Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area

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I. Executive Summary

Electricity generated from solar photovoltaic (PV) panels has become a significant source of carbon-free power in the United States over the last decade. Compared to other solar-electric technologies, solar PV systems are unique in that they are highly scalable and may be deployed in configurations ranging from just a few kilowatts (kW) (residential-scale) to hundreds of megawatts (MW) (utility-scale). This report examines the comparative customer-paid costs of generating power from equal amounts of utility- and residential-scale solar PV panels in the Xcel Energy Colorado system. The report was prepared by consultants at The Brattle Group for First Solar, with support from the Edison Electric Institute. Xcel Energy Colorado provided data and technical support.

The analysis in this report looks at the Xcel Energy Colorado system in 2019 and compares the per-megawatt hour (MWh) customer supply costs of adding 300 MW of PV panels (measured in $W_{\text{-DC}}$) either in the form of: (1) 60,000 distributed 5-kilowatt residential-scale (rooftop) systems owned or leased by retail customers; or (2) 300 MW of utility-scale solar power plants that sell their entire output to Xcel Energy Colorado under long-term purchase power agreements (PPA).

Using a Reference Case and five scenarios with varying investment tax credit (ITC), PV cost, inflation, and financing parameters, the study finds that customer generation costs per solar MWh are estimated to be more than twice as high for residential-scale systems than the equivalent amount of utility-scale PV systems. The projected 2019 utility-scale PV power costs in Xcel Energy Colorado range from $66/MWh to $117/MWh (6.6¢/kWh to 11.7¢/kWh) across the scenarios, while residential-scale PV power costs range from $123/MWh to $193/MWh (12.3¢/kWh to 19.3¢/kWh) for a typical residential-scale system owned by the customer. For leased residential-scale systems, the costs are even larger and between $140/MWh and $237/MWh (14.0¢/kWh to 23.7¢/kWh). The generation cost difference between the utility- and residential-scale systems owned by the customer ranges from 6.7¢/kWh to 9.2¢/kWh solar across the scenarios. To put this in perspective, national average retail all-in residential electric rates in 2014 were 12.5¢/kWh.

The large gap in per-MWh costs between utility- and residential-scale systems results principally from: (a) lower total plant costs per installed kilowatt for larger facilities; and (b) greater solar electric output from the same PV capacity (300 MW-DC) due to optimized panel placement, tracking and other economies of scale and efficiencies associated with utility-scale installations.

Additionally, the analysis finds that residential-scale PV systems cost $195 million more than the utility-scale systems under the Reference Case on an NPV basis over 25 years. If the same amount of residential-scale PV systems (1,200 MW) were installed in 2019 as in 2014, they would cost customers roughly $800 million more in NPV than a comparable purchase of utility-scale systems, under conditions assumed for the Reference Case.

These cost results include only the *customer-paid costs for the generation* from equal amounts of PV capacity deployed in two configurations in one utility service area. A complete tally of the differences between equal amounts of the two types of PV capacity would require that these two resource options be alternatively embedded in a complete, subsequently optimized integrated resource plan (IRP) for Xcel Energy Colorado or other systems of interest, which would better reflect the effects of each PV option on system costs and potential benefits such as savings on transmission and distribution outlays and ancillary service costs. However, as discussed below, we evaluate avoided and/or increased transmission and distribution costs between the two types of PV plants, as well as externalities, and conclude that including these added or avoided costs is unlikely to change our conclusion.

Additionally, while the results of this analysis apply solely to the Xcel Energy Colorado system and should not be transferred to other areas without attention to comparative insolation levels and other cost drivers that vary by region, the authors believe that the general relationship between costs is likely to hold true for most of, if not all, U.S. utilities with significant solar potential. The authors also find through the sensitivity cases that the results are robust to changes in federal tax credits, inflation, interest rates, and changes in PV costs than we project in our Reference Case.

Overall, the findings in this report demonstrate that utility-scale PV system is significantly more cost-effective than residential-scale PV systems when considered as a vehicle for achieving the economic and policy benefits commonly associated with PV solar. If, as the study shows, there are meaningful cost differentials between residential- and utility-scale systems, it is important to recognize these differences, particularly if utilities and their regulators are looking to maximize the benefits of procuring solar capacity at the lowest overall system costs. With the likely onset of new state greenhouse gas savings targets from pending EPA rules, the options for reducing carbon emissions and the costs of achieving them will take on an even greater importance.

Simply stated, most of the environmental and social benefits provided by PV systems can be achieved at a much lower total cost at utility-scale than at residential-scale.

II. Introduction and Purpose

Electricity generated from solar photovoltaic (PV) panels has become a significant source of carbon-free power in the United States over the last decade as a result of the dramatic cost reductions and higher efficiency associated with PV technology, cost savings associated with balance of system, and new mechanisms for lowering the cost of capital that are starting to emerge.

Compared to other solar-electric technologies, solar PV is unique in that it is highly scalable and may be deployed in configurations ranging from just a few kilowatts (kW) to hundreds of megawatts (MW). PV technology is also unique in that it can be installed in free-field applications or on the more confined spaces of residential rooftops. At one size extreme, small residential rooftop PV systems typically attach to the local utility's distribution system, generally sending surplus power into that system and supplying some of the on-site load requirements of the residential host. These small systems (referred to as "residential-scale" in this report) are frequently made financially possible by net energy metering (NEM) arrangements, which traditionally allow the subscribing customer to net their solar production against their utility bill on a kWh-for-kWh basis.

At the other size extreme, larger systems (referred to as "utility-scale" in this report) usually interconnect via the high-voltage transmission grid, supplying energy to the buyer, typically an investor-owned or publicly-owned utility, at wholesale prices under a long-term power purchase agreement (PPA). Other arrangements for the deployment of PVs are also emerging, such as "community solar," which can allow residential customers to participate in the ownership of, and to receive a beneficial share of, the output from a larger, centralized PV facility. Finally, many commercial and industrial companies outside of the utility sector are becoming increasingly focused on sustainable energy solutions and have begun to seek arrangements to own or receive credit for the output of utility-scale PV solar facilities as a basis for directly serving or offsetting their energy consumption.[1]

As the penetration of residential-scale PVs has increased, discussions in many regulatory jurisdictions have begun to focus on the costs and benefits of residential-scale solar ownership from the perspective of the subscribing residential customer, the non-subscribing residential customer, and the utility. These discussions have tended to focus on two policy concerns: (1) the overall costs and benefits of residential-scale PV solar *as compared to non-solar resources* and (2) whether existing tariff arrangements, particularly those providing for "full retail" NEM credits for residential rooftop subscribers, produce an inequitable subsidy or cost shift to non-subscribing utility customers. Quite often, these discussions treat residential-scale solar as if it were the only form of PV power able to provide solar attributes and benefits. Implicitly or explicitly, utility-scale PV installations are frequently overlooked as a 100% solar option that can be compared to both residential-scale PVs and to other utility-scale and distributed resource options.

This report attempts to fill this void by presenting a thorough comparison of the cost of utility- and residential-scale PV power. Rather than comparing solar to other forms of generation, or focusing on the distributive effects of incumbent rate designs, *this report compares solar to solar customer costs*. We do so by studying the relative costs and attributes of residential- and utility-scale PV deployment in the context of an actual utility system.

More specifically, we examine and compare the per-MWh generation cost to retail utility customers of equal amounts of PV capacity (PV panel capacity measured in $W_{\text{-DC}}$) installed in residential- and utility-scale systems in the Xcel Energy Colorado (also known as Public Service Company of Colorado, or PSCo) system. Table 1 summarizes the key assumptions made for these two types of PV systems. All tax benefits customers receive are incorporated in our costs.

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1 "Walmart, Kohl's, Costco, Apple, IKEA and more have all embraced solar energy. Collectively, the 25 companies with the most solar capacity in the U.S. now have 1,110 systems totaling 569 megawatts (MW), generating enough electricity to power more than 115,000 homes." Solar Means Business 2014: Top U.S. Commercial Solar Users, Solar Energy Industries Association, 2014. http://www.seia.org/sites/default/files/resources/17ay15uqAzSMB2014_1.pdf. (accessed Feb 3, 2015)

Table 1: Key Assumptions for Utility- and Residential-scale PV Systems

PV Category	Assumptions
Utility-scale	- Single Tracking Panels - Greater than 5 MW - 300 MW_{DC} panel [250 MW_{AC} inverter]
Residential-scale	- Fixed Tilt Panels - 5 kW on average [0-10 kW range] - 300 MW_{DC} panels [60,000 5 kW_{AC} inverters]

Providing electric service to customers requires investments and expenditures in generation, transmission, and distribution. These costs are translated into revenue requirements for utilities and then into electric rates to customers. Changes in resources used to produce electricity can change the costs that the utility incurs in any of those three segments.

As explained further below in this report, our primary focus is on the generation segment when equal amounts of PV capacity, utility- or residential-scale, are added. We focus on the costs actually paid by customers, or monetized costs, because these are an essential starting point for well-informed economic and regulatory policy discussions. For example, many policies attempt to meet specific resource planning or environmental objectives—sometimes including the attainment of specific PV installation targets—at the lowest feasible cost.

A. Comparison Framework and Results

The analysis in this report compares for the Xcel Energy Colorado system in 2019 the per-MWh customer supply costs of adding 300 MW-DC of PV capacity either in the form of (1) 60,000 distributed 5-kilowatt residential-scale (rooftop) systems owned or leased by retail customers or (2) 300 MW of utility-scale solar power plants that sell their entire output to Xcel Energy Colorado under long-term PPAs.[2]

[2] The year 2019 was selected because four years was seen as realistic period for the addition of this increment of PV in Xcel Energy Colorado's area.

Xcel Energy Colorado was chosen for this study because it is reasonably representative of a midsize utility system in the Western U.S. from a number of perspectives, including, among others, the size of system, load profile, and the current level of penetration of residential-scale systems in its service territory. Xcel Energy Colorado's service territory is also reasonably representative of investor-owned utilities in the West in terms of the mix of urban and rural load and distribution feeders. We employed an increment of 300 MW of PV because this level of addition is consistent with Xcel Energy Colorado's currently planned addition of utility-scale resources in 2019.[3] This level of incremental solar capacity is large enough to produce a useful cost comparison but is not so large as to cause a complete reconfiguration of its existing resource plan.

In this study, we have analyzed a Reference Case and five scenarios with varying ITC, PV cost, inflation, and financing parameters. We provide brief descriptions of the Reference Case and the scenarios below, with more details provided in Section III. In each of these scenarios, costs for residential-scale PV systems are considered in two ways: as a simple system purchased and owned by customers [our base case] or modeled as a leased system.

<u>Reference Case</u> uses the projected installed PV costs for 2019; assumes that the ITC is at 10%; and tax-equity financing absorbs the ITC credits as part of the financing of the utility- and residential-scale lease systems. Residential-scale purchases do not receive any ITC credits in 2019, consistent with the current tax code.

<u>Scenario 1 (2019 ITC at 30%)</u> uses the projected installed PV costs for 2019; assumes that the ITC remains at 30%; and tax-equity financing absorbs the ITC credits as part of the financing of the utility- and residential-scale lease systems. In this scenario, residential-scale purchases are also assumed to take advantage of the 30% ITC.

<u>Scenario 2 (2019 Developer absorbing ITC)</u> uses the projected installed PV costs for 2019; assumes that the ITC is at 10% and developers (as opposed to third-party tax equity) absorb the ITC credits for both utility- and residential-scale lease systems.

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3 Xcel Energy Colorado plans on adding 170 MW of utility-scale PV into their system by 2019.

Scenario 3 (2019 Higher Inflation) uses the projected installed PV costs for 2019; assumes that the ITC is at 10%; tax-equity financing absorbs the ITC credits as part of the financing of the utility- and residential-scale systems; and inflation is higher at 4%. Residential-scale purchases do not receive any ITC credits in 2019, consistent with the current tax code.

Scenario 4 (2019 Lower PV Cost) scales down the projected installed PV costs for 2019 by 20%; assumes that the ITC is at 10%; and tax-equity financing absorbs the ITC credits as part of the financing of the utility- and residential-scale systems. Residential-scale purchases do not receive any ITC credits in 2019, consistent with the current tax code.

Scenario 5 (2014 Actual PV Cost) uses the actual installed PV costs for 2014; assumes that the ITC is at 30%; and tax-equity financing absorbs the ITC credits as part of the financing of the utility- and residential-scale lease systems. Residential-scale purchases are also able to take advantage of the 30% ITC credits, consistent with the current tax code.

The results of our analysis demonstrate clearly that the generation costs per MWh of PV electricity from 300 MW of utility-scale systems are roughly one-half the costs of an equivalent amount of PV electricity from 60,000 residential-scale systems when added to the Xcel Energy Colorado system in 2019. The projected levelized cost of energy from utility-scale PV in 2019 ranges from $66/MWh to $117/MWh (6.6¢/kWh to 11.7¢/kWh) across the scenarios considered, while residential-scale PV energy costs $123/MWh to $193/MWh (12.3¢/kWh to 19.3¢/kWh) for a typical residential-scale system owned by the customer and even more if the residential-scale system is leased.[4] The generation cost difference between the two is 6.7¢/kWh to 9.2¢/kWh solar across the scenarios. To put this in perspective, national average all-in retail residential electric

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[4] Today about 70% of residential systems are leased from third party owners. Industry reports and our own calculations, reported below, indicate that the cost of solar power to residential customers from leased systems is typically larger than the cost of solar power from otherwise-identical systems that are customer-owned. The calculated per-MWh difference between utility- and residential-scale leased systems, as shown in Table 2, is therefore even larger than the difference between utility- and residential-scale owned systems. However, the cost of power from residential-scale leased systems also varies substantially by solar provider, finance and tax assumptions, region, and lease provider. In addition, industry reports indicate that customer ownership is likely to overtake leasing in the next several years. Because our target year is 2019, customer ownership is the more logical benchmark for comparison.

rates in 2014 were 12.5¢/kWh.[5] One reason for this difference in electricity cost between utility- and residential-scale systems is that the utility-scale system produces almost 50% more electrical energy per year than an equal capacity of residential-scale systems.[6]

Table 2: Levelized Cost of Utility- and Residential-scale PV ($ per Solar MWh)

No	Scenario	Utility-scale	Residential-scale Purchase	Cost Difference (Res-Utility)	Residential-scale Lease
Reference	**2019 ITC @ 10%**	**83**	**167**	**83**	**182**
Scenario 1	2019 ITC @ 30%	66	123	**57**	140
Scenario 2	2019 Developer absorbs ITC	66	N/A	**N/A**	140
Scenario 3	2019 Higher Inflation	95	187	**92**	206
Scenario 4	2019 Lower PV Cost	69	137	**67**	149
Scenario 5	2014 Actual PV Cost	117	193	**76**	237

