the perspective of Public Service's program participant (e.g., Solar*Rewards participants) and non-participant customers. As the study progressed it was determined that the relevant costs that should be included in the study were those that impact the physical Public Service electric supply system directly and not those costs associated with: 1) participant out-of-pocket expenses, 2) administration of the Solar*Rewards program, or 3) incentive payments made to participants under the Solar*Rewards program.

A key feature of this DSG study effort was empanelling a Technical Review Committee ("TRC") comprised of industry experts to review and provide input to the Company regarding the technical aspects of the proposed study methodology, to periodically review the results of the study tasks, and to review and comment on a draft of the final report. The TRC included representatives from the following organizations:

- Black Hills Energy
- Colorado Association of Municipal Utilities (CAMU)
- Colorado Harvesting Energy Network (CHEN)
- Colorado Rural Electric Association (CREA)
- Colorado Solar Energy Industries Association (COSEIA)
- Colorado Energy Office (CEO)[6]
- National Renewable Energy Laboratory (NREL)
- Office of Consumer Counsel (OCC)
- PUC Staff
- Rocky Mountain Institute (RMI)
- Solar Alliance[7]
- Solar Energy Industries Association (SEIA)
- Vote Solar
- Western Resource Advocates (WRA)

Study Tasks and Methodologies

In its draft study plan, the Company outlined five main study tasks in order to determine the costs and benefits of DSG to its system:

1. Survey, review, and summarize prior DSG studies,
2. Characterize solar generation and determine correlation to load,
3. Calculate generation portfolio impacts,
4. Calculate distribution system impacts,
5. Calculate transmission system impacts.

[6] Formerly known as the Governor's Energy Office (GEO).

[7] During October 2011, the Solar Alliance merged with the Solar Energy Industries Association; SEIA is the surviving organization.

DSG Study Task 1 – Survey, review, and summarize prior DSG studies

Numerous studies have been conducted attempting to quantify the value of adding solar (specifically PV) generation to a utility's electric distribution system.[8] Most all of the studies reviewed under this task were based on an avoided cost methodology; that is, they are forward looking and examine a list of potential utility costs that might be deferred or avoided by adding a sufficient amount of solar generation at distribution voltages.[9]

A study conducted by Navigant Consulting for NREL and published in February 2008 provided a summary of both the quantification methodologies and a range of values found in the studies conducted up to that point in time. In addition, NREL maintained a PV Value Clearinghouse[10] that was used to identify relevant prior studies related to DSG. Each utility among those studied differs with respect to such parameters as:

- customer load shape,
- predicted load growth,
- solar resource,
- existing generation portfolio, and
- access to organized electricity markets.

Also, as each study was conducted at a different point in time with significantly differing forecasts of fuel prices and emissions costs, the quantified benefits found in the prior studies provide little insight as to the current benefits of DSG on the Public Service electric system. What is of value from the review of prior studies is the type of benefits examined and the quantification methodologies employed.

In general, the types of benefits examined in prior studies can be categorized in the same way as they have been categorized in this study:

- Generation system value,
- Transmission system value,
- Distribution system value.

[8] This study report strives to consistently use the acronym DSG to refer to solar generation interconnected at distribution voltages and to reserve the broader acronym DG to refer to any distribution-interconnected electricity generation resource whether it is from solar, wind, natural gas, etc.

[9] Another approach to valuing the benefits of DSG would be to employ an embedded cost of service approach consistent with rate-making principles. Class customers who net-meter solar generation have net load shapes (hourly customer load minus hourly customer solar generation) different than the class average customer and thus a reallocation of the allocated costs within that customer class may be justified. Analyses can be conducted to determine how customer on-site solar production might impact the relevant cost allocation factors and thus the cost level of these allocations.

[10] http://www.nrel.gov/analysis/pvclearinghouse/ (URL currently inactive)

Generation System Value

Avoided energy and avoided variable O&M costs

Prior studies have found that the bulk of DSG benefits to a utility and its customers reside in the ability of solar generation to displace generation from other power supply sources within a utility's portfolio.[11] The methodologies applied to quantify these costs in the studies reviewed included the use of generation dispatch simulation software tools (e.g., ProSym[12]) or, for utilities in the footprint of an independent system operator, locational marginal pricing data where available.[13]

One important and consistent finding from prior avoided energy cost studies is the declining benefit value with increasing DSG penetration or the "law of diminishing returns"; that is, the first tranches of DSG result in the highest levels of avoided energy costs.[14] This finding is generally attributed to the non-dispatchable nature of solar generation. That is, with a static load profile and a static solar generation profile, increasing levels of solar penetration result in the avoidance of energy from lower cost generation units.

Avoided or deferred generation capacity

The predominate method for quantifying the benefits of avoided or deferred generation capacity due to DSG involved the assignment of future avoided capital and fixed O&M costs. The assigned costs were typically set at the cost of new combustion turbine generation units needed to serve load growth and maintain reliable service. Other less-utilized methods included the use of pricing information from demand reduction programs as a proxy for the value of avoided generation capacity.

Some studies grant generation capacity credit to DSG for partial avoidance of a new generation unit, whereas other studies only grant credit if the MW level of DSG is sufficient to completely defer a new generation unit by at least one year or avoid the unit entirely. For those studies that require complete deferral or avoidance, generation capacity is assigned based on a short-term, capacity market rate for years prior to the deferral or avoidance year.

DSG generation capacity credit

In order to assess whether or not a certain amount of DSG can defer or avoid the need for a utility to expend capital dollars for additional generation capacity, it is necessary to determine the generation "capacity credit" to be afforded to DSG.[15,16] Most studies

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[11] RWBeck (APS), page xxii; Navigant, page viii; CPR (Austin), page ES-4; CPR (NY), page 11; CPR (WE), page ES-4; CPR(NV), page 4; See Appendix A for full reference cites.

[12] ProSym is a registered trademark of Ventyx.

[13] See Appendix I for a summary of the findings from prior DSG studies categorized by value type.

[14] LBNL, page 19.

[15] A generation facility's generation capacity credit (or capacity value) is frequently confused with the facility's capacity factor. A facility's generation capacity credit is a probabilistic measure of the percent of the facility's nameplate generation rating (measured in MW) that can be relied on to serve customer loads. A facility's capacity factor is the ratio of the total amount of energy (measured in MWh) that facility is expected to generate over a specific time period to the maximum amount of energy it could generate if operated during the time period at full nameplate capacity; capacity factors are typically provided on an annual basis.

[16] The Company conducts its reliability and resource planning studies consistent with Federal Energy Regulatory Commission (FERC) orders that require load serving entities to treat behind-the-meter generation as generation and

employed the use of a probabilistic methodology to estimate the generation capacity credit attributable to DSG; these methodologies include effective load carrying capability ("ELCC") and loss of load expectation ("LOLE") approaches.

As with avoided energy costs most studies found that higher penetrations of DSG result in lower marginal generation capacity credit.[17] Again this finding was attributed to the non-dispatchable nature of DSG; as more solar generation (which obviously only occurs during daylight hours) is added to a system, the utility's net electric system load peak shifts more towards late-evening hours and away from those hours in which incremental solar generation additions can provide value.

Avoided emissions costs

When quantified, the methodology most employed was to obtain the avoided fossil fuel consumption (typically from the avoided energy cost study), estimate the associated levels of emissions, and then assign a cost to the emitted substance. The most typical emission cost quantified was carbon dioxide.

Fuel price hedge value

As the primary cost of solar generation is in upfront capital—with much lower ongoing O&M costs as opposed to other fuel-based generation resources—an additional benefit is not only the displacement of other generation sources of electricity, but also the relative cost certainty of the displacement. Thus the benefit of such a fuel price hedge is not in guaranteeing lower electricity prices for the future, but in lessening the likelihood of high future fuel costs. However, by locking in relatively stable prices for future years, one must also forego the opportunity that other generation resource costs could be lower in the future; that is, a fuel hedge is most similar to an insurance policy. A typical method for quantifying the fuel hedge benefit of DSG in prior studies was to use NYMEX natural gas futures contracts to estimate a market value of the hedge.

Ancillary services requirements

Although several studies qualitatively discussed the ancillary service benefits that DSG could bring to a utility system, none were able to quantify the benefits. One study did address the potential for increased levels of ancillary service costs (e.g., regulating reserves[18]), but was unable to quantify the cost due to a lack of available solar generation meter data.

Transmission System Value

Avoided or deferred transmission capacity

For non-transmission operating utilities, the benefit was in avoiding the purchase of transmission access fees; for transmission owning/operating utilities the benefit was in the deferral or avoidance of future transmission capital projects. As with generation capacity,

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not as load reduction. FERC Order on Rehearing and Compliance, *Midwest Independent Transmission System Operator, Inc.*, Docket Nos. ER08-394-004 and ER08-394-005, Issued February 19, 2009.

[17] LBNL, page 19.

[18] Regulating reserves are those generation resources that a utility maintains to respond to sudden losses in generation or transmission resources.

some studies assign value to DSG's share of future avoidance and others only assign value if and when DSG levels are sufficient to defer or avoid an entire transmission asset. Again, as with generation capacity value, a transmission capacity credit needs to be assigned to DSG to determine the MW amount of transmission capacity deferred or avoided for each MW of DSG; this was typically measured at the utility system-peak load hour.

<u>Reduced transmission line losses</u>
Generation added on a distribution system avoids the delivery of generation across a transmission system and lowers the effective current on the transmission system; this allows the generation that does flow on the transmission system to do so with higher efficiency (i.e., with lower line losses). Several studies specified that the avoided transmission line losses should be calculated based on avoided transmission system line losses and not on average line losses. That is, the correlation between solar generation and system load should be taken into account.

As with some other benefits, transmission line loss savings decrease with increasing levels of DSG; that is, the first tranches of solar on the distribution system provide the highest level of avoided transmission line losses.

<u>Distribution System Value</u>

<u>Avoided or deferred distribution capital costs</u>
The benefits are the deferral or avoidance of future distribution capital projects.

<u>Reduced distribution line losses</u>
Generation added on a distribution system can avoid line losses across a distribution feeder; however this value is highly dependent upon where on the feeder the generation system interconnects and other feeder-specific details such as customer load profiles. For example, DSG that interconnects at the head of the feeder (i.e., very close to, or at, the substation) will result in little or no reduction in feeder line losses as power flow along the feeder is unchanged.

DSG Study Task 2 - Characterize Solar Generation and Determine Correlation to Load

The quantification of DSG avoided costs requires that time interval generation data—at an hourly resolution or higher—be obtained or created. Depending upon the category of avoided cost under consideration, either proxy DSG generation profiles which exhibit an historical level of correlation to <u>forecasted</u> electrical load are needed (e.g., for the quantification of avoided energy costs in future years) or historical DSG generation profiles that contain the <u>actual</u> correlation to <u>historical</u> electrical load are needed (e.g., for the quantification of generation capacity credit). As the Company does not have interval meter data for the vast majority of the DSG installations on its electrical system, it was necessary to categorize actual DSG installations by geographic location and tracking capability. Once categorized, the Company could assign proxy solar generation profiles to these categories based on typical meteorological data or on actual solar generation data from similar systems with interval meter data.

Characterization of Solar*Rewards Projects

Installed DSG capacity on the Public Service electric system has been acquired primarily through the Company's Solar*Rewards ("S*R") programs. As of 9/30/10, ~6,650 DSG systems totaling 59 MW had been installed through the Company's various S*R programs. Projects acquired through the Small (<= 10 kW) and Medium (>10 kW but <= 500 kW) S*R programs are processed through a Web-based application with relevant information stored in a S*R database. The S*R database acquires project information relevant to this study such as:

- Standard offer program (i.e., Small or Medium),
- Azimuth and elevation for fixed systems (for up to 3 separate arrays per project),[19]
- Tracking capability (as applicable),
- Installed capacity (in kW_{DC}),
- Estimated annual generation (in kWh_{AC}),[20]
- Premise information
    - Address and zip code,
    - Premise number, and
- Completion date.

Similar information for those DSG projects funded through the Large Program S*R competitive solicitations was compiled separately.

An audit of the S*R database project data was conducted by examining outlying results from:

- A comparison of installed system size vs. S*R Program size ranges,
    - Adjustments were made to the installed kW of four projects totaling 40 kW,
- A calculation of annual $kWh_{AC}/kW_{DC,}$
    - Adjustments were made to the annual expected energy on 21 projects to more closely approximate typical generation levels for the projects' kW rating, location, and mounting orientation,
- A review of azimuth and elevation angles and tracking capabilities,
    - Adjustments were made to the orientation and/or tracking capability on 39 projects totaling 266 kW. The most common adjustment was to switch the azimuth and elevation entries (e.g., projects originally entered with an azimuth of 30° and an elevation of 180°),

Google Earth and Google Street View[21] served as useful tools with which to help confirm that Solar*Rewards project data which appeared suspect were indeed correct or incorrect, especially for projects in the Company's Front Range electric service territory where Google Earth provided high resolution and current images. At the time of the S*R database audit, these tools

[19] Residential rooflines, in particular, frequently require panel installation on different roof sections which face different directions in order to install the customer's desired kW of PV panels.

[20] Estimated annual generation is based on a PVWatts calculation. PVWatts is a web-based solar generation modeling tool developed by NREL available as a stand-alone application or included within NREL's System Advisor Model.

[21] Google, Inc. (2012); Google Earth available at http://www.google.com/earth/download/ge/agree.html; Google Street View available at: http://maps.google.com/maps?hl=en&tab=wl.

were less useful to confirm suspect data for projects in other parts of the Company's electric service territory.[22]

In aggregate, adjustments were made to less than 1% of the ~6,650 projects in the S*R database, which the Company believes is a good indication that the database information is of relatively high quality and is appropriate for use in this study.

<u>Categorization of DSG by Location</u>

NREL has created annual, hourly typical meteorological year ("TMY") weather data for various locations in Colorado that can be used to estimate typical, hourly solar generation for PV systems of various locations, orientations and tracking capabilities. NREL's TMY2 data set is based on historical weather observations recorded from 1961 to 1990 at six Colorado locations:

- Alamosa,
- Boulder,
- Colorado Springs,
- Eagle,
- Grand Junction, and
- Pueblo.

Four of these TMY2 sites (Alamosa, Boulder, Eagle, and Grand Junction) correspond to the Company's service territory.[23] Each DSG project was mapped to one of these four TMY2 sites based on zip code.

Figure 3 shows the S*R project locations of the initial 59 MW (red dots) along with the four TMY2 sites. As the figure shows, the TMY2 sites align fairly well with the vast majority of the DSG project locations.

Given the fact that the installed DSG systems are dispersed around the TMY2 site locations, for this study, the Company refers to four solar resource zones: San Luis Valley (Alamosa), Northern Front Range (Boulder), Mountains (Eagle) and Western Slope (Grand Junction).

<u>Characterization of the 59 MW</u>

Each of the DSG arrays was further categorized by tracking capability and, for the fixed systems, azimuth (90°, 135°, 180°, 225°, and 270°) and elevation (10° and 30°).[24]

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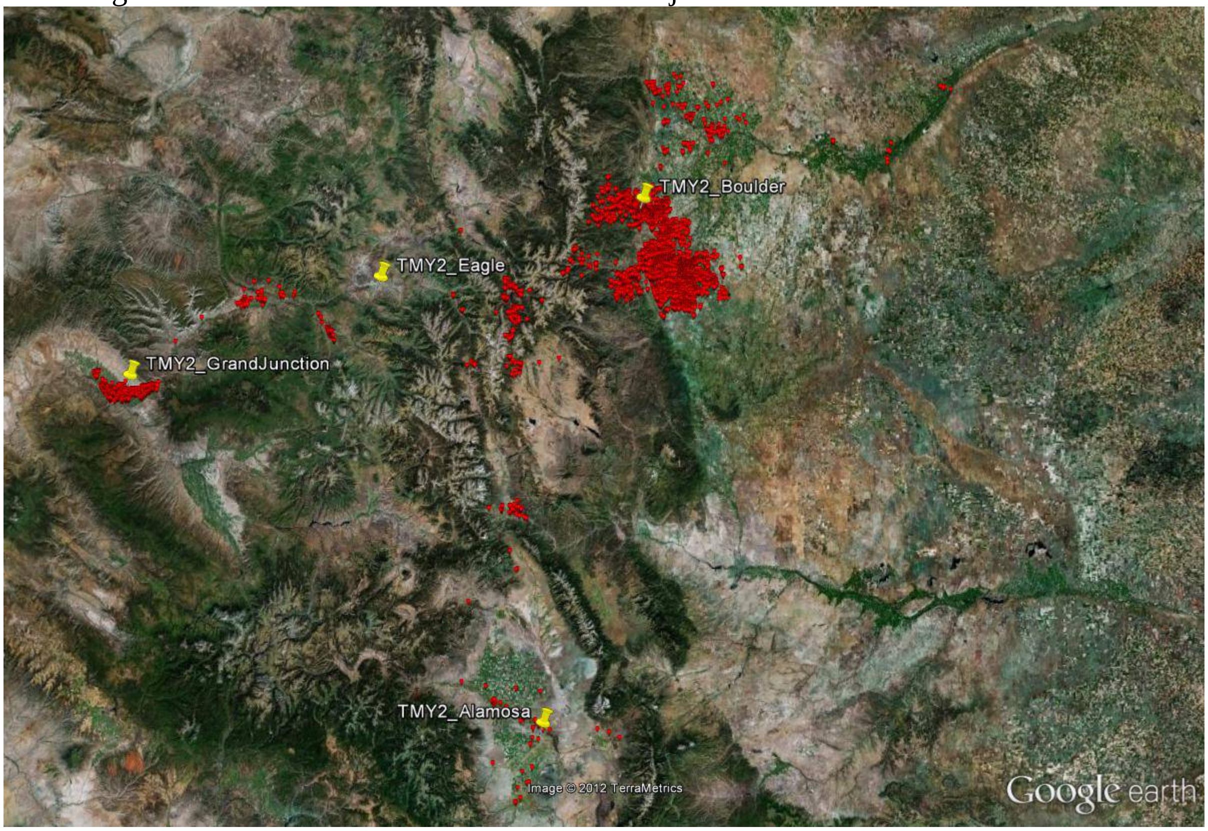
[22] As an example, at the time of the data audit, a Google Earth image of the Mosca substation in the San Luis Valley showed no installed solar field although the SunE Alamosa1 solar facility was completed at that location in late 2007. Google Earth has since updated its San Luis Valley images and most all Valley installations were visible at the time this study was completed.

[23] NREL has produced an update to the TMY2 data set called TMY3. The TMY3 data set is based on historical weather observations from 1961 to 1990, as well as on additional weather data from 1991 to 2005. TMY3 data sets are available for 25 Colorado locations, of which thirteen correspond to the Company's service territory. As the goal of the categorization exercise was to reduce the geographic locations down to a manageable size, the Company selected the four TMY2 data sets corresponding to the Company's service territory as the geographic proxies instead of the larger TMY3 data set.

Figure 3 Location of the 59 MW of DSG Projects in Relation to TMY2 Sites



Various pivots of the project data were made to characterize the initial 59 MW of DSG. Table 2 shows the number of projects, installed MW, and projected annual energy generation by Solar*Reward program. Although the vast majority of individual DSG projects resulted from the Small Program (97% of the total), only 56% of the total MW, and 54% of the total annual MWh resulted from these Small Program projects; in contrast, 31% of the installed MW and 34% of the total annual MWh resulted from only 24 projects acquired through the Large Program RFPs (which represent < 0.5% of the total number of projects).

Table 3 shows the number of projects, installed MW, and projected annual energy generation by interconnection voltage. As would be expected given the information in Table 2, the vast majority of the installed MW is interconnected at secondary voltage levels. This information is utilized later in the analysis to credit DSG with avoided distribution line losses.

[24] Azimuth measures the panel orientation relative to the compass points (e.g., 90° is due east and 180° is due south), elevation is measured as the angle relative to the horizon (e.g. 0° is horizontal and 90° is vertical).

Table 2 59 MW DSG categorized by Solar*Reward Program

Solar*Rewards Program	Projects	%	MW	%	MWh	%
Small (0-10 kW)	6,478	97%	33.1	56%	46,348	54%
Medium Tier1 (10-100 kW)	129	2%	5.4	9%	7,431	9%
Medium Tier1 (100-500 kW)	21	0%	2.4	4%	3,201	4%
Large (26-2,000 kW)	24	0%	18.1	31%	29,052	34%
Total	6,652	100%	59.0	100%	86,032	100%

Table 3 59 MW DSG categorized by Interconnection Voltage

Interconnection Voltage	Projects	%	MW	%	MWh	%
Secondary	6,631	99.7%	52.4	89%	75,771	88%
Primary	20	0.3%	5.5	9%	8,737	10%
Transmission	1	0.0%	1.2	2%	1,524	2%
Total	6,652	100%	59.0	100%	86,032	100%

Table 4 shows the number of projects, installed MW, and projected annual energy generation by Public Service customer tariff.[25] All of these projects have been installed on the customer side of the meter as net-metered generation. As net-metered generation project sizes are limited to 120% of the customer's expected annual load demand rate customers can, and do, install larger systems. Thus, whereas residential and small commercial customers represent nearly 95% of the 59 MW DSG projects, they only represent 54% of the installed MW and 51% of the projected annual energy.

Table 4 59 MW DSG categorized by Customer Tariff

Customer Tariff	Projects	%	MW	%	MWh	%
R	5,896	88.6%	28.5	48%	39,897	46%
RD	8	0.1%	0.1	0%	104	0%
C	398	6.0%	3.4	6%	4,705	5%
SG	328	4.9%	20.4	35%	31,049	36%
SGL	1	0.0%	0.0	0%	15	0%
PG	20	0.3%	5.5	9%	8,737	10%
TG	1	0.0%	1.2	2%	1,524	2%
Total	6,652	100%	59.0	100%	86,032	100%

Table 5 shows the number of projects, installed MW and projected annual energy generation by geographic location. As mentioned previously, the vast majority of all projects have been installed in the Company's Northern Front Range service territory. Of interest is the ratio

[25] Residential ("R") and Small Commercial ("C") tariffs are all-in energy rates. Residential Demand ("RD"), Secondary General ("SG"), Secondary General Low-Load Factor ("SGL"), Primary General ("PG"), and Transmission General ("TG") are demand-based rates.

between annual MWh and installed MW between the locations; specifically, the San Luis Valley area projects represent 6% of the total installed MW, yet account for 8% of the projected annual energy; whereas the Northern Front Range area projects represent 80% of the installed MW, yet account for only 77% of the projected annual energy. Two factors account for this difference; first, an installed MW of San Luis Valley solar will generate more annual energy than a MW installed in the Northern Front Range given the superior solar resource in the San Luis Valley. Second, a greater percentage of the San Luis Valley installed solar is tracking as compared to the Northern Front Range solar installations; tracking PV generates more annual energy than fixed PV per installed kW.

Table 5 59 MW DSG categorized by Solar Zone

Solar Zone	Projects	%	MW	%	MWh	%
Mountain	295	4.4%	1.6	3%	2,256	3%
Northern Front Range	5,597	84.1%	47.2	80%	66,588	77%
San Luis Valley	147	2.2%	3.7	6%	6,748	8%
Western Slope	613	9.2%	6.5	11%	10,440	12%
Total	6,652	100%	59.0	100%	86,032	100%

Table 6 illustrates the percentage of installed DSG by geographic location and by tracking technology. Note that an insignificant amount of the installed DSG systems track in 2 axes. Therefore, for all further analyses within this study, 2-axis tracking systems were binned with the 1-axis systems to simplify the analyses and presentation of results.

Table 6 59 MW DSG categorized by Tracking Technology and Solar Zone

Mounting Technology	Mountain	%	Northern Front Range	%	San Luis Valley	%	Western Slope	%	Total	%
Fixed	1.6	2.6%	40.6	68.8%	3.1	5.2%	4.2	7.1%	49.4	83.7%
1-axis	0.0	0.0%	6.5	11.0%	0.6	1.1%	2.4	4.0%	9.5	16.1%
2-axis	0.0	0.0%	0.1	0.1%	0.0	0.0%	0.0	0.0%	0.1	0.2%
Total	1.6	3%	47.2	80%	3.7	6%	6.5	11%	59.0	100%

Table 7 presents a breakdown of the 49.4 MW of fixed DSG installed. Whereas the majority of fixed DSG has been installed in a south-facing orientation (82%), significant percentages have been installed facing in an easterly (~11%) or westerly direction (~7%).[26] This result was expected to have some bearing on the annual, hourly generation profiles as east-facing systems typically generate a greater percentage of their annual generation during morning hours whereas west-facing systems generate a greater percentage of their annual generation during afternoon hours. Also, east-facing systems typically generate more annual energy than west-facing systems given the greater likelihood of higher afternoon temperatures and afternoon monsoon conditions, both of which tend to reduce PV output. Conversely, as

[26] These estimates are based on the Total column in Table 6 and include the systems that are installed relatively flat on customer's roofs (i.e., those systems binned as 10° tilt). In general, the closer to flat (i.e., 0° tilt) a panel is installed, the less impact the azimuth angle will have on the expected generation profiles.

Public Service is a late-afternoon, summer-peaking system, those DSG systems facing west are likely to be afforded more generation capacity credit than east facing systems.

Table 7 49.4 MW of Fixed DSG categorized by Azimuth and Elevation

		Elevation					
	Degrees	**10**	**%**	**30**	**%**	**Total**	**%**
Azimuth	**90**	0.2	0.4%	2.0	4.1%	2.2	4.5%
	135	0.5	1.0%	2.9	5.8%	3.4	6.8%
	180	10.7	21.7%	29.9	60.5%	40.6	82.1%
	225	0.2	0.4%	2.3	4.6%	2.5	5.0%
	270	0.2	0.4%	0.6	1.1%	0.7	1.5%
	Fixed Total	11.8	23.8%	37.6	76.2%	49.4	100%

Although obvious variations among the installed DSG projects exist, as a generalization, the typical DSG installation as of 9/30/10 was a Northern Front Range, residential, fixed, south-facing system. However, only slightly more than half of the expected solar generation on an annual basis is expected from these small residential systems.

In order to create a single, TMY2 hourly generation profile that represented the entire 59 MW, each of the TMY2 generation profiles developed within PVWatts was weighted by the MW of installed DSG in each of the respective categories. This single DSG electric generation profile was used to determine forecasted avoided energy costs and some components of the distribution system analyses.

Characterization of the 140 MW

The hourly solar generation profiles developed for the initial 59 MW of DSG were based on location and orientation data from the actual DSG systems installed. At the time these profiles were developed, the Company assumed that they could be utilized for the 140 MW forecast case also. That is, the Company assumed that the incremental 81 MW of DSG (140 MW – 59 MW = 81 MW) would consist of similar systems installed in similar locations as the initial 59 MW.

As a check on this assumption, the Company analyzed the actual 60 MW of DSG installations that have occurred between 9/30/10 and 12/31/11 and the incremental 21 MW of DSG projects in the pipeline as of 12/31/11. Table 8 shows information similar to Tables 2 through 6 above for the initial 59 MW, the incremental 81 MW, and the total 140 MW. Since 9/30/10, there has been a trend towards more DSG MWs: 1) installed in the Medium Programs (10-500 kW), 2) interconnected at transmission voltages, 3) installed at demand-rate customer sites, and 4) installed as fixed systems vs. tracking ones.

Federal American Reinvestment and Recovery Act ("ARRA") funds and the entrance of national, 3rd party ownership companies into the Colorado market are behind several of these changes. For example, the 6.7 MW incremental DSG installed at transmission voltage was the result of two projects located at the Denver Federal Center constructed with ARRA funds. In addition, ARRA funds were also used to finance a multitude of 3rd-party ownership, 100-kW scale, fixed systems at public school facilities; such facilities are typically demand rate customers. Finally, during this time frame, the national, 3rd-party ownership companies operated almost exclusively in the Northern Front Range solar zone.

Table 8 Selected Descriptors for the Tranches of DSG

	59 MW		81 MW		140 MW	
	MW	%	MW	%	MW	%
Small (0-10 kW)	33.1	56%	20.6	25%	53.7	38%
Medium (10-500 kW)	7.8	13%	43.5	54%	51.2	37%
Large	18.1	31%	16.9	21%	35.0	25%
Secondary	52.4	89%	66.2	82%	118.5	85%
Primary	5.5	9%	8.1	10%	13.6	10%
Transmission	1.2	2%	6.7	8%	7.9	6%
R	28.6	48%	19.2	24%	47.7	34%
C	3.4	6%	3.4	4%	6.8	5%
SG	20.4	35%	43.6	54%	64.0	46%
PG	5.5	9%	8.1	10%	13.6	10%
TG	1.2	2%	6.7	8%	7.9	6%
Mountain	1.6	3%	1.6	2%	3.2	2%
Northern Front Range	47.2	80%	72.0	89%	119.1	85%
San Luis Valley	3.7	6%	2.1	3%	5.8	4%
Western Slope	6.5	11%	5.4	7%	11.9	9%
Fixed	49.4	84%	81.0	100%	130.4	93%
Tracking	9.6	16%	-	0%	9.6	7%

As tracking DSG systems typically generate more annual energy than fixed systems and also tend to generate a larger fraction of their nameplate MW rating later into the afternoon than fixed systems, the 59 MW DSG electricity generation profile may slightly overstate the avoided cost benefits in the 140 MW case. In general, however, the total 140 MW installed has similar characteristics to the initial 59 MW and the assumption that the 140 MW of DSG would have similar generation profiles as the initial 59 MW appears justified.

<u>Characterization of DSG meter data</u>

As mentioned previous, the Company does not have historical meter data for each of the 6,652 DSG systems installed on its electric system. However, the Company has obtained complete, calendar year, 15-minute interval meter data for nine systems during 2009 and fourteen systems during 2010.[27] These historical meter data were used to quantify the historical level of correlation between DSG electricity production and Public Service electrical load as well as to evaluate the level of generation capacity credit to be afforded DSG. The meter data are predominately from larger-sized installations that represent < 1%

[27] Pursuant to PUC rule 3656(l), PV system owners are to provide a qualified retail utility "real-time" access to generation and meteorological data for systems > 250 kW. The predominate manner in which DSG system owners have complied with the Company's request for such real-time access is to grant the Company access to the generation systems' web-based, system monitoring applications. This access allows the Company to download historical electrical generation and relevant meteorological data on 15-minute intervals at a minimum.

of all DSG projects installed; however, the projects for which the Company does have data represent 26% of the 59 MW of installed DSG (15.5 MW of metered projects).

Tables 9 and 10 show the orientations and locations of the systems with meter data during 2009 and 2010 respectively.[28]

Table 9 DSG systems with 2009 Meter Data

	Fixed 10°		Fixed 30°		1-axis Tracking	
Solar Zone	**Count**	**MW_{DC}**	**Count**	**MW_{DC}**	**Count**	**MW_{DC}**
Mountain						
Northern Front Range	2	2.03	1	1.18	3	3.35
San Luis Valley					1	0.60
Western Slope					2	2.33
	2	2.03	1	1.18	6	6.27
Total					**9**	**9.5**

Table 10 DSG systems with 2010 Meter Data

	Fixed 10°		Fixed 30°		1-axis Tracking	
Solar Zone	**Count**	**MW_{DC}**	**Count**	**MW_{DC}**	**Count**	**MW_{DC}**
Mountain						
Northern Front Range	3	2.13	2	2.75	4	5.35
San Luis Valley			2	2.35	1	0.60
Western Slope					2	2.33
	3	2.13	4	5.10	7	8.28
Total					**14**	**15.5**

Examination of the meter data revealed various lengths of time for which no electrical generation was indicated during daylight hours. Reasons for such generation gaps can include conditions such as: dense cloud cover, solar generation equipment malfunctions (e.g., an inverter trip), data acquisition system malfunctions, and panel shading due to snow cover. Gaps due to solar generator malfunction could be separated from gaps due to data acquisition malfunction by reviewing other channels of recorded data (e.g., air temperature or solar insolation). If all data acquisition channels showed the same gap, the outage was charged to the data acquisition system, otherwise the outage was charged to a generator malfunction. Likewise, if a gap in generation occurred during winter months but the data acquisition

[28] As all the fixed systems providing meter data were installed in a due south orientation (or would have been binned with south-facing systems), it was not necessary to also bin these projects by azimuth. In addition to the large, net-metered projects providing interval meter data for this study, the Company also included the use of solar generation data from the 8.2 MW_{DC}, SunE Alamosa1 system located in the San Luis Valley. The entire 8.2 MW facility was categorized as a 1-axis tracking system even though roughly 12% of the installed MW is 2-axis tracking and roughly 9% is south-facing fixed.

channels continued to record other data (such as air temperature)—and a review of historic weather data indicated recent snowfall—the gap was attributed to snow cover.[29]

Linear regressions between the hourly generation data sets from similar systems in similar locations were utilized to fill in the missing generation data. Given the limited number of meter data sources, the Company filled in any generation gaps charged to either generation equipment or data acquisition malfunctions in order to not unduly penalize all other DSG sources. This is a somewhat generous approach to filing in missing data as it effectively reduces the expected forced outage rate ("EFOR") of the generation systems used as a proxy for all other systems.