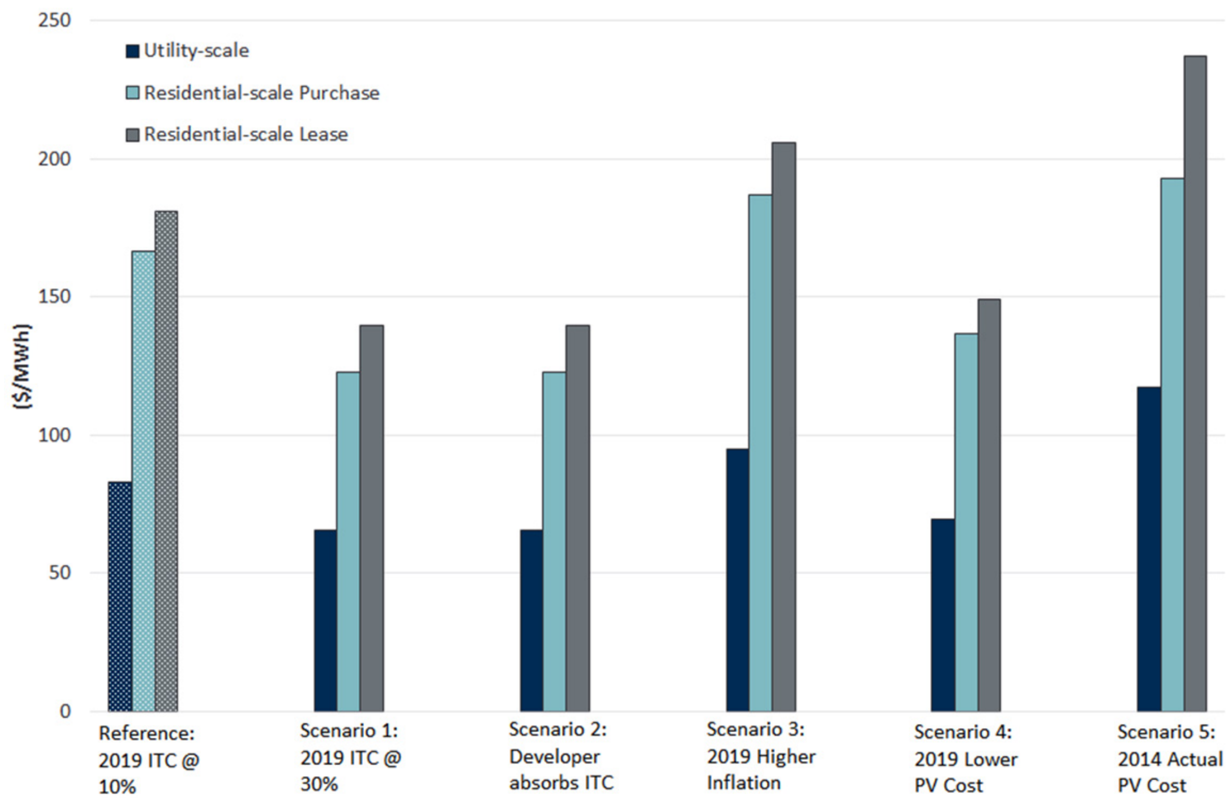
Notes:
1-All Scenarios other than Scenario 2 assume there is a tax equity partner.
2-In Scenario 1, 30% ITC assumption has been applied to all three cases uniformly.
3-Scenario 2 is only relevant to the utility- and residential-scale leased systems and does not to impact residential-scale purchases.

Table 2 and Figure 1 show our comparison of the levelized costs for utility- and residential-scale PV systems, customer-owned residential-scale systems (residential purchase), and leased residential-scale systems. As these results indicate, the large generation cost advantage of utility-scale PVs does not change with differences in other factors that normally affect costs to costumers such as tax credits, use of tax equity, renewable energy certificate (REC) prices, inflation, or a more rapid decrease in the price of PV panels.

5 EIA Electric Power Monthly, January 2015, Table 5.3.

6 As discussed later in the report, utility-scale solar PV would yield an annual 597,000 MWh and residential-scale PV would yield 400,000 MWh.

Figure 1: Levelized Cost of Utility- and Residential-Scale PV ($ per Solar MWh)



The large gap in per-MWh costs between utility-scale systems and residential-scale systems is *not* a result of the declining cost of manufacturing solar panels or federal tax credits, a trend which is common to both types of systems. Instead, the cost gap results principally from (a) lower total plant costs per installed kW for larger facilities resulting from construction economies of scale and related factors; and (b) greater solar electric output from the same PV capacity (300 MW-DC) due to optimized panel placement, tracking, and other economies of scale and efficiencies associated with utility-scale installations. The cost differential would increase further if one were to assume that utility-scale facilities will be built in favorable locations with higher insolation; however, in this report, we chose conservative assumptions and used the same level of insolation for both residential- and utility-scale system as the basis for comparison.

While we have expressed our results thus far as levelized costs per MWh solar, it is possible to express the differences in customer payments in net present value (NPV) terms over the life of two equal-sized (300 MW_{-DC}) projects, which we assumed to be 25 years.[7] Table 3 shows that residential-scale PV costs $87 million to $195 million more than the utility-scale on an NPV basis over 25 years for the Reference Case and remaining five Scenarios. In 2014, 1,200 MW of residential-scale PV systems were installed in the U.S. If the same amount of residential-scale PV systems (1,200 MW) were installed in 2019, these PV systems would cost customers roughly $800 million more in NPV than a comparable purchase of utility-scale systems, assuming Reference Case conditions.[8]

Table 3: Net Present Value Monetized Customers Cost of Solar Purchases from 300 MW_{-DC} Utility- and Residential-Scale PV Systems ($ Millions)

No	Scenario	Utility-scale	Residential-scale Purchase	Cost Difference (Res-Utility)	Residential-scale Lease
Reference	**2019 ITC @ 10%**	**556**	**752**	**195**	**812**
Scenario 1	2019 ITC @ 30%	438	554	116	625
Scenario 2	2019 Developer absorbs ITC	438	N/A	N/A	625
Scenario 3	2019 Higher Inflation	538	716	178	785
Scenario 4	2019 Lower PV Cost	463	617	153	668
Scenario 5	2014 Actual PV Cost	781	869	87	1061

Note: NPVs are calculated using 7.6% discount rate, approximating Xcel Energy's WACC.

7 It is certainly possible that PV plants of all types will provide valuable power past their 25th year. We assume, conservatively, that neither utility- nor residential-scale projects will incur costs past year 25, so that all cost streams end at that point. This assumption is likely to be conservative because utility-scale projects generate nearly twice as many solar kWh as residential-scale systems of equivalent DC capacity, so the residual value of utility-scale systems per installed W_{-DC} is likely to be significantly higher. In any event, discounting would reduce the net cost or benefit of the residual value of either a residential- or utility-scale system to less than 15% of its current nominal level. We also assume no decommissioning or disposal cost for either option.

8 We would expect significant variations in cost, including the costs of land, as well as insolation and other factors, for installations across the U.S. On balance we do not think these regional variations will change our basic conclusion.

It is important to understand that all of our cost results include only the *customer-paid costs for the generation* from equal amounts of PV capacity deployed in two configurations in one particular utility service area. A complete tally of the differences between equal amounts of the two types of PV capacity would require that these two resource options be alternatively embedded in a complete, subsequently optimized integrated resource plan (IRP) for Xcel Energy Colorado or other systems of interest. When optimized, such an IRP would reflect the effects of each PV option on system costs and potential benefits such as savings (or incremental reinforcement costs) on transmission and distribution outlays, and differences in ancillary service costs.

Although we did not quantify these monetized non-generation costs and benefits in this report, we review them in more detail in Section IV. Based on many published reports and our understanding of the structure of the Xcel Energy Colorado system, we find that including these monetized non-generation costs and benefits, while essential in actual planning and policy exercises, would very likely increase the gap between the cost of utility- and residential-scale PV systems for Xcel Energy Colorado (See Section VI). We believe that the general relationship of the cost difference between the two types of PV systems is likely to hold true for most of, if not all, U.S. utilities with significant solar potential.

We also address briefly the issue of non-monetized benefits (sometimes referred to as "social benefits" or "externalities") which are frequently offered as a basis for offsetting or reducing the cost of PV facilities in policy discussions, particularly when comparing residential-scale PV systems to other resource alternatives.[9] These benefits are typically more difficult to quantify, therefore they are generally reviewed qualitatively in policy discussions. Because we focus here on the relative costs of utility-scale and residential-scale PV systems, we do not include these types of considerations in assessing the overall costs and benefits of PV solar compared to other available supply side resources. We do conclude, however, that the magnitude of most non-monetized benefits achieved is generally proportionate to the higher solar output associated with scale. Thus, as an example, the value of the non-monetized benefits of displacing carbon

9 See, for example, European Commission Staff Working Paper SWD (2012) 149 Final; Impact Assessment Accompanying the Document Renewable Energy: A Major Player in the European Energy Market; p.12.

emissions or water consumption is roughly 50% greater for 300 MW of PV capacity deployed as utility-scale than it is for 300 MW of PV capacity deployed as residential-scale.

While there may be policy considerations or resource constraints associated with one scale of PV power or the other that warrant departure from a least-cost approach, costs nonetheless are an appropriate starting point.[10]

B. Comparison to Other Solar Studies

Many different types of studies have been conducted on various aspects of PV power, including IRPs, solar valuation analyses, and cost/benefit studies of distributed solar and of rate options such as net energy metering. Xcel Energy Colorado itself has both an IRP and a study of the costs and benefits of distributed solar (PSCo Distributed Solar Study).[11] It is important to understand that our study is unique in its form and not equivalent to any of these more familiar inquiries, including Xcel Energy's own studies. Instead, our analysis is a comparison of per MWh generation costs for two equally-sized solar additions to a resource plan. In our study, solar is compared against solar, not against fossil-fueled generation.

IRPs and similar least-cost analyses search for the long-term resource mix that combines lowest present value costs, policy objectives, and practical constraints. In our analysis, neither of the PV options we examine is a complete IRP. Instead, the two options are equivalently-sized elements of alternative resource plans that use solar PV in equal DC panel capacity amounts but in two different configurations. The goal here is to illustrate the cost differences of the two solar types. As explained below, however, if full resource plans were undertaken, our results suggest that a resource mix employing utility-scale solar would cost customers far less than a mix with an equal

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10 For example, some areas may not have land available for utility-scale projects, while others may have little suitable rooftop space.

11 See "Public Service Company of Colorado 2011 Electric Resource Plan," October 31, 2011, and "Cost and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System," May 23, 2013. Solar stakeholders in Xcel Energy Colorado area filed a reply to Xcel Energy Colorado's Distributed Solar Study, Docket No. 11M-426E, "Comments on Xcel Energy's PSCo's DSM Study report" from the Colorado Solar Energy Industries Association, September 2013. We refer to this as the Solar Stakeholder Comment. Xcel's reply to these comments is included in our bibliography.

amount of residential-scale capacity. As with all IRP efforts, this should be validated in case-specific exercises.

Solar valuation studies attempt to estimate all types of benefits from solar energy, public as well as private, and sometimes compare these benefits to costs. These studies typically try to capture the full range of costs and benefits from solar energy, both monetized and non-monetized. A typical study of this type might include, as an example, a consideration of the value of greenhouse gas reductions as a benefit of solar as well as the number of jobs created by a solar installation.[12] Our study is limited to the analysis of the *total monetized generation costs borne by utility customers*—*i.e.*, the dollars utility customers pay for their solar electric supply over time under the two solar alternatives in the Xcel Energy Colorado area. This analysis is consistent with prevalent principles of cost of service regulation, which ensure that rates charged to customers are based on directly measurable costs (and cost savings) that affect the utilities' overall cost of service to a customer.

As explained more fully in Section IV, a broader inclusion of all of the monetized and non-monetized attributes of PV would significantly strengthen our conclusion that utility-scale solar is more cost-effective for customers than residential-scale systems. However, it is not our purpose to quantify the value of these attributes with precision.

C. GUIDE TO THIS REPORT

In Section II, below, we discuss the analytic framework developed as a basis for comparing the relative cost to customers of 300 MW-DC of utility-scale solar and 300 MW-DC of residential-scale solar added to the Xcel Energy Colorado system. The analytic framework includes both a basis for estimating the installed capital cost of a utility-scale system and a typical residential-scale system and models the output of such systems based on actual geographic location and granular insolation data from Xcel Energy Colorado's service territory. We establish a "Reference Case" and five Scenarios in order to account for possible variations in tax treatment for solar installations and other factors. In Section III, we model the utility customer costs associated with

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12 An overview of value of solar (VOS) studies and study methodologies can be found in "A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation," Interstate Renewable Energy Council, October 2013.

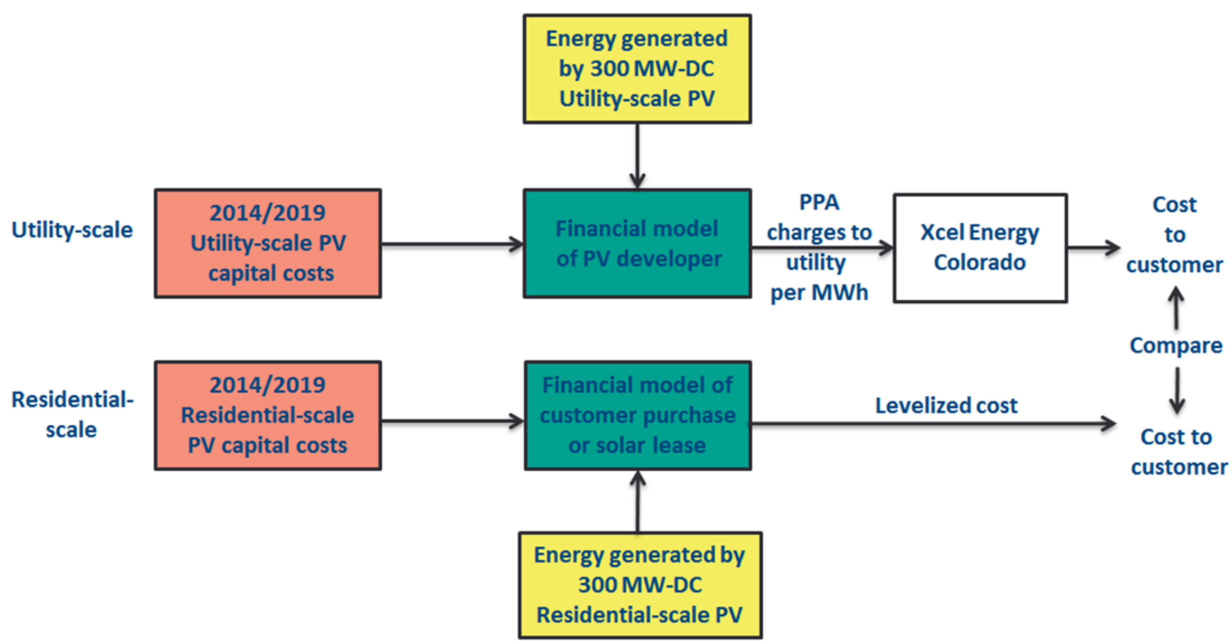
utility- and residential-scale systems in the Reference Case and across these Scenarios. In Section IV, we discuss the likely effects on our primary conclusions of factoring monetized non-generation costs and non-monetized costs, *i.e.*, societal benefits or externalities, into the analysis.

III. The Analytic Framework

A. Overview and Scenarios

As shown in Figure 2, our analysis of the comparative generation costs of utility- and residential-scale PV systems occurs in three major steps. In the first step, denoted by boxes with red shading, we analyze national data on PV installations by size, type, and project capital costs. In the second step, shown in the boxes with yellow shading, we analyze insolation and other engineering data to estimate the energy produced by 300 MW of utility- or residential-scale systems, each located in the Xcel Energy Colorado service area. The third step (green shaded boxes) utilizes a developer financial model to estimate the annual stream of utility or residential customer payments for utility- and residential-scale PV systems, respectively. We assume that utility-scale PV purchases by Xcel Energy Colorado will be resold to its residential customers without any added margins or costs; the cost charged to Xcel Energy Colorado's retail customers is equal to Xcel Energy Colorado's purchase price for each MWh of solar PV. The remainder of this Section and the next examines each of these three steps in more detail.

Figure 2: Overview of Study Methodology



As discussed earlier, we compare the costs per MWh of solar electricity generated by 300 MW of DC PV capacity added either as 60,000 distributed 5-kilowatt residential-scale systems or as utility-scale plants for the Xcel Energy Colorado system in 2019. This comparison constitutes our "Reference Case." We have also defined four additional Scenarios by varying some of the important drivers of the lease model. A fifth Scenario that represents the Reference Case under 2014 conditions was developed as well. Table 4 summarizes and compares important drivers of the solar financing model for the Reference Case as well as the five Scenarios. These assumptions/drivers are applied uniformly to both PV alternatives.

Table 4: Comparison of Reference Case and Scenario Drivers

No	Name	Installed PV Costs	ITC	ITC monetized by	Inflation
Reference Case	2019 ITC @ 10%	Projected costs in 2019	10%	Tax-equity partner	2%
Scenario 1	2019 ITC @ 30%	Projected costs in 2019	30%	Tax-equity partner	2%
Scenario 2	2019 Developer Absorbing ITC	Projected costs in 2019	10%	Developer	2%
Scenario 3	2019 Higher Inflation	Projected costs in 2019	10%	Tax-equity partner	4%
Scenario 4	2019 Lower PV Cost	Projected costs in 2019 discounted by 20%	10%	Tax-equity partner	2%
Scenario 5	2014 Actual PV Cost	Actual costs in 2014	30%	Tax-equity partner	2%

B. Projecting The Installed Cost Of PV Plants

To estimate total installed cost, two main data sources were used: the National Renewable Energy Laboratory's (NREL's) Open PV Project[13] and solar studies from the Lawrence Berkley National Laboratory (LBNL).[14] In addition to these sources, several other solar studies[15] were used to corroborate the final PV cost estimates.

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13 https://openpv.nrel.gov/about.

14 *See* "Tracking the Sun VII," prepared by LBNL September 2014 and "Utility-Scale Solar 2013," prepared by LBNL, September 2014.

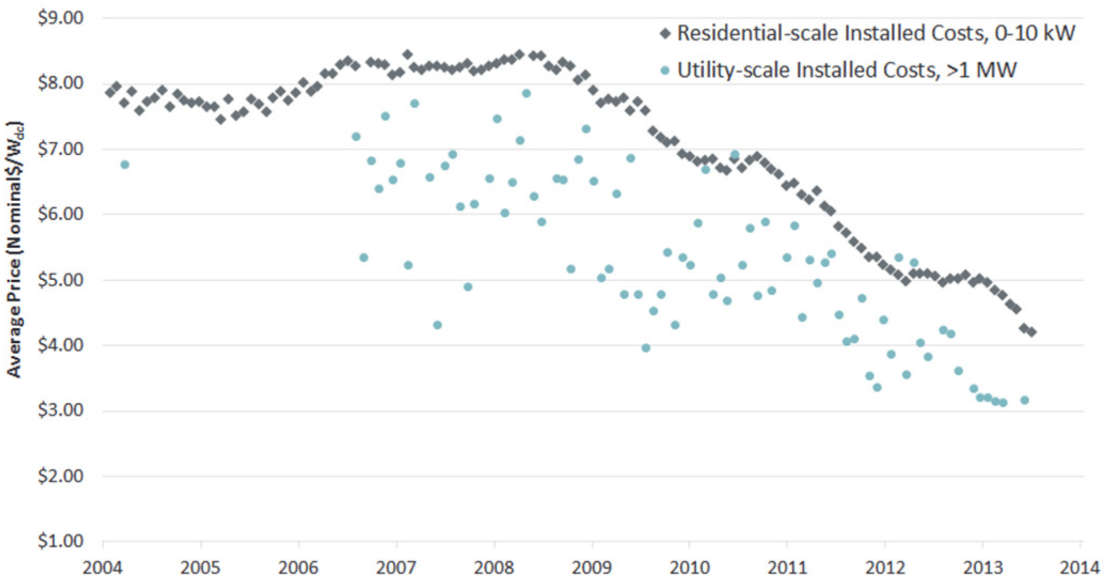
The NREL Open PV dataset was used to estimate costs for both 2014 and 2019. Open PV presents installed costs for over 315,000 installations between January 2004 and August 2014. This data was first sorted into different categories based on the capacity of the installation. For this portion of the analysis, projects between 0 and 10 kW were assumed to be residential-scale while projects larger than 1 MW were treated as utility-scale.[16] After defining the two categories for analysis, monthly average installed costs were calculated. Monthly values outside of the 1st and 99th percentiles of data were removed from the analysis to eliminate any outliers. The results of these calculations are presented in Figure 3 below.

Continued from previous page

15 Studies reviewed include "Arizona Public Service Integrated Resource Plan," prepared by APS in April 2014, p. 288, "U.S. Solar Market Insight Report | Q2 2014," prepared by GTM and SEIA, p. 53, "Capital Cost Review of Power Generation Technologies: Recommendations for WECC's 10- and 20-Year Studies," prepared for WECC in March 2014, p. 30, and "PacifiCorp Integrated Resource Plan," prepared by PacifiCorp in April 2013, p. 113.

16 Defining which electric projects are "utility-scale" can be difficult and is not consistent across the industry. GTM and SEIA define utility-scale as projects owned by or that sell directly to a utility, and LBNL defines utility-scale projects as those projects greater than 5 MW. While the EIA does not distinguish between other types of generation projects and "utility-scale" projects explicitly, they collect and report utility-scale data for projects greater than 1 MW in capacity. In this analysis, we start with the EIA definition (>1 MW), but then we scale down the costs by a multiplier to be able to apply them to projects with size greater than 5 MW (to account for the scale economies).

Figure 3: NREL Open PV Installed Cost



Source: NREL Open PV Project monthly averages

Two distinct methodologies were applied to determine costs for 2014 and to estimate costs for 2019. The last month with continuous and reliable data for 2014 at the time of this analysis was May 2014, which is roughly mid-year. Therefore, the average value for May 2014 was taken as a good benchmark for 2014 average costs for both utility- and residential-scale solar installations.

For estimating the costs for 2019, we used the historical cost decline rates and applied it to the representative cost for 2014 identified above (May 2014 data) to project the costs forward. To account for the economies of scale that exist for utility-scale projects that are larger than 1 MW, we calculated an "economies of scale multiplier" to further reduce our utility-scale cost estimates given that this study assumes utility-scale systems to be greater than 5 MW.[17] In order to calculate this multiplier, we took a ratio between two LBNL reports to adjust our utility-scale cost estimates down. In its 2013 report, LBNL provides utility-scale data for projects greater than 2 MW. For its 2014 report, LBNL switches to reporting utility-scale projects greater than 5 MW. Therefore, a ratio was taken between each report's installed costs as restated in 2012 dollars, the latest common year available for both reports. This choice ensured that the costs applied to the

[17] In its utility-scale solar report published in September 2014, LBNL comments that "evidence of PV scale economies is perhaps most visible among projects of less than 5 MW-AC in size."

same installation period. For the 2014 LBNL study, the 2012 $/W-DC is $2.95 for systems greater than 5 MW and for the 2013 LBNL study, the 2012 $/W-DC is $3.25 for systems greater than 2 MW. Using these numbers, we calculated the economies of scale multiplier as 0.91 and applied it to both the 2014 and 2019 analyses to adjust the utility-scale installed costs estimate.

1. 2014 Actual Capital Costs

Table 5 presents the maximum, minimum, average, and median installed costs for residential-scale PV systems. The average cost declines in each month as do the number of reported projects.

Table 5: Residential-Scale Installed Costs, Feb 2014 – May 2014 ($/W-DC)

Month	Reported Projects	Maximum	Minimum	Average	Median
[1]	[2]	[3]	[4]	[5]	[6]
Feb-2014	1313	$9.21	$1.85	$4.77	$4.80
Mar-2014	114	$7.95	$2.88	$4.63	$4.80
Apr-2014	77	$8.57	$2.82	$4.55	$4.65
May-2014	62	$7.44	$2.83	$4.25	$4.17

Source: NREL Open PV Project; Analysis by The Brattle Group
[1]: Selected by The Brattle Group
[2]: Number of raw data points that exist for residential installations (0-10 kW)

Table 6 presents the same information for the utility-scale projects. There is a significant decrease in the number of reported projects. While there are fewer utility-scale projects under construction, these types of project tend to be underreported in NREL's Open PV project as well as in other reports.[18]

[18] *See* "U.S. Solar Market Insight Report | Q2 2014," prepared by GTM and SEIA, p. 58.

Table 6: Utility-Scale Installed Costs ($/W$_{-DC}$)

Month	Reported Projects	Maximum	Minimum	Average	Median
[1]	[2]	[3]	[4]	[5]	[6]
Dec-2013	12	$5.66	$2.24	$3.21	$2.83
Jan-2014	1	$3.15	$3.15	$3.15	$3.15
Feb-2014	6	$4.16	$2.49	$3.13	$3.10
May-2014	2	$3.51	$2.83	$3.17	$3.17

Source: NREL Open PV Project; Analysis by The Brattle Group

[1]: Selected by The Brattle Group. No projects for March and April exist within the Open PV database and are thus not included in this table.

[2]: Number of raw data points that exist for utility-scale installations (>1 MW)

We selected the average installed costs for May 2014 for both utility- and residential-scale systems as the best indicator of costs given that it yields the most recently available data on these costs. Therefore, the installed costs for residential-scale projects was determined as $4.25/W$_{-DC}$. For the utility-scale PV, our final 2014 utility-scale cost estimate is $2.88/W$_{-DC}$ (after applying the economies of scale multiplier to $3.17/W$_{-DC}$).

2. 2019 Projected Capital Costs

To project 2019 PV plant capital costs from 2014 actual levels, we employed a statistical projection method. Our method is based on a single straightforward assumption: for both utility- and residential-scale PV, total plant costs per W$_{-DC}$ will continue to decline at the respective average percentage rate that they have declined in the last five years.[19] In other words, if average utility-scale project costs were declining at five percent per year during the past five years we assume they will decline at the same average percentage rate through 2019.

Obviously, this assumes that trends in the past for both utility- and residential-scale PV systems will continue in the future at a constant percentage rate. This is undoubtedly a simplification, as the two types of PV systems have some cost elements that are identical (*e.g.*, PV panels) and some that are different (customer acquisition costs, mounting systems). Even for elements that

19 Our algorithm for studying costs assumes that there are no substantial innovations that will substantially impact the price gap currently seen between residential-scale and utility-scale PVs.

are common to both types of PV plants, such as PV panels, differences in purchasing practices may affect their ultimate delivered costs.

All this notwithstanding, both residential- and utility-scale PV installations have been declining in a manner that looks similar to a constant percentage trend. Moreover, a constant percentage trend has the statistical property that cost declines never reach zero but do get gradually smaller in absolute terms, matching real-world observations for many technologies as they mature. Technological breakthroughs may create quantum decreases in the cost of PVs in the future, but we do not assume such breakthroughs occur by 2019.

To implement this assumption, a cost decline curve was calculated by selecting two data points and using the below equation:

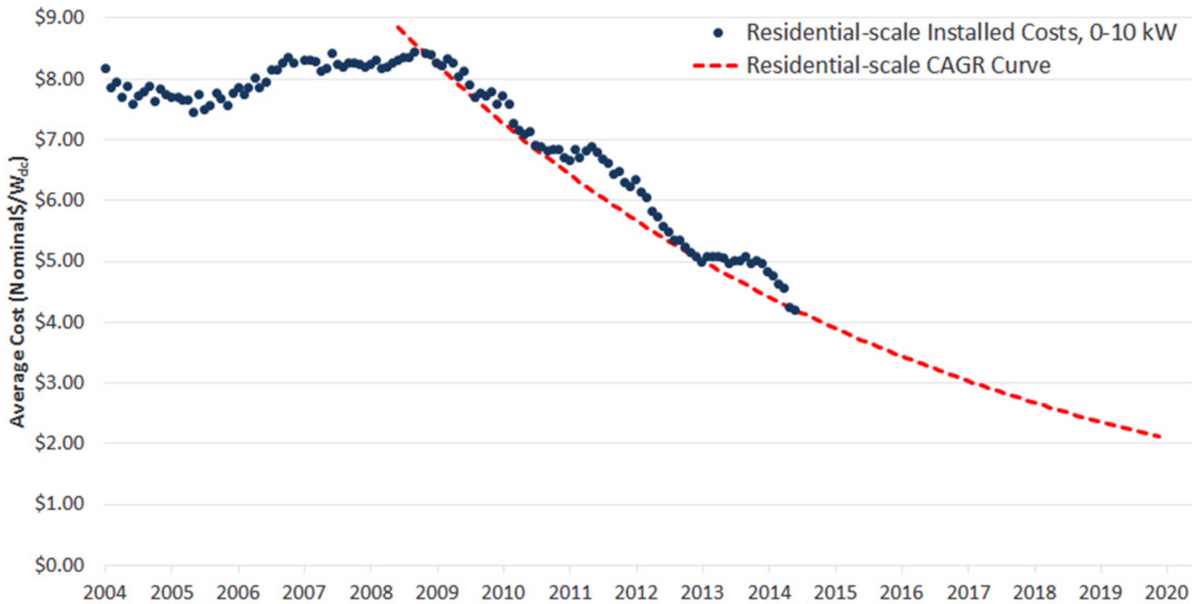
$$Decline\ Rate = \left[\frac{MP_1}{MP_2}\right]^{\frac{1}{(Date_1 - Date_2)}}$$

Decline Rate = the cumulative average decline rate
$MP_{1\ or\ 2}$ = the monthly average cost for date 1 and date 2, respectively
$Date_{1\ or\ 2}$ = the month-year date for the first or second data point

In order to be consistent in the methodology used to estimate costs for residential- and utility-scale projects, the same dates (effective endpoints) were used for the equation above. The months selected for the start and end dates for the analysis were February 2009 and May 2014. The start date was selected to match more accurately the current cost trend in the market for PV panels. Residential- and utility-scale solar systems experienced a period of stagnation of costs before 2009. Figure 3: above depicts this trend. Starting in 2009, though, PV costs started to decrease substantially. Therefore, in order to capture the most recent trends, we decided that starting at the beginning of the period with rapidly declining prices would be most representative of the current PV market for residential- and utility-scale systems. As to the end date, utility-scale data after May 2014 is less reliable and substantially less available, and our period for estimating compound decline rates ends at this point.

Figure 4 below overlays the actual monthly values with the projected cost data. The decline curve matches the actual values sampled from the Open PV Project fairly well, as shown in Figure 6.