<u>Residential System Meter Data</u>

With the support and direction of the TRC, the Company also obtained solar generation meter data for approximately 100 residential, Northern Front Range DSG systems covering the August 2010 through December 2011 time period.[30]

As insufficient data are available for the 2010 period, the residential system data were not used directly in the study for avoided energy or avoided capacity credit calculations. However, the 2011 residential system data have been compared to 2011 meter data acquired from other, south-facing fixed systems installed in the Northern Front Range area; see, for example, Figure 4 which covers a seven day period in July 2011 around the 2011 peak load day (July 18th). In general, there is an excellent match to the overall daily shapes of solar generation. However, the residential generators' capacity factors are significantly lower than those of the larger systems. As Table 11 indicates, the residential generator monthly capacity factors are, on average, roughly 80% of those of the larger fixed systems for which the Company has interval meter data.[31]

The residential generator data were generated from fixed DSG systems that included a mix of installed orientations; for example, 18% of the kW faces due east and 12% faces due west. Thus decreased generation at solar noon should be expected from this portfolio of residential generators (whose mounting orientation is dictated by the customer's roof lines) vs. the large-scale, south-facing systems (whose mounting orientation can be, to a greater extent, selected to give more annual generation and more generation at solar noon).

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[29] Gaps in generation due to snow coverage were also clearly indicated as generation gaps that were evident across all systems located in the same solar resource zone during winter months.

[30] These meter data were obtained from systems owned by SolarCity. SolarCity records its generation data as a cumulative value (as opposed to interval values from the web-based monitoring systems) and is recorded rounded up to the nearest kWh. As the typical SolarCity system size is ~5 kW, a plot of the generation data from individual systems are quite erratic given the low kWh resolution. However, once hourly data from a sufficient number of systems are available, the aggregate curve is sufficiently well-behaved as to be usable. Beginning in January 2011, a sufficient number of systems are available to provide hourly generation data that are stable.

[31] Note that the presentation of these data are to illustrate the differences in the SolarCity residential data as a proxy for all Northern Front Range residential systems vs. using the larger installed fixed systems as a residential proxy. The differences in these performances should not be interpreted as substandard performance of the SolarCity generation systems as compared to any other residential installations.

Figure 4 Comparison of Residential and Large-Scale DSG Profiles

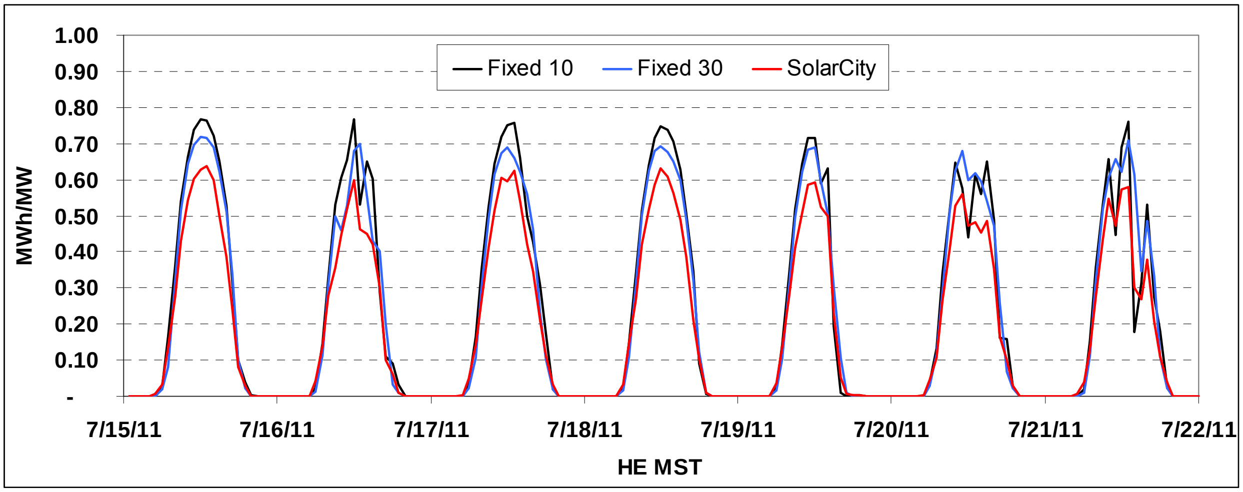

Table 11 Monthly Capacity Factors for Northern Front Range, Fixed Systems

Month	Fixed 10	Fixed 30	SolarCity	% of Fixed
Jan-11	8%	12%	8%	84%
Feb-11	10%	15%	10%	80%
Mar-11	18%	20%	15%	77%
Apr-11	19%	21%	16%	79%
May-11	19%	19%	15%	81%
Jun-11	23%	23%	18%	81%
Jul-11	22%	22%	18%	83%
Aug-11	20%	21%	17%	81%
Sep-11	18%	20%	15%	77%
Oct-11	15%	19%	13%	74%
Nov-11	11%	17%	10%	72%
Dec-11	5%	13%	6%	71%
average	16%	18%	13%	78%

Without incremental meter data from additional, small DSG systems, the Company cannot make any claim other than that the generation profiles for the larger systems do not appear to be a perfect proxy for the more numerous, residential systems.[32] As detailed below, historical meter data from the larger systems were employed in the calculation of DSG generation capacity credit. As generation capacity credit is typically driven by late-afternoon, summer generation, and Figure 4 shows a good match between residential DSG generation and the metered generation during these hours, any potential overstatement in generation capacity credit is not expected to be as large as the differences between the annual generation values (e.g. capacity factors) between the small residential generators and the larger systems.

[32] This claim also assumes that the SolarCity residential systems examined here are a good proxy for all other residential systems. The Company has no evidence to suggest that this is not the case.

Historical Correlation between Solar Generation and Electric System Load

ProSym is an hourly chronological model that Public Services uses to simulate operation of its electric supply system. The ProSym model uses an 8,760 hourly load profile for each year of a simulation. These 8,760 hourly load profiles are based on historical Public Service system electric load data. As with NREL's TMY2 data sets, ProSym's annual, hourly load profiles are based on historical data, but the profiles do not represent any particular historical year.

At the start of this DSG study, it was not known what impacts the use of typical meteorological data and typical electric system load data might have on the calculation of avoided energy cost for DSG as compared to the use of actual solar generation data and actual system load in this same calculation. As discussed previously, one use of the historical PV meter data was in calculating correlation levels between historical solar generation and historical electric load. With these correlation levels known, ProSym avoided energy calculations could be conducted for purposes of comparing: 1) base TMY2 solar generation data vs. base ProSym load, 2) daily TMY2 data rearranged so as to exhibit historical levels of correlation[33] to base ProSym load, and 3) daily TMY2 data rearranged so as to exhibit perfect levels of correlation to Public Service system load.

Historical correlation between solar generation and electric system load was calculated on a daily basis. That is, correlation was measured across the total MWh of solar generation each day during daylight hours for each month and the total MWh of system load during the same period. As system load is—on average—significantly lower during weekend periods, correlation calculations were conducted separately for weekday and weekend periods. Table 12 shows the average, historical correlation levels between the solar generation and system load.

[33] Correlation based on rank correlation wherein correlation is calculated based on the relative ranking of each point in a data set instead of on the value of each point. As an example, the two data sets {2,5,9} and {8,12,13} have a correlation value of 0.91, whereas they are perfectly rank correlated (i.e., rank correlation = 1.0) as the rank of 2 in the first data set and the rank of 8 in the second data set are both 1, the rank of 5 in the first data set and the rank of 12 in the second data set are both 2, etc. For this study, perfect rank correlation between load and generation should serve as an upper bound on the avoided cost values as the maximum levels of solar generation within the month should fall on the same days as maximum system load. As higher loads usually result in higher costs, this scenario should result in near-maximum avoided costs.

Table 12 Average Correlation between Solar Generation and System Load

Month	Weekdays	Weekends
Jan	(0.52)	(0.22)
Feb	(0.51)	0.04
Mar	(0.43)	0.25
Apr	(0.18)	(0.37)
May	0.16	0.40
Jun	0.36	(0.11)
Jul	0.47	0.15
Aug	(0.04)	0.24
Sep	0.27	0.42
Oct	(0.15)	0.09
Nov	0.20	0.25
Dec	(0.57)	0.20

As expected, there is a positive correlation between solar generation and system load during summer months; in the summer, bright sunny days tend to increase ambient temperatures leading to a corresponding increase in cooling loads. Also, as expected, there is a negative correlation between solar generation and system load during winter months; in the winter, bright sunny days tend to increase ambient temperatures leading to a reduction in heating loads.[34]

A spreadsheet model was developed to impose the historical rank correlation shown in Table 12 on the TMY2 solar data by rearranging the DSG electric production for each day within a month until the measured rank correlation matched the historical rank correlation target within 2.5 percentage points.[35] For perfect rank correlation, the rank of the TMY2 solar generation during daylight hours was set to match exactly the rank of the ProSym system load during daylight hours.

Avoided energy cost calculations were then performed within ProSym for a single test year (2014) of the study period to test the impact of each of the three scenarios; that is, the raw TMY2 data, the historically-correlated TMY2 data, and the perfectly rank correlated TMY2 data. The raw TMY2 data showed the lowest levels of avoided energy cost with perfect correlation and historical correlation showing roughly identical avoided energy costs (~2.7% higher than the raw TMY2 case) on an annual basis. Such a small difference in avoided energy costs is within a reasonable error estimate of the avoided energy cost calculations themselves and indicates that the use of TMY2 solar generation and a typical Public Service electric system load profile is tolerable for annual DSG avoided energy cost calculations.[36]

[34] One somewhat surprising result is the relative lack of correlation between solar generation and system load for weekdays during the month of August. A review of the data indicates that this result is most likely caused by a strong drop in system load from the beginning to the end of August as air temperatures drop from summer highs; this creates a very strong, downward trend in system load within the month. In opposition, solar generation is fairly flat across the month.

[35] Solar generation patterns can be rearranged on a daily basis since solar generation goes to zero when the sun sets every night.

[36] However, as the use of the historically-correlated data should, theoretically, provide a more accurate result, this study used the historical rank correlation, TMY2 data set for all avoided energy cost calculations.

DSG Study Task 3 – Calculate Costs and Benefits to the Generation System

Avoided Energy Costs

Avoided energy cost benefits to an electric generation supply system are the variable costs (e.g., fuel, variable O&M, and generation unit start costs) of other generation resources in a utility's portfolio that are avoided as a result of the must-take, DSG energy. As indicated above, avoided energy costs in this study were calculated within the ProSym model employing the historically-correlated, TMY2 data set representative of the first 59 MW and the first 140 MW of DSG installations on the Public Service system.

Avoided energy costs for this study were calculated by running two different 20-year simulation cases of the Public Service electric supply system within ProSym 1) a "base case" without DSG and 2) a "change case" with DSG. Through a comparison of the electric supply system energy costs between these two cases (aka a "delta case study"), an estimate of the avoided energy cost DSG brings to the system was developed. The base case in the avoided energy cost study represented the existing Public Service generation portfolio excluding, however, any DSG installations. The base case model included any planned non-DSG renewable resources and thermal generation resource additions necessary to reliably meet forecasted peak load and energy levels. The change case started with the base case than added DSG to the model by way of the TMY2 generation profile for each year of the study as a must-take generation resource. Generation data for the first year of the study period (2012) was set equal to the TMY2 levels, but adjusted so that the historical correlation imposed on the data was maintained across future years.[37]

An assumption of an annual degradation rate of 0.75% per year for PV generation sources was made over the 20-year study period; i.e., each hourly generation value was reduced by a factor of 0.0075 from the prior year's value. NREL's most recent PV panel degradation estimates for recently-constructed, silicon panels predict a long-term panel degradation of roughly 0.50% per year.[38] Thus, this study's assumption of a total PV system degradation rate of 0.75% reflects the reality that factors other than panel degradation are expected to affect the performance of DSG systems over time. These other factors include increased panel shading over time, degradation in wiring and inverter performance over time, and removal of complete systems prior to the end of the 20 year life assumption.

Analysis of the ProSym model output indicated large variations in the annual avoided cost calculations between the two cases. Investigations into the cause of these variations identified that thermal generation unit start cost variations from year to year within the ProSym model were primarily responsible for the large swings in avoided costs. Although the generation unit start costs are a very small component of the overall electric system costs (in $ terms), annual

[37] For example, since January 1, 2014 is a Wednesday, but January 1, 2015 is a Thursday, it was necessary to adjust the 8,760 TMY2 curve to ensure that the historical correlation imposed on the TMY2 curve was maintained in the annual hourly TMY2 profiles input into ProSym for each year of the study.

[38] "Outdoor PV Degradation Comparison", Conference Paper, NREL/CP-5200-47704, February 2011 http://www.nrel.gov/docs/fy11osti/47704.pdf

variations in these costs are magnified (in $/MWh terms) when dividing by the relatively small amount of annual DSG energy studied here.[39] That is, the ProSym model avoided energy cost calculations are quite sensitive to the relatively small amounts of incremental solar generation added in the change cases.

As an alternative to the ProSym delta case study described above, the Company calculated an estimate of avoided energy costs for DSG utilizing the hourly marginal energy costs of the ProSym base case simulation. Avoided energy costs were calculated by generation-weighting the hourly marginal energy costs with the hourly DSG profile.[40] With the use of generation-weighted marginal energy costs as an estimate of DSG avoided energy costs, it should be noted that the annual avoided energy cost on a unitized basis (i.e., on a $/MWh basis) is identical between the 59 MW and the 140 MW cases. In actuality, the law of diminishing returns would predict that there should be a reduction in the $/MWh avoided energy costs for the 140 MW DSG change case vs. the 59 MW DSG change case.

Figure 5 shows the resulting annual marginal energy costs developed from the ProSym model simulation of the Public Service system for 2012 to 2035 along with the base case natural gas forecast used in that simulation and an implied, natural gas marginal unit heat rate.[41] The implied gas heat rate indicates that DSG tends to displace generation that is a blend of an efficient combined-cycle unit (roughly a 7 MMBtu/MWh heat rate) and a less efficient combustion turbine (roughly a 10 MMBtu/MWh heat rate)[42] which is consistent with the Company's expectations.[43]

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[39] Estimated annual DSG capacity factors based on meter data for the large systems is 1,470 MWh/MW_DC levelized over the 20-year study period assuming 0.75% annual degradation.

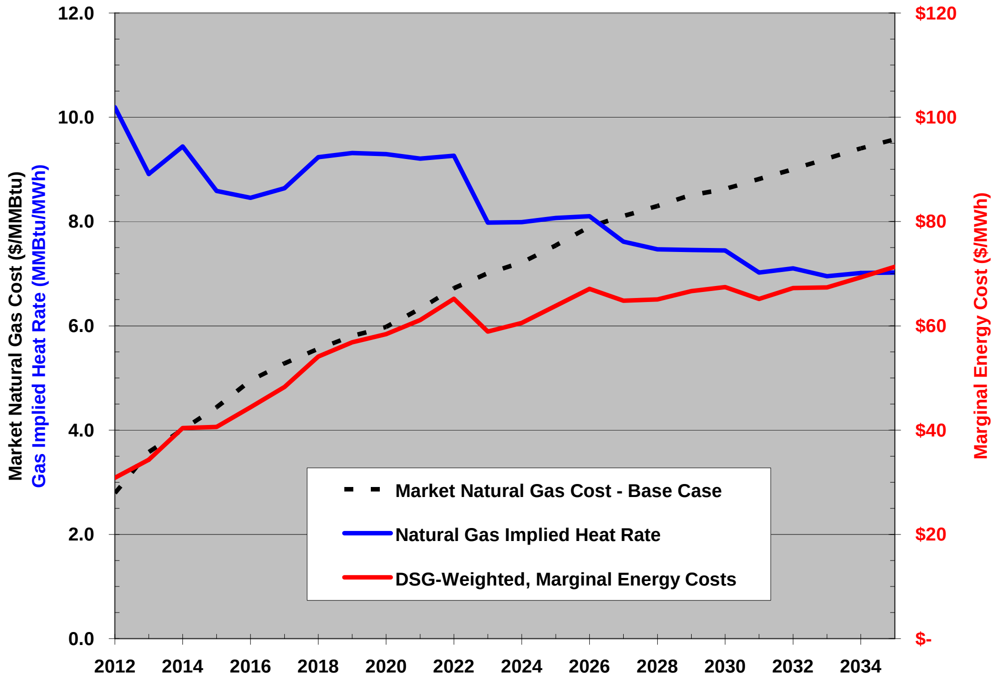
[40] Marginal energy costs differ from avoided energy costs in that marginal costs include the variable operating costs of the generating unit used to provide the next MWh of supply, whereas avoided costs are based on the change in total system costs when different load or generation resource assumptions are made. In order to calculate annual, avoided costs attributable to a solar generation profile, each hourly marginal energy cost (as calculated by ProSym) was multiplied by the hourly MW of DSG generation in that hour. Then, the annual sum of this product was divided by the sum of the annual DSG MWh. Levelized energy costs calculated from the annual solar-weighted marginal energy costs were roughly 2% higher than the levelized energy costs calculated from the annual avoided energy costs as calculated by ProSym.

[41] ProSym results assume generation at transmission voltages; credit for avoided transmission and distribution line losses are documented later in the study.

[42] However, as Figure 7 illustrates, the model results indicate that solar generation is avoiding a mix of gas-fired and coal-fired generation through 2017.

[43] The calculation of implied gas heat rate assumed incremental gas delivery costs pursuant to existing Colorado Interstate Gas system tariffs ($0.017/MMBtu + 0.74% fuel) and VOM assumptions consistent with the Company's 2011 ERP ($2.00/MWh escalating at 1.55%).

Figure 5 ProSym Marginal Energy Cost and Implied Gas Heat Rates



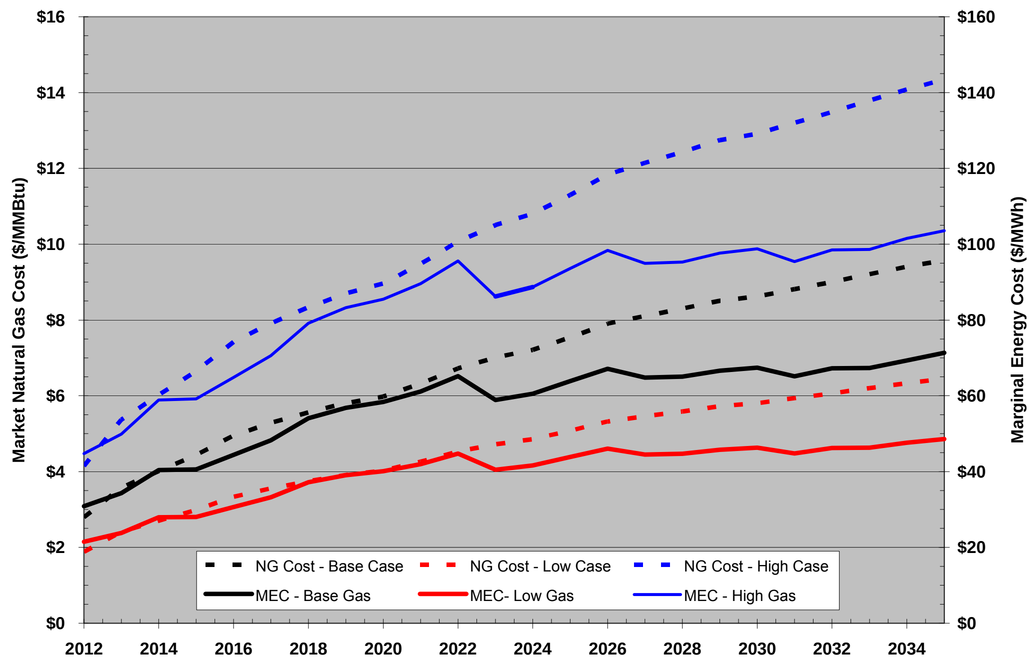
At the August 18, 2010 workshop the Commissioners requested that this DSG study include estimates of avoided energy costs attributable to DSG for a range of different natural gas price forecasts (i.e, gas price sensitivities). Forecast gas prices representing a Low Gas case (67% of the base case) and a High Gas case (149% of the base case) were developed and applied against the implied gas heat rates shown in Figure 5; annual results for the three gas curves are shown in Figure 6 and Appendix III. Levelized, avoided energy costs for the three gas sensitivities are shown in Table 13.[44]

Table 13 2012-2035 Levelized, Avoided Energy Costs

	Low Gas ($/MWh)	Base Gas ($/MWh)	High Gas ($/MWh)
Avoided Energy Costs	$ 35.80	$ 52.10	$ 76.10

[44] Levelized at a 7.60% discount rate.

Figure 6 Avoided Energy Cost - Gas Price Sensitivity



Avoided Generation Capacity Costs

Avoided generation capacity cost benefits are brought to an electric generation supply system when fixed costs (e.g., PPA capacity payments, capital for new unit construction, fixed O&M costs) of generation resources are deferred or avoided as a result of DSG energy on that system. Whether or not DSG actually defers or avoids such costs is impacted by several factors:

- Does the system need incremental generation capacity to meet peak customer demand plus planning reserves and, if so, when?
- What cost should be used for the avoided generation capacity resource?
- What generation capacity credit should be assigned to solar generation?

System Need for Incremental Generation Capacity and Capacity Pricing

As the Company's system is currently long on generation capacity until 2017,[45] avoided capacity cost credit was assigned to DSG in this study for the years 2012-2016 based on the Company's current estimate of the market value of capacity, $2.79/kW-mo.[46] The market value of capacity was credited for the four summer months of each year in which the Company was projected to be long capacity. Beginning in 2017 when the Public Service system shows an incremental capacity need, avoided capacity costs were based on the economic carrying charge ("ECC") representation of a generic, combustion turbine's capital and fixed O&M costs.[47] Avoided generation capacity costs were set to $5.55/kW-mo in 2017

[45] See Table 1.4-2 on page 1-27 of Volume I of the Company's 2011 Electric Resource Plan (PUC Docket No. 11A-869E).
[46] See Attachment 2.8-1 Modeling Assumptions on page 2-266 of Volume II of the 2011 ERP.
[47] See Table 2.8-1 on page 2-221 of Volume II in the 2011 ERP for a description of the generic CT unit.

increasing over time at an assumption for inflation, and were assigned to DSG for all twelve months of each year.[48]

Generation Capacity Credit for DSG

In order to estimate the avoided generation capacity cost credit to be assigned to the 59 MW of installed DSG, the Company conducted an effective load carrying capability ("ELCC") study based on historical system load and solar generation patterns for 2009 and 2010.[49] The resulting ELCC value (expressed as a % of the DSG DC MW nameplate rating) determines how many MW of utility generation capacity the 59 MW of DSG can be expected to defer or avoid. As described above, the Company has acquired interval solar generation data from all the largest installed PV systems. These data were aggregated into hourly generation profiles as functions of solar resource zone and tracking capability. In order to provide a single, hourly generation profile representative of the total installed 59 MW, the individual generation profiles were scaled based on the MW of generation represented by that profile.[50]

The ELCC study of the initial 59 MW resulted in a value of 34% of DC nameplate for 2009 and 32% for 2010. In this cost/benefit study, the Company utilizes an average ELCC value of 33% of DC nameplate for all DSG.

In the ELCC study described above, the Company utilized the normalized generation profiles (as a function of solar zone and tracking capability) to create a single, composite generation profile that was MW-weighted by the components of the 59 MW installed; the study was then conducted utilizing this single solar generation profile. In the ELCC study provided in Appendix V, the Company calculated ELCC results for each of the individual generation profiles; that is, for each of the solar zones and tracking capabilities for which the Company had meter data. In Table 14 the Company demonstrates that—not unexpectedly—identical ELCC results can be obtained by MW weighting the individual ELCC results from the Appendix V study by the installations that make up the 59 MW.

[48] See Table 2.8-3(a)on page 2-227 of Volume II in the 2011 ERP for the generic CT ECC values in $/kW-mo terms.

[49] The methodology followed by the Company in conducting the ELCC study for the 59 MW was identical to the methodology fully described in the "Effective Load Carrying Capability (ELCC) Study for Solar Generation Resources" report dated February 28, 2012 and attached to this study as Appendix VI.

[50] Table 7 shows the distribution of the 59 MW across the solar resource zones and tracking capabilities; Tables 9 and 10 show what meter data are available by solar zone and tracking capability. In the analysis, all generation in the Mountain and Western Slope solar zones without representative meter data was mapped to the Northern Front Range zone. 2009 San Luis Valley fixed systems were modeled with the 2009 San Luis Valley tracking data.

Table 14 ELCC Results by Solar Zone and Tracking Capability for the 59 MW

Solar Zone	Technology	Average ELCC	59 MW Actual	59 MW Proxy	Pro Rata ELCC
Northern Front Range	Fixed PV	31%	73%	79%	24%
	Tracking PV	41%	11%	11%	5%
San Luis Valley	Fixed PV	27%	5%	5%	1%
	Tracking PV	47%	1%	1%	0%
Western Slope	Fixed PV		6%	0%	0%
	Tracking PV	46%	4%	4%	2%
Aggregate			100%	100%	33%

A similar analysis for the 140 MW of DSG resulted in a slightly lower ELCC value of 32%. The minor reduction in ELCC for the 140 MW is a direct result of a larger proportion of DSG installations occurring from fixed systems located in the Northern Front Range regions in the 140 MW DSG portfolio vs. the 59 MW DSG portfolio.

<u>Micrositing Impacts on Generation Capacity Credit</u>

Without historic meter data from all installed DSG systems with which to conduct ELCC studies, the Company has assumed that the historic data that do exist are suitable proxies for all the other systems sited in the same solar resource zone. The Public Service electric system is a late afternoon, summer peaking system; as such, binning east-facing systems as south-facing tends to overestimate the generation capacity credit results and binning west-facing systems as south-facing systems tends to underestimate the generation capacity credit results. Without incremental meter data, the Company cannot estimate the aggregate impact on generation capacity credit that binning both the 11% of fixed systems facing east and the 7% of fixed systems facing west as south-facing systems may have on the study results. As a larger percent of the fixed systems are east-facing as opposed to west-facing, it is more likely that the study results overestimate the ELCC value of the actual DSG installed.

The Company has also not estimated to what level the Rocky Mountains and foothills located west of the Northern Front Range solar zone influence the generation capacity credit that should be afforded DSG. In general, the closer a Northern Front Range DSG system is sited to the foothills and mountains, the earlier those systems become shaded as compared to systems located farther east. However, as the sun travels 15 degrees each hour, illustrative examples of these earlier sunsets can be created.[51]

For example, the mountain peaks west of Denver, CO are approximately 12,500 feet high and the State Capitol building in Denver is located at 5,280 feet and is approximately 50 miles to the east. The sun angle at sunset at this location is thus 1.6 degrees and sunset occurs ~6 minutes

[51] The solar industry has developed various tools with which to estimate the shading impacts of the various obstructions surrounding a specific DSG site; obstructions can include the customer's own roofline or chimney, nearby trees or tall buildings, or distant geographic features like mountains. In general, these tools are generally employed to estimate the impacts of obstructions on annual solar generation as opposed to the impacts on solar generation at a specific time of day during a specific time of the year.

earlier than it would absent the mountains. Such a small difference is not expected to significantly affect the study results for a DSG system located in Denver.

Conversely, if the foothill peaks just to the west of Boulder, CO are approximately 6,500 feet high and the city elevation is at roughly 5,400 feet, then DSG systems in downtown Boulder (~1.2 miles east of the foothills) have a sun angle at sunset of ~10 degrees and experience a sunset roughly 40 minutes earlier than they would absent the foothills. Systems located in this proximity to these foothills would be expected to provide significantly less generation capacity credit than systems located farther east.

Avoided Emissions Costs

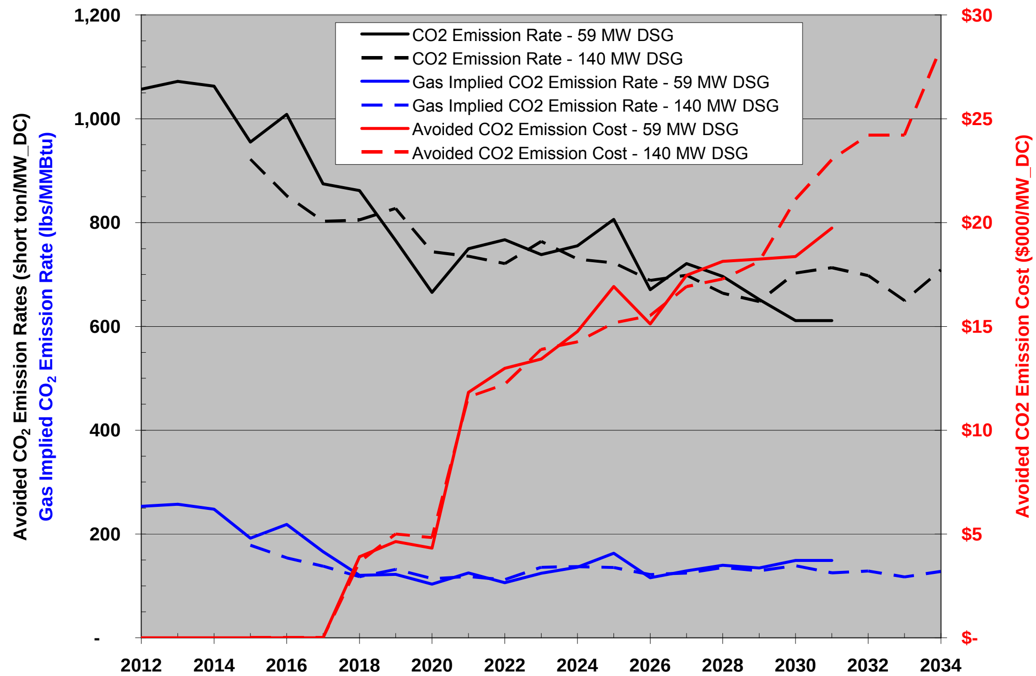
Annual tons of CO_2 emissions avoided by DSG were obtained from the ProSym avoided cost case simulations. Figure 7 shows avoided CO_2 emission rates on both an installed capacity (i.e., tons/MW) and on a natural gas volume basis (i.e., lbs/MMBtu) and the calculated value of the avoided CO_2 emissions.[52]

Model emission rates (on either a MW or MMBtu basis) are fairly consistent between the 59 MW and the 140 MW cases. Up until 2017, the ProSym model results indicate that DSG is displacing some coal-fired generation in addition to gas-fired generation. This is evident from the gas implied emission rates being in excess of the typical range of gas-fired CO_2 emission rates (e.g., roughly 119 lbs/MMBtu). Major changes planned for the Company's generation fleet in the 2016-2018 time frame are responsible for the decreasing avoided carbon emission rates resulting from DSG in the future. These changes include the retirement of ~600 MW of Company-owned coal generation, fuel switching 460 MW of Company-owned coal generation to natural gas, the expiration of 300 MW of coal-based capacity and energy purchases, and the construction of a new, highly-efficient, 570 MW gas-fired combined cycle plant.

As the carbon dioxide emission rates are consistent between the 59 MW and the 140 MW cases and as generation-weighted, marginal energy costs are being used to quantify the avoided energy costs, it is possible to generate a single stream of unitized avoided costs for DSG instead of separate streams of costs for the 59 MW and 140 MW cases. That is, the unitized cost curve can be used as an estimate of the avoided costs for a relatively small amount of solar installed on the Public Service system over the next several years. On this basis, the 2012-2032 levelized cost of the average avoided carbon dioxide emissions attributable to DSG shown in Figure 7 is approximately $5/MWh.

[52] Avoided CO_2 emissions volumes were quantified on a $/MW_DC basis utilizing the "3-Source Blend" carbon dioxide sensitivity prices from the 2011 ERP. This curve is a simple average of the volumetric CO_2 emission cost forecasts from PIRA, CERA, and Wood Mackenzie. The knee in the curve at 2021 derives from the fact that only one of the three entities predicted legislation in advance of 2021 at the time of this study. The blended price is roughly $15.75/short ton at 2021 escalating at around 7% per year. Although this study assumes a carbon tax methodology in order to quantify the estimated carbon dioxide emissions costs, other mechanisms could be adopted in order to lower carbon dioxide emission rates which would not be as straightforward to price as a carbon tax. One example would be the early retirement of coal-fired generation units.