Figure 4: Residential-Scale Installed Costs with Decline Curve



Sources: The Open PV Project; Analysis by The Brattle Group

Table 7 reports the detailed information used to calculate the decline rate for residential-scale system installed costs. This table reports the beginning and ending dates used to calculate the decline rate as well as the final forecasted value for 2019. This analysis projects residential-scale PV costs of $2.25 per $W_{\text{-DC}}$ by June of 2019.

Table 7: Residential-Scale Cost Decline Calculations

Start Date for Decline Rate	Start Cost for Decline Rate ($/W-DC)	End Date for Decline Rate	End Cost for Decline Rate ($/W-DC)	Monthly Decline Rate for Residential-scale	Residential-scale value on 6/1/2019 ($/W-DC)
[1]	[2]	[3]	[4]	[5]	[6]
Feb-2009	$8.21	May-2014	$4.25	-1.04%	$2.25

Source: NREL Open PV Project; Analysis by The Brattle Group

[1]: Start month of decline rate analysis, selected by Brattle

[2]: Average monthly cost calculated using NREL Open PV data

[3]: End month of decline rate analysis, selected by Brattle

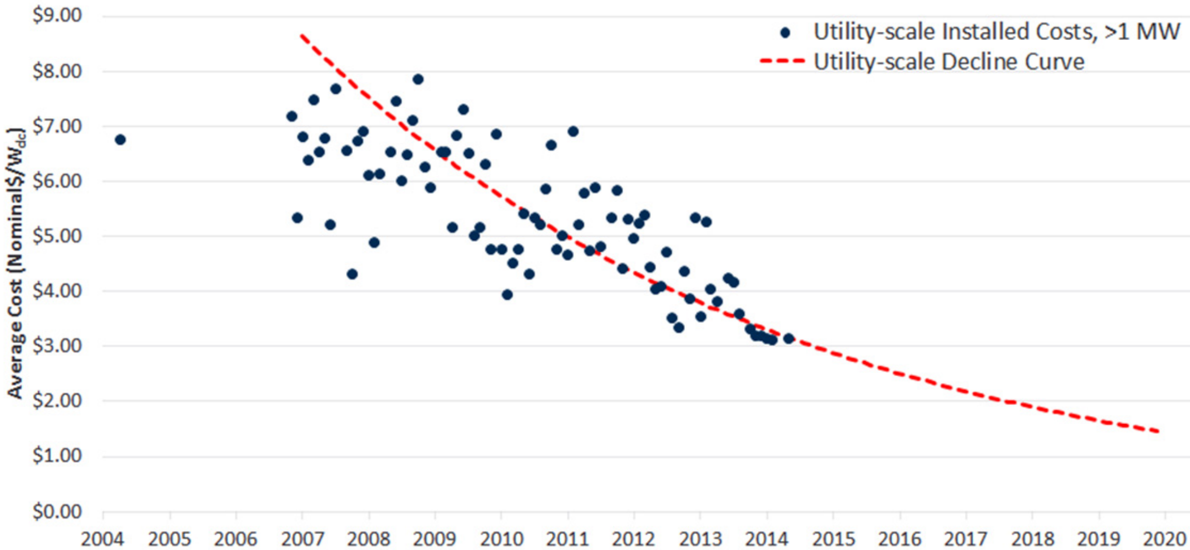
[4]: Average monthly cost calculated using NREL Open PV data

[5]: ([4] / [2]) ^ (1 / ([3] – [1])

[6]: Final value after decaying the cost to June 2019

Similarly for utility-scale solar systems, Figure 5 overlays the original monthly calculations with the estimated cost data. The decline curve matches the actual values sampled from the Open PV Project relatively well, as shown in Figure 6.

Figure 5: Utility-Scale Installed Costs with Decline Curve



Source: NREL Open PV Project; Analysis by The Brattle Group

Table 8 reports the detailed information used to calculate the decline rate for utility-scale systems. For utility-scale projects, this analysis projects costs of $1.57 per W-DC by June of 2019, and $1.43/W-DC after the economies-of-scale multiplier of 0.91.

Table 8: Utility-Scale Cost Decline Calculation

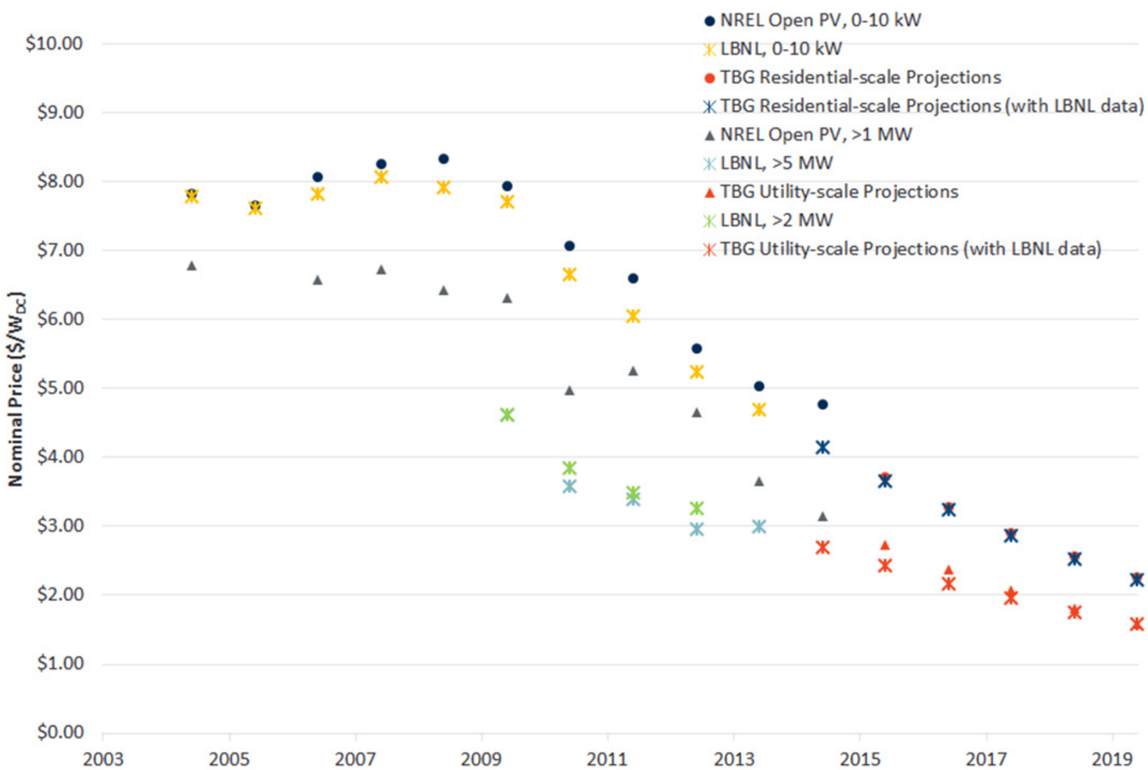
Start Date for Decline Rate	Start Cost for Decline Rate ($/W-DC)	End Date for Decline Rate	End Cost for Decline Rate ($/W-DC)	Monthly Decline Rate for Utility-scale	Utility-scale value on 6/1/2019 ($/W-DC)	EOS adjusted Utility-scale Value on 6/1/2019 ($/W-DC)
[1]	[2]	[3]	[4]	[5]	[6]	[7]
Feb-2009	$6.55	May-2014	$3.17	-1.15%	$1.57	$1.43

Source: NREL Open PV Project; Analysis by The Brattle Group
[1]: Start month of decline rate analysis, selected by Brattle
[2]: Average monthly cost calculated using NREL Open PV data
[3]: End month of decline rate analysis, selected by Brattle
[4]: Average monthly cost calculated using NREL Open PV data
[5]: ([4] / [2]) ^ (1 / ([3] – [1])
[6]: Value after decaying the cost to June 2019
[7]: Final value after adjusting with the economies-of-scale multiplier of 0.91

Figure 6 combines the NREL Open PV data with the values provided in the LBNL reports discussed above. Because the LBNL reports costs on a yearly basis, yearly averages of the raw

Open PV data were calculated rather than using the monthly averages as shown above. In general, LBNL values are slightly lower for residential-scale projects and significantly lower for utility-scale projects. This discrepancy can partly be explained by different size thresholds used by LBNL and NREL in defining the utility-scale systems.[20] However, for utility-scale projects in 2013 and onwards, the gap narrows. Furthermore, a decline curve was calculated using LBNL's yearly data and Figure 6 shows that by 2019, the projects calculated using LBNL data match those using NREL Open PV data. All data points in red represent projections calculated using the decline equation.

Figure 6: Comparison of LBNL and NREL Open PV Data



Notes:

(1) NREL values are simple averages; (2) LBNL residential-scale values are medians;

(3) LBNL utility-scale values are weighted averages

[20] LBNL assumes 5MW and above as utility-scale while NREL only differentiates 1 MW and above. This observation on discrepancy reconfirms that there are economies of scale between 1 MW and 5 MW.

We have also reviewed several other studies that provide comparable projections for PV costs. These projections, summarized in Appendix A, further corroborate our estimates.

C. Projected Power Output from Colorado PV Plants

The second major step in our analysis was the determination of the solar-electric output from the assumed 60,000 5 kW residential-scale systems distributed around Xcel Energy Colorado's service area and from 300 $MW_{\text{-DC}}$ utility-scale plants added within the same general area.

The first step in this analysis was to determine the size and location of the utility-scale alternative. Xcel Energy Colorado informed us that 300 MW of additional utility-scale solar capacity would likely come in the form of two plants: a 170 MW plant expected to be in service in their area by 2019 and the balance assuming a second plant.[21] Based on input from Xcel Energy, we assumed that both these plants would be located in the Pueblo area that has favorable insolation and a strong transmission backbone, both preferred conditions for developing utility-scale solar projects.

Forecasting the exact locations for the 60,000 added residential-scale systems was a more complex exercise. For the purposes of computing solar-electric output, the important assumptions concerning these systems were their physical dispersion and their average orientation relative to the sun. As an illustration, if all systems were installed in a part of Denver that happened to have greater cloud cover than other parts of the city, power output would be lower than if systems were scattered uniformly throughout the metropolitan area.

To project the location of the residential-scale systems, EnerNex worked with Xcel Energy Colorado to develop a statistical algorithm that distributed 60,000 additional systems in approximately the same geographical pattern that current residential-scale systems are now installed within the Xcel Energy Colorado area. In other words, we assumed that residential-scale PV installation patterns would continue being installed along the feeders in Xcel Energy

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21 *See* http://www.xcelenergy.com/Company/News/News_Releases/Xcel_Energy_proposes adding_economic_solar,_wind_to_meet_future_customer_energy_demands.

Colorado's system where they are now being installed. The details of this statistical analysis are described in Appendix B.

Once the locations of the two types of PV systems were determined, we began an extensive effort to collect insolation data applicable to these systems. Because we wanted to be as accurate as possible, we did not use estimated annual insolation data derived from models, as is common. Instead, EnerNex conducted a thorough survey of all actual measured insolation levels in and around the Xcel Energy Colorado service area, also described in Appendix B. For both utility- and residential-scale, we used actual insolation data measured at one-minute intervals during the most recent year available as the basis of our analysis. Furthermore, while insolation data observed for the Pueblo areas (where we assumed utility-scale solar projects would be built) were better than those observed for the Greater Denver area (where we assumed the majority of residential-scale PVs would be installed), we conservatively used the same irradiance data from the Greater Denver area for modeling both utility- and residential-scale PV installations.

Starting with this insolation data, solar-electric production for each type of PV plant was modeled through a three step process. These three steps accounted for spatial smoothing of solar irradiance; panel tilt and tracking; and conversion losses of power production (electrical losses including AC/DC conversion, panel and inverter efficiencies, soiling, shading, snow, downtime, and other factors).[22] In addition, utility-scale plants typically oversize the PV panel capacity (MW_{-DC}) against the inverter capacity (MW_{-AC}) by approximately 20%. Therefore the inverter capacity for utility-scale was assumed to be approximately 20% smaller (250MW_{-AC} inverter for 300MW_{-DC} panels).[23] These analytic steps are explained in more detail in Appendix B.

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22 The three steps are: 1) converting measured irradiance levels to average Global Horizontal Irradiance (GHI) levels to account for spatial smoothing; 2) converting average GHI to plant-average plane-of-array incident irradiance to account for panel tilting and tracking benefits; and 3) converting average incident irradiance to electric power production accounting for electrical losses, soiling, shading, *etc.*). The methodologies used are similar to those described in the report titled "Simulating Solar Power Plant Variability: A Review of Current Methods" by Sandia National Laboratory (published June 2013), and used in the NREL PVWatts simulation tool (technical reference published in October 2013).

23 If the inverter size for utility-scale was not reduced, the levelized annual generation of the utility-scale PVs would have increased from 597 GWh to 624 GWh, a 4.6% increase.

Based on this analysis, we found that 300 MW-DC solar capacity would yield approximately 597,000 MWh annually in a utility-scale project and approximately 400,000 MWh annually when deployed in residential-scale systems, both within the Xcel Energy Colorado's service area.[24] Relative to a DC capacity of 300 MW for both types of PVs, we calculated the annual capacity factor for utility-scale PVs in Xcel Energy Colorado's area to be 24.22% and Xcel-area residential-scale PVs to be 16.24%, which amounts to approximately 50% more capacity for utility-scale solar.[25, 26]

The processes and results of deriving the capacity factors were peer reviewed by industry experts and compared against actual production from near-by sites. Details of the methods and data used are included in Appendix B.

IV. Modeled Customer Costs

The developers of utility-scale PV projects must finance and recoup the complete costs of selling, installing, and operating utility-scale PV plants over the course of their lifetime. We assume all these costs are recouped via a 25-year power purchase agreement with Xcel Energy Colorado and then passed through to customers with no mark-up by Xcel Energy Colorado. Thus, to determine customer costs for this solar power, we model the economics of a developer incurring the capital

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24 The average annual production over 25 years is 596,655 MWh and 400,125 MWh respectively for utility- and residential-scale PV systems, assuming 0.5% per year derating caused by aging of the PV panels. The tracking ability of utility-scale accounts for nearly half of this difference. Note that the utility-scale assumes a system with 300 MW-DC solar panels and a 250 MW-AC inverter system, which limits the maximum output to 250 MW. The capacity factor is 24.22% if the base capacity of such a system is considered to be 300 MW. When the base capacity of such a system is considered to be 250 MW, then the capacity factor will be 29.06%. *See* Appendix B for further details.

25 The irradiance data used for both utility-scale and residential-scale in the analysis was for locations within the urban Denver area, typical for residential-scale PV installations. If irradiance data for utility-scale PVs were taken from a location outside of Denver (Sunspot, approximately 150 miles southeast of Denver), which is a more typical location for utility-scale PVs, the capacity factor of utility-scale would increase from 24.22% to 27.07% (assuming 300 MW base capacity) or from 29.06% to 32.48% (assuming 250 MW base capacity).

26 The calculation method applied to convert irradiance data to capacity factors is the same method used in NREL's PV Watts calculator. *See* Appendix B for further details.

costs calculated in Section II and producing annual solar power estimated above. For customer owned residential systems, the cost of ownership was computed via a relatively straightforward calculation of payments on a loan, net of federal tax credits, at an extremely conservative interest rate of 3.8%.[27] Similarly, to estimate customer costs for leasing a residential-scale system we model the lease charges made by residential-scale developers whose costs and solar production are as computed above. All tax benefits received are assumed to be reflected in customer-paid costs.[28]

We estimate the per-MWh and total present value costs of the utility PPA and residential-scale lease PV alternatives using a financial model originally developed for Connecticut's Clean Energy Finance and Investment Authority (CEFIA), commonly referred to Connecticut's "Green Bank."[29] The model calculates revenue requirements driven by assumptions for technical parameters, capital and operating costs, economic assumptions such as inflation, capital sourcing (debt, equity and tax equity), and associated costs, as well as other incentives, as applicable. We use an inflation rate of 2% calculated as the difference between 30-year nominal and real interest rates reported by the Office of Management and Budget Circular, A-94.[30] We also assume a 25 year contract life for the utility-scale PVs and a 25 year asset life for the residential-scale PVs. (All NPVs are also calculated over 25 years.)

Revenues over the economic life of the assets are back-calculated (in nominal terms at stipulated rates of assumed contract escalation) such that they cover operating costs and recover capital investment and associated target returns over stipulated time frames and, in the case of debt, with sufficient down-side protection (further discussed below). The revenue requirements, case

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27 Based on our use of the Xcel Energy Colorado system as our geographic base, we do not incorporate any state or local system. REC revenues as well as tax incentives or grants for residential-scale PV estimated by Xcel Energy are deducted for loan costs.

28 Colorado does not have a state tax credit for residential-scale solar. Local tax or subsidy programs applying either to utility- or residential-scale solar are also not included.

29 Overview of Rooftop Solar PV "Green Bank" Financing Model, Bob Mudge and Ann Murray, The Brattle Group, January 17, 2013, available at www.brattle.com. For more information, *see*: http://www.ctcleanenergy.com/AboutCEFIA/RooftopSolarPVModel/tabid/700/Default.aspx.

30 *See* http://www.whitehouse.gov/omb/circulars_a094/a94_appx-c.

by case, are represented and compared in terms of (i) levelized costs per MWh of energy production (nominal basis) and (ii) NPV in absolute dollar terms.

In the model, capital is assumed to be sourced in the form of debt, tax equity, and owner/developer equity. These sources differ in cost and time horizon for the recovery of investment and return: debt—15 years, tax equity—10 years, and developer equity—25 years (assumed economic life). In theory, from a sheer cost of capital perspective, a project owner would seek to maximize the lowest cost source of capital—typically debt—and minimize the most expensive—typically owner equity. However, the challenge of optimizing tax benefits and lender and tax equity risk tolerances poses further constraints, as discussed below.

Assumptions about the Investment Tax Credit (ITC) and accelerated tax depreciation—and how they are absorbed—significantly drive assumptions for capital structure and are very material to the Scenario outcomes. At present, utility- and residential-scale PVs both qualify for a 30% ITC and 5-year modified accelerated cost-recovery system (MACRS) tax depreciation. To date in the solar industry, third-party tax equity investors have frequently been called upon to absorb these tax benefits because utility-scale developers are not always in a position to optimize tax benefits on their own and residential-scale owners cannot claim accelerated depreciation at all. Accordingly, with the exception of Scenario 2, a general assumption in the financial model is that the ITC and accelerated depreciation are "monetized" by third-party tax equity.

For simplicity, the cases assume 35% tax equity as a percentage of total capital with a 10% ITC and 55% with a 30% ITC. Tax equity is assumed to be integrated via a "partnership flip" structure in which the tax equity investor earns its target return from a combination of allocated pre-tax cash flow and tax benefits (the ITC and accelerated depreciation). In turn, debt structuring options are a function of tax equity assumptions, in the following two ways. First, it has historically been difficult to secure both debt and tax equity at the level of an individual project (or project portfolio, in the case of residential-scale system). We assume in our modeling that this historic incompatibility persists and therefore, whenever tax equity is assumed, the accompanying debt must be "backlevered" at the sponsor level, effectively subordinating the debt to the tax equity. In addition, the amount of debt in such Scenarios (in % or dollar terms) is further constrained by lower cash flow available for debt service coverage after payments to tax equity and higher assumed interest costs. This means that debt as a percentage of overall capital is generally well under 50% in the presence of tax equity. (This combination of factors leads to overall costs being higher with tax equity than if the developer can absorb the tax benefits on its own.)

Importantly, we hold these capital structure assumptions constant when comparing between utility- and residential-scale solar. Nonetheless, *changes* in underlying assumptions that affect capital cost and recovery, such as the percentage ITC, will tend to have a greater impact (up or down) on residential-scale outcomes, because capital recovery forms a greater part of the overall revenue requirement for residential- than for utility-scale. For the residential-scale customer self-purchase option, we assume the customer enters into a 25-year fixed-rate home equity loan at 3.8% annual interest to effectuate an outright purchase of the system.[31] We assume the residential-scale purchases do not receive accelerated depreciation. We also assume that residential-scale purchases do not receive investment tax credit (with the exception of Scenarios 1 and 5).[32] We have adapted the CEFIA Solar Financing model to this option.

A. Comparative Generation Cost Results by Scenario

After a careful analysis of solar PV installed cost data and selection of other parameters for the Solar Financing Model, we ran the model for the Reference Case and five Scenarios described earlier. It is important to reiterate that we compare the costs of two equal sized (300 MW_{-DC} capacity) utility- and residential-scale PV systems. While performing this comparison, we use the levelized costs per MWh as our metric since these systems have different capacity factors and different MWh output levels (Table 9). We also report the NPVs associated with the Reference

31 This is the average home equity loan rate as of the preparation of this report. Research of home equity loan rates for various cities within Colorado at the time of the study showed a range of 3.25% to 5.88%. We selected 3.8% as a representative rate for Colorado (source: bankrate.com). To ensure that we were conservative in our calculations, we chose the lowest-cost financing option available to consumers, though all consumers may not have access to home equity loans. While we are projecting 2019 results, we believe it is conservative to assume that interest rates will continue at their historically-low levels. PACE programs that included loans for residential solar systems may also offer comparatively lower costs of debt, but we are not aware of PACE programs able to offer loans at rates significantly below 3.8%.

32 Residential purchases are not eligible for the ITC effective January 1st, 2017. *See* http://www.akingump.com/en/experience/practices/global-project-finance/tax-equity-telegraph/faqs-expiration-of-30-percent-itc-after-2016-1.html#_ftn1\ U.S. Energy Tax Incentives Act of 2005, Section 25D credit.

Case and other Scenarios; however one should keep in mind that these NPVs are associated with different levels of MWh production (Table 10). Further detail on the inputs and results of these runs is attached as Appendix C.

Reference Case (2019 ITC at 10%)

Our Reference Case uses the projected installed PV costs for 2019, assumes that the ITC is lower at 10%, and tax-equity financing absorbs the ITC credits as part of the financing of the utility- and residential-scale lease systems. Residential-scale purchases do not receive any ITC credits in 2019 consistent with the current tax code. We find that the levelized cost of 300 MW-DC capacity is \$83/MWh for utility-scale PV systems; \$167/MWh for residential-scale PV systems purchased by the customers; and \$182/MWh for residential-scale PV systems secured through leasing. Based on these numbers, a 300 MW-DC capacity utility-scale system costs \$83/MWh less than a 300 MW-DC residential-scale PV capacity purchased by the customers.

Table 9: Levelized Cost Comparison between Residential- and Utility-Scale PV (\$ per MWh)

No	Scenario	Utility-scale	Residential-scale Purchase	Cost Difference (Res-Utility)	Residential-scale Lease
Reference	**2019 ITC @ 10%**	**83**	**167**	**83**	**182**
Scenario 1	2019 ITC @ 30%	66	123	**57**	140
Scenario 2	2019 Developer absorbs ITC	66	N/A	**N/A**	140
Scenario 3	2019 Higher Inflation	95	187	**92**	206
Scenario 4	2019 Lower PV Cost	69	137	**67**	149
Scenario 5	2014 Actual PV Cost	117	193	**76**	237

Scenario 1 (2019 ITC at 30%)

Scenario 1 uses the projected installed PV costs for 2019; assumes that the ITC remains at 30%; and tax-equity financing absorbs the ITC credits as part of the financing of the utility-scale and residential-scale lease systems. In this scenario, residential-scale purchases are assumed to take advantage of the 30% ITC. We find that the levelized cost of 300 MW-DC capacity is \$66/MWh for utility-scale PV systems; \$123/MWh for residential-scale PVs purchased by the customers; and \$140/MWh for residential-scale PVs secured through leasing. Based on these numbers, a 300 MW-DC capacity utility-scale system costs \$57/MWh less than a 300 MW-DC residential-scale PV capacity purchased by the customers. As expected, higher ITC reduces the levelized system costs for both PV alternatives.

Scenario 2 (2019 Developer Absorbing ITC)

Scenario 2 uses the projected installed PV costs for 2019; assumes that the ITC is lower at 10%; and developers absorb the ITC credits (as opposed to third party tax equity) for both utility-scale and residential-scale lease systems. Residential-scale purchase case is not applicable for this scenario as the cost will not vary with the party absorbing the ITC. As discussed above in the "Modeled Customer Costs" section, the absorption of ITC by third parties or developers significantly drives assumptions for capital structure. We find that the levelized cost of 300 MW-DC capacity is $66/MWh for utility-scale PV systems and $140/MWh for residential-scale PVs secured through leasing. The levelized system costs are lower when developers are able to absorb the tax credits (as opposed to tax equity financing), as the cost of debt is lower under 100% developer financing.

Scenario 3 (2019 Higher Inflation)

Scenario 3 uses the projected installed PV costs for 2019; assumes that the ITC is lower at 10%; tax-equity financing absorbs the ITC credits as part of the financing of the utility- and residential-scale systems; and inflation is higher at 4%. Residential-scale purchases do not receive any ITC credits consistent with the current tax code. We find that the levelized cost of 300 MW-DC capacity is $95/MWh for utility-scale PV systems; $187/MWh for residential-scale PVs purchased by the customers; and $206/MWh for residential-scale PVs secured through leasing. Based on these numbers, a 300 MW-DC capacity utility-scale system costs $92/MWh less than a 300 MW-DC residential-scale PV capacity purchased by the customers.

Scenario 4 (2019 Lower PV Cost)

Scenario 4 scales down the projected installed PV costs for 2019 by 20%; assumes that the ITC is lower at 10%; and tax-equity financing absorbs the ITC credits as part of the financing of the utility- and residential-scale systems. Residential-scale purchases do not receive any ITC credits consistent with the current tax code. We find that the levelized cost of 300 MW-DC capacity is $69/MWh for utility-scale PV systems; $137/MWh for residential-scale PVs purchased by the customers; and $149/MWh for residential-scale PVs secured through leasing. Based on these numbers, a 300 MW-DC capacity utility-scale system costs $67/MWh less than a 300 MW-DC residential-scale PV capacity purchased by the customers.

Apart from the 2019 Scenarios discussed above, we analyzed a fifth scenario using 2014 tax and PV cost assumptions.

Scenario 5 (2014 Actual PV Cost)

Scenario 5 uses the actual installed PV costs for 2014; assumes that the ITC is at 30 %; and tax-equity financing absorbs the ITC credits as part of the financing of the utility- and residential-scale lease systems. Residential-scale purchases are able to take advantage of the 30% ITC credits consistent with the current tax code. We find that the levelized cost of 300 MW-DC capacity is $117/MWh for utility-scale PV systems; $193/MWh for residential-scale PVs purchased by the customers; and $237/MWh for residential-scale PVs secured through leasing. Based on these numbers, a 300 MW-DC capacity utility-scale system costs $76/MWh less than a 300 MW-DC residential-scale PV capacity purchased by the customers. Higher levelized costs are mostly a function of the higher installed PV costs in 2014 compared to 2019 (despite the higher investment tax credit).[33]

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33 The levelized cost of $237/MWh for leased residential-scale PVs is seemingly higher than what is being offered in the Colorado market today. However it is lower than what residents in California (where the majority of residential-scale PVs are being installed) are offered (levelized around $250/MWh). NREL, in its report titled "Financing, Overhead, and Profit: An In-Depth Discussion of Costs Associated with Third-Party Financing of Residential and Commercial Photovoltaic Systems," issued October 2013, calculates the average 20 year PPA cost of a 5.1 kW-DC residential-scale system (system cost of $4.52/W-DC) to be at $297/MWh (starting at 21¢ per kWh, or $210/MWh, escalating at 3.5% per year.) These observations suggest that there could be cross-marketing strategies that are not captured in our analysis.

Table 10: NPV Comparison of Xcel-Colorado Generation Costs Between Residential- and Utility-Scale PV ($MM)

No	Scenario	Utility-scale	Residential-scale Purchase	Cost Difference (Res-Utility)	Residential-scale Lease
Reference	**2019 ITC @ 10%**	**556**	**752**	**195**	**812**
Scenario 1	2019 ITC @ 30%	438	554	116	625
Scenario 2	2019 Developer absorbs ITC	438	N/A	N/A	625
Scenario 3	2019 Higher Inflation	538	716	178	785
Scenario 4	2019 Lower PV Cost	463	617	153	668
Scenario 5	2014 Actual PV Cost	781	869	87	1061

Table 10 reports net present values for the cost of utility- and residential-scale systems. Based on Table 10, residential-scale PV costs $87 million to $195 million more than the utility-scale on an NPV basis over 25 years for the Reference Case and remaining five Scenarios. In 2014, 1,200 MW of residential-scale PV systems were installed in the U.S. If the same amount of residential-scale PV systems (1,200 MW) were installed in 2019, these PV systems would cost customers roughly $800 million more in NPV than a comparable purchase of utility-scale systems, under conditions assumed for the Reference Case.[34]

The earlier sections illustrate that the per-MWh customer generation costs of utility-scale PV systems are substantially lower—in fact, about half the cost—compared to residential-scale systems. The discussion in the preceding section focused on the installed cost and production from each PV system. The next two section review other cost differences between the two types of PV systems. While the discussion of these differences is mostly qualitative, a "ballpark" estimate of these cost differences is provided (where possible) to illustrate the magnitude of the differences.[35]

34 See footnote 8 above.

35 Where possible, data applicable to the Xcel Energy Colorado system was used for these calculations.

V. Monetized Non-Generation Costs and Benefits Not Quantified in this Study

In this section, we consider various monetized non-generation costs and benefits that are not quantified in this study, including the cost of integrating PV capacity and ancillary services, the cost of rest-of system fuel consumption and transmission losses, avoided or increased transmission system capital costs, avoided or increased distribution system capital costs, and avoided or increased distribution system operating costs. These types of costs (or benefits if avoided), and our conclusions regarding each with respect to their effect on the relative cost of residential- and utility-scale systems, are summarized in Table 11. For this particular study, we note that some of these findings may change significantly at higher or lower levels of residential-scale PV penetration than we assumed.