Figure 7 Avoided Carbon Dioxide Emissions



DSG Study Task 4 – Calculate Costs and Benefits to the Distribution System

<u>Description of the Company's Electric Distribution System</u>

During 2010, Public Service maintained approximately 730 individual distribution feeders across its service territory. Of these, roughly 75% are located in the geographical area represented by the Northern Front Range Solar Zone region. While approximately 540 of the Company's feeders have some DSG installed, 58 feeders had 55% of the 59 MW of DSG under study here; that is, roughly 10% of the feeders with solar have over 50% of the installed DSG. Of these 58 feeders, roughly 85% are located in the Northern Front Range Solar Zone.

Hourly feeder load profiles are driven by the customer load served by the feeder; customer load for specific feeders can vary from nearly 100% residential to 100% commercial and industrial customers. In general, these customer classes have significantly different average and peak day load profiles; see for example the graphs shown in Appendix IV for Residential and Small Commercial customer classes.[53] It should also be noted that there is no guarantee that a specific feeder will experience its annual peak load on the same day as the aggregate system experiences its annual peak load or on the same day or hour as any other feeder.

[53] In addition to the load profiles shown in Appendix IV, the Company provided monthly System Peak Day, Average Weekday, and Average Weekend/Holiday load profiles as part of its 2011 Electric Resource Plan (PUC Docket No. 11A-869E) for the following customer classes: Residential, C&I (Secondary Voltage), C&I (Primary Voltage), C&I (Transmission Voltage), and FERC Jurisdictional. See Section 2.7, "Hourly Load Profiles", pages 155-215 of Volume II.

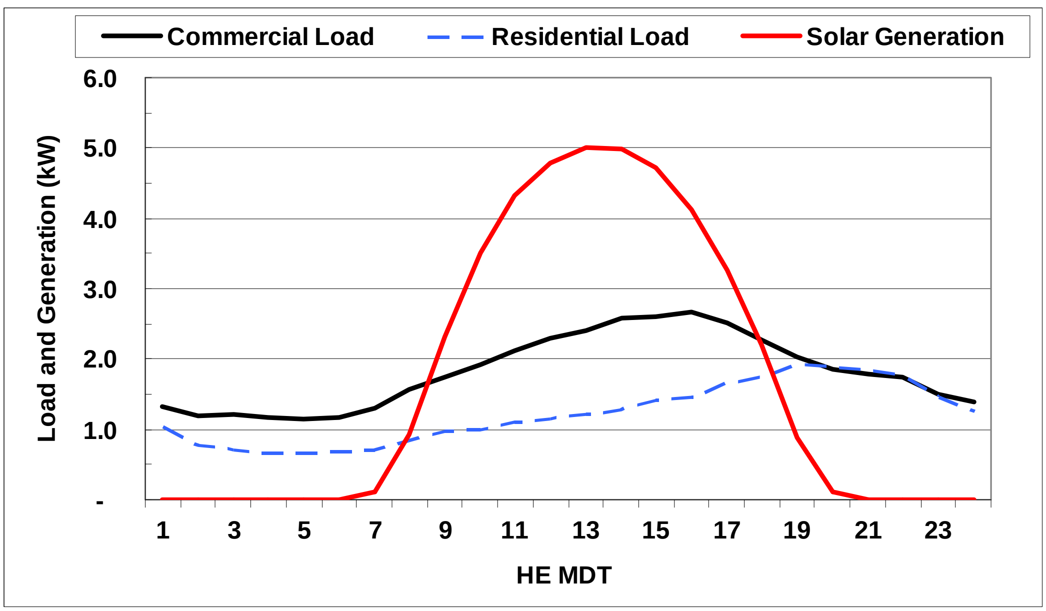
Avoided Distribution System Capital Costs

Capital Cost Deferral

In order to defer a distribution feeder capital investment by 1 to 2 years, the existing feeder's peak load needs to be at or near the feeder's capacity and the feeder's peak load must be decreased by ~10 percent. A typical PSCo feeder's rated capacity is 17.3 MVA; thus, in order to defer a distribution capital investment for such a feeder, a sufficient amount of DSG must be installed so as to generate approximately 1.7 MW_{AC} during feeder peak load periods.

In general, daily solar generation will peak near solar noon (i.e., when the sun is at its highest point in the sky).[54] As indicated above, different feeders have different load profiles; typical Public Service feeders peak during the month of July. Figure 8 shows the significantly better correlation between commercial-class load and solar generation on a peak commercial-class load day than between residential-class load and solar generation on a peak residential-class load day.[55] Given this difference, it should be expected that significantly more DSG would be required to be installed on a heavy residential feeder than a heavy commercial feeder in order to potentially defer a distribution capital investment.[56]

Figure 8 Customer Loads and Solar Generation - July 2010



It should be noted that the Public Service distribution system has a dynamic feeder configuration; that is, individual customers can be fed from different feeders other than the one to which they

54 This generalization is directly impacted by daily weather conditions (e.g., clouds, air temperature, wind direction and velocity) and how the PV panels are oriented.

55 DSG generation is representative of that from a 6.6 kW DC system on a clear sky, July day. This system size would generate an annual amount of electricity equal to the simple average of a small commercial and residential customer's annual load.

56 As the graphs in Appendix IV clearly show, there is a significantly better match between solar and commercial loads than between solar and residential loads not only during peak summer days, but throughout the entire year.

were originally interconnected. Thus a DSG installation that is assumed to be placed at an optimal location along a particular feeder in order to provide some level of distribution system benefit may be at a less than optimal location as new distribution system projects are installed or as distribution system maintenance is conducted and feeder switching occurs.

The Company examined several representative feeders with differing load profiles and, based on 2010 load and solar meter data, determined the DSG installations needed to generate 1.7 MW_{AC} during the feeder peak load hour. Results for five representative feeders are shown in Table 15 below.

Table 15 Installed DSG to Defer Distribution Capital Investment

Feeder	Customers	% Residential	% Commercial	Time of 2010 Peak (MDT)	DSG at Time of Peak (kW_{AC}/kW_{DC})	1.7 MW_{AC} Equivalent to Defer (MW_{DC})
Feeder A	207	0%	100%	7/14 4:00 PM	0.45	4
Feeder B	281	41%	59%	7/19 3:00 PM	0.50	8
Feeder C	3,050	91%	9%	7/26 7:00 PM	0.07	123
Feeder D	3,305	98%	2%	7/26 7:00 PM	0.07	107
Feeder E	3,527	98%	2%	8/22 7:00 PM	0.32	15

As Table 15 illustrates, any potential to differ a capital investment at a reasonable DSG penetration rate is most likely to exist on feeders with higher levels of commercial load as opposed to high residential load feeders. For example, Feeder A only serves commercial customers; during its 2010 instantaneous feeder peak load hour, DSG electric production would have been 0.45 kW_{AC}/kW_{DC}. At this level of generation, approximately 4 MW_{DC} of DSG would have generated the 1.7 MW_{AC} needed to reliably reduce feeder peak loading. Conversely, Feeders C and D which are heavy residential feeders would require over 100 MW_{DC} of installed DSG to generate the 1.7 MW_{AC} needed to reliably reduce feeder peak loading..[57] Feeder E, which is also a heavy residential feeder, would have required a more modest 15 MW_{DC} installed in order to reduce peak loads.[58]

Based on 2011 levels of loading, 5% of the Company's distribution feeders are candidates for a potential capital investment deferral by means of a net, peak load reduction. As demonstrated above, necessary levels of installed DSG to potentially defer a capital investment are significantly less on feeders with commercially-driven peak loads versus residential-driven peak loads. Empirically it was found that feeders with less than 85% residential customers will peak earlier in the day and have a better correlation with the DSG generation profile than feeders with

[57] Although Table 17 indicates that the feeder instantaneous peak and DSG generation during that time are the drivers for a capital deferral, the actual calculation is slightly less straightforward as the shape of the feeder load profile during the peak period also has an impact. If the feeder has a needle peak (i.e., a rapid rise to the peak followed by a rapid decline), a single point estimate as to the amount of DSG that could reduce this peak value as illustrated above is sufficient. However, if the feeder has a more rounded profile at its peak, then it is possible that a greater amount of DSG may be needed if solar production tapers off faster than does feeder load as sunset approaches. That is, a new, net feeder peak still in excess of the target MW to defer may appear at a time closer to sunset.

[58] However, see the section titled "Capital Cost Avoidance" for a discussion of the reliability of DSG to reduce peak loads from year to year.

greater than 85% residential customers. Roughly 50% of all the Public Service feeders have less than 85% residential customers, thus there are roughly 19 feeders that might be potential candidates for capital deferral based on loading and customer type (740 feeders * 5% * 50% = 19 feeders). While this is a rule of thumb that can be used for analyzing a large number of feeders, it should be noted that there are, of course, exceptions to this rule.

In order to quantify the potential cost benefit DSG could bring by way of deference or avoidance of a distribution capital project, the Company reviewed its list of 2012 capital budget projects to obtain a current estimate of the dollar value of typical distribution projects that might be deferrable through DSG. Within that 2012 budget, the typical substation capital investment that could potentially be deferred with DSG is roughly $9 million.[59] The net present value to defer the total capital investment by ~1.5 years is ~$540K.[60]

As prior DSG studies have indicated, the only way to defer a distribution system capital project is with a targeted installation of DSG.[61] Depending upon the capital project, the targeted DSG installation may provide the most benefit when located as close to the feeder load center as possible. A DSG installation has little to no distribution system benefits when placed at or near the head of the feeder. It should also be noted that a typical substation capital investment project is not designed to solve an issue with just a single feeder. Usually a major substation project is designed to solve multiple feeder overload conditions and multiple other contingency issues on other feeders and substation transformers. Thus it is likely that multiple feeders leading from a substation must have targeted DSG installations in order to defer the single capital investment.

The amount of DSG that must be installed across all the involved feeders to defer a distribution system capital investment project would need to be studied on a case by case basis as each substation project is different. However, in order to provide a relative level of the potential deferral value some simple calculations can be made. If a total of 16 MW of DSG could defer a typical substation capital investment project[62], then the levelized value that could be assigned to DSG for that deferral over the DSG's 20-year period is ~$2.40/MWh. Conversely, if the 59 MW of DSG installed on the Public Service system were to have already resulted in the deferral of a single, average substation capital project, then the levelized value that could be assigned to the 59 MW of DSG for that deferral is ~$0.64/MWh.[63]

However, no heavy residential feeder on the Public Service system has more than 1.3 MW of DSG installed, and this 1.3 MW is only 1.3% of the roughly 100 MW required for an average, heavy residential feeder capital project deferral. No heavy commercial feeders with significant levels of installed DSG are near capacity. Therefore there has been no potential for a commercial feeder capital project deferral on the Public Service system. Thus the 59 MW installed as of 9/30/10 has not resulted in any capital investment deferrals. Also, as the incremental 81 MW of DSG installed since 9/30/10 is similar to the first 59 MW, and the

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[59] Of this value, roughly 3% would be charged to a transmission capital budget and the balance to a distribution capital budget.
[60] This assumes a 7.6% cost of capital and that capital costs escalate by 2.5% per year.
[61] See, for example, RWBeck (APS), page 3-8, Navigant, page x.
[62] For example, 16 MW could be represented by four, heavy commercial feeders each of which would require 4 MW of DSG.
[63] $0.64/MWh = $2.40/MWh * 16 MW/59 MW.

Company has not experienced any significant load growth, the first 140 MW of installed DSG will likely not defer any capital investment either.

Capital Cost Avoidance

Public Service plans new distribution systems based on a forecasted peak load on the proposed feeders. Forecasting the peak load on a new feeder involves assessing historical load patterns for the forecasted customer mix being served by the feeder. When installing new distribution lines, Public Service has access to standard cable and wire sizes produced by the industry. When determining the proper cable and wire sizes, it selects equipment that is sized to be large enough to handle forecasted peak feeder loads. In order to create a new standard for less expensive, lower capacity distribution lines based on a forecast of DSG electricity generation that might ultimately be installed on that feeder, DSG would need to be a reliable peak generation resource. For the following reasons, the Company does not believe that DSG can be considered a peak generation resource of sufficient reliability to install lower capacity, less expensive equipment:

- Advancing cloud fronts and distribution or transmission system voltage events can cause DSG output to drop rapidly or, in the case of inverter trips, instantaneously. Although air conditioning driven load also drops following the passage of a cloud front, the drop in load lags behind solar generation exposing the feeder to the full extent of customer load (as opposed to exposing the feeder to the net customer load that exists when DSG is generating).
- Reliably forecasting DSG electricity production during the forecasted feeder peak load hour is currently not possible due to the large variation in the peak load hour of distribution loads and the large variation in DSG output production during those hours.[64]

Avoided Distribution Line Losses

Distribution system line loss savings[65] are quantified by inflating the avoided energy cost, avoided emission cost, fuel hedge, and avoided generation capacity credit values attributed to DSG by an amount representative of the line losses associated with moving power across the Public Service electric distribution system. That is, in the absence of DSG, enough generation would be needed from a transmission-interconnected resource to both replace the solar generation and the line losses that occur on the distribution system. Line loss savings for avoided energy, emission, and fuel hedge benefits are calculated using average line losses over the year whereas avoided generation capacity credit values are calculated using system peak line losses. In addition to primary system line loss savings, incremental distribution system line loss savings can occur in substation transformers and, depending upon the specific feeder, the distribution secondary system.

[64] For example, from 2009 to 2012, Feeder D on Table 16 peaked at 5 PM in 2009, 7 PM in 2010, and 6 PM in 2011 and 2012. DSG electricity generation at peak hours from 5 PM to 7 PM can range from 0.42 kWh_{AC}/kW_{DC} to 0.07 kWh_{AC}/kW_{DC}.

[65] Distribution system losses are calculated as the square of feeder current (I) times an average resistance value (R); that is, losses = I^2*R. Feeder current can be estimated by dividing feeder demand (W) by the feeder voltage (V); that is $I = W / V$.

System Peak Line Losses

In order to estimate the level of avoided distribution line losses during the system peak load hour, it is necessary to determine the level of load on each feeder during that same hour.[66] The overall electric system peak load is non-coincident with the individual feeder peak load hours which can—and do—occur on different days of the year and different hours of the day. Two methodologies were employed to determine feeder loads during the system peak load hour: for the 58 Public Service feeders on which 55% of the 59 MW has been installed, the Company retrieved the feeder load directly from its Energy Management System ("EMS"); for the other feeders,[67] the Company retrieved the individual feeder, non-coincident peak load from another database and applied a coincident factor[68] to obtain the estimated feeder load during the system peak load hour.[69]

A 2010 Electric System Demand and Energy Loss Study estimated system peak hour line losses for the primary and secondary distribution systems as 85,994 kW.[70] A feeder resistance ("R") value for each of the 58 feeders with the highest levels of DSG penetration was calculated within a distribution-feeder modeling software package (SynerGEE® Electric).[71] For the remaining feeders, an average R value was calculated such that the line losses across all the feeders during the system peak load hour added up to 85,994 kW.

The 2010 system peak load occurred on July 16th at 5:00 PM (MDT); based on the 2010 meter data estimated DSG production rate at this time was 0.44 kW_{AC}/kW_{DC}. An estimate of what total feeder load would have been absent the DSG production (5,427 MW) was calculated by adding the actual system peak load (5,401 MW) to the DSG production (26 MW = 0.44 * 59 MW). For each feeder, line losses were calculated from the calculated load and the previously-estimated R value. 2010 peak system line losses without the 59 MW of DSG were estimated to be 86,744 kW; thus the installation of the 59 MW of DSG is estimated to have avoided 750 kW (= 86,774 – 85,994) of distribution system line losses during the system peak load hour. On a percentage basis, this is a 0.86% reduction in system peak, distribution line losses.[72]

From the 2010 Electric System Demand and Energy Loss Study, the distribution secondary system losses were estimated to be 104,985 kW (with the no-load loss component accounting for 27,995 kW of that figure) and the substation system transformer losses were estimated to be 29,160 kW (with no-load loss component accounting for 9,888 kW of that figure).[73] For the secondary system and the substation transformer losses, Public Service does not have sufficient information necessary to directly calculate how DSG affects losses for these

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[66] The Company assumed constant feeder voltage for the calculation of feeder current.

[67] Which number approximately 670 feeders.

[68] The coincident factor was calculated as the ratio between the sum of the non-coincident feeder peaks to the system peak.

[69] The extraction of the feeder demand during system peak and the calculation of R for each of the remaining 671 feeders would have required an excessive amount of effort.

[70] Electric System Demand and Energy Loss Study, Prepared for Public Service Company of Colorado, Martin Gustafson, P.E., September 20, 2010.

[71] SynerGEE® Electric is a product of Germanischer Lloyd SE.

[72] 0.0086 = 750/86,774

[73] The presence of DSG generation has no effect on the no-load losses.

portions of the electric distribution system. In order to estimate the loss savings from the first 59 MW of DSG, the same percentage (0.86%) was applied to the substation transformer losses and the secondary losses, this resulted in 663 kW saved on the secondary system and 168 kW on the substation transformers. The total savings during the system peak load hour on the distribution system are estimated as 1,581 kW (750 kW line losses + 168 kW substation transformers + 663 kW on the secondary system). Thus, DSG installed on the primary voltage distribution system can be grossed up by 1.58% for distribution losses when calculating avoided generation capacity credit.[74] DSG installed on the secondary voltage distribution system can be grossed up by 2.75%.[75]

<u>Annual Energy Line Losses</u>

In order to estimate the level of avoided distribution line losses during 2010, it is necessary to determine the hourly load on each feeder. Two methodologies were employed to determine hourly feeder loads: for the 58 Public Service feeders on which 55% of the 59 MW has been installed, the Company retrieved the feeder load directly from its Energy Management System ("EMS"); for the other feeders, an average feeder hourly load profile was created so that the total energy usage and the load factor were equal to the 2010 distribution energy usage and system load factor. The Company assumed an average value of 40 kW DSG installed on the average feeder.[76]

From the 2010 Electric System Demand and Energy Loss Study, annual distribution energy usage was calculated to be 26,684,396 MWh, distribution line losses were calculated to be 316,327 MWh, and the load factor on the primary distribution system was 0.564. Thus losses accounted for 1.2% of the energy on the distribution lines. Hourly line losses and R values were calculated for the 58 feeders with the SynerGEE Electric model. Average hourly line losses and R values were calculated for the other feeders such that the summation of the individual feeder losses equaled the distribution energy losses from the 2010 study.

To calculate what the energy losses would have looked like without the first 59 MW of DSG, hourly feeder load was increased by the level of the hourly TMY2 proxy DSG profile and the energy losses were recalculated.

Annual system losses without the 59 MW of DSG were estimated to be 319,036 MWh; thus the installation of the 59 MW of DSG is estimated to have avoided 2,709 MWh (= 319,036 – 316,327) of distribution system line losses. On a percentage basis, this is a 0.85% reduction in annual distribution line losses.[77]

From the 2010 Electric System Demand and Energy Loss Study, the distribution secondary system energy losses were estimated to be 498,006 MWh (with no load losses accounting for 245,237 MWh), and the substation system transformer losses were estimated to be 160,142 MWh (with no load losses accounting for 86,619 MWh). For the secondary system and the substation transformer losses, Public Service does not have sufficient information necessary

[74] 1.0158 = 1/(1-918/59,000)
[75] 1.0275 = 1/(1-1,581/59,000)
[76] 40 kW = (1-0.55)*59MW/670 feeders
[77] 0.0085 = 2,709/319,036

to directly calculate how DSG affects losses for these portions of the system. In order to estimate the loss savings from the first 59 MW of DSG, the same percentage (0.85%) was applied to the substation transformer losses and the secondary losses; this resulted in 2,146 MWh saved on the secondary system and 624 MWh saved on the substation transformers. The total annual savings on the distribution system are estimated as 5,479 MWh (2,709 MWh line losses, 624 MWh substation transformers, and 2,146 MWh on the secondary system). Thus, DSG installed on the primary voltage system can be grossed up by 3.65% for distribution losses when calculating avoided energy costs, avoided emissions costs, and avoided fuel hedge costs.[78] DSG installed on the secondary voltage system can be grossed up by 6.15%.[79]

<u>Voltage Support</u>

Public Service requires a voltage range of 120V +/- 5% at the customer meter, thus the Company has a nominal send out voltage of 125V to allow for voltage drops across the feeder, the distribution transformer, and the secondary and service lines. Primarily during periods of peak feeder load, supplemental voltage support may be needed to maintain feeder voltage within the target range along the feeder. Such supplemental voltage support is typically provided by means of capacitor banks strategically located along a feeder. Minimal voltage support is needed during non-peak periods to maintain the 120V +/- 5% requirement.

In order to determine the level of voltage support provided by DSG, SynerGEE Electric was used to model voltage profiles along select feeders. SynerGEE Electric uses a load allocation method based on the connected KVA where the feeder load can be adjusted based on past or future loading assumptions; for the purposes of this study, historical loading information was used. For each individual feeder, the DSG was placed along the feeder model in a location that represented the actual location of the DSG installation on the feeder. SynerGEE Electric was used as a static load tool; that is, the feeders were modeled with DSG on and then again with DSG turned off. The voltage delta was calculated by comparing the voltage profile from the two cases.

Feeders with low load require little voltage support to maintain the 120V +/- 5% requirement. Four (4) of the Company's seven (7) feeders with relatively high levels of DSG (i.e., greater than 1 MW) have peak load-to-capacity ratios of less than 40% and thus DSG would be expected to provide little voltage support value. The other three (3) feeders (Feeders 1, 2, and 3) have peak load-to-capacity ratios of 72%, 82%, and 83% respectively and are better candidates with which to quantify potential voltage support benefits.

During 2010, Feeder 1, a heavy residential feeder, peaked at 7 PM (MDT) when DSG output was likely near or at zero, therefore DSG provided no voltage support during this feeder's peak load. Feeder 2, a heavy commercial feeder, peaked at 2 PM (MDT); the model calculated a maximum voltage rise of 0.78 V on one segment of the feeder during the peak and an average voltage rise across the entire feeder of 0.61 V when 2.4 MW of DSG were modeled. Feeder 3, another heavy commercial feeder, peaked at 3 PM (MDT), with a maximum voltage rise of 0.91 V on one segment of the feeder and an average voltage rise of 0.37 V across the entire feeder when 2.1 MW of DSG were modeled.

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[78] 1.0365 = 1/(1-3,333/(59*1603)), where annual DSG generation was assumed to be 1603 MWh/MW_{DC}

[79] 1.0615 = 1/(1-5,479/(59*1603))

As other sections of this study have shown, given the relatively poor correlation between DSG and residential load profiles as compared to commercial load profiles, potential voltage support benefits are most likely to be found on heavy commercial feeders. The voltage support on Feeders 2 and 3 from the addition of ~ 2.25 MW of DSG is about half the amount of voltage rise typically provided from a 1,200 KVAR capacitor bank. Thus, if DSG were a reliable voltage support product, 4.5 MW could potentially defer the addition of a single 1200 KVAR capacity bank. With an installed cost of $25K, the levelized value over 20 years of a 1.5 year deferral of a capacitor bank with 4.5 MW of DSG is approximately $0.02/MWh.[80]

It should be noted that the SynerGEE Electric model assumes constant DSG electric production and does not account for any short-term variability in generation output. Should a feeder peak occur during sky conditions that cause large swings in power generation (e.g., high, thin clouds), it would be expected that voltage support from DSG would be reduced.[81] With the data at hand, the Company cannot determine how large a reliability degradation should be expected.

<u>Incremental Distribution System Costs</u>

<u>Distribution Feeder Export</u>

It is expected that the cost to integrate DSG on the Public Service electric supply system will increase with increasing DSG penetration. As an example, the 4 MW of DSG needed to defer a capital investment caused by peak loads on Feeder A shown in Table 15, may <u>increase</u> system costs during other periods of the year. For example, if this feeder experienced a load profile similar to the Commercial customer class average, during low load and high DSG output conditions (typically April and May) DSG production in excess of the feeder load may result in a situation where the feeder will be exporting power back out to other feeders through the substation. Accommodating such reverse feeder power flow is not currently how distribution substations are designed, thus the Company would need to rework its distribution system protection schemes which would typically require a capital investment; this incremental capital investment would serve to reduce or negate any potential deferral benefits of DSG.

<u>Voltage Fluctuation-Induced O&M Costs</u>

Feeder voltage fluctuations caused by large swings in DSG electric production could potentially cause long-term maintenance issues for some feeder equipment. For example, equipment such as capacitor banks and load tap changers are designed to self-regulate during significant feeder voltage excursions; each excursion requires two equipment operations as the equipment initially responds to the elevated or depressed voltage and then again when normal voltage levels return. Such DSG-induced voltage excursions could result from clouds or PV inverter trips. More frequent distribution equipment operations are likely to result in higher equipment O&M costs.

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[80] It should also be noted that capacitor banks have other beneficial values over and above voltage support. Capacitor banks reduce the reactive power flow along the entire feeder which, in turn, reduces the distribution primary line losses. Although PV inverters can also provide reactive power benefits, to do so during daytime hours reduces real power generation and would impact the economics of a non-utility owned PV system. The Company cannot at this time quantify whether the incremental costs to incent system owners to perform these services will be less than or greater than the estimated system benefits.

[81] The relative impact of clouds on instantaneous DSG output is a function of the geographical dispersion of the installed PV generation systems; for a given level of installed DSG, the generation profile from a single system will exhibit greater levels of volatility than the generation profile from multiple, smaller systems.

In order to calculate the maximum voltage rise that could occur due to large excursions in PV generation, two feeders were modeled during the spring timeframe when DSG electric production output is the highest and the feeder load is the lowest. In order to calculate the maximum feeder voltage rise, it was assumed each of the two feeders had sufficient DSG installed to reduce peak load by 10 percent of the feeder's capacity; one feeder was modeled with 5.0 MW of DSG and the other was modeled with 3.9 MW of DSG. The first feeder had a maximum voltage rise of 1.67 V with an average voltage rise of 1.18 V on the entire feeder. The second feeder had a maximum voltage rise of 1.35 V with an average voltage rise of 0.33 V on the entire feeder.[82] Voltage fluctuations of this magnitude, if they persist for a long enough time to initiate a response from the feeder equipment, could cause two extra capacitor bank operations per fluctuation and two extra load tap changer operations per fluctuation. Currently, any increased operational costs due to DSG fluctuations cannot be quantified because information about the average duration of each fluctuation and the latency between full output production and reduced output production on a feeder-specific basis is not readily available.

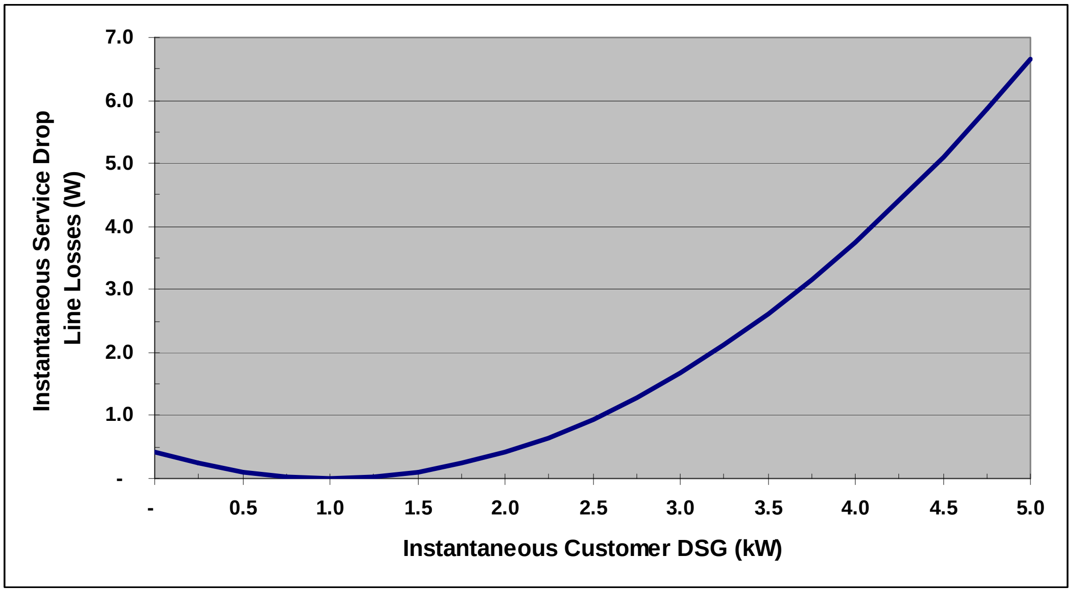
Increased Secondary Distribution Line Losses

Counter-intuitively, distribution feeder secondary line losses are expected to increase above non-DSG conditions after a certain level of DSG is installed on the feeder. This result is caused by higher net current flows on certain segments of the 120-volt, secondary distribution system and is a direct result of the mismatch between individual customer load profiles and DSG electricity production profiles.

A customer's 120-volt service drop is their connection to the Company's distribution system. Maximum service-drop, line loss savings occur when net current flow is zero; that is, when a customer's real-time, generation exactly matches the customer's real-time load. As Figure 9 illustrates, when a customer's generation exceeds twice his load, line losses on the customer's service drop exceed what they would have been with no generation.[83] Because line losses increase with the square of net load, line losses increase at ever increasing rates with greater levels of DSG electricity production.

[82] Based on a 125V nominal voltage.
[83] Figure 4 assumes an instantaneous customer load of 1 kW, customer voltage of 120 volts, and a service drop resistance of 50 mΩ.

Figure 9 Illustrative Service Drop Line Losses



A comparison of an average residential customer's, 2010 annual hourly load and the 2010 annual hourly DSG electric production profile from a south-facing fixed PV system (sized to generate 100% of the customer's annual load) indicate that hourly DSG exceeded twice the hourly customer load for approximately 8% of all daylight hours. For a system sized to 120% of annual customer load,[84] hourly DSG exceeded twice the hourly customer load for 10% of all daylight hours.

The calculation of how much DSG must be installed on a specific feeder in order to result in a net increase in annual distribution feeder line losses is impacted by the physical layout of the feeder, where on the feeder the DSG is installed, how much DSG is installed relative to customer load, and the load profiles of all the customers on the feeder (both those with and without DSG). Based on the information it currently has, the Company does not believe that any secondary distribution system has reached a DSG penetration level such that annual line losses are greater than what they would have been absent DSG.

DSG Study Task 5 – Calculate Costs and Benefits to the Transmission System

Avoided Transmission System Capital Costs

Based on the levels of DSG under study here, the transmission capital costs that could potentially be deferred or avoided are tied to: 1) transmission costs associated with the deferral or avoidance of the need for additional generation capacity (i.e., transmission interconnection costs and/or transmission network upgrades) and 2) transmission costs associated with the deferral or avoidance of a distribution substation capital investment.

[84] 120% of expected annual load sets the maximum-sized unit a net-metered customer can install in Colorado.

The avoided generation capacity source in this study is the generic combustion turbine assumed in the Company's 2011 ERP.[85] Typical transmission interconnection costs for such systems represent about 1.5% of the total installed cost of the plant which is the assumption used in this study.

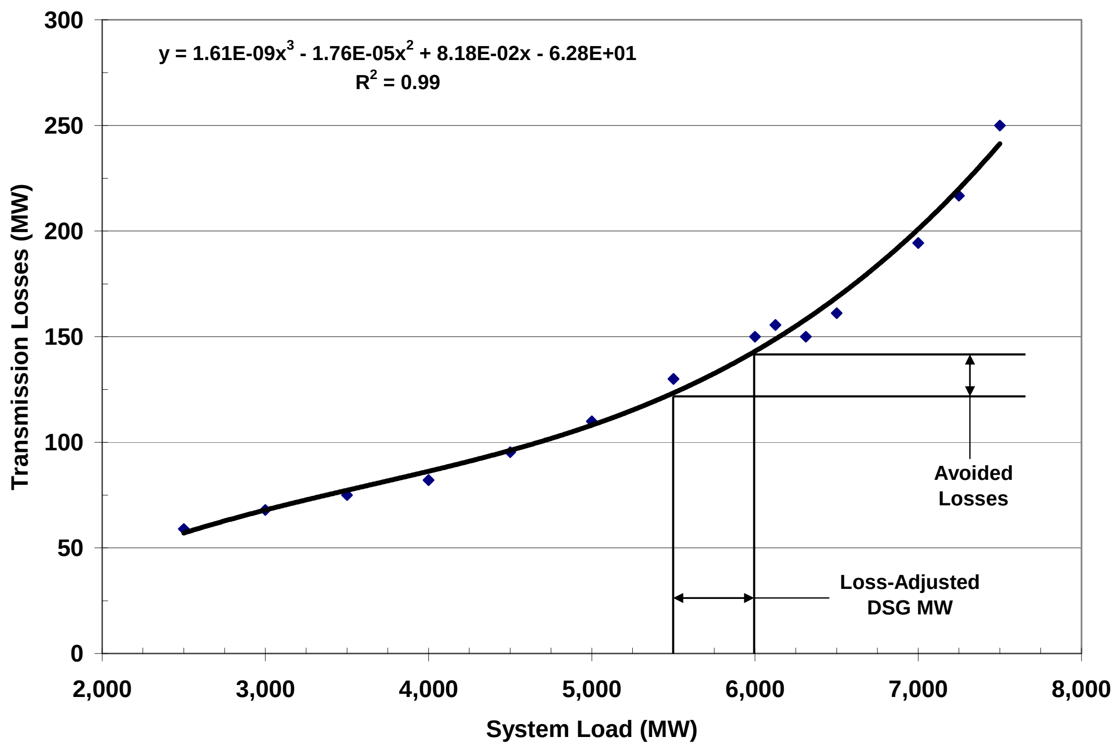
As part of Task 4, the Company quantified the potential value of deferral of a distribution substation capital project. Of the total deferral value, roughly 3% could be attributed to a transmission capital budget.

Avoided Transmission System Line Losses

Transmission line loss savings were quantified by inflating the avoided energy cost, avoided emission cost, fuel hedge, and avoided generation capacity credit values attributed to DSG by an amount representative of the line losses associated with moving power across the Public Service electric transmission system. That is, in the absence of DSG, enough generation would be needed from a transmission-interconnected source to both replace the solar generation and the line losses that occur on the transmission system. Line loss savings for avoided energy, emission, and fuel hedge benefits are based on annual, DSG generation-weighted values whereas avoided generation capacity credit values are based on an assumption of the loss savings represented by the top 50 load hours.[86] The Company utilized information in a transmission loss analysis study of its system[87] to quantify the MW of transmission line loss savings due to the installation of 59 MW of solar on its distribution system. Figure 10 shows the curve fit to the transmission loss data contained within the study.

[85] This generic combustion turbine has an assumption of zero transmission network upgrade costs because Public Service has identified that several of its existing generation sites (i.e., brown field sites) could accommodate the interconnection of a new combustion turbine with no need for additional transmission network upgrades to deliver the power from the new generating unit to customer load.
[86] The Company selected this benchmark as approximately 50% of the total loss of load probability (LOLP) associated with the 59 MW is obtained within the top 50 load hours.
[87] "Electric System Loss Analysis (Revised)", Siemens PT&D, Inc., March 2006, Report #R35-05.

Figure 10 Transmission Line Losses



In order to more accurately quantify the MWs of transmission system loss savings that occur in any hour from DSG, it was necessary to gross up the DSG MW from their level at distribution voltage to an equivalent level at transmission voltages. The Company assumed a gross-up factor equal to average transmission line losses of 2.5% obtained in the transmission line loss study[88] as the gross-up factor is the same variable it was trying to calculate. Thus, "Loss-Adjusted DSG MW" in Figure 10 is calculated as DSG/(1-0.025).

For the avoided energy cost methodology, the Company forecast a 20-year period of future electric load profiles. At the end of this 20-year period, the Company was projecting peak electric loads on the order of 8,000 MW. If the Company were to simply apply a transmission loss curve based on the current transmission system (that is, assume a static transmission system for the next 20 years), peak hour system losses—based on the curve fit from the existing study—would reach 300 MW which is over 50% higher than estimates based on current peak hour loads. At the suggestion of the TRC, the Company instead has assumed for this study that incremental transmission investments will be made such that current peak and annual transmission line loss savings from DSG are static over the 20 year period.

As with other avoided costs, average avoided transmission line loss savings decrease with increasing levels of DSG (with an assumption of a static transmission system). That is, the first 59 MW of DSG will avoid higher transmission line losses than will the second 59 MW of DSG since, to the extent that DSG avoids peak hour transmission line losses, the maximum peak load hour losses have already been accounted for.

[88] Table E.3, page x of Executive Summary

The average, DSG-weighted, line loss savings were calculated by applying the logic illustrated in Figure 10 to 2009-2011 historical, hourly load and DSG electricity production. Annual average line loss savings were divided by DSG electric production such that the average of the resulting loss savings could be applied separately to the avoided cost calculations and used to itemize the transmission systems benefits separate from the other benefits.

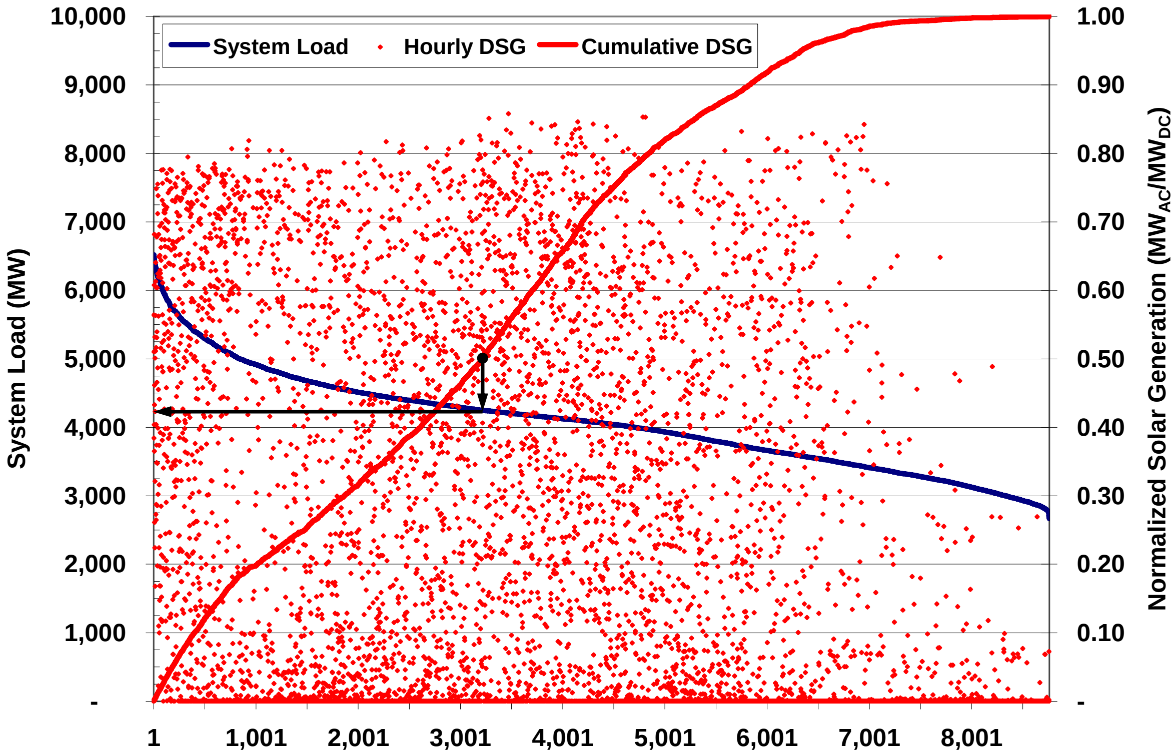
The study found that, on average, 92,160 MWh of annual electric production from 59 MW of large-system meter data DSG resulted in 2,120 MWh of annual transmission line loss savings. The resulting annual, DSG-weighted transmission line loss savings (2.30% of the avoided energy) are slightly less than annual, system average transmission line loss values (2.56% of total system load).[89] The Company attributes this result to the relatively low correlation of DSG electricity production to peak system conditions (both during summer and winter peak hours), and the relatively low number of hours of peak system conditions. That is, on an annual basis, DSG is generally producing electricity during <u>average system</u> load conditions and not predominately during the <u>highest system</u> load conditions.

This result is illustrated in Figure 11 below which plots the Company's 2010 system load duration curve along with the corresponding hourly DSG electricity production (normalized by the 59 MW) and the annual, cumulative solar generation based on the proxy meter data available for the larger systems. Note that 50% of the total, annual 2010 DSG electricity production occurred when system load was below about 4,250 MW. From Figure 10 above, it is evident that 50% of the DSG electricity production occurred during periods of relatively low transmission line losses (i.e., <= 2.0%) and the finding that annual DSG-weighted transmission line loss levels are close to system average is thus not surprising.

During the top 50 system load hours of 2009, 2010, and 2011, the transmission line loss savings attributable to the 59 MW DSG averaged 2.28% of the installed DSG MW. Thus avoided transmission-interconnected generation capacity can be grossed up by 2.28% for avoided transmission line losses.

[89] As the calculated result is close to the average, the Company's use of the average transmission loss value to perform its initial DSG gross-up is justified.

Figure 11 2010 System Load Duration and DSG Electricity Production



DSG Study Task 6 – Document DSG Costs

DSG Integration Costs

At the time the Company conducted its most recent solar integration cost study (the "2009 integration study")[90] it lacked actual DSG electricity production data with which to quantify the integration costs DSG can be expected to place on the Public Service system. As a result, the 2009 integration study utilized hourly DSG electricity production data developed from simulated PV systems and hourly solar resource data obtained from satellite imagery. The analysis framework and methodology employed in the 2009 solar integration study was similar to that employed in the Company's wind integration studies: i.e., the costs that intermittent resources add to the overall cost of operating the Public Service power supply system derive from these intermittent resource's contribution to inaccuracies in the hourly and day ahead forecast of net load[91] for the system and the resultant impacts these inaccuracies place on the ability of system operators to optimally commit and dispatch the fleet of generating units to serve that net load.

[90] "Solar Integration Study for Public Service Company of Colorado", EnerNex Corporation, February 9, 2009.
[91] Net load here is defined as forecasted system load minus forecasted, non-dispatchable generation (i.e. wind generation).

DSG integration costs presented here are based on the approach for quantifying solar integration costs proposed in Phase 2 of the Company's 2011 ERP.[92] With current gas costs, these integration costs are roughly $2/MWh on a 20-year levelized basis. Other integration costs that are <u>not</u> captured in this methodology include:

- regulation costs,
- operating reserve costs,
- gas supply system costs, and
- increased O&M costs at marginal generation units.

As the Company acquires more experience with solar generation on its system it will be better able to quantify these types of integration costs and include them in future solar integration cost studies if applicable.

As indicated in the Background section of this report, the Company is not including in this study any information pertaining to the S*R program costs incurred to incent its customers to install net-metered DSG or an estimate of the out-of-pocket costs of the Company's customers who installed DSG.

Summary of DSG Net Avoided Costs

As discussed in the Avoided Emissions Costs section, the data can be presented in a unitized fashion to represent any relatively small addition of DSG to the Public Service system.[93] On this basis, Table 16 presents a summary of the levelized net avoided costs of DSG by category and with Low and High Case natural gas sensitivity results.[94] Figure 12 presents the annual nominal values of each of the system costs and benefits examined in the study. Figure 13 presents the same data except categorized as a generation, distribution, or transmission system net avoided cost. Tabular values for the data shown in Figures 12 and 13 are provided in Appendix III.

Consistent with the findings of prior studies on other utility systems and the Company's expectations, the majority of the avoided cost savings are from avoided energy costs and, as the sensitivity results show, these avoided cost estimates are very sensitive to the assumed levels of future natural gas prices.

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[92] Solar integration costs are quantified based on the results for Scenario D illustrated in Table 4 of the 2009 study report.

[93] The study assumes that the 0.75% annual degradation applies to both annual energy amounts and peak generation.

[94] Values are levelized over the 23 year period beginning in 2012 with a 7.60% discount rate. Small differences in values between the two categorizations of costs and benefits are due to rounding.

Table 16 Categorization of Levelized Net Avoided Costs[95]

	Low Gas			Base Gas			High Gas	
		$/MWh	%		$/MWh	%		$/MWh	%
Avoided Energy Costs	$	35.80	55%	$	52.10	63%	$	76.10	69%
Fuel Hedge Value		6.60	10%		6.60	8%		6.60	6%
Avoided Emissions Costs		5.10	8%		5.10	6%		5.10	5%
Avoided Capacity & FOM Costs		11.50	18%		11.50	14%		11.50	11%
Avoided Distribution Upgrades		0.50	1%		0.50	1%		0.50	0%
Avoided Transmission Upgrades		0.20	0%		0.20	0%		0.20	0%
Avoided Line Losses		4.70	7%		6.20	8%		8.30	8%
Solar Integration Costs		(0.50)			(1.80)			(4.40)	
Net Avoided Cost	$	63.90	100%	$	80.40	100%	$	103.90	100%
Generation	$	58.50	92%	$	73.40	92%	$	94.90	91%
Transmission		2.50	4%		3.20	4%		4.30	4%
Distribution		2.90	5%		3.60	4%		4.60	4%
Net Avoided Cost	$	63.90	100%	$	80.20	100%	$	103.80	100%

The study expressly assumes that the price of an option contract on natural gas, avoided carbon dioxide emission costs, and combustion turbine capital costs are unchanged between the large differences across the natural gas forecasts. Such assumptions are obviously simplifications of complex interconnections; the actual correlation between these costs and any natural gas forecast are likely to be influenced by many factors including such things as an increased demand for gas-fired combustion turbines in a low gas forecast world as more utilities switch from coal to gas. This study did not attempt to estimate the effects of such correlations.

Additional Observations

Given the diurnal and intermittent nature of the solar resource and the resulting poor correlation of solar generation to an individual customer's load, customers who install DSG use the Company's transmission, distribution, and generation systems more than non-DSG customers. That is, DSG customers not only rely on these systems for the delivery of energy and capacity from the Company when the solar generation is less than their load (for example, during night or other times when the solar resource is insufficient, or when the customer's generation equipment is non-functional) but they also rely on the distribution system to take away the excess solar generation produced (that is, the amount of solar generation that exceeds their load). Customers with DSG are also dependent upon the Company's generation, transmission and distribution systems to maintain sufficient line voltage such that their generation equipment may function pursuant to the requirements of IEEE 1547.[96]

[95] Minor differences in Net Avoided Cost due to rounding.

[96] IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems" requires that a PV generation system disconnect from the grid in the event of a grid disturbance and not reconnect until the disturbance has been corrected. Such grid disturbances include low voltage excursions; i.e., in the case of a grid blackout. Thus it is the reliable and persistent operation of the utility's generation, transmission, and distribution systems that allow DSG systems to operate and for customers who install DSG to receive reliable service whether their solar systems are operational or not.

Figure 12 Categorized Annual Net Avoided Costs

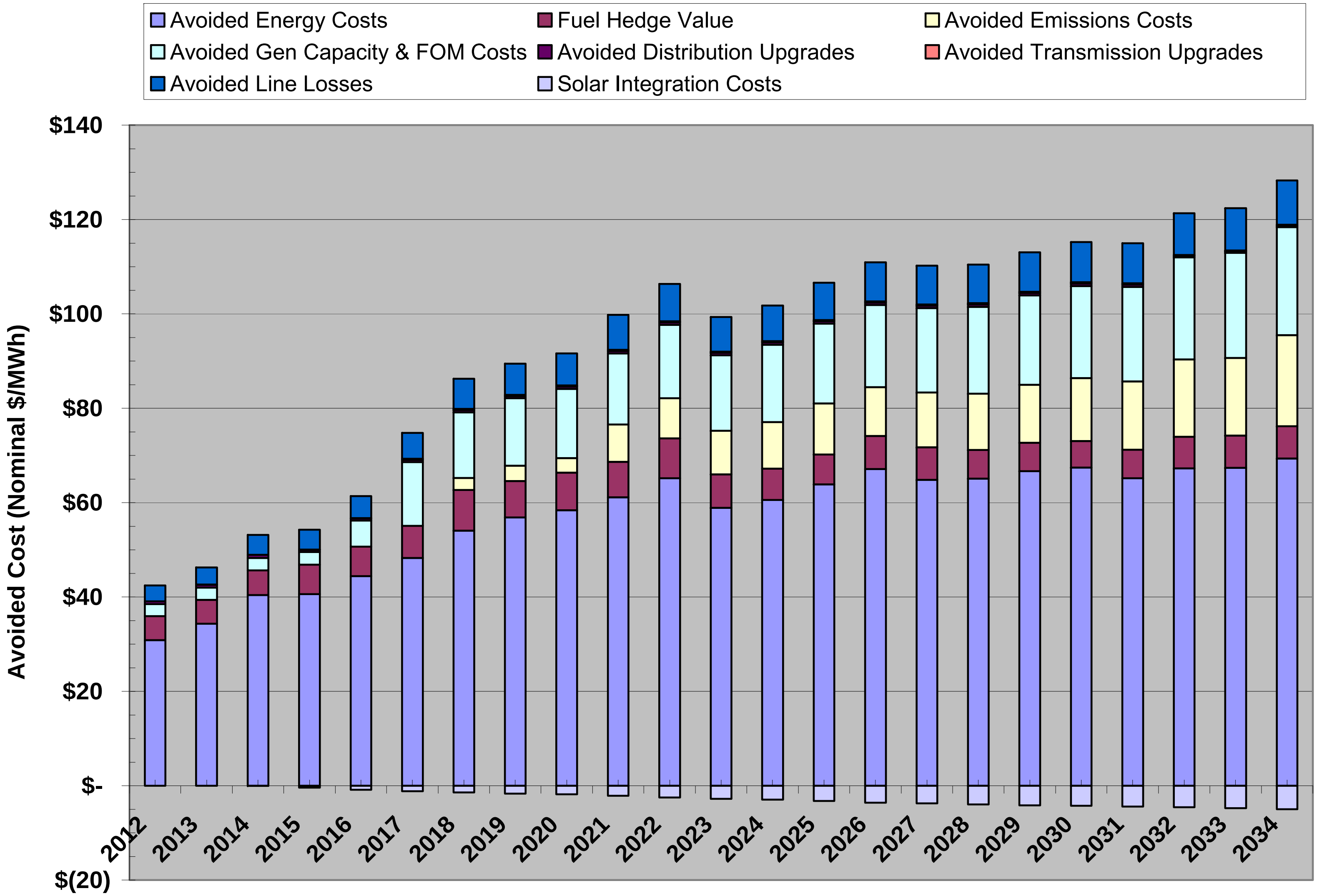
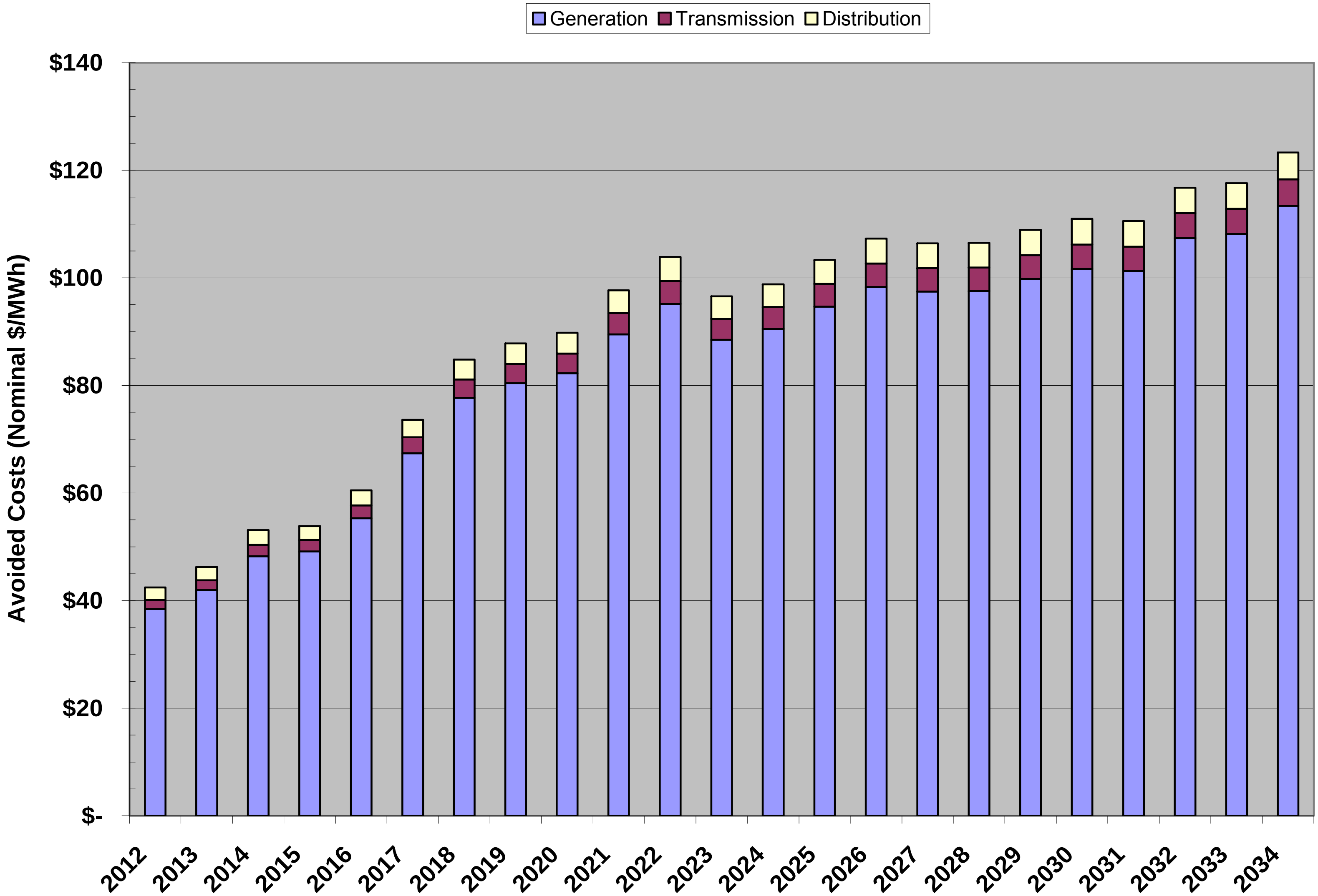


Figure 13 Net Avoided Costs Categorized by Utility Component



DSG Study Conclusions

This study was conducted in response to Colorado Public Utilities Commission Decision No. C09-1223. Public Service's objective in this study was to investigate and document the costs and benefits of distributed solar generation on its electric supply system at current DSG penetration levels and projections for near-term penetration levels. The study was originally structured to examine the first 59 MW of DSG on the Public Service of Colorado system along with the incremental 81 MW of DSG. Annual hourly estimates of solar generation from DSG systems were estimated based on the historical hourly generation data for several large (i.e., greater than 250 kW_{DC}) solar generation facilities interconnected to the Company's distribution system.

Avoided energy costs from the 2012 to 2034 time frame were calculated in a ProSym representation of the Company's electric generation supply portfolio. Analysis of the avoided cost results indicated that the relatively low levels of DSG MWh under study magnified small changes in avoided system costs being calculated in ProSym resulting in extremely large variations in annual avoided costs when represented on a $/MWh basis. In order to present study results without such variations, DSG-weighted marginal energy costs were employed instead.

Avoided carbon dioxide emission rates from the 59 MW and 140 MW ProSym cases were quite similar during the time period under study. Thus, in order to simplify the presentation of study results, it was beneficial to present the study results on a unitized basis as representative of a relatively small amount of DSG on the Company's system as opposed to two separate streams of costs and benefits attributable to either 59 MW or 140 MW of DSG. As other studies have indicated, increasing amounts of DSG over and above the levels studied here are likely to result in lower net benefits given the law of diminishing returns. However, the avoided energy cost results from the ProSym modeling in this study, with their large variations from year to year, could not be used to verify this expectation.

Major findings of this study include:

Installed DSG Portfolio:

- Over 90% of the DSG systems installed on the Company's system are from systems sized 10 kW_{DC} or smaller, however the contribution to system benefits from this class of systems is significantly less. On an installed capacity or annual MWh basis, the small system class provides closer to 40% of the system benefits.
- Analysis of the solar generation meter data from ~100 SolarCity residential customers indicate that the use of hourly solar generation profiles obtained from several large, south-facing fixed PV solar generation systems as a proxy for smaller residential PV fixed systems will overestimate the annual energy generation from these smaller systems. Thus the use of the large system meter data as a proxy for the smaller systems in this study likely overestimates the system benefits from the entire Public Service DSG portfolio.

Generation System Costs and Benefits:

- The bulk of the net benefits from DSG derive from impacts on the Company's generation system; in particular, avoided energy costs impacts.
- The value of DSG to the generation system is heavily impacted by the correlation between solar generation and system load.
- Model results indicate that DSG displaces a blend of coal-fired and gas-fired generation until roughly 2017 at which point over 1,300 MW of coal-fired generation is removed from the Company's generation portfolio. After 2017 DSG is expected to displace mostly efficient gas-fired generation.
- Little error would appear to be introduced into annual avoided energy costs from hourly ProSym modeling with the use of non-serially correlated solar generation and system load data.
- The avoided capacity credit attributable to DSG for generation resource planning purposes is greatly impacted by the geographic location of DSG in Colorado and the DSG system's tracking capabilities. Tracking PV greatly increases the generation capacity credit attributable to DSG. The bulk of the DSG currently installed on the Company's system has been installed in the Northern Front Range and in fixed panel orientations which provides one-third less avoided generation capacity credit than tracking systems installed in the San Luis Valley which indicate the highest levels of avoided generation capacity credit.
- The use of actual solar generation meter data in the current DSG ELCC study results in significantly lower ELCC values compared with use of satellite-derived solar resource data and generic PV generation models.

Distribution System Costs and Benefits:

- The value of DSG to the electrical distribution system is heavily impacted by the correlation between DSG electricity production and feeder load.
- Distribution capital deferral potential as a result of DSG is more likely on heavy commercial feeders as opposed to heavy residential feeders given the better correlation between DSG electricity production and commercial load patterns. However, any deferral potential would apply in very limited circumstances, few of which currently exist on the Company's system.
- Given the correlation between hourly solar generation and hourly feeder load across the entire calendar year, annual avoided distribution line losses are no greater than annual average line losses.
- At high DSG feeder penetration rates, distribution line losses might be expected to increase over levels that would exist with no DSG.

Transmission System Costs and Benefits:

- Given the correlation between hourly solar generation and hourly system load across the entire calendar year, annual avoided transmission line losses are no greater than annual average line losses.
- The majority of the transmission system benefits quantified in this study are tied to the deferral/avoidance of a generation capacity resource and the assumed incremental transmission costs associated with that new generation resource.

Appendix I - Survey of Prior DSG Studies

Source of Cost/Benefit	Study	Quantification Methodology	Major Assumptions	Notes
Costs and Benefits to the Generation System				
Avoided or delayed generation capacity	CPR: Austin, 2006	Generic CT capital cost adjusted for generation dependable capacity		Generation dependable capacity valued as a slice of a deferred/avoided CT
	CPR: NY, 2008	Demand reduction (DR) program payments		Generation dependable capacity valued as a slice of avoided demand reduction costs
	RW Beck: APS, 2009	GE LMS100 CT and apportioned transmission system upgrade capital costs adusted for generation dependable capacity	Levelized capital costs utilized instead of declining revenue requirements	No adjustment to LMS100 capital costs for energy value attributable to the low heat rate unit; generation dependable capacity valued at market rates if a complete unit was not deferred/avoided
Avoided fixed O&M	RW Beck: APS, 2009	Generic CT FOM, natural gas pipeline reservation fees, short-term purchased demand charges	ST purchased demand charges used in event that DSG MW are insufficient to completely avoid an LMS100	
Generation dependable capacity	CPR: Austin, 2006	Electrical Load Carrying Capability		Generation dependable capacity credit decreases with increasing DSG penetration.
	CPR: NY, 2008	Electrical Load Carrying Capability and Solar Load Control Capacity		Generation dependable capacity credit decreases with increasing DSG penetration.
	RW Beck: APS, 2009	Loss of Load Equivalency		Generation dependable capacity credit decreases with increasing DSG penetration.
Avoided energy and variable O&M costs	CPR: Austin, 2006	Marginal energy cost studies	½% annual DSG degradation rate	
	PSCo: PV Study, 2006	ProSym avoided cost study	PV Watts solar generation with a Boulder location	
	CPR: NY, 2008	2007 NYISO LMPs plus Congestion Pricing	Fixed systems analyzed were: south facing, south-west facing, and horizontal orientations	
	CPR: WE Energies, 2009	MISO day-ahead LMPs		
	RW Beck: APS, 2009	PROMOD avoided cost studies	Forward NG curve based on NYMEX NG contract with AZ delivery adjustments	Avoided energy costs (in $/MWh terms) decrease with increasing DSG penetration
Avoided emissions costs	RW Beck: APS, 2009	Avoided carbon dioxide emissions quantities from PROMOD results	CO_2 priced at: $0/ton in 2010, $21/ton in 2015, $52/ton in 2025	
Fuel Price Hedge Value	CPR: Austin, 2006	Difference between the discounted value of NYMEX NG futures prices at risk-free rates and the discounted value of natural gas forecast prices at the utility's cost of capital	No contract counterparty credit risk; requires gas price forecast for term past NYMEX gas futures	
	CPR: WE Energies, 2009	Difference between the discounted value of NYMEX NG futures prices at risk-free rates and the discounted value of natural gas forecast prices at the utility's cost of capital	No contract counterparty credit risk; requires gas price forecast for term past NYMEX gas futures; Wisconsin-average heat rate for 2007 used to convert gas cost to electricity cost.	Unclear in the paper why the futures price and forecast price of natural gas differ by the magnitude presented
Ancillary services requirements: Operating and Spinning Reserves	RW Beck: APS, 2009	Qualitative description of potential increased ancillary service requirements only	APS system operators "monitor and predict the impact and timing of storm fronts on the APS system quite well"	No increased costs assumed based on expected actions of real-time operators
Ancillary services requirements: Regulating Reserves	RW Beck: APS, 2009	Compare DSG generation from a single generator to aggregate DSG generation at 10-minute intervals		Level of regulation reserves required for DSG is not likely to be zero, but couldn't be quantified due to lack of solar generation data

Source of Cost/Benefit	Study	Quantification Methodology	Major Assumptions	Notes
Costs and Benefits to the Transmission System				
Reduced transmission system line losses	CPR: Austin, 2006	Marginal loss factors calculated from load flow analysis	Losses calculated at a point in time	
	CPR: WE Energies, 2009	Marginal loss factors calculated from historic hourly loads and average MISO loss data	Losses calculated at a point in time	
	RW Beck: APS, 2009	Estimate annual I^2R loss savings on a 100 MVA basis from addition of DSG based on assumed hourly DSG profiles	Total system losses are constant for each year of the study due to assumed system improvements; i.e., study assumes no annual load growth and a static transmission system	Incremental avoided transmission system line losses decrease with increasing DSG penetration
Avoided or delayed transmission capital expenditures	CPR: Austin, 2006	Present value of the transmission expansion plan capital costs divided by annual load growth times the transmission dependable capacity of DSG times a time-value of money term	DSG generation capacity assumed for transmission dependable capacity	Transmission dependable capacity valued as a slice of a deferred/avoided transmission expansion plan
	CPR: WE Energies, 2009	Transmission dependable capacity of DSG times monthly transmission access fees	Transmission dependable capacity calculated on a monthly basis based on peak hour load reduction	Transmission dependable capacity valued as a slice of avoided access fees; low value due to poor match to load
	RW Beck: APS, 2009	Determine if installed DSG can completely defer or avoid a 500 MW (AC) transmission project	90% confidence interval for comparing peak load hour demand and solar generation to determine transmission capacity credit	No deferral or avoidance value for low penetration case; one year deferral value in 2021 for medium penetration case; avoidance value in 2021 for large penetration case
Costs and Benefits to the Distribution System				
Reduced distribution system line losses	CPR: Austin, 2006	Marginal loss factors calculated from load flow analysis		
	CPR: WE Energies, 2009	Marginal loss factors calculated from hourly load data at specific feeders		
	RW Beck: APS, 2009	Load flow studies on three-phase lines using ABB's Feeder-All program; load flow studies on specific feeders using EPRI's Distribution System Simulator program.		Feeder specific analysis used to validate system level analysis. Value included in avoided transmission loss value
Avoided or delayed distribution capital expenditures	CPR: Austin, 2006	Present value of the distribution expansion plan divided by annual load growth times the distribution dependable capacity of DSG times a time-value of money term	DSG generation capacity assumed for distribution dependable capacity	Distribution dependable capacity valued as a slice of a deferred/avoided distribution expansion plan
	PSCo: PV Study, 2006	Analyze feeder and substation targeted for capital investments and determine MW of DSG necessary to defer investment	Metro Denver feeder and substation analysed had commercial/residential split similar to entire system	No amount of DSG could offset feeder or substation investment due to constraint that generation is needed until 7 PM
	CPR: WE Energies, 2009	Determine distribution dependable capacity of DSG; analyze specific feeders in need of capital investments		Low value due to poor match to feeder load
	RW Beck: APS, 2009	Determine distribution dependable capacity of DSG; analyze specific feeders in need of capital investments	Capital defferal is only possible if simultaneous loss of DSG does not increase feeder load above a 10 percent contingency level	Value can acrue only if DSG is targeted on specific feeders
Distribution equipment service life extension	RW Beck: APS, 2009	Qualitative description only		Insufficient data available to quantify benefit
Reduction in initial capital investment	RW Beck: APS, 2009	Determine if DSG can reduce load during peak hours to allow use of smaller equipment	Lifespan of PV matched lifespan of distribution equipment; no simultaneous failure of DSG during peak load hour that exposes distribution system to full customer load	Incremental demand reductions not significant enough to reduce equipment sizes

CPR: Austin, 2006 – "The Value of Distributed Photovoltaics to Austin Energy and the City of Austin", Clean Power Research, LLC, March 17, 2006. Available at:
http://www.cleanpower.com/Content/Documents/research/distributedgeneration/AE_PV_ValueReport.pdf

CPR: Nevada, 2003 – "Potential Economic Benefits of Distributed Photovoltaics to the Nevada Power Company", Clean Power Research, Gridwise Engineering Co., PowerLight Corp., November 24, 2003. Available at:
http://www.cleanpower.com/wp-content/uploads/EconomicBenefitsPVNevadaPower.pdf

CPR: NY, 2008 – "Energy and Capacity Valuation of Photovoltaic Power Generation in New York", Clean Power Research, LLC, March 2008. Available at:

CPR: We Energies, 2009 – "PV Value Analysis for We Energies", Clean Power Research, October 2009. Available at:

LBNL: – "Changes in the Economic Value of Variable Generation with Increasing Penetration Levels: A Pilot Study of California", Andrew Mills and Ryan Wiser, Lawrence Berkeley National Laboratory, CREPC/SPSC Pre-Meeting Webinar, March 21, 2012. Available at: http://www.westgov.org/wieb/meetings/crepcsprg2012/briefing/LBNLevvghp.pdf

PSCo: PV Study, 2006 – "Photovoltaic Study: Final Evaluation Results from Pilot Program", Public Service Company of Colorado, Report to the Colorado Public Utilities Commission, Docket 05M-283E, August 31, 2006. Available at:

RW Beck: APS, 2009 – "Distributed Renewable Energy Operating Impacts and Valuation Study", Prepared for Arizona Public Service, RW Beck, January 2009. Available at:
http://www.aps.com/_files/solarRenewable/DistRenEnOpImpactsStudy.pdf

Appendix II - Additional Observations from DSG Meter Data

Impacts from Snow Cover

Any source of panel shading acts to significantly reduce the generation potential of installed solar panels. As PV panels are typically wired into an inverter through series and parallel circuits, a relatively small shaded section of a single panel can reduce the total system output to a greater extent than the shaded area percentage might indicate.[97] Forecasting the solar resource is only part of forecasting solar generation during winter periods as snow cover is likely to be a significant driver in accurately forecasting solar generation during these periods.