Table 11: Monetized Non-Generation Cost Differences between Utility- and Residential-Scale PV Not Quantified in This Study

Cost Category	Content	Estimated Impact
1 - Changes in the Bulk Power System Operating Costs	Integrating Capacity and Ancillary Services	• Costs likely to be slightly higher for residential-scale PV
	Rest-of-System Fuel Cost* Differences and Transmission Losses	• Fuel costs significantly lower for utility-scale PV due to higher capacity factor • Transmission losses lower for residential-scale PV
2 - Changes in Non-Solar Generation Capacity	Avoided Generation Capacity	• Slightly lower costs for utility-scale PV
3 - Changes in Transmission System Capital Costs	Avoided Transmission Capital Costs	• Slightly to moderately lower costs for residential-scale PV
4 - Changes in Distribution System Capital and Operating Costs	Avoided or Increased Distribution System Capital Costs	• Highly variable and case-specific, but generally unlikely to be large positive or negative at the levels considered in this study
	Avoided or Increased Distribution System Operating Costs and Losses	• Slightly to moderately higher costs for residential-scale PV • Slightly to moderately lower losses for residential-scale PV at the levels considered in this study

To give further perspective on these cost categories, the following subsections examine each of these monetized non-generation cost categories in slightly greater detail.

1 - CHANGES IN THE BULK POWER SYSTEM OPERATING COSTS

An increase in any type of PV power on a utility system can lead to: i) increased needs for ancillary services to balance the variability of the solar output; ii) reduced fuel costs due to replacement of energy generated by fossil-fuel based generators; and iii) reduced energy losses on transmission lines as PVs installed on distribution networks closer to load may reduce energy losses, thus reducing system fuel use and emissions.

The amount of increased ancillary service needs cannot be quantified without a detailed study. Even within a given system, the needs may vary by the quantity of PV capacity being added. A recent study of the Duke Carolina system performed by the Pacific Northwest National Laboratory (PNNL) found that adding distributed solar capacity equal to 20% of the peak load caused planning reserve requirements to increase by 30% and regulation to increase by 140%, compared to a case without PV capacity added.[36] These increases led to a system cost increase of $1.43 to $9.82 per MWh of PV energy, depending on assumptions regarding fuel price and other factors.

While adding PV capacity can lead to an increase in ancillary service needs, the differences in ancillary services costs between utility- and residential-scale are difficult to determine. Utility-scale systems that oversize the panel array relative to inverter capacity will likely have a better profile (less variability) than any given residential-scale system but the geographical diversity of residential-scale systems aggregated also contributes to reduced variability.[37] However, other advantages of utility-scale include better location selection (higher insolation), better controllability and visibility by the system operator, and being able to provide downward ancillary services. On balance, we expect that residential-scale PV capacity will typically require slightly higher ancillary service needs than equal amounts of utility-scale PV capacity, all other factors being the same.

Aside from ancillary service needs, the higher capacity factor of utility-scale PVs will contribute to much higher reductions in bulk power system operating costs by displacing more fossil fuel.

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36 *See* http://www.duke-energy.com/pdfs/carolinas-photovoltaic-integration-study.pdf.

37 For more explanation of these considerations, see Appendix B.

Assuming power generated from PV systems will replace power generated from very efficient combined-cycle units (with a heat rate of 7,000 Btu/kWh and natural gas price at $4.50/MMBtu), 300 MW of utility-scale PV saves about $6.2 million per year more in fuel costs than same-size residential-scale systems, or about $9.75 per MWh generated by utility-scale PVs.[38, 39]

One advantage of residential-scale PV is that it is closer to the load and therefore reduces transmission losses.[40] The calculation of loss differences can be complex and somewhat system-specific. If we assume the reduction in transmission losses is approximately 3%, utility-scale PVs' transmission losses cost about $564,000 per year.

To summarize, ancillary services costs are likely to be slightly higher for residential-scale PV capacity than for utility-scale PV capacity. To the extent that both forms of PVs displace the same type of fossil fuel generation, fuel costs will be lower with utility-scale PVs, on the order of $6.2 million per year. Transmission losses will be lower with residential-scale PVs in the ballpark of $564,000 per year. Overall, inclusion of these factors is likely to increase the cost difference between utility-scale and residential-scale PV systems.

2 - Changes in Non-Solar Generation Capacity

In the Xcel Energy Colorado system and in most other utility systems, the distribution utility is required to buy or own capacity resources sufficient to serve the expected peak load in its area and to maintain a safe reserve margin. In the two alternatives we examine, 2019 peak gross system demand for the Xcel Energy Colorado is unchanged, so in both cases Xcel Energy Colorado must maintain the same level of capacity resources. It is therefore appropriate to compare the contribution of both the utility- and residential-scale PV systems to Xcel capacity contribution between the two types of PVs.

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38 197,000 MWh * $4.5/MMBtu * 7,000 Btu/kWh = $6.2 million.

39 The natural gas price of $4.5/MMBtu is based on the PSCo forecasts. For more information see, Colorado PUC, Docket No. 11A-869E.

40 This also applies to other PV systems that could be of larger scale than the typical residential-scale PVs that are interconnected directly to the distribution system, rather than the bulk transmission system as is the case for most utility-scale PVs.

Previous studies performed by Xcel Energy Colorado have examined precisely this question. In the 2013 Distributed Solar Generation study, Xcel Energy estimated that the effective load-carrying capacity (ELCC) of distributed solar in its service area was 33% of DC nameplate capacity.[41] In the same study, Xcel Energy indicates that the ELCC is approximately 40% of DC nameplate for a single axis utility-scale PV system; the type we assume is installed for the utility-scale option.[42] Thus, based on Xcel Energy's ELCC calculations, the additional capacity necessitated by a group of residential-scale systems, compared to the same size (300 $MW_{\text{-DC}}$ capacity) utility-scale system, is higher by 7%. Assuming a new peaking unit requires a $70.32/kW annual carrying charge, this adds up to close to $1.5 million per year, or approximately $7 per MWh of additional solar power provided by utility-scale systems.[43,44]

Based on our literature review, there is a wide variation in assumptions with respect to the capacity value of solar. Arizona Public Service (APS) uses a capacity value of 70% of the nameplate capacity for a single-axis utility-scale PV system. For residential-scale PV installations, APS assigns a capacity value of 45%.[45] Public Service Company of New Mexico, another utility with a footprint farther south than the Xcel Energy Colorado system, assigns a capacity value of 55% to new fixed-tilt utility-scale PV resources.[46] Avista, with a footprint farther north than Xcel Energy Colorado, assigns a capacity value of 63% to utility-scale PV for the summer but 0% for the winter.[47] On the lower end, PacifiCorp assigns a 13.6% capacity credit to utility-scale PV resources.[48] PNNL's study for Nevada shows an ELCC range of 38.47% to 57.41% depending on

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41 Xcel Distributed Solar Study, p. 24.

42 *Ibid*, p. 25

43 PSCo 2011 Electric Resource Plan, Volume II Technical Appendix, dated October 31, 2011.

44 300MW * 7% * $70.32/kW-year = $1,476,720/year ≈ $1.5 million/year.
$1,476,720 / 209,626 MWh (generation difference of the two PV types in year 1, see footnote 28) = $7.04/MWh

45 Arizona Public Service 2014 Integrated Resource Plan, p. 288.

46 PNM Integrated Resource Plan 2017-2033, p. 16.

47 Avista 2013 Electric Integrated Resource Plan, p. 6–15.

48 PacifiCorp 2013 Integrated Resource Plan, Volume I, p. 94.

the amount of solar being added.[49] The assumptions used above for calculating the difference in the capacity value of new PV installations fall within the range we have found in the literature.

3 - Changes in Transmission System Capital Costs

Because residential-scale solar is located at the point of use, there is potentially a reduction in the need for transmission capacity to serve system load, all other factors being the same. Utility-scale solar relies on the bulk transmission system to reach load and therefore transmission is not avoided. Thus, at least in concept, residential-scale systems saves transmission capital costs relative to utility-scale systems. The exact amount of transmission that can be avoided by residential-scale solar capacity, and the cost of this transmission, can be estimated only in the context of actual systems conducting thorough planning exercises.[50]

Xcel Energy's 2013 study of distributed solar and its solar stakeholders' reply illustrate the potential range of avoided transmission costs that residential-scale systems might provide. Xcel Energy estimated that moderate amounts of distributed solar (59 MW in its study) would reduce only transmission interconnection costs, amounting to $0.20/MWh. Using a statistical method and historical Form 1 data, solar stakeholders computed avoided transmission costs of $18.30/solar MWh.[51] This range is in keeping with many other studies of transmission costs avoidance from distributed PV systems. For example, the Public Service Company of New Mexico assumes that new utility-scale PV resources will be located on distribution facilities and therefore does not assign incremental transmission costs to utility-scale solar.[52] Wyoming Municipal Power Agency Integrated Resource Plan's 2011 IRP also assumes zero incremental transmission costs.[53] However, compared to our study, both Public Service Company of New

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49 *See* http://www.researchgate.net/publication/242329472_Capacity_Value_of_PV_and_Wind_Generation_in_the_NV_Energy_System.

50 Transmission system operating costs other than energy losses are extremely small per MWh delivered and in general not sensitive to small changes in transmission capital plant, so virtually all studies treat these costs as *de minimis.*

51 Xcel Distributed Solar Study, p. 43; Solar Stakeholder Study, p. 6.

52 PNM Integrated Resource Plan 2014–2033, p. 57.

53 Wyoming Municipal Power Agency Integrated Resource Plan, p. B-4.

Mexico and Wyoming Municipal Power Agency assume very modest increases in PV systems (20 MW and 1 MW, respectively). Avista, a utility with a footprint in a region that is not ideal for solar, estimated a levelized transmission cost of $21.62/MWh, which is at the high end of what we have found for transmission costs incurred from installing utility-scale PV systems.[54]

Without having examined any of these calculations in detail, it is clear that the magnitude of these avoided costs is nowhere near large enough to reduce the gap between utility- and residential-scale PV materially. The cost gap we calculated for the Reference Case is, at $83/MWh, approximately four times the largest avoided transmission cost found in the aforementioned studies. Moreover, these cost savings are likely to be offset, at least in part, by the other non-generation cost elements that tend to favor utility-scale systems, as discussed earlier in this section. Thus, even assuming values for non-generation monetized costs advanced by Xcel Energy's solar stakeholders, the overall monetized costs of utility-scale compared to residential-scale solar are approximately consistent with our generation-only numbers, at least for the Xcel Energy Colorado system.

4 - Changes in Distribution System Capital and Operating Costs

In the Xcel Energy Colorado system and in most other utility systems, the distribution utility is required to serve all loads. Therefore it is likely that the distribution network needs will be the same regardless of the existence of distributed generation, including residential-scale PVs, *i.e.*, the utility will need to serve the load through traditional means when distributed generation resources are not available. However, increasing distributed generation could potentially stress the existing distribution system. Potential issues associated with increased residential-scale PV systems on the distribution network include:

- Reverse Power Flow (this could confuse switches and relays designed for a one way flow)
- Voltage Violation (includes over/under voltage caused by PV systems and also temporary overvoltage caused by single-phase-to-ground fault)
- Voltage Fluctuation (PV system induced voltage variability causing increased operation of voltage control equipment)

54 Avista 2013 Electric Integrated Resource Plan, pp. 6–8.

- Feeder Section Loading (current-carrying capacity of lines could be exceeded)
- Feeder Imbalance (caused by uneven distribution of PV systems)
- Fault Current (mis-operation of feeder and substation switches)
- Distribution Line Power Losses (decrease for low penetration PV systems, but can increase for high penetration PV systems)
- Unintentional Islanding (especially for higher solar penetration level)
- Others (harmonics, dynamics, flicker, *etc.*)

Our highly detailed simulations of four representative distribution feeders showed that adding only 300 MW of residential-scale PV to the Xcel Energy Colorado system, which has a peak load of nearly 7,000 MW, will not cause wide system impacts, but may impact the distribution system at both the local and feeder level. Distribution line power losses would be reduced in the residential-scale PV alternative because the residential-scale solar generation reduces the inflow of power needed to supply end load.

The PNNL study of the Duke system observed overall reduction in losses and increase in voltage violations. Reduction in losses comes from the reduction in power flowing on the distribution network. However, it should be noted that with higher penetration level of residential-scale PV systems, the losses could increase, particularly for the secondary circuits. This occurs when net generation from residential-scale PV systems becomes higher than the original load, *i.e.*, more power flows on the secondary circuits. The PNNL Duke study identifies such observations during lower load periods. The PNNL Duke study also showed upper bound voltage violations for low load seasons.

Overall, we do not believe that in most cases the net cost of these impacts on distribution systems will be large enough to mitigate the large gap between residential- and utility-scale generation costs and may in some cases widen it. In most cases, we expect these costs to be one or two orders of magnitude lower than generation costs.

VI. Non-Monetized Benefits

In addition to the monetized non-generation costs and benefits discussed above, it is possible to consider other benefits associated with PV systems that are difficult to quantify. Such non-monetized benefits are sometimes identified in resource planning and other policy discussions as a basis for offsetting the generation costs associated with PV systems, particularly residential-scale PV systems. These non-monetized benefits are often referred to as "externalities" and are not usually used to offset any utility costs that are included in utilities' revenue requirements and cost-based rate calculations. As discussed below, these types of benefits can be difficult to quantify, and given the level of penetration—300 MW—considered here, may be immaterial. However, as noted below, many of these types of benefits are positively correlated with output, and therefore, one would expect greater value to be ascribed to utility-scale systems because of the significantly higher relative output of those systems.

Some of the types of non-monetized benefits that have been identified include:

- **Water Savings**: Some cost-benefit studies include the value of water savings, including water that is returned to water bodies after use in traditional or hydroelectric power plants. Both monetized water use (*i.e.,* generators' payments to water suppliers)[55] and non-monetized "water externalities" correspond very strongly to electric generator fuel use. As a result, utility-scale solar could reduce water externalities by nearly 50% more compared to residential-scale solar, further widening the gap between utility- and residential-scale PV.
- **Fuel Price Hedge**: Solar electricity does not change in price as traditional utility fuel prices rise or fall, and thus provides price certainty. This is particularly relevant for vertically integrated utilities, such as Xcel Energy Colorado, where the cost of production is passed through to the end-customers. However the quantity of power produced by solar may vary and therefore the price hedge value, if any, cannot be easily quantified.
- **Energy Security**: Because solar energy is inherently indigenous, there is no reliance on fuel sources that may be interrupted by fuel supply chain disruptions, foreign or domestic. Many island systems are viewing solar (and wind) as ways to increase generation from indigenous resources. However, the production from these renewable resources could vary season to season and year to year, leaving the utility to secure fuel sources for the worst scenario. The effectiveness of energy security is less pronounced in interconnected systems and with the small

55 Monetized water savings will depend largely on water contracts that vary utility by utility or plant by plant. Some contracts are based on the water usage quantity, while other contracts can be of a fixed cost nature where reduced usage will not lead to immediate savings. Therefore we have included water savings as non-monetized costs while recognizing that there are cases when some of this cost could be monetized.

quantity of 300MW studied here, the effect of energy security is likely limited and difficult to quantify.