As indicated under Task 2, certain periods of "missing" solar generation meter data were attributed to the effects of snow. Snow impacts solar generation both as the snow falls and accumulates and later, when sufficient sunshine exists for generation, but the accumulated snow has not melted or slid off or been purposefully removed. As an illustration of this effect, Figure 14 shows such a snow event that occurred beginning on January 8, 2011. The Figure presents direct normal irradiance (DNI)[98], ambient air temperature[99], average, normalized DSG electricity production from an aggregation of those Northern Front Range systems with meter data, and data from the average of the SolarCity generators. As is evident from the graph, DSG electricity production did not return to expected levels until roughly 4-5 days after the snow ended and after a sufficient number of hours of rebounding temperatures. As Figure 14 also shows—not unexpectedly—PV generation returns first to those systems installed at steeper elevation angles; that is, snow melts and slides off the 30° fixed and tracking systems faster than it does on the relatively flat 10° fixed systems.[100]

Minute-Scale Load and Generation Profiles from a Single Customer

The Company has been granted access to an individual customer's, web-based, load and PV generation monitoring system in order to help identify the source of excessive inverter trips on the customer's system. Among other load and PV system performance variables, the monitoring system records PV generation and gross customer load integrated over a minute time scale. A visual observation of these minute-scale data during peak summer and peak winter system load conditions illustrates many of the observations mentioned previously in this study.[101]

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[97] This phenomenon is well understood in the PV industry which is developing micro-inverters and module level power controllers to, in part, offset these impacts.

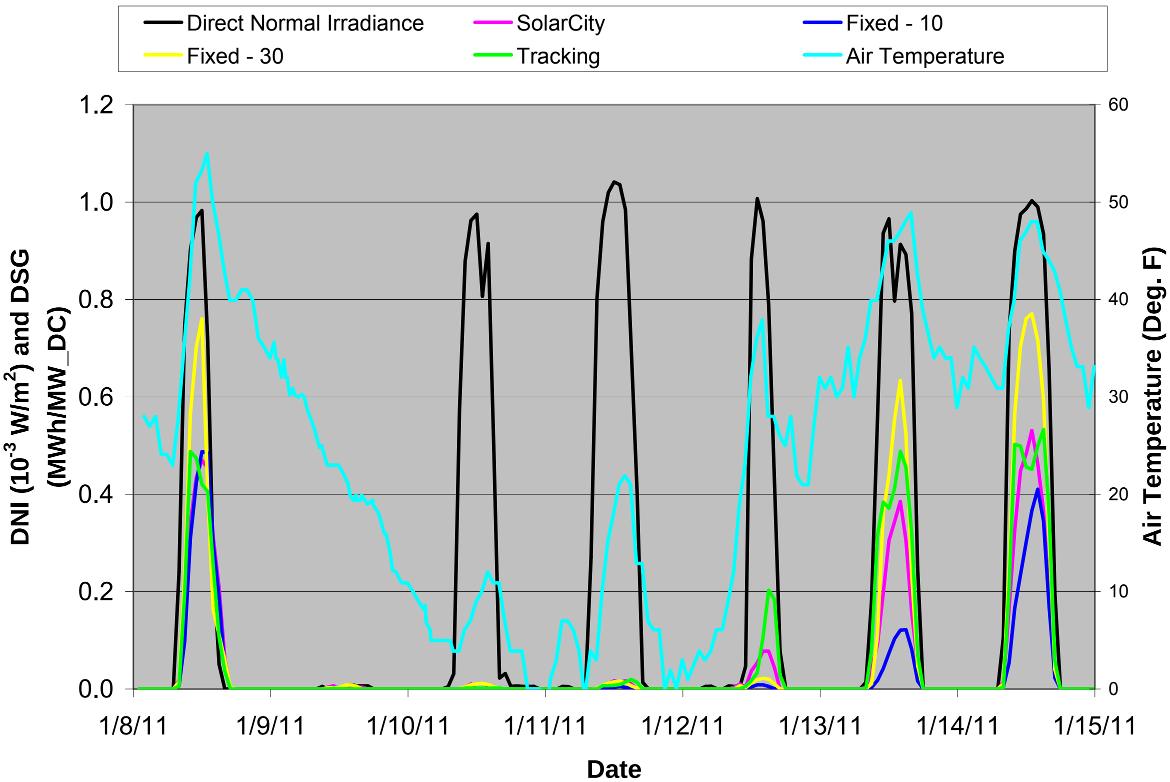
[98] DNI as recorded at NREL's Solar Resource Research Laboratory (SRRL); http://www.nrel.gov/midc/srrl_bms/. The SRRL is a preferred source of DNI information as it is an attended facility and snow is removed promptly from the monitoring equipment. Unless snow is removed from the pyranometers typically employed at most DSG facilities with solar resource monitoring, the recorded solar resource data suffers from the same snow shading impacts as the PV panels themselves.

[99] As recorded at Centennial Airport in the south Denver metro area; http://www.wunderground.com/US/CO/Denver.html

[100] The average elevation angle of the SolarCity systems shown in Figure 14 was approximately 22°.

[101] This residential customer is located in the Northern Front Range solar resource zone.

Figure 14 DSG Performance during January 2011 Snow Event



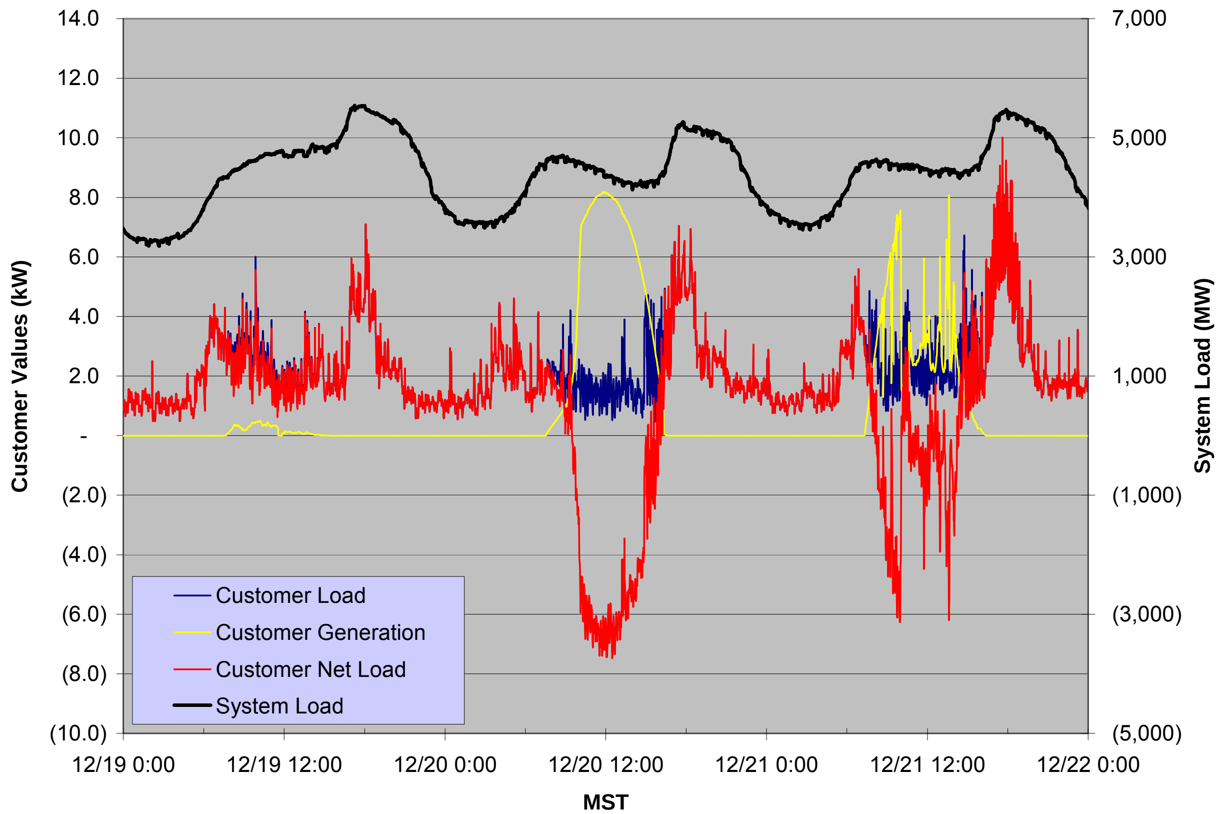
<u>Winter</u>

Figure 15 is a plot of the residential customer's gross load, gross PV generation, and net load (load – PV generation) along with total system load for the time period December 19, 2011 – December 21, 2011.[102]

- December 19 was a heavily overcast, snowy day; as such, the Company's generation fleet met nearly all of the customer's usage.
- December 20 was a bright and sunny day; however the customer's generation system did not achieve its potential until the layer of accumulated snow slid off around 9:45 am. Note that even on this very clear and sunny day, the customer's generation had gone to zero during the Company's peak system load hours and the Company's generation fleet was used to meet the customer's load during system peak hours. Also, during most hours of daytime PV generation, the export of PV generation (negative Customer Net Load) was in excess of two times Customer Load thus service drop line losses on this day were greater than they would have been absent PV generation.
- December 21 was a partly overcast day and the generation resource used to meet the customer's load changed rapidly from the on-site solar system to the Company's generation fleet.

[102] December 19 was the third highest winter load day on the Public Service system during the 2011-2012 winter season. The Company has access to historical data beginning on December 9, 2011. The highest winter peak load day occurred on December 5 and the second highest winter load day occurred on December 6.

Figure 15 Residential Customer Winter Load and Generation

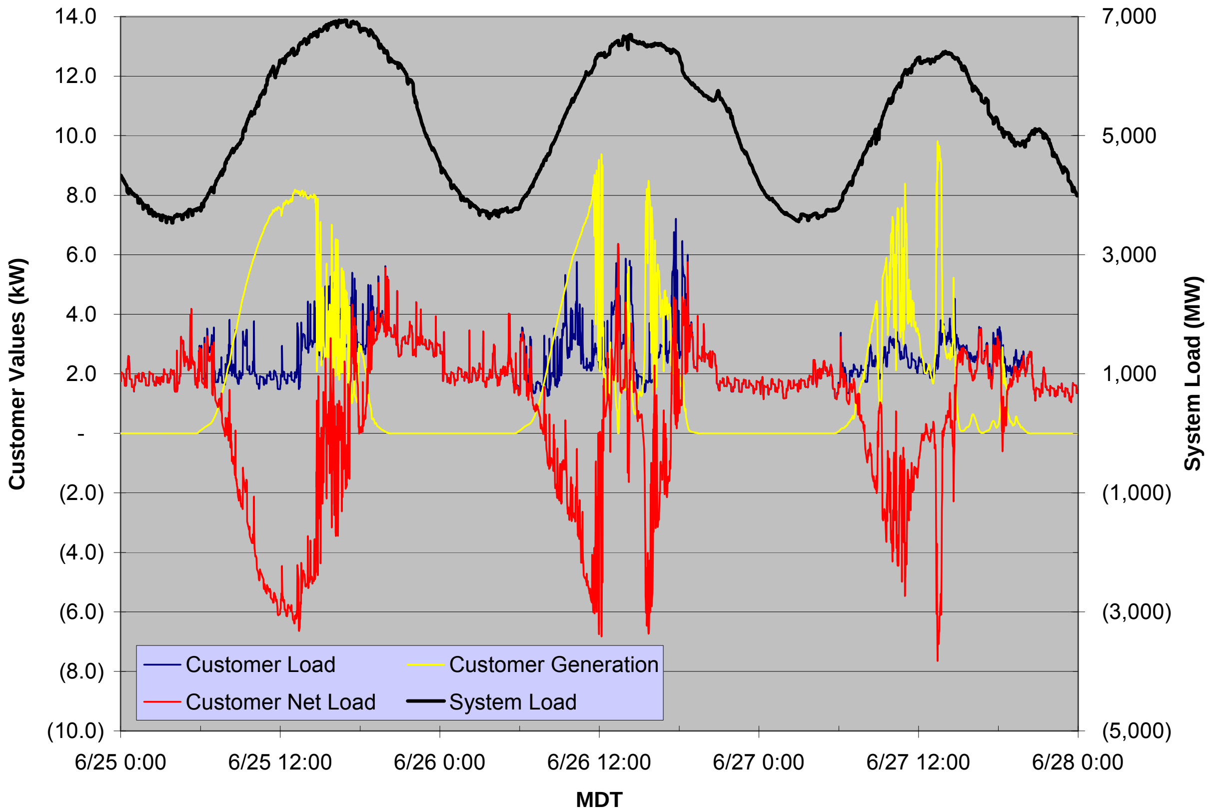


<u>Summer</u>

Figure 16 is a plot of the residential customer's gross load, gross PV generation, and net load (load – PV generation) along with total system load for the time period June 25, 2012 – June 27, 2012. June 25 was the peak system load day during summer 2012.

- June 25 was an extremely hot day; clear in the morning, but overcast in the afternoon during the system peak load hour. During system peak conditions the PV system was, on average, generating slightly less than the customer's load but on shorter time intervals the generation resource used to meet customer load changed rapidly from the on-site solar system to the Company's generation fleet.
- June 26 and June 27 were generally overcast days with the generation resource used to meet the customer's load changing rapidly from the on-site solar system to the Company's generation fleet.

Figure 16 Residential Customer Summer Load and Generation



Appendix III - Annual Avoided Cost Data for Figures 12 and 13

An assumed annual degradation rate of 0.75% per year applies to both annual energy and peak generation rates. DSG electricity production rate averages approximately 1,470 MWh/MW across the study period.

Table 17 Annual Avoided Costs - Base Gas Assumption

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Avoided Energy Costs	$ 30.84	$ 34.30	$ 40.39	$ 40.60	$ 44.40	$ 48.27	$ 54.08	$ 56.84	$ 58.37	$ 61.11	$ 65.19	$ 58.87	$ 60.55	$ 63.86	$ 67.09	$ 64.82	$ 65.06	$ 66.63	$ 67.42	$ 65.16	$ 67.24	$ 67.36	$ 69.32
Fuel Hedge Value	5.12	5.10	5.26	6.24	6.24	6.82	8.61	7.72	7.96	7.52	8.40	7.12	6.68	6.33	7.04	6.88	6.08	6.05	5.64	6.04	6.69	6.84	6.85
Avoided Emissions Costs	-	-	-	-	-	-	2.56	3.26	3.09	7.91	8.52	9.25	9.80	10.83	10.36	11.63	11.96	12.29	13.36	14.46	16.42	16.46	19.31
Avoided Capacity & FOM Costs	2.50	2.57	2.64	2.72	5.58	13.49	13.89	14.29	14.67	15.10	15.55	16.00	16.43	16.90	17.40	17.90	18.39	18.92	19.48	20.02	21.61	22.27	22.89
Avoided Distribution Upgrades	0.63	0.64	0.64	0.46	0.46	0.46	0.47	0.47	0.47	0.48	0.48	0.49	0.49	0.49	0.50	0.50	0.50	0.51	0.51	0.52	0.30	0.31	0.31
Avoided Transmission Upgrades	0.02	0.02	0.02	0.01	0.01	0.23	0.24	0.24	0.24	0.25	0.25	0.25	0.26	0.26	0.26	0.27	0.27	0.28	0.28	0.29	0.23	0.23	0.23
Avoided Line Losses	3.32	3.62	4.18	4.23	4.70	5.49	6.40	6.65	6.80	7.45	7.96	7.38	7.56	7.93	8.26	8.18	8.19	8.38	8.53	8.49	8.85	8.91	9.35
Solar Integration Costs	-	-	(0.03)	(0.42)	(0.88)	(1.19)	(1.44)	(1.67)	(1.83)	(2.14)	(2.50)	(2.77)	(2.95)	(3.25)	(3.58)	(3.77)	(3.94)	(4.14)	(4.24)	(4.42)	(4.59)	(4.78)	(4.96)
Net Benefit	$ 42.40	$ 46.20	$ 53.10	$ 53.80	$ 60.50	$ 73.60	$ 84.80	$ 87.80	$ 89.80	$ 97.70	$ 103.90	$ 96.60	$ 98.80	$ 103.30	$ 107.30	$ 106.40	$ 106.50	$ 108.90	$ 111.00	$ 110.60	$ 116.80	$ 117.60	$ 123.30
Generation	$ 38.46	$ 41.97	$ 48.26	$ 49.14	$ 55.33	$ 67.39	$ 77.70	$ 80.44	$ 82.27	$ 89.50	$ 95.17	$ 88.46	$ 90.51	$ 94.66	$ 98.30	$ 97.46	$ 97.55	$ 99.76	$ 101.65	$ 101.27	$ 107.38	$ 108.15	$ 113.42
Transmission	1.68	1.83	2.11	2.13	2.36	2.98	3.44	3.56	3.64	3.97	4.23	3.94	4.04	4.22	4.39	4.36	4.37	4.47	4.55	4.53	4.65	4.68	4.90
Distribution	2.29	2.45	2.73	2.57	2.81	3.21	3.67	3.79	3.88	4.20	4.46	4.18	4.27	4.46	4.63	4.59	4.60	4.70	4.78	4.76	4.73	4.76	4.98
Net Benefit	$ 42.40	$ 46.20	$ 53.10	$ 53.80	$ 60.50	$ 73.60	$ 84.80	$ 87.80	$ 89.80	$ 97.70	$ 103.90	$ 96.60	$ 98.80	$ 103.30	$ 107.30	$ 106.40	$ 106.50	$ 108.90	$ 111.00	$ 110.60	$ 116.80	$ 117.60	$ 123.30

Table 18 Annual Avoided Costs - Low Gas Assumption

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Avoided Energy Costs	$ 21.48	$ 23.81	$ 27.92	$ 28.07	$ 30.64	$ 33.26	$ 37.19	$ 39.06	$ 40.10	$ 41.96	$ 44.72	$ 40.46	$ 41.60	$ 43.84	$ 46.03	$ 44.51	$ 44.69	$ 45.76	$ 46.30	$ 44.80	$ 46.21	$ 46.30	$ 47.64
Fuel Hedge Value	5.12	5.10	5.26	6.24	6.24	6.82	8.61	7.72	7.96	7.52	8.40	7.12	6.68	6.33	7.04	6.88	6.08	6.05	5.64	6.04	6.69	6.84	6.85
Avoided Emissions Costs	-	-	-	-	-	-	2.56	3.26	3.09	7.91	8.52	9.25	9.80	10.83	10.36	11.63	11.96	12.29	13.36	14.46	16.42	16.46	19.31
Avoided Capacity & FOM Costs	2.50	2.57	2.64	2.72	5.58	13.49	13.89	14.29	14.67	15.10	15.55	16.00	16.43	16.90	17.40	17.90	18.39	18.92	19.48	20.02	21.61	22.27	22.89
Avoided Distribution Upgrades	0.63	0.64	0.64	0.46	0.46	0.46	0.47	0.47	0.47	0.48	0.48	0.49	0.49	0.49	0.50	0.50	0.50	0.51	0.51	0.52	0.30	0.31	0.31
Avoided Transmission Upgrades	0.02	0.02	0.02	0.01	0.01	0.23	0.24	0.24	0.24	0.25	0.25	0.25	0.26	0.26	0.26	0.27	0.27	0.28	0.28	0.29	0.23	0.23	0.23
Avoided Line Losses	2.49	2.70	3.08	3.13	3.50	4.18	4.93	5.09	5.21	5.78	6.17	5.77	5.91	6.18	6.42	6.41	6.41	6.56	6.69	6.71	7.04	7.10	7.49
Solar Integration Costs	-	-	-	-	-	-	-	-	(0.04)	(0.25)	(0.50)	(0.68)	(0.80)	(1.00)	(1.22)	(1.35)	(1.47)	(1.60)	(1.67)	(1.79)	(1.90)	(2.03)	(2.15)
Net Benefit	$ 32.20	$ 34.80	$ 39.60	$ 40.60	$ 46.40	$ 58.50	$ 67.90	$ 70.10	$ 71.70	$ 78.70	$ 83.60	$ 78.70	$ 80.40	$ 83.80	$ 86.80	$ 86.80	$ 86.80	$ 88.80	$ 90.60	$ 91.00	$ 96.60	$ 97.50	$ 102.60
Generation	$ 29.10	$ 31.48	$ 35.83	$ 37.03	$ 42.45	$ 53.57	$ 62.25	$ 64.32	$ 65.78	$ 72.23	$ 76.70	$ 72.14	$ 73.72	$ 76.90	$ 79.60	$ 79.58	$ 79.65	$ 81.42	$ 83.11	$ 83.53	$ 89.03	$ 89.84	$ 94.54
Transmission	1.26	1.37	1.56	1.58	1.76	2.32	2.70	2.79	2.85	3.13	3.34	3.14	3.21	3.35	3.47	3.47	3.48	3.55	3.63	3.64	3.75	3.78	3.97
Distribution	1.88	1.98	2.18	2.02	2.21	2.56	2.93	3.02	3.08	3.37	3.57	3.37	3.44	3.58	3.71	3.71	3.71	3.79	3.86	3.87	3.82	3.86	4.05
Net Benefit	$ 32.20	$ 34.80	$ 39.60	$ 40.60	$ 46.40	$ 58.50	$ 67.90	$ 70.10	$ 71.70	$ 78.70	$ 83.60	$ 78.70	$ 80.40	$ 83.80	$ 86.80	$ 86.80	$ 86.80	$ 88.80	$ 90.60	$ 91.00	$ 96.60	$ 97.50	$ 102.60

Table 19 Annual Avoided Costs - High Gas Assumption

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Avoided Energy Costs	$ 44.74	$ 49.88	$ 58.90	$ 59.20	$ 64.83	$ 70.56	$ 79.17	$ 83.25	$ 85.50	$ 89.56	$ 95.60	$ 86.20	$ 88.68	$ 93.57	$ 98.36	$ 94.97	$ 95.32	$ 97.62	$ 98.78	$ 95.41	$ 98.47	$ 98.63	$ 101.52
Fuel Hedge Value	5.12	5.10	5.26	6.24	6.24	6.82	8.61	7.72	7.96	7.52	8.40	7.12	6.68	6.33	7.04	6.88	6.08	6.05	5.64	6.04	6.69	6.84	6.85
Avoided Emissions Costs	-	-	-	-	-	-	2.56	3.26	3.09	7.91	8.52	9.25	9.80	10.83	10.36	11.63	11.96	12.29	13.36	14.46	16.42	16.46	19.31
Avoided Capacity & FOM Costs	2.50	2.57	2.64	2.72	5.58	13.49	13.89	14.29	14.67	15.10	15.55	16.00	16.43	16.90	17.40	17.90	18.39	18.92	19.48	20.02	21.61	22.27	22.89
Avoided Distribution Upgrades	0.63	0.64	0.64	0.46	0.46	0.46	0.47	0.47	0.47	0.48	0.48	0.49	0.49	0.49	0.50	0.50	0.50	0.51	0.51	0.52	0.30	0.31	0.31
Avoided Transmission Upgrades	0.02	0.02	0.02	0.01	0.01	0.23	0.24	0.24	0.24	0.25	0.25	0.25	0.26	0.26	0.26	0.27	0.27	0.28	0.28	0.29	0.23	0.23	0.23
Avoided Line Losses	4.55	5.01	5.82	5.85	6.48	7.44	8.59	8.95	9.17	9.93	10.61	9.76	10.01	10.52	10.99	10.81	10.83	11.08	11.27	11.13	11.53	11.59	12.12
Solar Integration Costs	(0.15)	(1.27)	(1.87)	(2.44)	(3.14)	(3.60)	(3.98)	(4.31)	(4.55)	(5.03)	(5.57)	(5.96)	(6.24)	(6.69)	(7.18)	(7.46)	(7.72)	(8.01)	(8.17)	(8.43)	(8.69)	(8.97)	(9.23)
Net Benefit	$ 57.40	$ 61.90	$ 71.40	$ 72.00	$ 80.50	$ 95.40	$ 109.50	$ 113.90	$ 116.60	$ 125.70	$ 133.90	$ 123.10	$ 126.10	$ 132.20	$ 137.70	$ 135.50	$ 135.60	$ 138.70	$ 141.10	$ 139.40	$ 146.60	$ 147.40	$ 154.00
Generation	$ 52.21	$ 56.27	$ 64.94	$ 65.72	$ 73.50	$ 87.27	$ 100.25	$ 104.21	$ 106.68	$ 115.06	$ 122.51	$ 112.60	$ 115.36	$ 120.94	$ 125.97	$ 123.92	$ 124.02	$ 126.88	$ 129.09	$ 127.50	$ 134.51	$ 135.23	$ 141.34
Transmission	2.29	2.52	2.93	2.94	3.26	3.95	4.53	4.71	4.83	5.21	5.55	5.13	5.26	5.52	5.76	5.68	5.69	5.82	5.91	5.85	5.99	6.02	6.29
Distribution	2.91	3.14	3.55	3.38	3.70	4.18	4.76	4.95	5.06	5.44	5.79	5.37	5.50	5.75	5.99	5.91	5.92	6.05	6.15	6.08	6.07	6.10	6.37
Net Benefit	$ 57.40	$ 61.90	$ 71.40	$ 72.00	$ 80.50	$ 95.40	$ 109.50	$ 113.90	$ 116.60	$ 125.70	$ 133.90	$ 123.10	$ 126.10	$ 132.20	$ 137.70	$ 135.50	$ 135.60	$ 138.70	$ 141.10	$ 139.40	$ 146.60	$ 147.40	$ 154.00

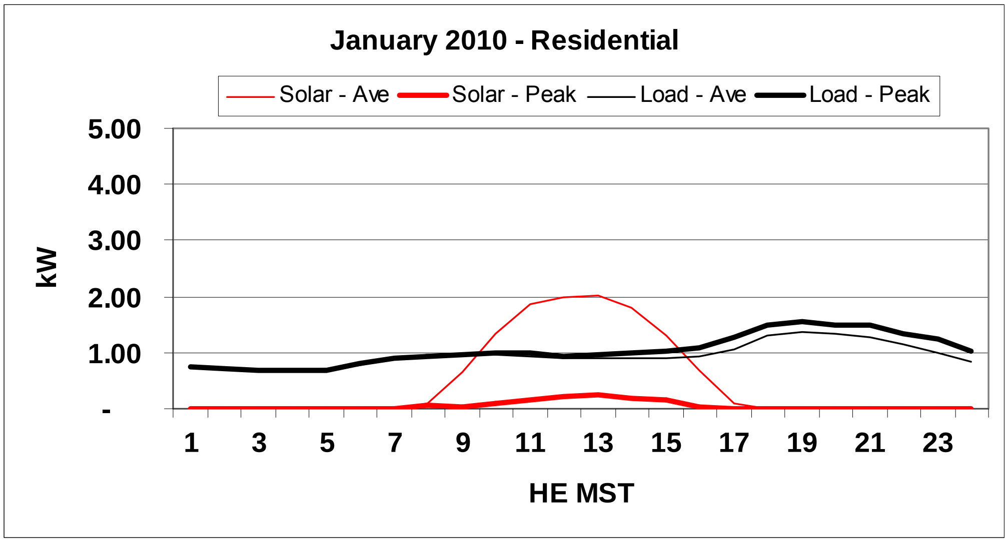
Appendix IV - DSG and Customer Load Profiles

Residential and Small Commercial
Monthly Peak and Monthly Average Load
and Proxy Solar Generation Profiles for 2010

The following 24 charts show the relationship between monthly average and monthly peak day Residential and Small Commercial load and the corresponding average and monthly peak load day solar generation during 2010. "Load – Peak" is the average hourly customer usage on the day with the peak customer-class hourly load; "Solar – Peak" is the hourly solar generation that occurred on that same day. Solar generation system sizes were set such that the typical system generated an annual amount of energy equal to the annual customer-class average load. For these 2010 graphs, this resulted in a 4.95 kW_{DC} Residential solar system and an 8.25 kW_{DC} Small Commercial solar system.

Graphs are provided in Hour Ending, Mountain Standard Time (HE MST) for January, February, November, and December and in Hour Ending, Mountain Daylight Time (HE MDT) for March, April, May, June, July, August, September, and October. For the March graphs, the average values calculated assume that the entire month was on MDT. For the November graphs, the average values calculated assume that the entire month was on MST.

These graphs show the significantly better correlation between Small Commercial customer load profiles and solar generation than between Residential load profiles and solar generation. The graphs also show the complete lack of contribution to customer class, winter peak demands from solar for the Residential systems.