- **Energy Resilience:** In some configurations, distributed generation could be less vulnerable to electric system supply disruptions. However, most residential-scale PV systems installed today are set up so that these PV systems will not generate during outages to avoid potential accidents caused by reverse flows into a downed wire. In addition, in some areas exposed to occasional very strong storms (e.g., Florida or Oklahoma), it is possible that residential-scale PV systems are more vulnerable to storm damage than utility-scale PV systems or central station conventional power. In such cases, installing smart inverters or combining distributed PV systems with storage facilities could potentially increase resiliency, however the exact contribution of the PV system to this benefit cannot be easily calculated, and achieving this resiliency would carry the additional attendant cost of deploying storage and other protection systems on distribution systems.
- **Greenhouse Gas (GHG) Reductions**: PV solar electricity, whether deployed at utility- or residential-scale, produces no GHG emissions from operation. The volume of avoided GHG emissions in either case depends directly on the fuel associated with the avoided resource. However, regardless of the fuel type of the avoided generation, utility-scale PV solar is anticipated to reduce emissions by nearly 50% more than residential-scale solar, further widening the gap between utility- and residential-scale PV systems. This differential is solely a function of the observed variance in generation output of equivalent amounts of installed utility-scale and residential-scale PV.
- **Criteria Air Pollutants Reductions:** Solar electricity is a zero criteria-pollutant source from its operation. Similar to GHG emissions, utility-scale PV systems could avoid more emissions from other generation resources compared to residential-scale solar PV systems.
- **Job Creation**. As with all other electric resource additions, PV plants create jobs in both construction and operation. In general, the installation of residential-scale PVs is thought to create more jobs than installing utility-scale PV systems. However, the respective impact of each PV type to jobs associated with researching, developing and producing the PV equipment (panels, inverters, *etc.*), is unknown. Moreover, job creation is an extremely difficult externality to quantify because, when measured properly, it must incorporate the net effects of all economic changes between the two scenarios studied, including in this instance the impact of customer bill differences

When comparing these non-monetized or social benefits between utility- and residential-scale systems of equal capacity, for every category listed above except energy resiliency and jobs, utility-scale PVs provides greater benefits concomitant with the nearly 50% more solar MWh it produces. For example, more solar production yields correspondingly greater fuel price hedge benefits and avoids correspondingly more greenhouse and criteria pollutants. Thus, including these non-monetized benefits would tend to widen rather than narrow the cost differential we have identified between utility- and residential-scale PV systems.

The possible exceptions to these generation-based benefits are energy resilience and job creation. Energy system resilience is a complex and evolving concept, but there is little dispute that distributed energy sources have the potential to provide greater resilience when they are designed and deployed with this purpose in mind, which is not, historically, the case. For example, residential-scale PV systems can be deployed in locations that maximize their benefits to the grid or designed to provide power to homes when grid-supplied service is interrupted (though this is not the usual way residential-scale systems are engineered in the U.S.).[56] Methods to direct the deployment of residential-scale systems collectively to optimize system operation, resilience, and security are beginning to emerge; to date, however, the deployment is random, determined by the desire of individual residential home owner/retail customers, not by distribution system planners.

While distributed PVs holds some potential of providing greater resilience benefits than utility-scale PVs, it is exceedingly difficult to put a monetary value on this difference given the early state of our knowledge concerning the measurement and valuation of resilience.[57]

Finally, no conclusion can be reached regarding the comparative job impacts of utility-scale compared to residential-scale PVs without a much more complete analysis. Job impacts are the product of construction-period outlays, operating period work created, and the net effect of the alternative considered on economic activity and consumer spending. An evaluation of these

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56 Typically residential-scale PVs are set so they will not produce power when power is lost due to distribution network problems. This is to avoid potential accidents caused to the workers recovering the system by power flowing from these distributed resources.

57 *See* Paul Stockton, "Resilience for Black Sky Days Supplementing Reliability Metrics for Extraordinary and Hazardous Events," NARUC, February 2014. Miles Keogh and Christina Cody, "Resilience in Regulated Utilities," NARUC, November 2013. Philip Mihlmester and Kiran Kumaraswamy, "What Price, Resiliency? Evaluating the cost effectiveness of grid-hardening investments," *Public Utilities Fortnightly*, October 2013. Bill Zarakas, Frank Graves, and Sanem Sergici, "Investing in Electric Reliability and Resiliency," The Brattle Group, Inc., presented to NARUC 2014 Summer Meeting Joint Electricity and Critical Infrastructure Committees, July 15, 2013.

effects is far beyond the scope of our analysis, but there is no conceptual reason to believe that there is a significant difference in net (direct plus indirect) job creation and destruction between equal amounts of utility- and residential-scale solar, all other factors held the same.

VII. Conclusions

This report has examined the comparative customer-paid costs of generating power from equal amounts of utility- and residential-scale PVs in Xcel Energy Colorado's area. Our results indicate that customer generation costs per solar MWh are estimated to be more than twice as high for residential-scale systems, than the equivalent amount of utility-scale PVs.

Projected 2019 utility-scale PV power costs in Colorado range from $66/MWh to $117/MWh across our scenarios, while residential-scale PV power costs range from $123/MWh to $193/MWh for a typical residential-scale system owned by the customer. For leased residential-scale systems, the costs are between $140/MWh and $237/MWh. Based on the Reference case and remaining five Scenarios we analyzed, residential-scale PVs costs $87 million to $195 million more than the utility-scale on an NPV basis over 25 years. In 2014, 1,200 MW of residential-scale PV systems were installed in the U.S. If the same amount of residential-scale PV systems (1,200 MW) were installed in 2019, these PV systems would cost customers roughly $800 million more in NPV than a comparable purchase of utility-scale systems, under conditions assumed for the Reference Case.

These results apply to the Xcel Energy Colorado system and should not be transferred to other areas without attention to comparative insolation levels and other cost drivers that vary by region. However, we believe that the general relationship between costs is likely to hold true for most of, if not all, U.S. utilities with significant solar potential. We also find that our results are robust to changes in federal tax credits, inflation, interest rates, and changes in PV costs than we project in our base case.

As noted earlier, our specific quantitative results apply only to the generation portion of electric power service. In order to evaluate the complete customer cost differences between the two types of PV power, it is essential to evaluate these options in an optimized integrated resource planning framework that incorporates all the comparative monetized non-generation cost and benefit differences, such as transmission and distribution system impacts. However, as explained in Section IV, a review of the literature suggests that the total customer costs of PV power within a fully optimized power system will be substantially less expensive for equal amounts of utility-scale compared to residential-scale PVs in the vast majority of cases. Nevertheless, a full evaluation of these considerations would have to take place in the context of an optimized integrated resource plan, which we have not undertaken here.

Finally, we have briefly examined non-monetized social benefits that could potentially offset the costs. Among the main categories, water, fuel price hedge, energy security, and emissions, social benefits are roughly proportional to the amount of solar generation and are therefore higher for utility-scale PVs. Resilience benefits may be higher for some residential (and community) systems, and jobs benefits are ambiguous.

Overall, our findings demonstrate that utility-scale PV system is significantly more cost-effective than residential-scale PV systems when considered as a vehicle for achieving the economic and policy benefits commonly associated with PV solar. If, as we have shown, there are meaningful cost differentials between residential- and utility-scale systems, it is important to recognize these differences, particularly if utilities and their regulators are looking to maximize the benefits of procuring solar capacity at the lowest overall system costs. With the likely onset of new state greenhouse gas savings targets from pending EPA rules, the options for reducing carbon emissions and the costs of achieving them will take on an even greater importance. Simply stated, most of the environmental and social benefits provided by PV systems can be achieved at a much lower total cost at utility-scale than at residential-scale.

Appendix A

Solar Installation Data Sources

In this study, we used individual installation data from NREL's Open PV project to estimate solar costs, and reports produced by LBNL to corroborate the analysis performed on the data retrieved from the NREL Open PV Project. This Appendix describes the data sources in greater detail, outlining the type of data these two institutions have acquired and discussing the data curation processes they might have performed.

Open PV Project by NREL[58]

The Open PV Project is a collaboration between the public, industry, and government with the objective of compiling a complete database of PV installations across the United States. To initiate the Open PV Project, NREL requested installation data from a variety of state-run solar incentive programs and assembled a baseline set of reliable PV installation data. The project was then opened to data contributions from various groups within the PV community, including PV installers, utilities, and the general public. A contributor is required to provide four data elements when uploading into the dataset:

- Date Installed (Completion date or interconnection date)
- Size/Capacity of the PV Installation (in kW_{-DC})
- Location (Zip Code or Street Address)
- Total Installed Cost (in nominal USD, before incentives)

NREL verifies the accuracy of data elements through a system of checks before providing online access. Contributors are required to create accounts with the Open PV Project, and NREL tracks each user's data against other similarly sized and located projects. Furthermore, each registered user has a reliability score that reflects the contributor's data trustworthiness, and this score varies over time. In general, government agencies with defined data collection processes are trusted the most, followed by utilities and PV installers, and each contributor's estimated reliability is reflected in their score. Using all the above information, NREL systematically validates the uploaded data on a case by case basis by referencing a contributor's reliability score and other installations with similar data characteristics.

58 For access, go to https://openpv.nrel.gov.

The data used for the cost estimates described below were downloaded from the Open PV Project's website in August of 2014. After downloading the data, a number of internal curation practices were implemented that reduced the initial size of the raw data. This dataset included more than 330,000 installation entries between 2004 and 2014. However, roughly 70,000 of the entries had missing cost data and were removed from the analysis. Furthermore, duplicate entries were identified and removed from the analysis. The duplicates were identified as having the same date, location, cost, and size of installation. In order to eliminate potential extreme outliers, the 20 most and least expensive projects were dropped. Finally, to calculate installed costs in $/W-DC, total installed costs were divided by the size of the PV Installation. These $/W-DC values were used to forecast 2014 and 2019 cost estimates.

Lawrence Berkley National Laboratory Solar Market Reports

Two LBNL reports that analyze cost trends in the Solar PV market were used to corroborate cost estimates calculated from the Open PV data. LBNL has access to 300,000 individual residential, commercial, and utility-scale PV systems, which represent 80% of all grid-connected PV capacity installed in the United States through 2013. Their report, *Tracking the Sun VII: An Historical Summary of the Installed Cost of Photovoltaics in the United States from 1998 to 2013*, summarizes the trends in the installed costs of these grid-connected PV systems. However, this report does not provide detailed data for the utility-scale PV market. For detailed data on the utility-scale market, we relied on the LBNL report, *Utility-Scale Solar 2013: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States*. Data for utility-scale solar projects were not tracked in earnest until 2007, when the demand for utility-scale systems began to increase. Data for residential panels, however, are available from 1998 to the present.

Both of these reports are based on *reported* cost data and *do not* rely on modeled values (they also do not forecast PV costs into the future). Furthermore, all costs reported by LBNL represent the costs paid to project developers or installers, before incentives. These values are similar to NREL's Open PV data since they are up-front, not levelized costs, reported in $/W-DC. It is important to note that LBNL defines residential-scale solar installations as solar projects with capacities between 0 and 10 kW and utility-scale installations as solar projects larger than 5 MW.[59] For that reason, residential-scale costs are reported as median values while utility-scale costs are reported as capacity weighted averages.

Lastly, these two LBNL studies report costs in 2013 dollars; however, for our analysis we converted all costs to nominal dollars (using an inflation rate of 2 percent). After the above adjustments and assumptions were set, LBNL values could be used for comparison purposes to the values calculated using NREL's Open PV data.

Table A.1 shows a comparison to other projected installed costs that were compiled through various sources.

Table A.1: Cost Comparisons to various reported, modeled, and projected PV installed Costs

Study	Technology	2012 (Nom $/W-DC)	2013 (Nom $/W-DC)	2014 (Nom $/W-DC)	2015 (Nom $/W-DC)	2016 (Nom $/W-DC)	2017 (Nom $/W-DC)	2018 (Nom $/W-DC)	2019 (Nom $/W-DC)
Utility-scale									
APS IRP	Utility fixed						$1.90		
APS IRP	Utility single						$2.27		
Pacificorp IRP	Utility fixed				$3.13				
Pacificorp IRP	Utility single				$3.37				
TEPPC WECC	Utility single small		$2.94						
TEPPC WECC	Utility single large		$2.55						
LBNL	>5 MW	$2.95	$3.00						
LBNL	>2 MW	$3.25							
GTM	Utility Estimated			$1.81					
GTM	Utility Modeled			$1.69					
SunShot	Utility-Scale					$2.07 - $1.38			
NC Sustainable	Utility-Scale	$3.75	$3.39	$3.08	$2.80	$2.57	$2.36	$2.19	$2.03
ICF MA study	Utility-Scale								$1.74
Brattle	>5 MW (adjusted)			$2.88					
Brattle	>5 MW (adjusted)								$1.43
Residential-scale									
APS IRP	Residential fixed						$4.19		
Pacificorp IRP	Residential fixed		$4.79						
TEPPC WECC	Residential fixed		$4.31						
LBNL	Residential fixed		$4.69						
GTM	Residential Reported			$4.52					
GTM	Residential Modeled			$3.74					
SunShot	Residential					$3.18 - $1.59			
NC Sustainable	0-10 kW	$6.47	$6.04	$5.65	$5.28	$4.94	$4.63	$4.35	$4.08
ICF MA study	0-10 kW								$4.30
Brattle	0-10 kW			$4.25					
Brattle	0-10 kW								$2.25

Source: Brattle Literature Review

59 While a significant amount of data existed for projects between 0 and 10 kW in the Open PV database, significantly less data are available for projects greater than 5 MW. For this reason, in the below analysis, utility-scale projects are defined as solar projects greater than 1 MW.

Overall, the final installed PV cost estimates are as follows (all expressed per $W_{\text{-DC}}$):

- 2014 Residential-scale PV: \$4.25/$W_{\text{-DC}}$;
- 2014 Utility-Scale PV: \$2.88/$W_{\text{-DC}}$;
- 2019 Residential-scale: \$2.25/$W_{\text{-DC}}$; and
- 2019 Utility-Scale: \$1.43/$W_{\text{-DC}}$.

APPENDIX B

EnerNex Report-

Production Levels of Utility-Scale and Residential-Scale PV Systems

EnerNex

REPORT

Production Levels of Utility-Scale and Residential-Scale PV Systems

Submitted to

First Solar

Principal Investigator

Jens Schoene, Director of Research Studies, EnerNex

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Final Version

Executive Summary

The economic analyses conducted for this study are based on the energy and the power produced by the current and future PV systems in the service territory of Xcel Energy Colorado. The production data (i.e., power/energy measurements) made available to us for the study year (2013 is selected as the representative year) is limited and, consequently, we needed to explore alternative options for obtaining realistic production levels of utility-scale and residential PV systems.

We assembled a large set of solar data (irradiance and production) and meticulously evaluated the available to determine which data sets were the most suitable one for our study. The identified/reviewed data sets (1) are from NREL's solar irradiance database, which includes solar irradiance from a number of locations in the Denver area and outside Denver (29 locations total) and (2) were provided by Xcel Energy and included production and irradiance data from 54 locations. Based on discussion with the project team and two independent solar experts, we selected data from the NREL solar irradiance database and well-established methods to derive energy and power production levels of the investigated PV systems from these data sets. The selected methodology to derive the production levels uses well-documented equations that are also employed in NREL's PVWatts simulation tool [1].

For the calculations of utility-scale PV production data, we assumed that the utility-scale PV plant uses single-axis-tracking PV systems that are overbuilt by 120%, that is, the DC rating of the panels are rated 1.2 times larger than the AC rating of the inverters. We used the one-minute irradiance data measured in 2013. For residential-scale PV installations, geospatial diversity consideration was taken into account by developing a methodology that has been peer reviewed by solar experts. The methodologies used for both PV types (utility-scale and residential-scale) are documented in Section 1.