January 2010 - Residential
Solar - Ave
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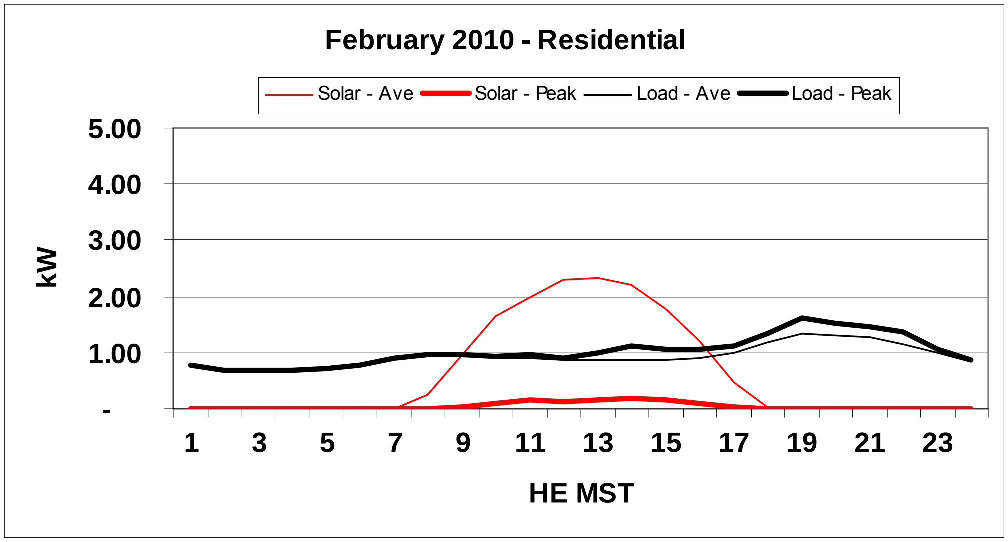
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Solar - Ave
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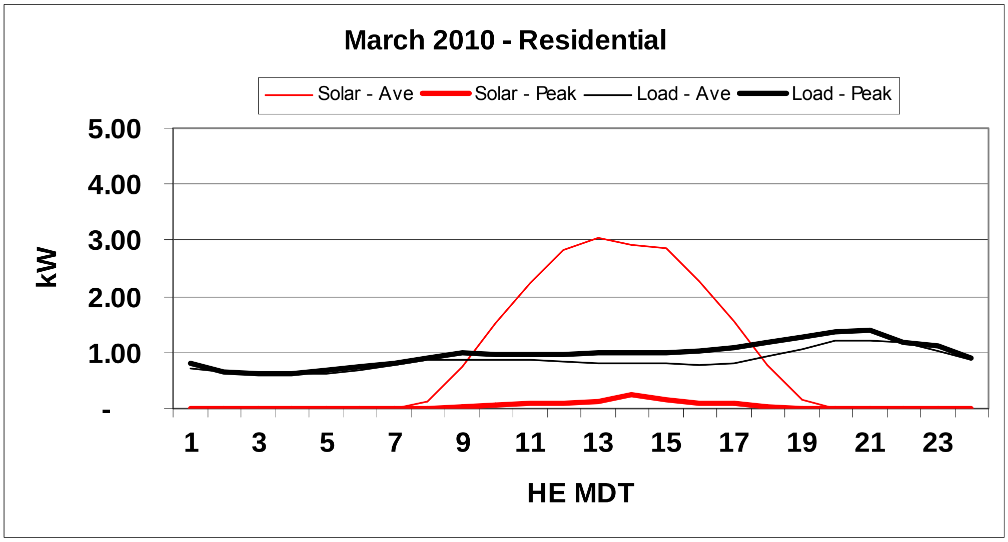
March 2010 - Residential
Solar - Ave
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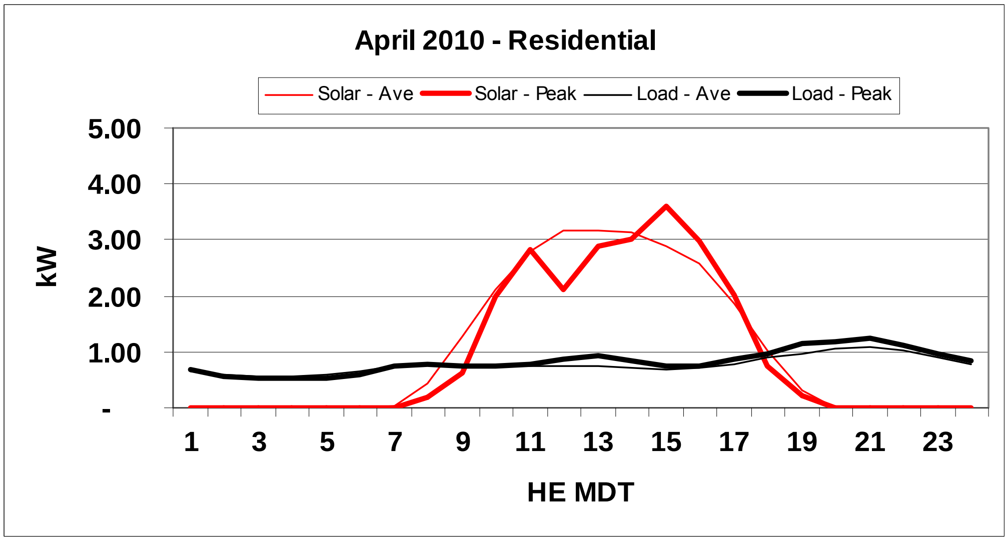
April 2010 - Residential
Solar - Ave
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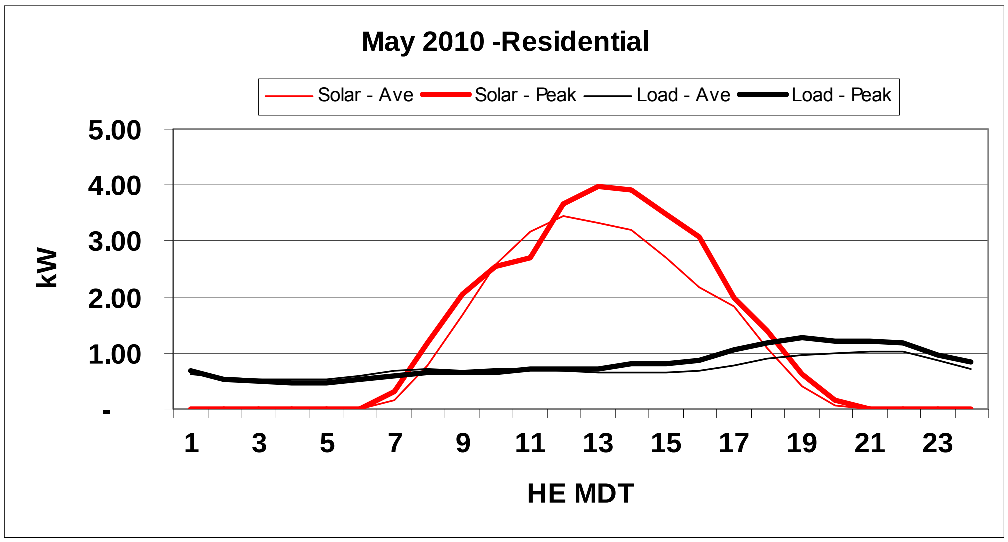
May 2010 -Residential
Solar - Ave
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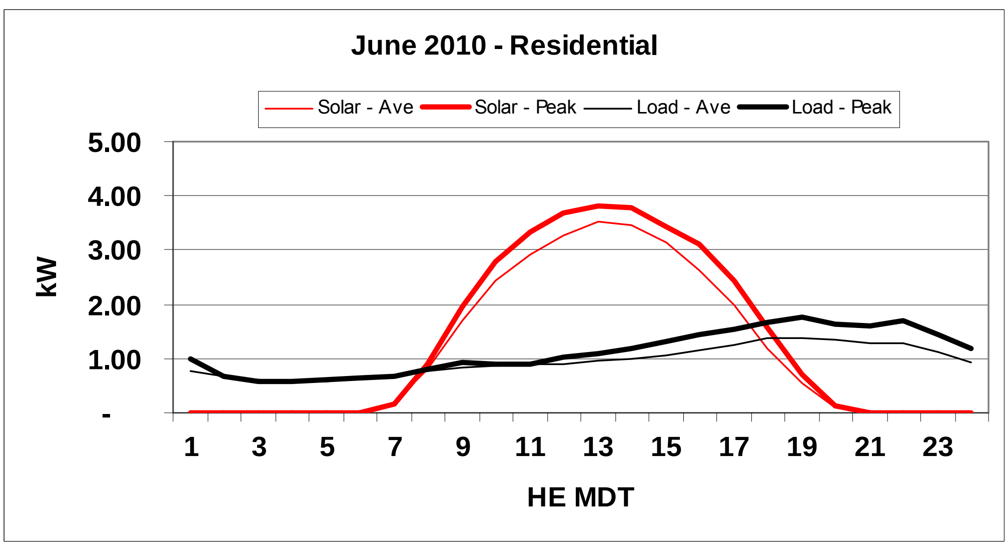
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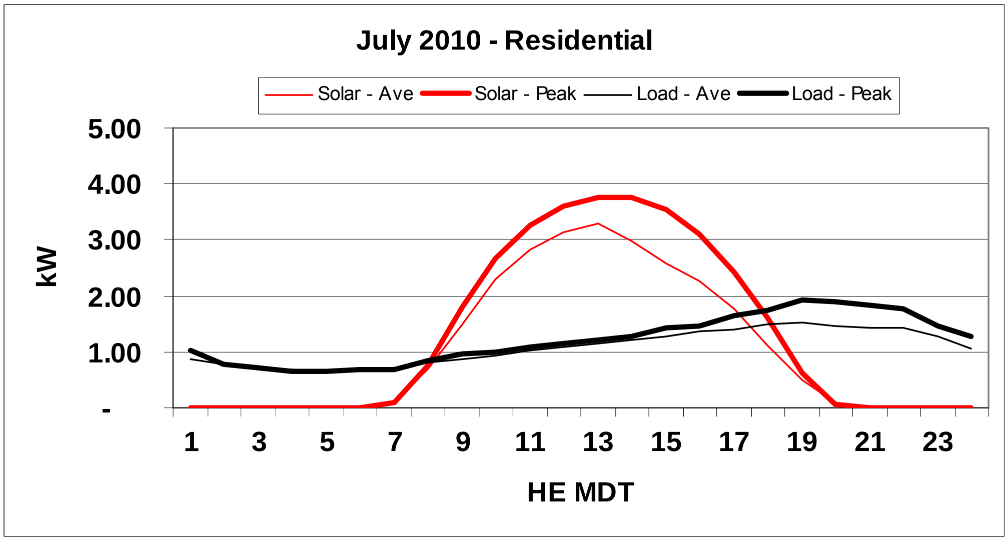
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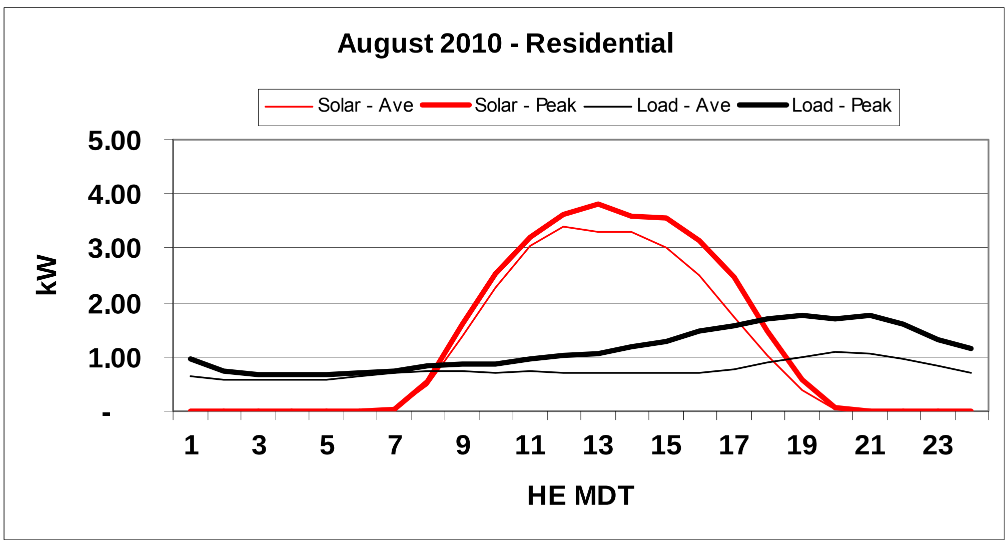
August 2010 - Residential
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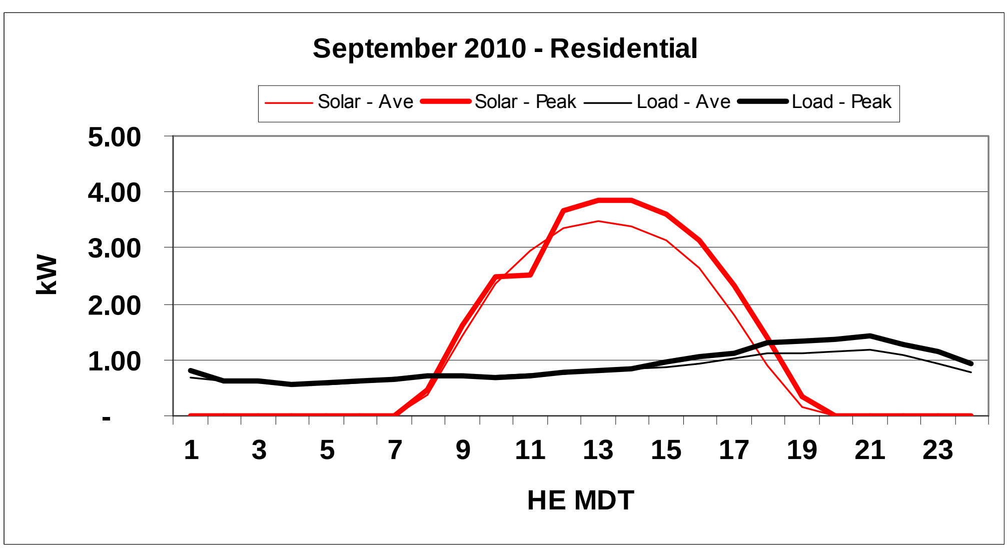
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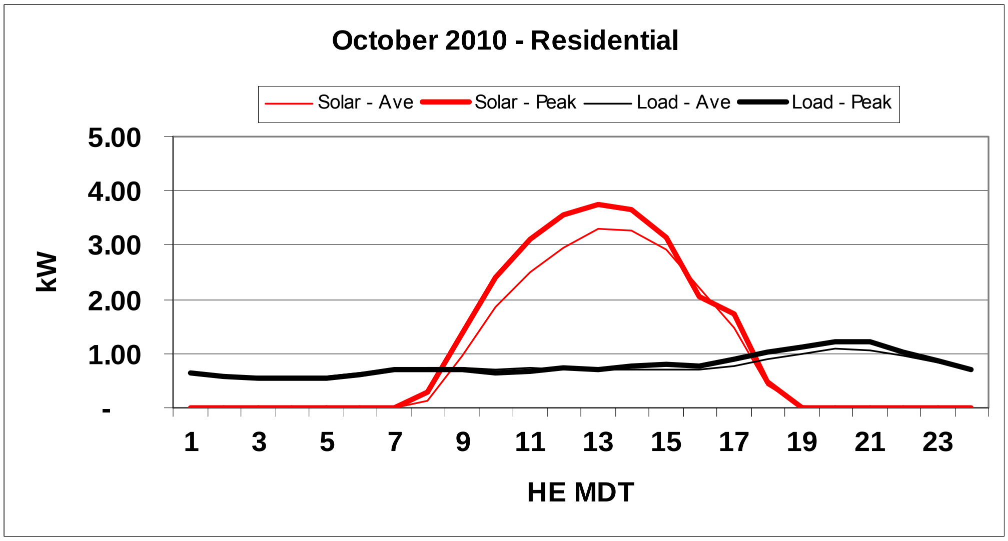
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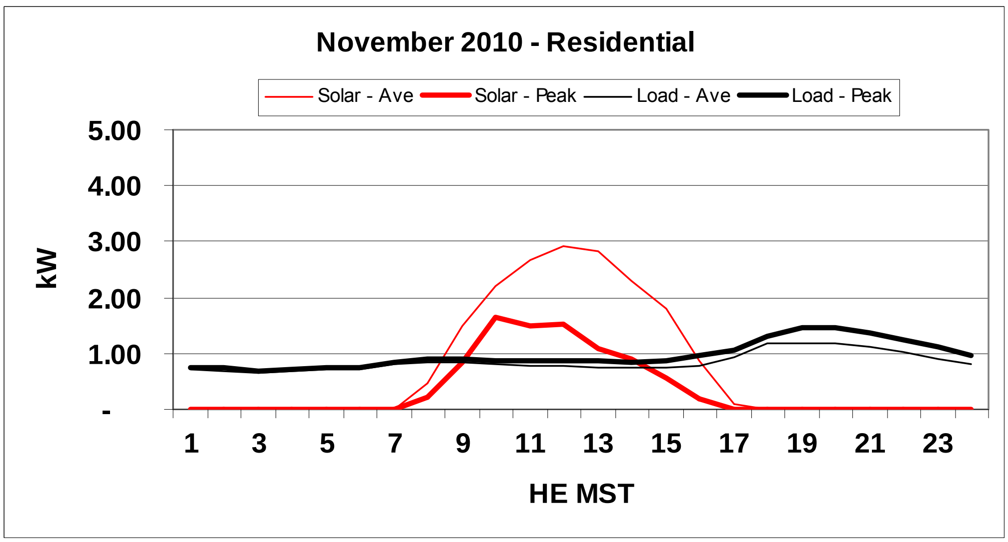
November 2010 - Residential
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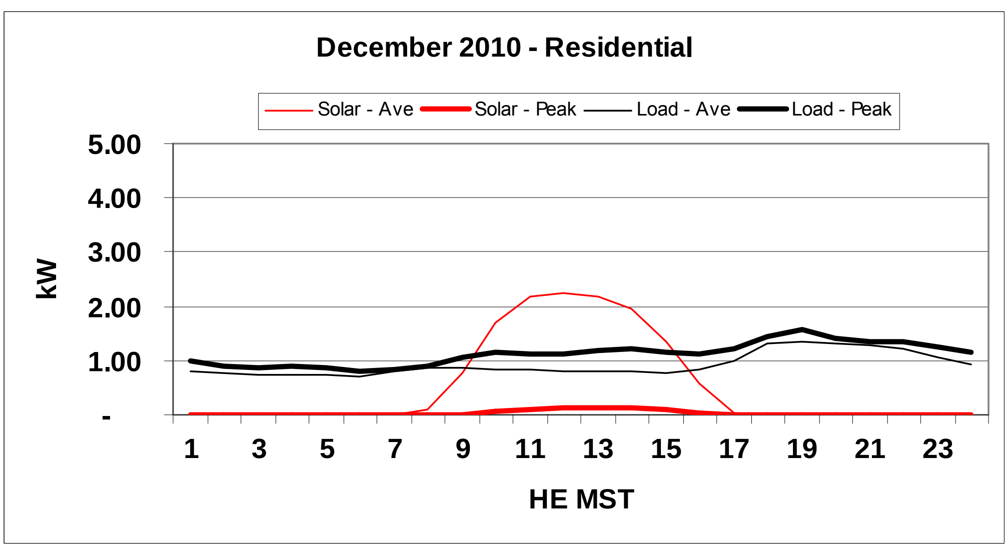
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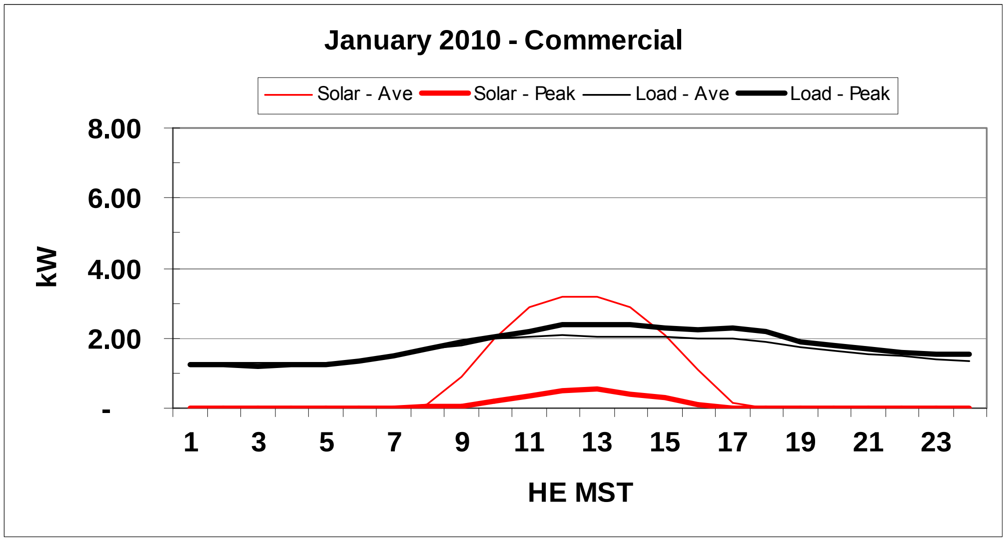
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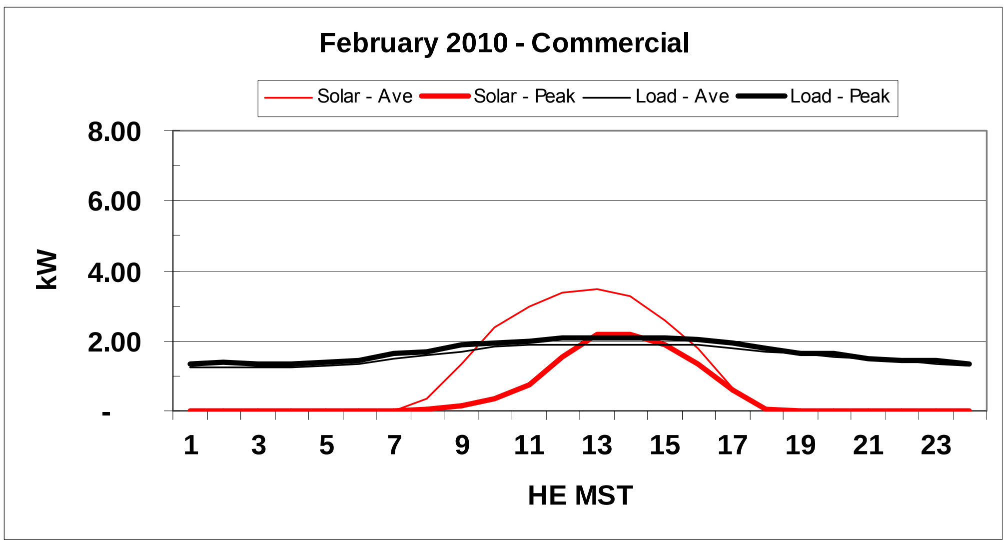
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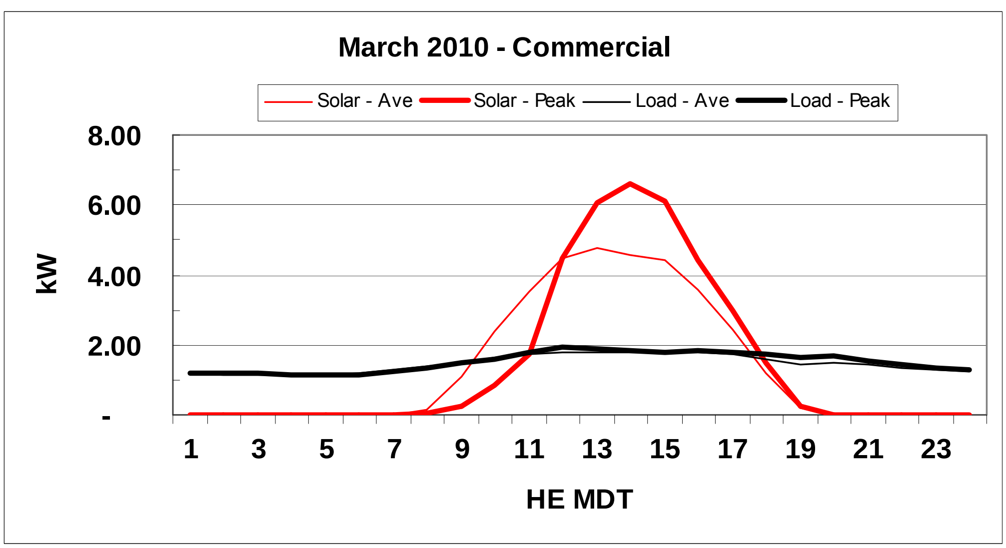
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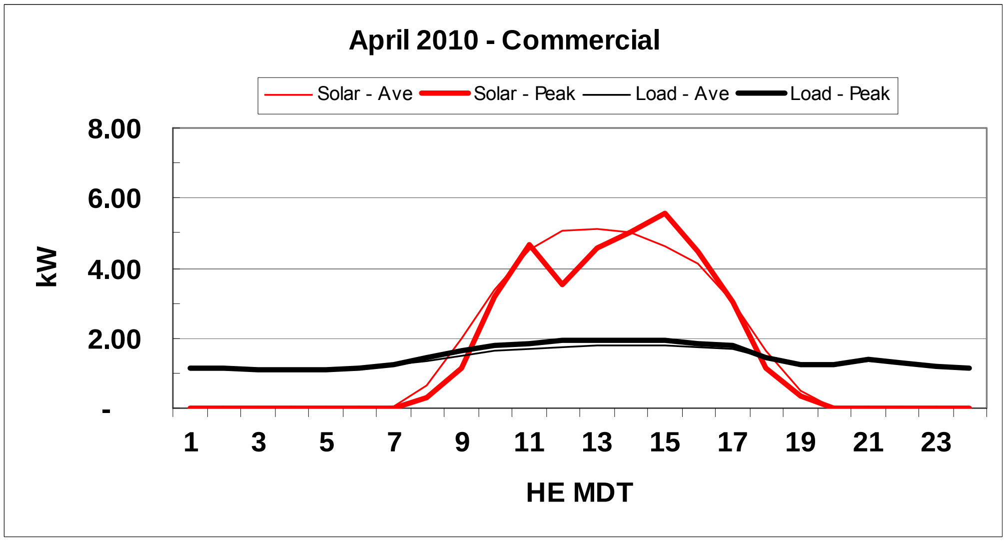
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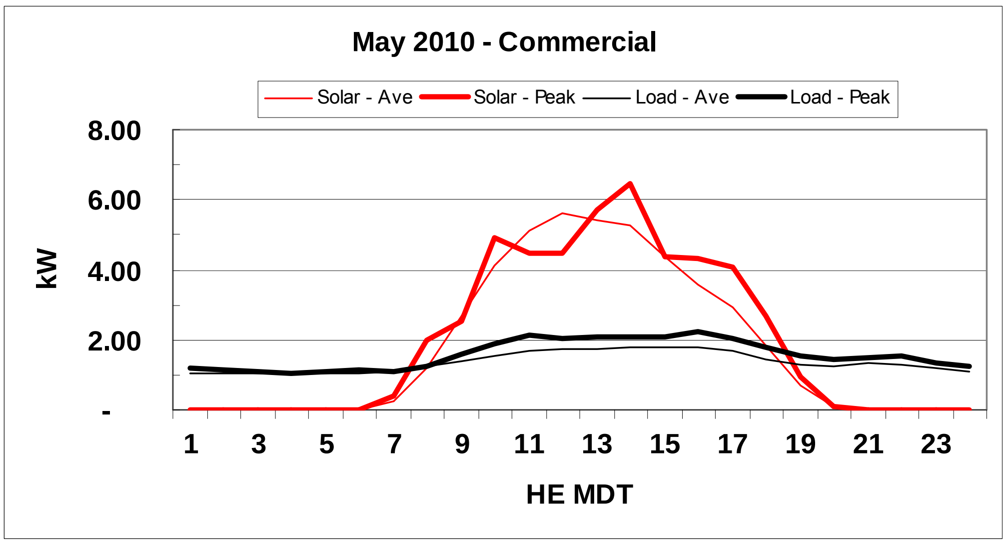
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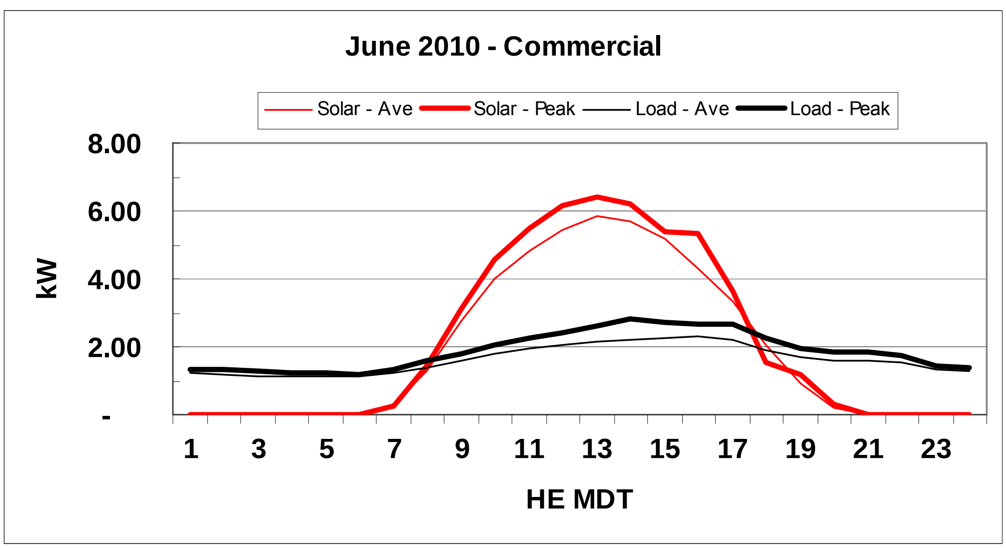
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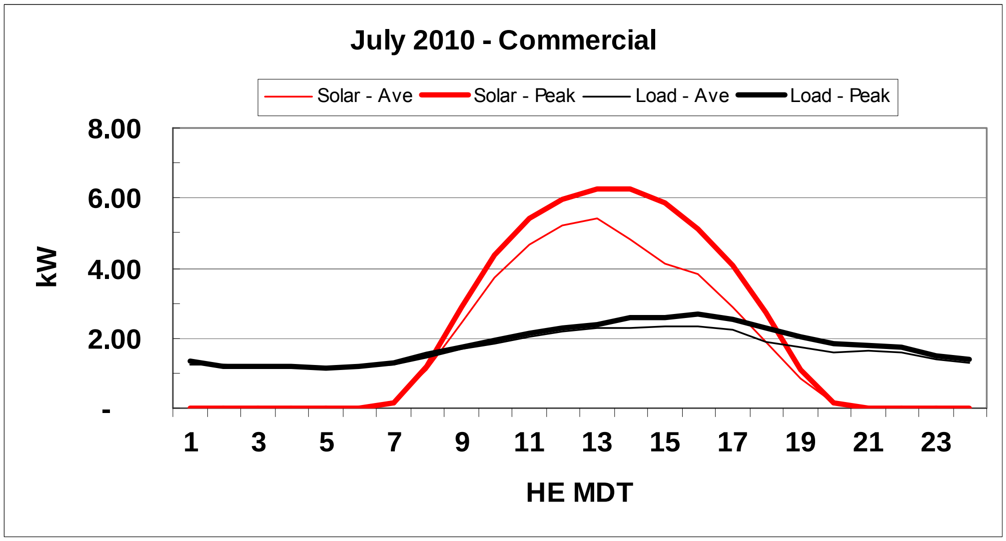
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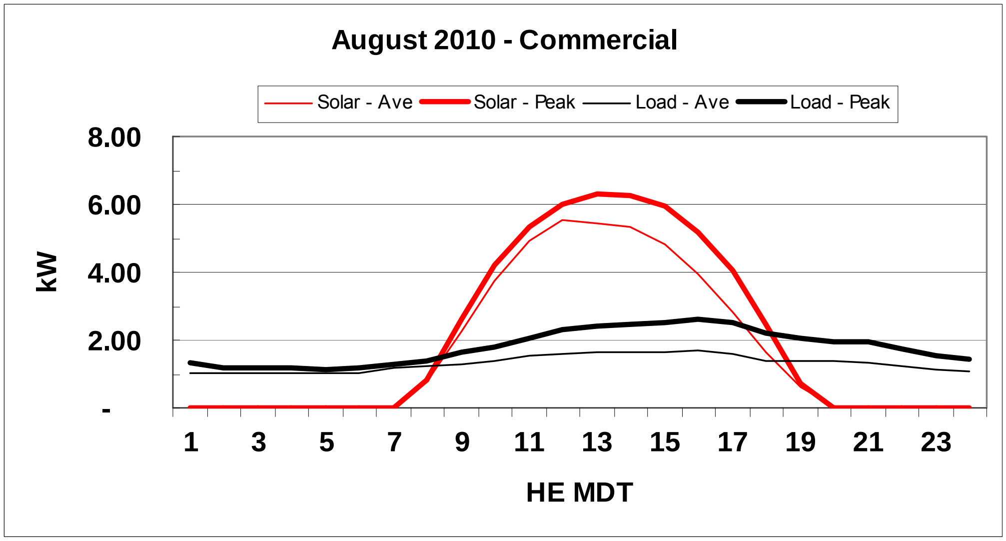
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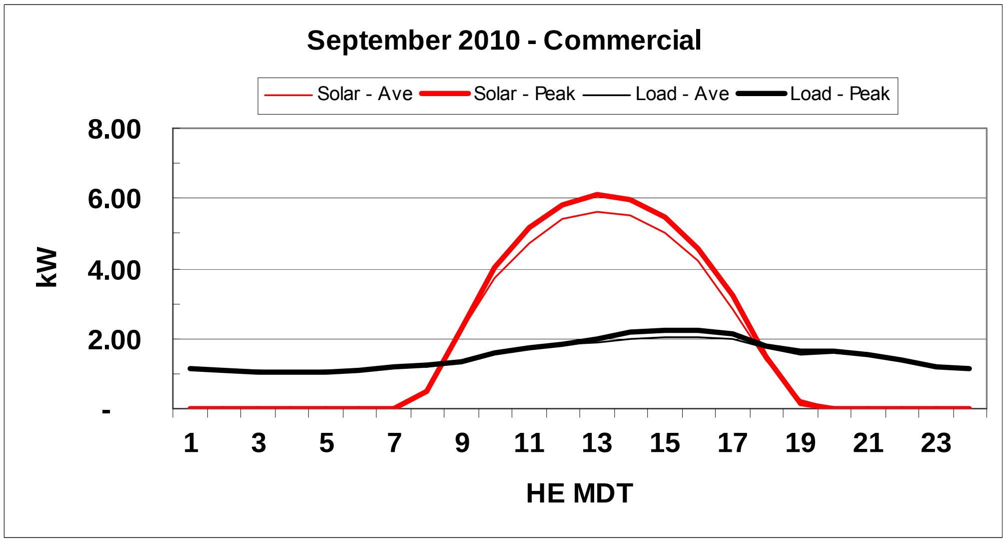
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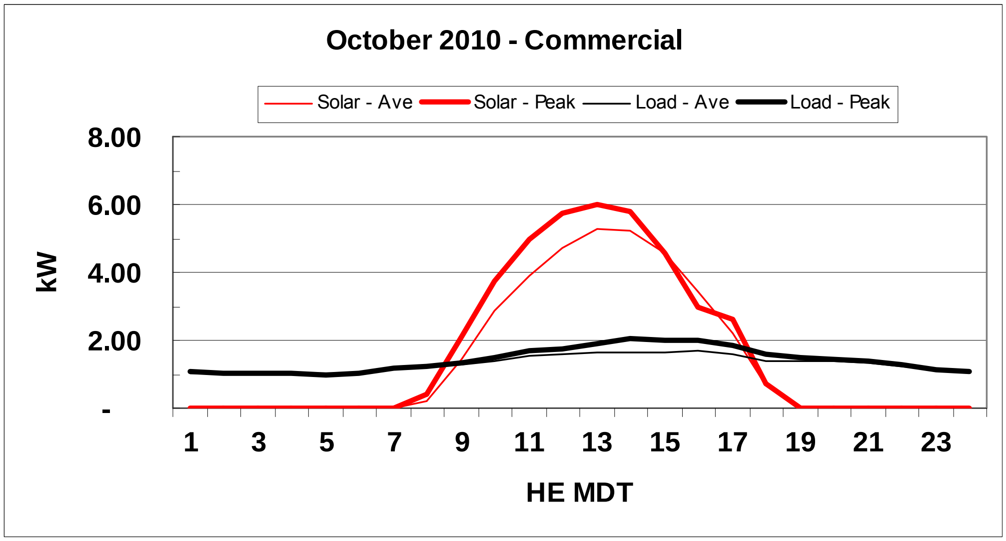
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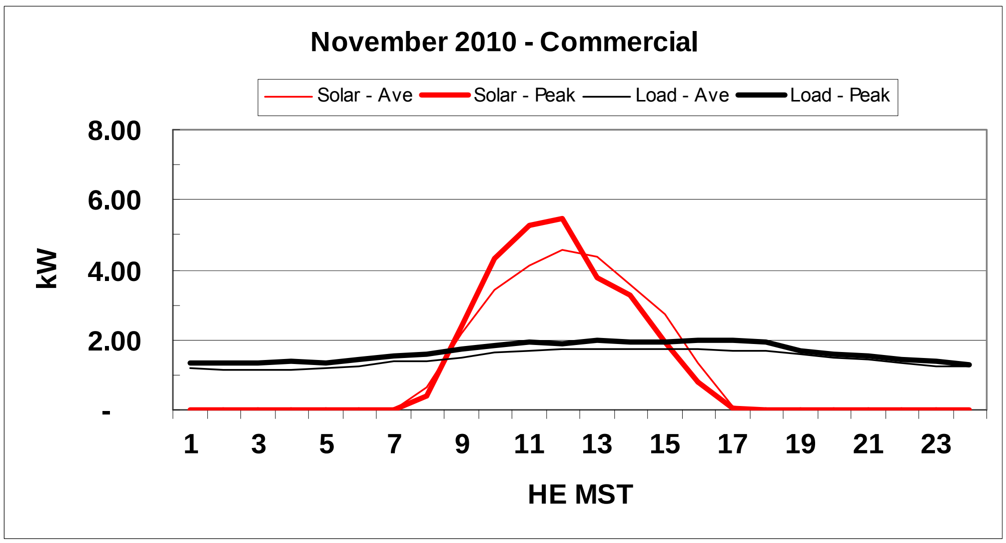
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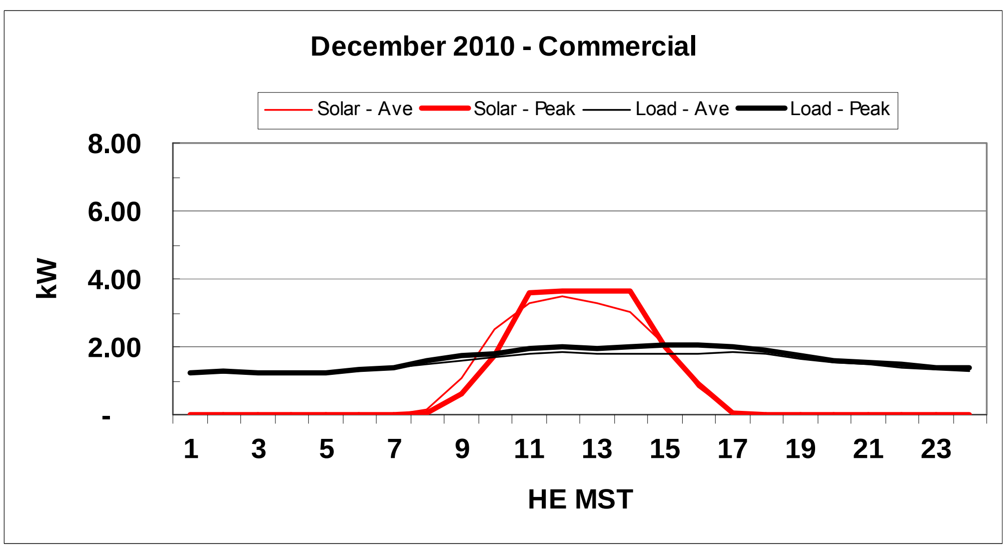
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Load - Ave
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Appendix V - Solar ELCC Study

Effective Load Carrying Capability (ELCC) Study for Solar Generation Resources

Public Service Company of Colorado

Prepared by:

Xcel Energy Services, Inc.
1800 Larimer St.
Denver, Colorado 80202

May 23, 2013

Table of Contents

Acknowledgements

Estimates of hourly generation from photovoltaic systems located in the Southern Front Range area (near Pueblo, Colorado) were developed by Lincoln Renewable Energy, LLC based on historical, meteorological data acquired from the Company's weather monitoring facility located at its Comanche facility. The modeled systems were based on typical, utility-scale design parameters for fixed and 1-axis tracking systems utilizing the PVSyst simulation software. Public Service is grateful for Lincoln Renewable Energy's supporting role in this study.

Executive Summary

Background

In order to reliably serve its customers' electrical demands, Public Service Company of Colorado (the "Company") forecasts expected, peak annual loads for its system as well as the ability of its existing and planned generation resources to reliably serve those forecast loads. For resource planning purposes, different generation technologies provide different levels of their nameplate generation capacity rating toward reliably serving peak system load. In general, the Company affords 100% of a dispatchable generator's summer, net dependable capacity for resource planning purposes but less than 100% of that value for non-dispatchable, intermittent generation technologies such as wind and solar. Effective load carrying capability ("ELCC") is one metric used to determine the contribution a generation resource or technology makes to electric system reliability. The Company last conducted a solar ELCC study in 2009. Due to a lack of actual solar generation data, the Company utilized satellite-derived solar resource data and computer-modeled solar thermal and photovoltaic ("PV") generation systems in that study. As the Company has since acquired historical, solar generation data for several types of PV systems located across its service territory and, whereas the Company expects total solar generation on its system at the end of 2012 to be roughly 240 MW_{DC}, an updated solar ELCC study is warranted.

Methodology

The calculation of ELCC incorporates the use of a probabilistic measure of electric system reliability such as the system loss of load expectation ("LOLE"). For this study, the Company set its reliability target as an LOLE of 1 day in 10 years. 2009 and 2010 historical system load and historical solar generation from multiple photovoltaic systems installed within the Company's service territory as well as PV generation from modeled systems utilizing ground-based meteorological weather data were used as inputs to a ProSym model of the Company's generation portfolio.

Results

ELCC values for photovoltaic generation on the Company's system were generated both as a function of broad geographic solar zones and the ability of the installed systems to track the sun's movement throughout the day. Average ELCC results are shown in Table 1 below.

Table 1
ELCC Results by Solar Zone and Technology (MW_{AC}/MW_{DC})

Solar Zone	Technology	Average
Northern Front Range	Fixed PV	31%
	Tracking PV	41%
Southern Front Range	Fixed PV	32%
	Tracking PV	40%
San Luis Valley	Fixed PV	27%
	Tracking PV	47%
Western Slope	Fixed PV	
	Tracking PV	46%

Introduction

Background

In order to reliably serve its customers' electrical demands, Public Service Company of Colorado ("Public Service" or the "Company") forecasts expected, peak annual loads for its system as well as the ability of its existing and planned generation resources to reliably serve those forecast loads. For resource planning purposes, the Company plans its generation portfolio to include a specified amount of generation over and above the forecast peak demands to cover inaccuracies in its load forecast and non-forecasted mechanical or electrical failures; this incremental generation is known as a planning reserve margin. The Company's current planning reserve margin is 16.3% applied to the 50th percentile demand forecast.[1]

For resource planning purposes, different generation technologies can be relied on to provide different levels of their nameplate generation capacity rating toward serving customer load. In general, the Company affords 100% of a dispatchable, fossil-fuel fired generator's summer net dependable capacity for resource planning purposes, but less than 100% of nameplate capacity for non-dispatchable, intermittent generation technologies such as wind and solar. Underestimating the contribution of intermittent generation resources to reliably meet forecast system peaks can result in the acquisition of additional generation supply and higher system costs. Overestimating the ability of intermittent generation resources to reliably serve forecast system peaks can result in lower levels of system reliability and increased risks of customer load being curtailed.

A facility's capacity <u>credit</u> (or capacity <u>value</u>) is frequently confused with the facility's capacity <u>factor</u>. A facility's <u>capacity credit</u> is a probabilistic measure of the fraction of the facility's nameplate rating (measured in MW) that can be relied on to serve customer loads. A facility's <u>capacity factor</u> is the ratio of the total amount of energy (measured in MWh) that the facility is expected to generate over a specific time period to the maximum amount of energy it could generate if it were operated during the time period at full nameplate capacity; capacity factors are typically provided on an annual basis. Although several methodologies exist through which an intermittent generation resource's capacity credit can be estimated,[2] for its resource planning purposes, the Company utilizes an effective load carrying capability ("ELCC") metric.

Prior Solar ELCC Studies on the Public Service System

In its 2007 Colorado Resource Plan[3] ("CRP"), the Company committed to provide the Colorado Public Utilities Commission ("Commission" or "PUC") with an analysis of the electric generation capacity credit to be afforded solar generating resources located in Colorado in that resource plan's Phase II evaluation of bids. The resulting ELCC study ("2009 Solar ELCC

[1] "Analysis of "Loss of Load Probability" (LOLP) at various Planning Reserve Margins", Prepared for Public Service Company of Colorado, Ventyx, December 2008.
[2] See, for example, "Determining the Capacity Value of Wind: An Updated Survey of Methods and Implementation", M. Milligan and K. Porter, NREL/CP-500-43433, June 2008 and "Photovoltaic Capacity Valuation Methods", T. Hoff, R. Perez, J.P. Ross, and M. Taylor, SEPA Report #02-08, May 2008.
[3] Colorado PUC Docket No. 07A-0477E.

Study") was concluded in February 2009 and provided to the Commission[4]. Major results of the 2009 Solar ELCC Study are presented in Table 2 below.[5]

Table 2
2009 Solar ELCC Study Results

	Fixed PV	**1-Axis PV**	**Trough**[6]
Location	MW_{AC} / MW_{DC}	MW_{AC} / MW_{DC}	MW_{AC} / MW_{AC}
Denver	0.47	0.55	0.70
Pueblo	0.50	0.60	0.81
Alamosa	0.48	0.55	0.68

At the time the 2009 Solar ELCC Study was conducted, the Company did not have access to historical meter data from actual solar generating facilities operating on its system with which to construct the hourly solar generation curves needed for the analysis. Given the lack of historic meter data, the 2009 Solar ELCC Study utilized satellite weather data from 2004 and 2005 which was input to the National Renewable Energy Laboratory's ("NREL") Solar Advisor Model ("SAM")[7] to produce hourly solar generation curves for use in the study. By necessity, the Company made assumptions as to the types of large-scale solar facilities likely to be bid it in the 2007 CRP Phase II bidding process. Table 3 below shows the assumed solar installations that made up the proxy Fixed PV and 1-axis PV units examined in the 2009 Solar ELCC Study.

As the Company has since acquired historical, solar generation data from several types of PV systems located across its service territory that were not available at the time of the 2009 Solar ELCC Study and, whereas the Company expects total solar generation on its system at the end of 2012 to be roughly 240 MW_{DC},[8] an updated solar ELCC study is warranted.

Study Methodology

LOLE for Generation Capacity Credit Valuation

The calculation of ELCC incorporates the use of a probabilistic measure of electric system reliability such as a loss of load expectation ("LOLE"). LOLE is an annual measure of system adequacy that is calculated by summing hourly loss of load probabilities ("LOLP"). LOLPs are calculated by a computer model of a utility's hourly loads, generation capacity, and generating unit, forced outage rates. For this study, the Company set its reliability target as an LOLE of 1 day in 10 years (or 2.4 hours/year), which is equivalent to an annual sum of hourly LOLPs of

[4] "An Effective Load Carrying Capability Analysis for Estimating the Capacity Value of Solar Generation Resources on the PSCo System", February 2009, Xcel Energy Services. Available as a Report filed on February 10, 2009 at the PUC's website (https://www.dora.state.co.us/pls/efi/EFI_Search_UI.search) under Docket 07A-447E.
[5] ELCC results for PV generation are shown here in terms of MW_{AC}/MW_{DC} whereas results were provided in the 2009 Solar ELCC Study in terms of MW_{AC}/MW_{AC} with an assumption of 0.8 MW_{AC} per MW_{DC}.
[6] Parabolic trough facility with no thermal storage capability.
[7] Current versions of the NREL modeling application are known as the System Advisor Model.
[8] At the time of the 2009 Solar ELCC Study, the Company had roughly 25 MW_{DC} of solar installed on its system.

2.74×10^{-4} (= 2.4/8760). An LOLE of 1 day in 10 years is a standard across the industry to represent an electric supply system with acceptable reliability.

Table 3
2009 Solar ELCC Study Proxy PV Systems

Fixed PV			
PV Module Type[9]	% of Total	Azimuth[10]	Elevation
CdTe	25%	180°	site latitude
CdTe	25%	200°	site latitude
c-Si	25%	180°	site latitude
c-Si	25%	200°	site latitude
1-Axis Tracking			
PV Module Type	% of Total	Tilt	
c-Si	50%	horizontal	
c-Si	50%	site latitude	

The ELCC attributed to solar generation can be calculated by analyzing two generation portfolios: one with incremental solar generation and another with an incremental, generic capacity resource such as a gas-fired combustion turbine. When the sum of each portfolio's LOLPs is equal to the target value, then the ELCC of the solar generation is obtained by dividing the incremental capacity resource MW_{AC} by the incremental solar MW_{DC}.

Modeling Steps

Public Service conducted this ELCC analysis utilizing a ProSym[11] production cost simulation model run with the software's reliability mode activated so as to calculate hourly LOLPs. As previously mentioned, the sum of hourly LOLPs for a single year analysis should total to 2.74×10^{-4} for an LOLE target of 1 day in 10 years.

In situations where the electric system being modeled is long generation capacity (i.e., existing generation capacity is in excess of expected peak loads plus planning reserve margins), the reliability contribution provided by additional generation resources will be <u>less than</u> the reliability contribution those same generation resources will bring to the system if it is more balanced between existing generation and expected peak loads. Similarly, when a system is short generation capacity (i.e., existing generation capacity is in deficit of expected peak loads plus planning reserve margins), the reliability contribution provided by additional generation resources will be <u>more than</u> the reliability contribution those same generation resources will bring to a balanced system.

For this study, the Company employed historic data for 2009 and 2010; during both of these years, the Company's generation portfolio was in a long capacity condition. In order to

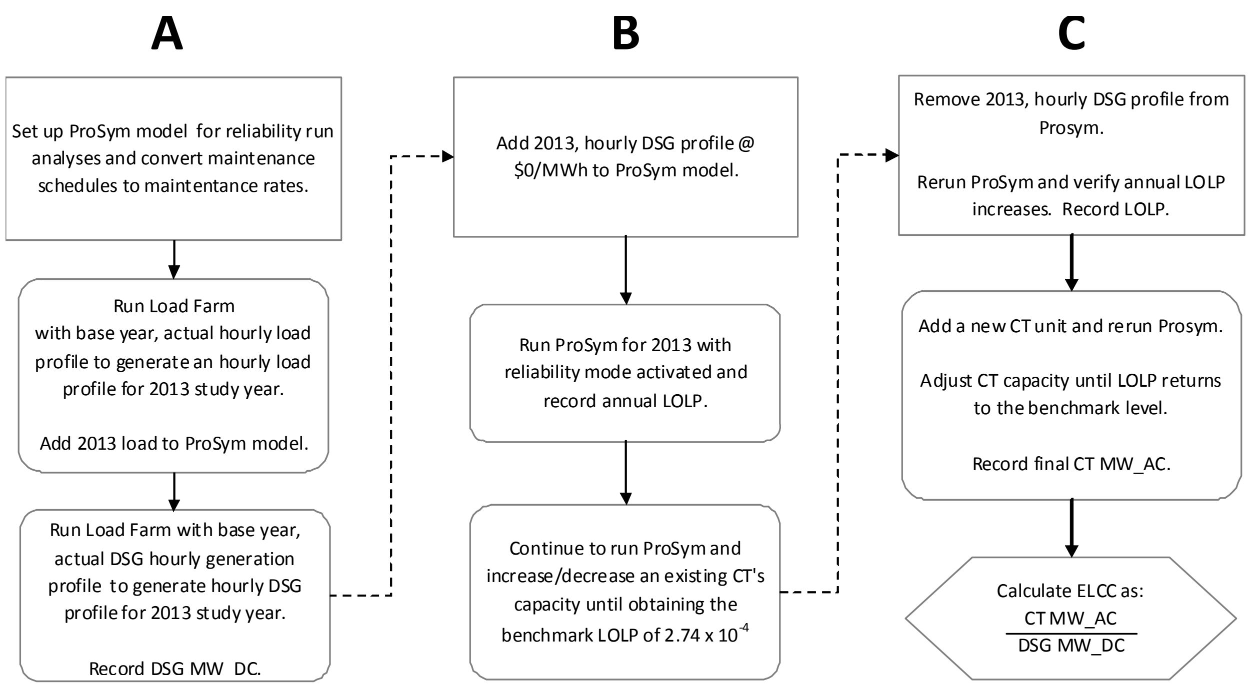
[9] CdTe is cadmium telluride (e.g., First Solar); c-Si is crystalline silicon.
[10] An azimuth of 180° is due south.
[11] ProSym is a Ventyx product.

compensate for this condition, the Company adjusted both its historical load and its generation portfolio in the ProSym model to achieve a more balanced condition. Historic, hourly, 2009 and 2010 loads were processed through ProSym's "Load Farm" module in order to grow the historical loads up to the Company's study year (2013) load forecast at which point the Public Service system is more in balance between generation capacity and forecast demand. Then, the generation capacity of an existing combustion turbine in the portfolio was adjusted in order to achieve an annual LOLP of 2.74 x 10^{-4}.[12]

As January 1, 2014 will occur on a different day of the week than did January 1, 2009 or January 1, 2010, and the ProSym model honors the weekday patterns of the year under analysis, it was necessary to also process the hourly solar data through the Load Farm module to retain the historic, temporal relationship between load and solar generation. Load Farm processing of the solar generation data resulted in the shifting of entire days' generation but did not alter the hourly solar profiles themselves.

Figure 1 below illustrates the basic steps that were followed to obtain the ELCC estimates for different PV generation resources using the ProSym model. A reference to a "base year" in Figure 1 refers to either 2009 or 2010 for this study.

Figure 1
ELCC Calculation Work Flow



12 The combustion turbine was modeled with an outage rate inclusive of maintenance assumptions of 4%.

Study Scope

Base Years

The Company selected 2009 and 2010 as base years as these are the years for which the Company has acquired solar generation and ground-based meteorological data. Although the Company has solar generation data collected at a frequency of 15-minutes or higher, as ProSym is an hourly simulation model, all sub-hourly solar data were averaged to achieve hourly data sets.

Geographic Areas and PV Tracking

Similar to the 2009 Solar ELCC Study, for this study the Company is estimating solar ELCC values for specific geographic areas and for fixed and tracking photovoltaic systems. In the 2009 Solar ELCC Study, the Company gathered meteorological data and satellite-derived solar resource data for Denver, Pueblo, and the San Luis Valley. However, for this study, the solar resource zones cover somewhat broader geographic regions as the actual solar generation systems providing the hourly generation data are more broadly dispersed across the Company's service territory as compared to the point estimates used in the prior study.

Solar Thermal

As the Company does not have access to any historical, hourly, solar thermal generation data which would help inform the Company as to appropriate ELCC values, the current study did not attempt to update its ELCC findings for parabolic trough, solar thermal facilities (without thermal energy storage) through new model runs. See the Results section for a brief discussion of the applicability of the study results for tracking PV systems to parabolic trough, solar thermal systems.

Solar Generation Data Sources

The four solar zones studied here are:

- Northern Front Range (NFR) – the Denver, CO metro region north to Fort Collins, CO,
- Southern Front Range (SFR) – the region around Pueblo, CO,
- San Luis Valley, CO (SLV), and
- Western Slope (WS) – the region around Grand Junction, CO.

For the 2009 base year, the Company utilized hourly solar generation data from the ten PV systems shown in Table 4 below. For the 2010 base year, the Company utilized hourly solar generation data from fifteen PV systems; these included data from the ten, 2009 base year sources and the five, incremental PV systems shown in Table 5 below.

Table 4
2009 Base Year Solar Generation Meter Data Sources

Solar Zone	Technology	kW_{DC}
Northern Front Range	Fixed PV	1,700
		1,175
		300
	Tracking PV	2,000
		725
		625
San Luis Valley	Tracking PV	8,200
		600
Western Slope	Tracking PV	1,725
		600

Table 5
Incremental 2010 Base Year Solar Generation Meter Data Sources

Solar Zone	Technology	kW_{DC}
Northern Front Range	Fixed PV	100
		1,575
	Tracking PV	2,000
San Luis Valley	Fixed PV	1,525
		825

At the time of the ProSym analyses, the Company had historical PV generation data on the Western Slope for tracking systems only and no generation data for PV systems in the Southern Front Range solar zone. In order to update ELCC estimates for the Southern Front Range region, the Company utilized historical, ground-based meteorological data from a monitoring station located at its Comanche generation facility near Pueblo.[13] Meteorological data for 2009 and 2010 were used to model utility-scale, fixed and tracking PV systems in lieu of solar generation data for the Southern Front Range solar zone.[14] The Company has no historical, ground-based meteorological data for the Western Slope region, thus it could not conduct a similar analysis for fixed systems located in this region.

The 2009 and 2010 solar generation data are generally not of revenue meter quality and required close inspection to identify gaps caused by problems in the collection of generation data. As the goal of the study is to obtain ELCC values for fixed and tracking PV generation resources located in broad geographic resource zones and not ELCC values for specific PV generators, the Company filled any gaps in the solar generation data caused by either data collection issues or

[13] http://www.nrel.gov/midc/xecs/
[14] Design of the PV systems within the PVSyst model and operation of the model was conducted by Lincoln Renewable Energy.

solar generation equipment malfunctions (e.g., inverter trips).[15] Proxy, hourly solar generation rates were calculated by applying the results of linear regressions with other PV generators in the same solar zone.

In addition to gaps in generation caused by data collection or generation equipment issues, other generation data gaps are evident in winter months. These additional winter month, generation gaps occur primarily during two events: 1) during snowy weather when sunlight levels are quite low and snow begins to accumulate on the PV panels, and 2) after the snowy weather passes and sufficient sunlight exists, but the PV panels are still fully or partially covered in snow. For this study, the Company did not fill in generation gaps that occurred during winter months as a result of either of these events. This decision is not expected to have any noticeable impact on the ELCC results as the Company's winter peak demand hours occur after sunset (when PV's contribution to system generation is zero).

The 2009 and 2010 solar generation curves were normalized with respect to the relevant system's MW_{DC} nameplate rating so as to create a set of normalized, hourly solar generation curves that could be categorized by base year (2009 or 2010), solar resource zone, and tracking capability. Next, a single, composite, hourly annual PV generation curve for each base year, solar zone, and tracking capability was derived from the average of the applicable, normalized hourly curves. Prior to loading the hourly generation curves into ProSym, each curve was scaled up to represent generation from a 35 MW_{DC} system.

Results

The study results for the 2009 and 2010 historical base years are presented in Table 6 below, along with a simple average of the two annual results. Blank spaces in Table 6 indicate a lack of solar generation meter data or ground-based meteorological data.

A 27% ELCC for fixed systems in the San Luis Valley is a somewhat surprising study result as solar resource studies have consistently indicated that the San Luis Valley is Colorado's premier solar resource (on an annual energy production basis) and the Tracking PV ELCC results are among the highest in the study.[16] Both the actual meter data utilized in the Northern Front Range and the model data utilized in the Southern Front Range indicate that the ELCC from fixed systems are roughly 75% of that from tracking systems. If this ratio was applied to tracking ELCC values for the San Luis Valley, an ELCC of 35% for the fixed systems would result.

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[15] The Company anticipates that as it acquires additional historical solar generation from a greater number of PV systems the actual forced outage rates (e.g., lost generation due to inverter trips) will be incorporated into the Company's ELCC analyses.

[16] As the San Luis Valley is in a solar zone remote from the Northern Front Range solar zone—which encompasses the Company's main load area—a potential mismatch between high electrical load conditions in the Northern Front Range and poor solar generation conditions in the San Luis Valley can occur at any time of the year. However, the 2009 and 2010 ELCC results for the SLV tracking PV systems would tend to indicate that this didn't appear to be the case during these two years.

As indicated in Table 5, the San Luis Valley, Fixed PV results are based on data from a single year for two PV systems.[17] The Company will continue to monitor these facilities and determine if they adequately represent fixed systems in the San Luis Valley.

Table 6
ELCC Results by Solar Zone and Technology (MW_{AC}/MW_{DC})

Solar Zone	Technology	2009	2010	Average
Northern Front Range	Fixed PV	31%	31%	31%
	Tracking PV	43%	40%	41%
Southern Front Range	Fixed PV	32%	32%	32%
	Tracking PV	40%	40%	40%
San Luis Valley	Fixed PV		27%	27%
	Tracking PV	49%	46%	47%
Western Slope	Fixed PV			
	Tracking PV	46%	46%	46%

Comparison to 2009 Study Results

In general, this study's results indicate ELCC values that are roughly 30% lower than those obtained from the 2009 Solar ELCC Study. The SLV Fixed PV result stands out as an exception to this generalization as the current value is approximately 44% lower than the 2009 study result.

Differences in the data sources between this study and the 2009 Solar ELCC Study may provide answers as to the lower ELCC values resulting from the current study:

- This study employs historic, solar generation meter data whereas the 2009 Solar ELCC Study used satellite-derived, solar resource data processed through a computer model of proxy PV systems to create hourly solar generation data.
- As Table 2 above indicates, the 2009 Solar ELCC Study assumed that 50% of all Fixed PV would be installed with an orientation west of south. Fixed systems pointed west of south (e.g., 200° azimuth) provide higher levels of energy generation later in the afternoon which better match the Company's peak summer load hours, likely resulting in higher ELCC levels than panels facing due south. All of the fixed systems for which the Company has solar generation meter data are due-south facing except for a single, 100 kW system which is oriented 15 degrees east of due-south.

[17] The 27% ELCC value has been increased by a factor of 1.02 from the value calculated from the ProSym analysis. Upon examination of hourly revenue meter data for 2010, the Company noted that during one of the peak LOLP days (July 16) one of the two fixed systems in the SLV had degraded output during the afternoon hours that was not compensated for in the hourly data sets prior to the ProSym analyses. Based on a recommended methodology in a recent NREL publication (NREL/TP-6A20-51523) the Company utilized the hourly LOLP results for 2010 to estimate the incremental ELCC value that would result from compensating for the generator/inverter outage that occurred on July 16, 2010.

For the reasons stated above, the Company believes the current study results provide a more accurate representation of the ELCC values that should be afforded PV generation resources installed within its service territory than the results from the 2009 Solar ELCC Study.

Study Result Applicability to Parabolic Trough, Solar Thermal Facilities

The 2009 Solar ELCC Study indicated that, on a MW_{AC}/MW_{AC} basis, solar thermal trough facilities had ELCC values similar to tracking PV systems.[18] Based on this relation, it is likely that the ELCC values for parabolic trough facilities indicated in the 2009 Solar ELCC Study are overstated.[19] However, as parabolic trough facilities experience a time lag between the capture of solar energy in the trough field and the delivery of that energy to the power block, it is expected that the specific design of a parabolic trough facility will have a marked impact on such a facility's ELCC value. As such, it is difficult to leverage the ELCC results for PV systems to parabolic trough systems and provide a quantitative value.

Load Duration Methodology Alternatives to ELCC

A review of the Company's top 50 load hours and the corresponding solar generation rates during those hours can provide additional transparency into the process of assigning generation capacity credit to intermittent generators. Figure 2 below shows the top 50 system load hours for 2010 along with solar generation during those same hours (in normalized MW_{AC}/MW_{DC} terms) from the Northern Front Range, fixed PV system, composite generation curve. As is clearly seen in the figure, significant variation in the hourly solar generation rates are evident in these top 50 load hours; the rate ranges from 75% to 1% of DC nameplate capacity. Even for the top 3 load hours, the rate ranges from 52% to 30% of DC nameplate. Similar charts for all the scenarios studied in Table 1 are provided in Appendix A.

Although an ELCC methodology is the preferred analytical approach to assigning generation capacity credit to intermittent generation resources such as wind and solar, other simpler methodologies based on utility system load duration information have been proposed. However, experts in the calculation of ELCC indicate that these simpler approaches should be benchmarked with ELCC results before their use.[20] In this spirit, the Company provides a comparison of the ELCC methodology results with those from a simple, load duration-based methodology in Appendix A.

Conclusions

The Company has updated its ELCC calculations for photovoltaic generation by solar resource zone and tracking capabilities. These updated values can be utilized for a variety of uses including resource planning loads and resources tables to determine resource acquisition needs and to assign capacity credit to solar generation resources for future Requests for Proposals. The Company contemplates that periodic updates to its ELCC results will be warranted as more solar

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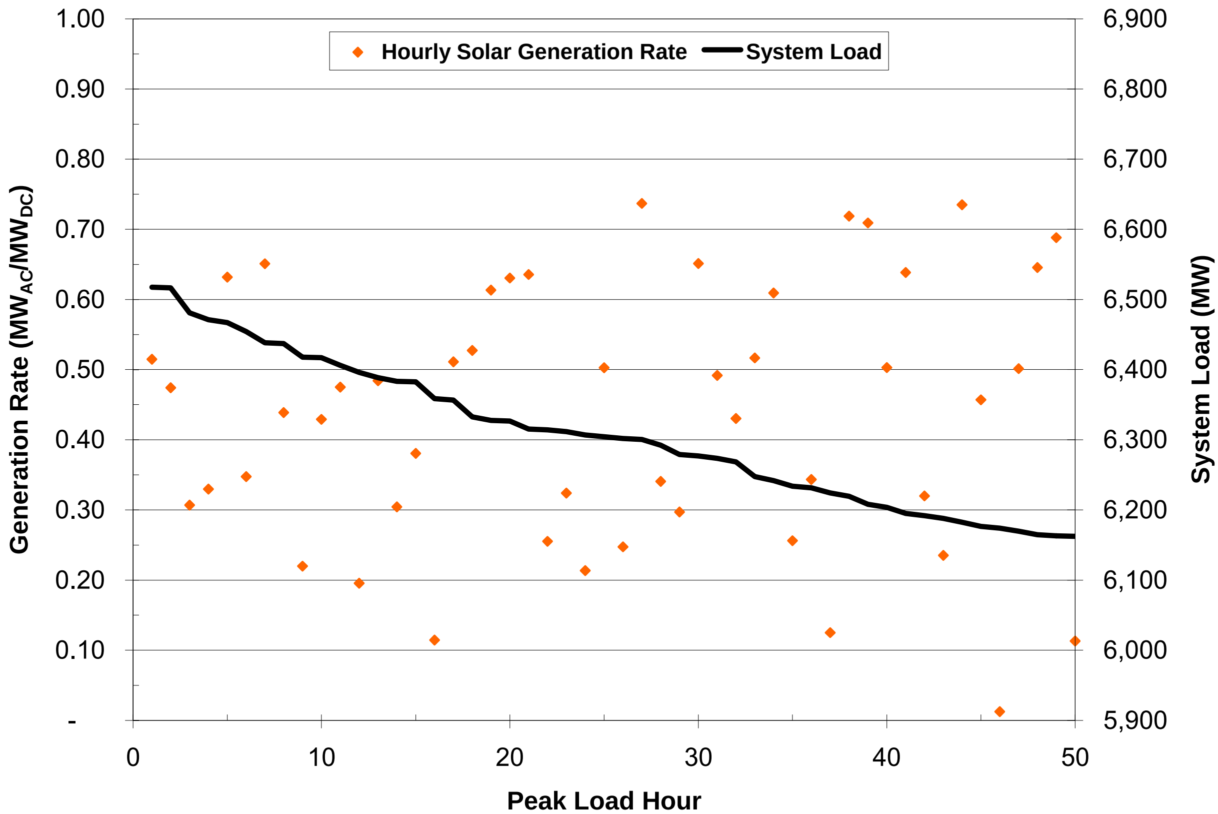
[18] See Footnote 5.

[19] That is, if the use of actual solar generation meter data in the current study and the use of satellite-derived solar resource data is a significant cause of the differences in ELCC values, it is probable that this difference would also impact the parabolic trough results from the 2009 Solar ELCC Study.

[20] "Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning (IVGTF1-2)", Joint NERC-UWIG Workshop, April 12, 2011. http://www.nrel.gov/docs/fy11osti/51485.pdf

generation systems are interconnected to the Company's system and more solar meter data become available.

Figure 2
2010 NFR, Fixed System Generation during Peak Load Hours



Appendix A

Load Duration Charts and Capacity Credit Methodology

Appendix A presents graphs of the top 50 system load hours and the hourly generation from the normalized PV generation curves for the solar resource zones and the tracking capabilities examined in the ELCC study. Also shown on the graphs is a line that represents the cumulative average of the individual hourly solar generation rates beginning with the peak load hour. Although significant variation in the hourly generation rates occurs across the top 50 load hours, the cumulative average value has fairly well stabilized after about the top 20 load hours.

Load duration methodologies assign a generation capacity credit by selecting a certain number of peak load hours and calculating the cumulative average solar generation rates up to that point. Table 7 below summarizes the average, cumulative generation capacity value for the top 50 load hours along with the ELCC results previously presented in Table 6.

Note that a direct comparison between the load duration methodology generation capacity value results and the ELCC results is complicated by the different assumptions made in each methodology. For example, the ELCC methodology is a probabilistic method that places greater emphasis on certain hours within the time period under study when the generation portfolio is closer to a capacity short position. The cumulative average results shown here for the load duration methodology places equal emphasis (i.e., 2%) on each data point in the 50 load hour average.

Notwithstanding the above, some general comments on the results can be made. In general, the simple, load duration methodology estimates capacity values that are approximately 25% greater than the more sophisticated ELCC method. Also, although only two years of data are analyzed here, there is a greater variation in results between the 2009 and 2010 load duration capacity credit values vs. the ELCC results shown in Table 6.

Table 7
Load Duration ("LD") and ELCC Capacity Credit Results

Solar Zone	**Technology**	**LD 2009**	**LD 2010**	**LD Average**	**ELCC Average**	**Ratio of LD Average to ELCC Average**
NFR	Fixed PV	36%	44%	40%	31%	1.29
	Tracking PV	49%	54%	52%	41%	1.27
SFR	Fixed PV	35%	41%	38%	32%	1.19
	Tracking PV	48%	55%	51%	40%	1.28
SLV	Fixed PV		35%	35%	27%	1.30
	Tracking PV	56%	58%	57%	47%	1.21
WS	Fixed PV					
	Tracking PV	54%	59%	57%	46%	1.24

Figure 3
2009, Northern Front Range, Fixed

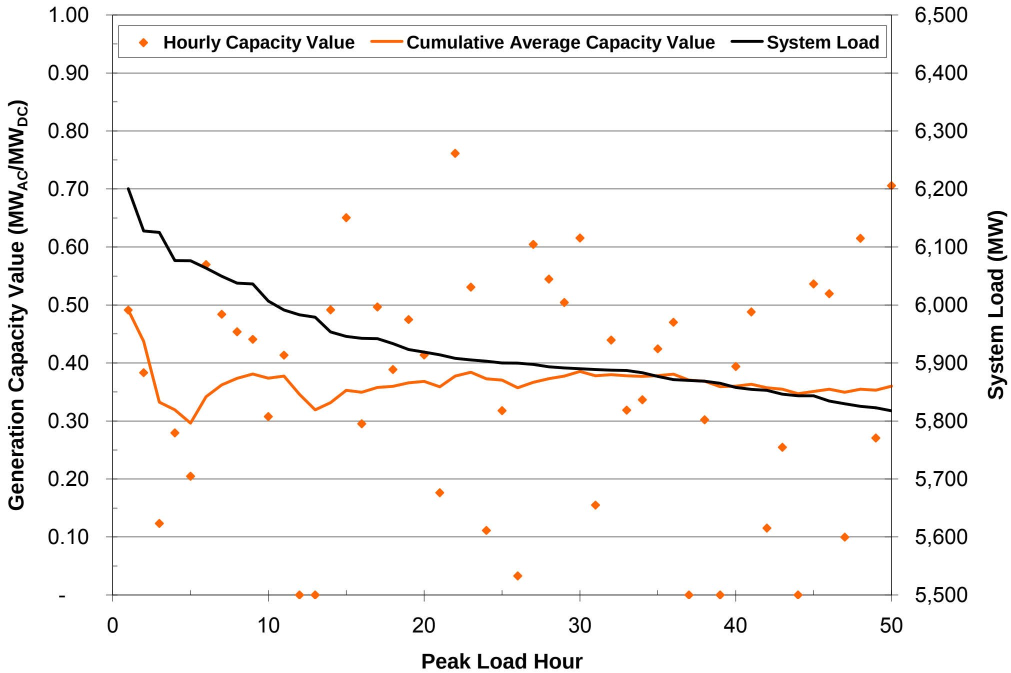


Figure 4
2009, Northern Front Range, Tracking

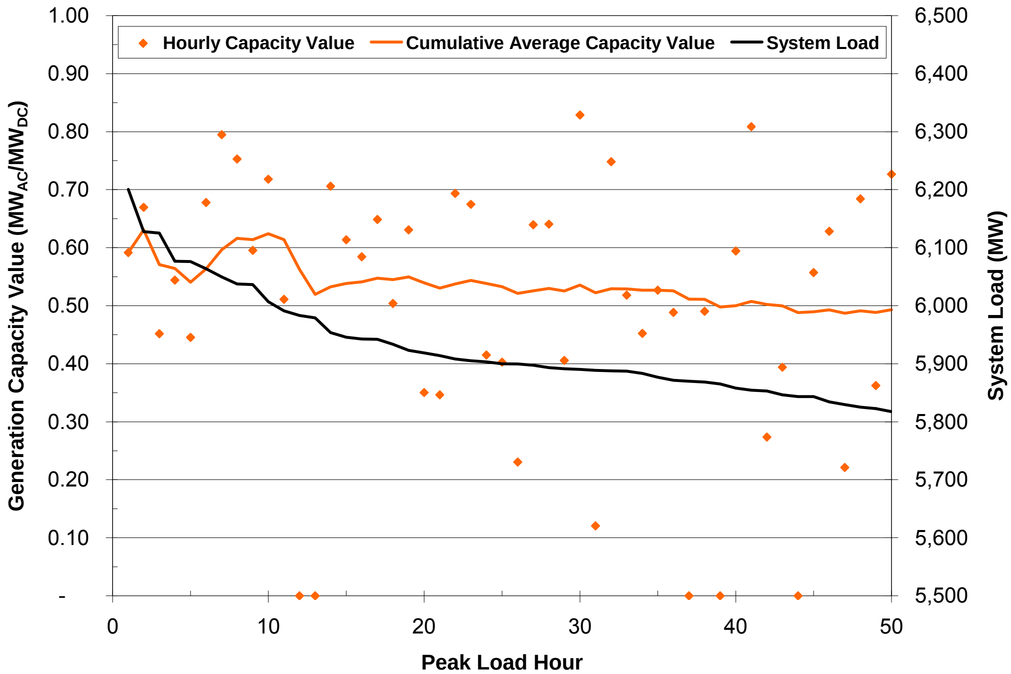


Figure 5
2009, Southern Front Range, Fixed

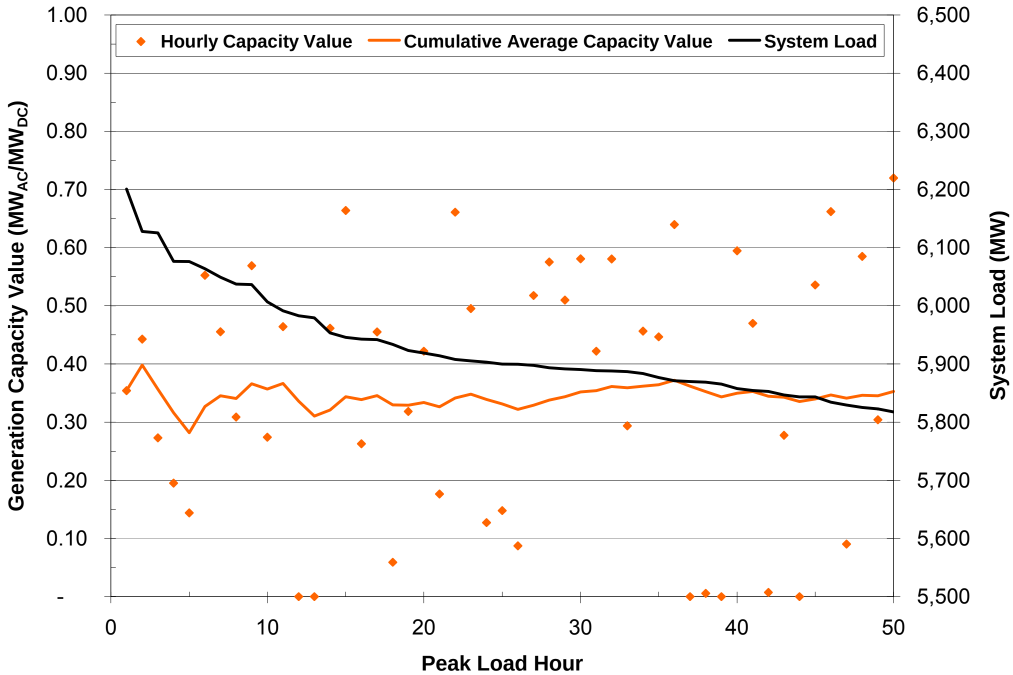


Figure 6
2009, Southern Front Range, Tracking

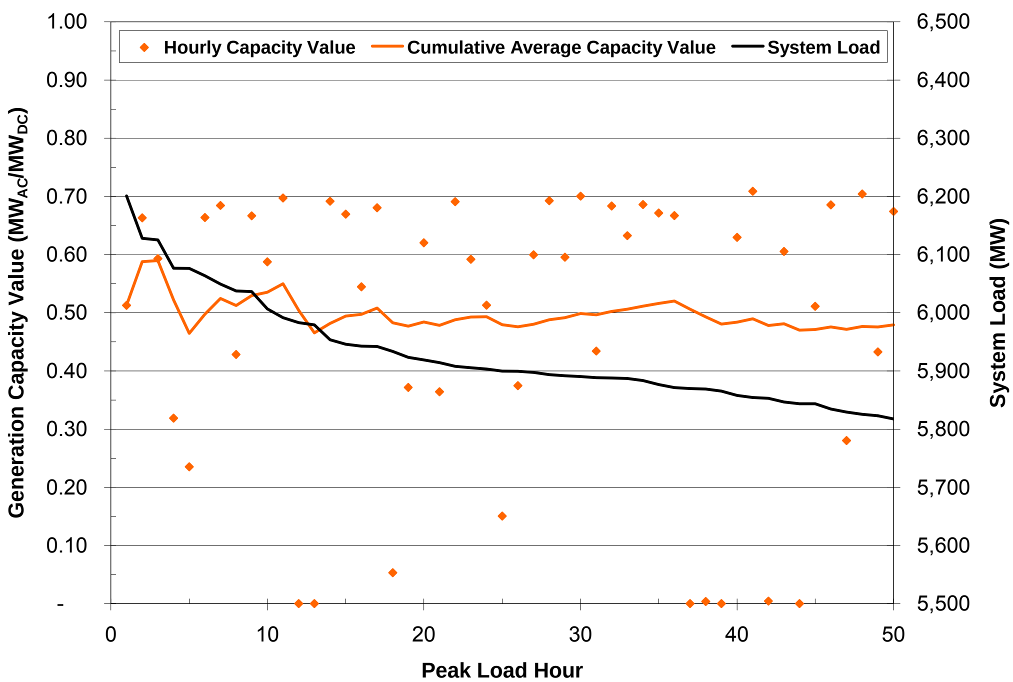


Figure 7
2009, San Luis Valley, Tracking

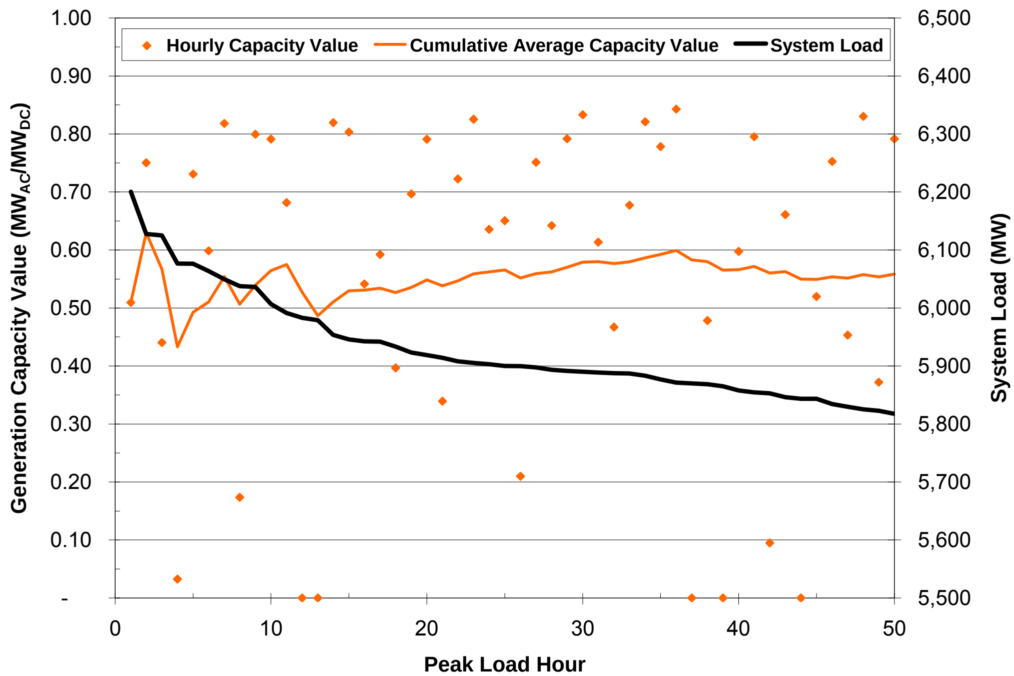


Figure 8
2009, Western Slope, Tracking

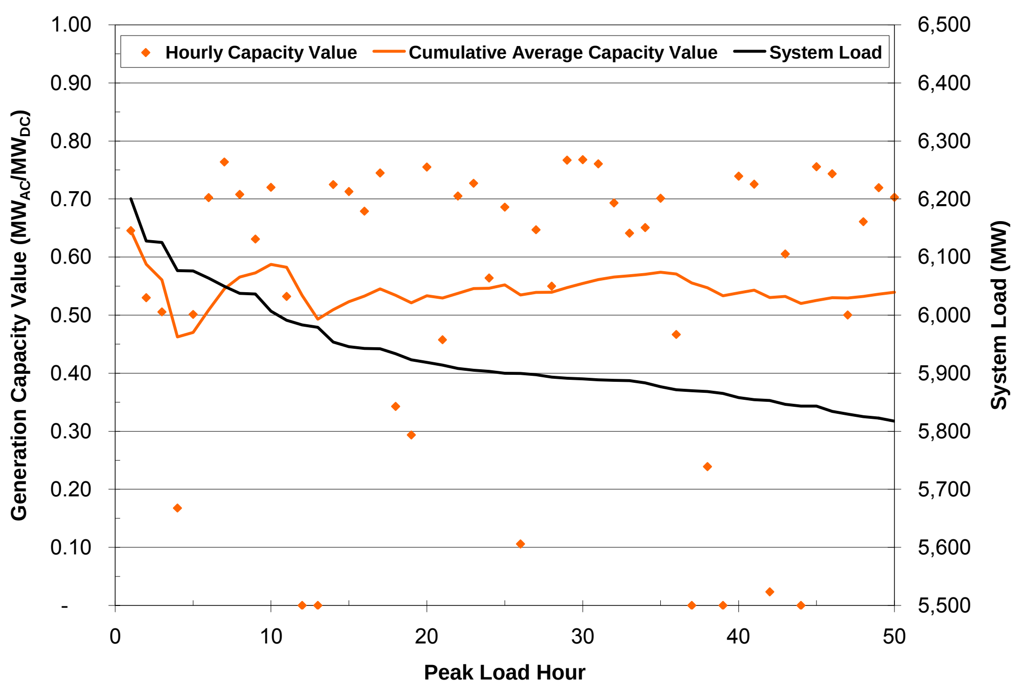


Figure 9
2010, Northern Front Range, Fixed

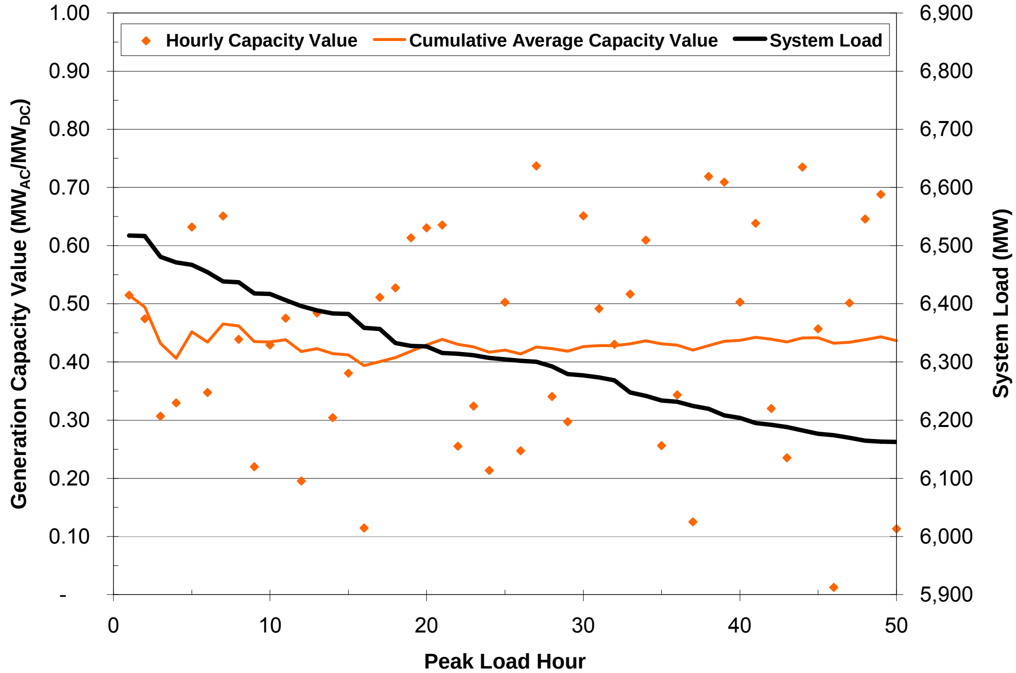


Figure 10
2010, Northern Front Range, Tracking

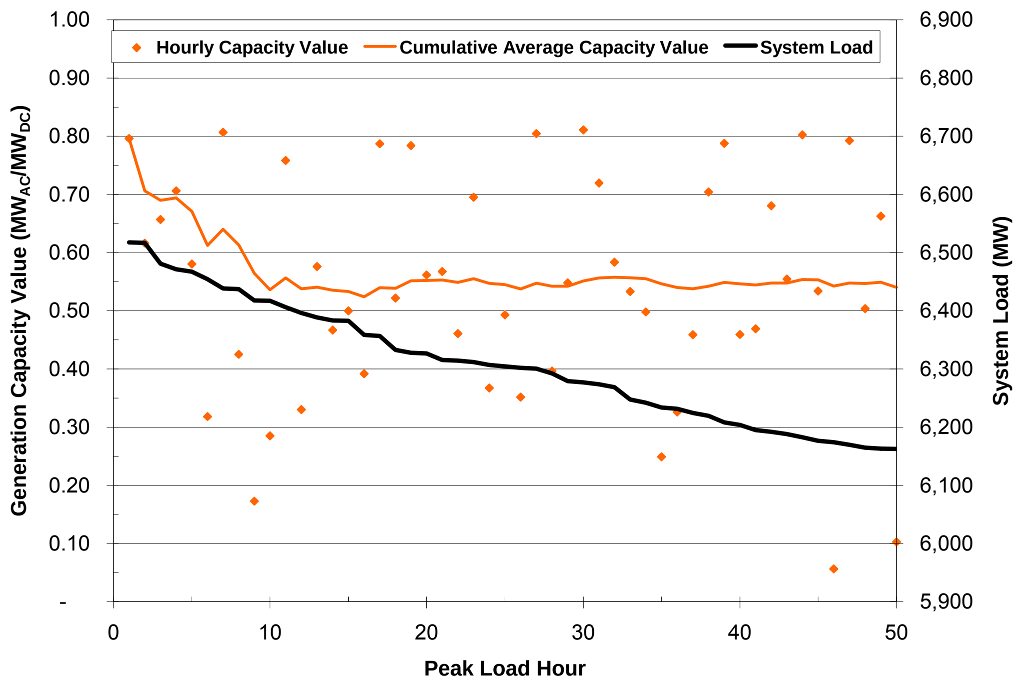


Figure 11
2010, Southern Front Range, Fixed

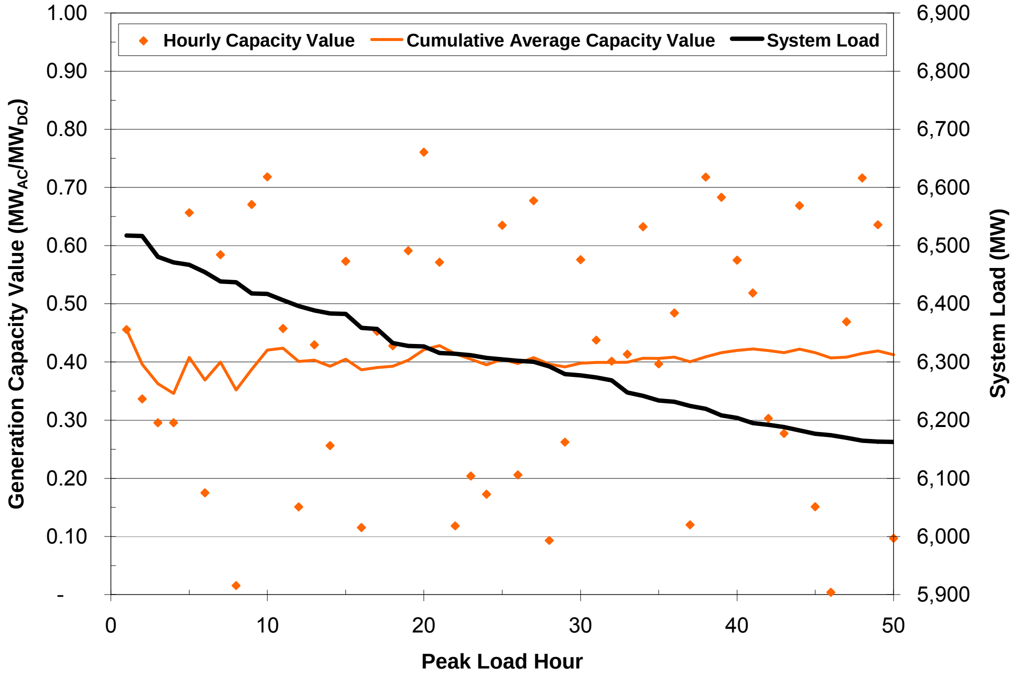


Figure 12
2010, Southern Front Range, Tracking

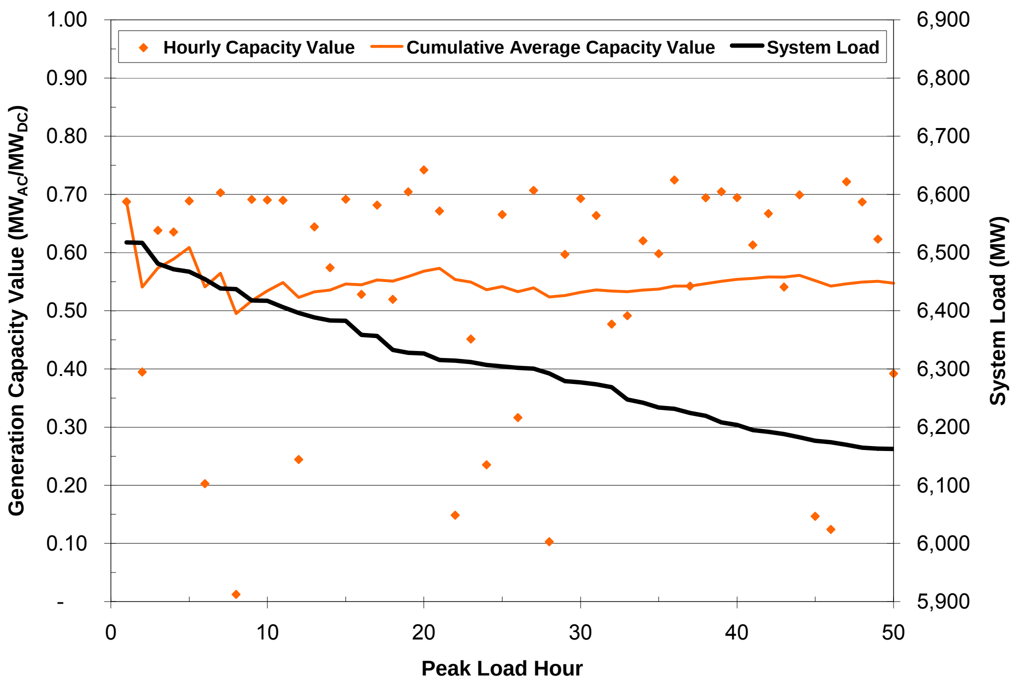


Figure 13
2010, San Luis Valley, Fixed

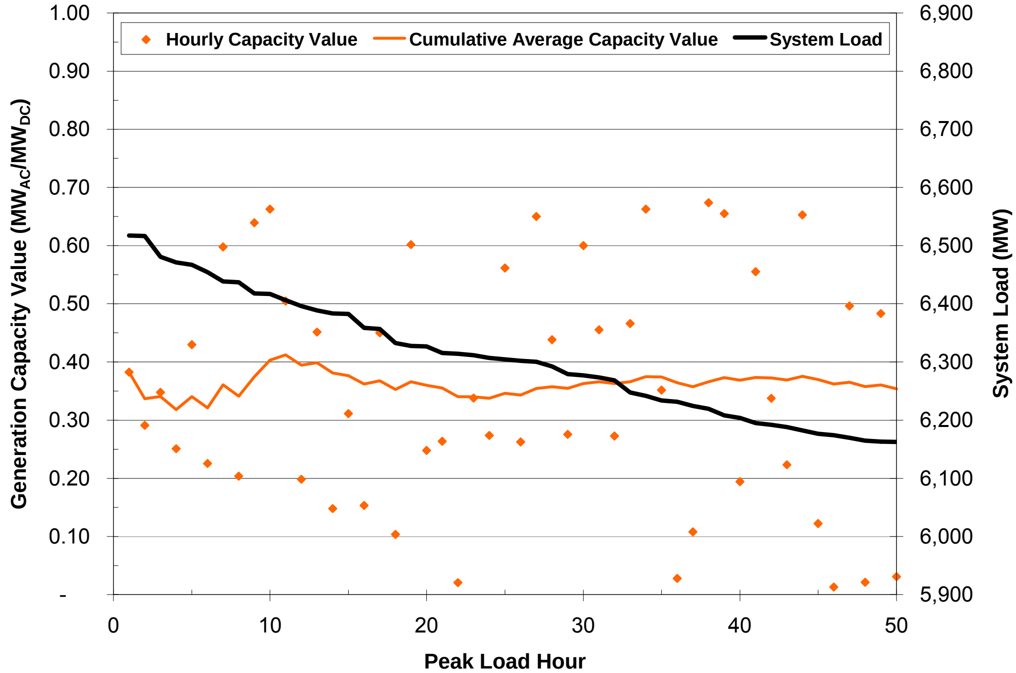


Figure 14
2010, San Luis Valley, Tracking

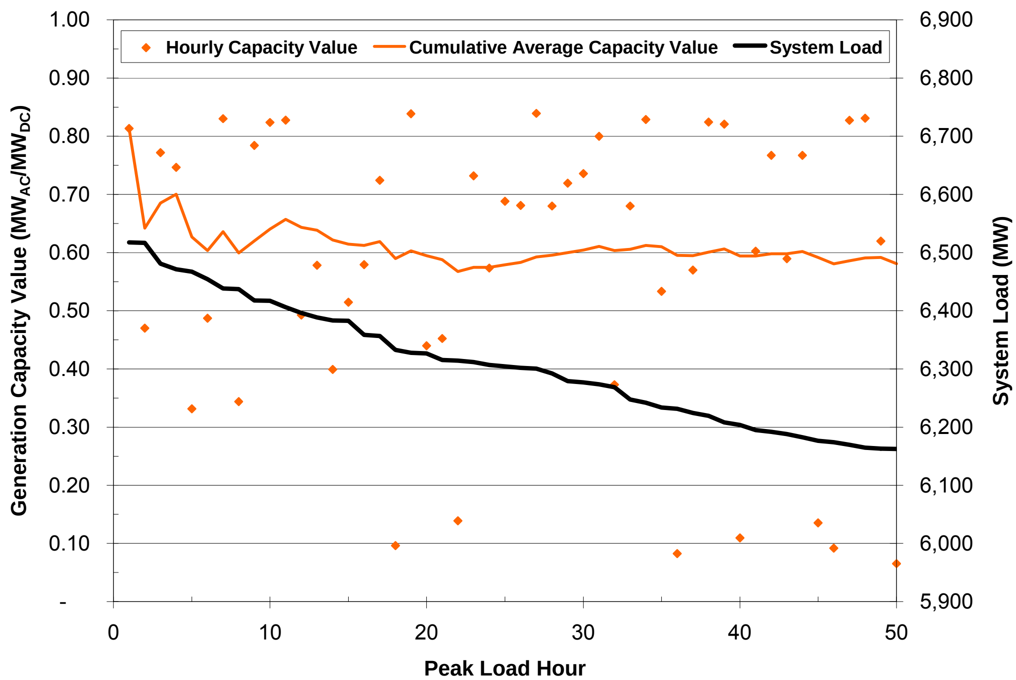


Figure 15
2010, Western Slope, Tracking