A key finding of this study is that the capacity factor of the utility-scale single-axis tracking PV system is significantly (+13%) larger than the capacity factor of the residential-scale PV system (given the same input irradiance data) with a significant portion of the difference being attributable to tracking (i.e., the difference of capacity factors for a utility-scale PV plant without tracking compared to residential-scale PV is only +6%). The differences in capacity factors result in even larger percentage differences for the annual energy production, as documented in Section 2. The calculated utility-scale PV plant capacity factor is 32%, i.e., the capacity factor is twice as large as the 16% capacity factor for residential-scale PV. For the economic analysis, we decided to use capacity factors for utility-scale PV that were calculated at the same location as residential-scale

PV in order to (1) facilitate a more direct comparison between the two PV types and (2) avoid a bias towards utility-scale PV. These capacity factors ranged between 29% and 31%.

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1 Review of Methodologies

In this section, we document the methodologies employed in this study to derive the AC power generated by the investigated PV systems from ground measured solar irradiance data. The energy levels can be readily calculated from the PV power production.

1.1 General Considerations

It is important to accurately capture the inherent variability of PV production due to changing irradiance levels. Variability happens on many time scales – selecting the appropriate time scale for the investigation is important to ensure accuracy of the simulation results. The selection criteria depend on the application and can be categorized broadly as follows [2]:

1) The investigation of the impact of PV on a distribution system (voltage control operation, system losses, fault behavior, feeder section loading, etc.) requires that solar variability is captured on at least a seconds-to-minutes timescale.
2) The investigation of the impact of large PV installations on the bulk system level, such as the amount of regulating and ramping reserves needed to balance the system, requires that solar variability is captured on at least a minutes-to-hours time scale.
3) The investigation of the impact of large PV installations on the bulk system level, such as variability and uncertainty increasing production costs by reducing the efficiency of generation unit commitment and dispatch, requires that solar variability is captured on at least an hours-to-days time scale.

The importance of a given parameter for the conversion process from solar irradiance to PV production depends on the study goals. For instance, capturing the impact of changing irradiance levels due to moving clouds (cloud transients) is relatively unimportant when the study goal is to determine the annual energy production of the PV system. On the other hand, accounting for cloud transients is important when investigating the effects of voltage variability.

1.2 Solar Irradiance-to-PV-Production Conversion

In this section, we review models and methodologies employed for converting irradiance data to PV production levels and discuss input parameters to the models that are suitable for our study. The methodologies presented here lean heavily on the ones reviewed in the June 2013 report “Simulating Solar Power Plant Variability: A Review of Current Methods” by Sandia National Laboratory [2] and the methodologies employed in NREL’s PVWatts simulation tool [1] and described in the technical reference for PVWatts published in October 2013 [3]. The reviewed methods are applicable to both residential-scale PV and utility-scale PV, but the input parameters to the models may vary with PV category as discussed in this section.

1.2.1 Background

Global Horizontal Irradiance (GHI) is a measure for the total amount of solar radiation received by a surface (such as the surface area of PV panel) that is horizontal to ground. GHI includes both the solar radiation that travels in a direct path from the sun (i.e., the Direct Normal Irradiance DNI) and solar radiation diffused by molecules and particles in the atmosphere (i.e., the Diffuse Horizontal Irradiance DHI). Clear sky index is defined as the amount of irradiation (counting both DNI and DHI) reaching the ground for each cloud condition divided by the value expected in clear sky conditions. During clear sky conditions (clear sky index equals '1'), the GHI will be primarily composed of DNI while during overcast conditions (clear sky index much smaller than '1') DIF will be dominant. Similarly, the older clearness index also yields information about the direct/diffuse composition of the irradiance. The clearness index is the ratio of the irradiance on a location on the earth's surface and the extraterrestrial irradiance above that location. GHI data can be readily obtained for many regions in the United States. The data can be used to determine the output of PV installations, although a few steps are necessary to accomplish this. In this section, we describe the process of converting measured irradiance levels to PV production levels. The process involves the following steps:

1) Convert measured irradiance levels to average GHI levels to account for spatial smoothing (Section 1.2.2).
2) Convert average GHI to plant-average plane-of-array incident irradiance to account for the panel tilt and tracking (Section 1.2.3).
3) Convert average incident irradiance to PV power production accounting for electrical losses, panel and inverter efficiencies, soiling, etc. (Section1.2.4).

The process can be applied to both categories of PV (utility-scale and residential), although some effects have a larger impact on certain PV categories than others. For instance, spatial smoothing (Section 1.2.2) is more important to account for when investigating utility-scale PV plants, while decreased PV production due to soiling may be more a factor for residential-scale PV assuming that many residential-scale PV panels are not cleaned routinely.

1.2.2 Point GHI-to-Average GHI

GHI sensors measure irradiance for a small area[1]. The irradiance measured by the sensor is accurate for a small part of a PV panel, but not necessarily for the total PV panel area nor for a PV plant consisting of many panels located some distance from each other. During cloudy sky conditions, some panels in a PV plant may be shaded by a cloud while other panels are

[1] The sensor area is very small compared to the footprint of a PV plant and, consequently, a GHI sensor can be viewed as a point sensor.

experiencing clear-sky conditions – if this is the case, the power produced by the plant will be determined by an average irradiance that depends on irradiance levels that exist at both shaded and unshaded panels. The averaging process effectively flattens edges that may exist in the GHI data (in particular during fast-moving clouds), which is known as spatial smoothing. Appendix A reviews methods that can be used to account for spatial smoothing.

The amount of spatial smoothing depends on the footprint of the PV installation – average irradiance for a large PV plant will have significant smoothing while a small residential-scale PV unit will experience very little smoothing. Consequently, in order to avoid exaggerating the variability of the PV plant production levels during cloudy conditions, it can be important in PV plant studies to accurately convert measured GHI data to average plant irradiance. Whether or not this effect is significant depends on the time scale of interest and the footprint of the PV panel as discussed below:

1) For the production of **residential-scale PV**, the time scale of interest is one minute (i.e., the measured irradiance data we are using have a temporal resolution of one minute). The typical footprint of the PV panels of a residential-scale PV unit is relatively small (i.e., in the order of square meters). For instance, assuming the length of the PV array is 10 m. The edge of a cloud moving at 10 km/h would take 3.6 seconds (i.e., the length of the array divided by the velocity of the cloud) to traverse the distance from one edge of the PV array to the opposite edge of the array. This means that spatial smoothing of the PV production for this array would occur on a second time scale and would not be visible on the one minute time scale of the irradiance data we are using. Consequently, <u>spatial smoothing due to the footprint of the residential-scale PV array does not need to be considered in our study</u>[1]. Note that we assumed a cloud velocity of 10 km/h, which is relatively slow. Our conclusion that spatial smoothing due to the footprint of the residential-scale PV array does not need to be considered also applies to faster cloud velocity because the significance of the smoothing effect for one minute data is reduced even further (i.e., the cloud takes even less time to traverse the PV array).
2) For the production of **utility-scale PV**, the time scale of interest is 15 minute (i.e., the measured irradiance data we are using have a temporal resolution of 15 minute). The footprint of a utility-scale PV plant varies widely, but is generally much larger than the footprint of residential-scale PV. NREL estimates the average land use of a large plant with PV units that employ single-axis tracking as 9 acres per rated AC capacity [4]. Furthermore, NREL determined the aggregate capacity of ten existing solar plants to be 256 MWac. Assuming (1) an average size per plant of 26 MWac, (2) 9 acres per MWac, and (3) a square footprint, the distance between one edge of the PV plant to the opposite edge is

[1] Spatial smoothing due to panel footprint, which is small for residential rooftop PV, is not to be confused with spatial smoothing due to the distance between residential PV units on a distribution feeder, which can be large. The latter is discussed in Section 1.4.

roughly 1 km ($\sqrt{26\ MW \cdot 9\ acres/MW}$). The edge of a cloud moving at 10 km/h would take six minutes (i.e., the length of the PV plant divided by the velocity of the cloud) to traverse the distance from one boundary of the PV plant to the opposite boundary of the plant. This means that spatial smoothing of the PV production for this array would not be visible on the 15 minute time scale of the irradiance data we are using. Consequently, spatial smoothing due to the footprint of a utility-scale PV plant does not need to be considered in our study. Note that this conclusion also applies to faster moving clouds and smaller PV plants.

1.2.3 Average GHI-to-Incident Irradiance

In this section, we describe the process of converting the average GHI to the incident irradiance imposed on the surface of a solar panel[1]. Just as the GHI, the incident irradiance includes irradiance directly reaching the surface and diffuse irradiance reaching the surface after being reflected by objects or particles. Obviously, the incident irradiance depends strongly on geometry, i.e., the orientation of the panel. There are other, less obvious factors that play a role as well, such as the latitude at which the panel is located and the composition of direct and diffuse irradiances and rigorous methods would need to account for these factors.

In this study, we employ the methodology used in NREL's PVWatts simulation tool [1] and described in the technical reference for PVWatts published in October 2013 [3]. The methodology to calculate the incident irradiance for a fixed array can be summarized as follows:

1) Calculate the direct incident irradiance
   a. Calculate the angle of incidence (α_{fixed}) for a fixed array using the panel surface tilt (β), panel surface azimuth (Υ_{panel}), solar azimuth (Υ_{solar}), and solar zenith (θ_{solar}) as input.
   b. Calculate the direct irradiance using α_{fixed} and the Direct Normal Irradiance (DNI) as input.
   c. Apply a correction factor for direct irradiance during conditions for which α_{fixed} is greater than 50° to account for reflection losses.
2) Calculate the diffuse incident irradiance
   a. Calculate the atmospheric brightness parameter (Δ) by using the Direct Normal Extraterrestrial Irradiance (DNI_0), the Diffuse Horizontal Irradiance (DHI), and the relative optical air mass (m) as input.
   b. Calculate the atmospheric clearness parameter (ε) by using the DNI, DHI, and θ_{solar} as input.

[1] Note that the orientation of the panel is arbitrary and, in the case of a panel with a tracking system, can even change with time. GHI can be viewed as a special case of the incident irradiance in that this irradiance level is, by definition, the amount of irradiance incident on a horizontal surface.

   c. Calculate the empirical coefficients for circumsolar brightening (F1) and horizon brightening (F2) using ε, Δ, and θ_{solar} as input.
   d. Calculate the diffuse irradiance using the DHI, α_{fixed}, β, θ_{solar}, F1, and F2 as input.
3) Calculate the total incident irradiance by summing up the direct incident irradiance and the diffuse incident irradiance.

The total incident irradiance for a fixed surface can be viewed as the total incident irradiance at one instant in time for a PV system with a tracking system and, consequently, the calculations of incident irradiances for a tracking system are not fundamentally different. Some complexity is added by having to account for the characteristics of the tracking system, mainly the axis properties (degree of freedom, axis tilt, axis azimuth, rotation limit) and the panel movement to capture the maximum yield of solar energy within the constraints of the tracking system. We selected the methodology described in [5] and referenced in the NREL PVWatts Technical Reference [3] to calculate the incident irradiances for a PV system with single axis tracking capability.

Table 1-1 gives an overview of the parameters we used to convert the average irradiance to incident irradiance on the solar panel surface of (1) a fixed array and (2) a solar system with single-axis tracking. Additionally, the data sources and default values are listed in the table. In our analysis, the same default values are used for all PV system of the same category. For instance, the panel surface azimuth for all utility-scale PV system is assumed to be the optimal 180° (south-facing) orientation while for residential-scale PV the panel azimuth is assumed to be 160°, which is an average value that accounts for the fact that residential-scale panels are not always optimally oriented due to building constraints. This particular value for the residential-scale panel azimuth is a rough estimate and may be changed if more substantiated data on residential-scale panel orientation for houses in the Xcel Energy service territory are provided to EnerNex.

Table 1-1: Parameters used to convert average irradiance to incident irradiance.

Parameter	Symbol / Abbreviation	Data Source / Default Value	Comment
Direct Normal Irradiance	DNI	NREL Data	-
Direct Normal Extraterrestrial Irradiance	DNI_0	NREL Data	-
Solar Zenith	θ_{solar}	NREL Data	-
Solar Azimuth	Υ_{solar}	NREL Data	-
Relative Optical Air Mass	m	NREL Data	-

Angle Of Incidence (fixed)	α_{fixed}	Calculated [3]	-
Angle Of Incidence (single-axis tracking)	α_{single}	Calculated [5]	-
Brightness Index	Δ	Calculated [6]	-
Clearness Index	ε	Calculated [6]	-
Panel Surface Azimuth	Υ_{panel}	Residential: 160° Utility Scale: N/A (tracking)	For residential-scale, 20° deviation from optimal south facing orientation (180°) is an estimate accounting for the fact that many residential-scale PV installations are not installed with optimum orientation due to building constraints.
Azimuth of Single-Tracking System Axis	Υ_{axis}	180°	North-south orientation of axis consistent with example in reference [7]
Panel Tilt	β	25°	PVWatts (old version) default value is 35.9°, but a smaller tilt angle is often used in practice (for reasons of wind load and mounting simplicity). This is accounted for in the new PVWatts version for which the default value is 20°
Tilt of Single-Tracking System Axis	B_{axis}	25°	Assuming tilted single tracker. Typical value for axis tilt [8].
Circumsolar Brightening	F1	Perez et al., 1990 [6]	Recommended values for F1 and F2 coefficients based on data from Albany, Geneva, Los Angeles, Albuquerque, Phoenix, Cape Canaveral, Osage, Trappes, and Carpentas.
Horizon Brightening	F2		
Rotation Limit	-	180° (no limit)[1]	-

1.2.4 Incident Irradiance-to-PV Production

In this section, we describe the process of converting the incident irradiance to PV production levels.

PV Module

The widely used PVWatts calculator developed by NREL [1] calculates the DC power P_{dc} in kW from an array with a specified nameplate DC rating P_{dc0} based on transmitted incident irradiance I_{tr} (see Section 1.2.3), cell temperature (T_{cell}) and a reference temperature (T_{ref}) of 25°C as follows [3]:

$$P_{dc} = \frac{1}{1000} I_{tr} \cdot P_{dc0} \cdot \left(1 + \Upsilon_{temp} \cdot \left(T_{cell} - T_{ref}\right)\right) \qquad I_{tr} > 125\ \mathrm{W/m^2}$$

where Υ_{temp} is the temperature coefficient (fixed at -0.5% per °C for a typical crystalline silicon module). The equation is valid for transmitted incident irradiance levels that are larger than 125 $\mathrm{W/m^2}$. For irradiance levels of 125 $\mathrm{W/m^2}$ or lower, Sandia field data has shown that the efficiency is reduced. The following equation accounts for the field-observed efficiency reduction:

$$P_{dc} = \frac{0.008\cdot}{1000} \cdot {I_{tr}}^2 \cdot P_{dc0} \cdot \left(1 + \Upsilon_{temp} \cdot \left(T_{cell} - T_{ref}\right)\right) \qquad I_{tr} \leq 125\ \mathrm{W/m^2}$$

PV production from utility-scale PV plants is often inverter-limited to reduce the annual levelized cost of generation. 'Inverter limited' means that the rated DC power of the PV panel exceeds the rated AC power of the inverter and, consequently, at times of high irradiance the inverter is driven into saturation and produces no more than rated AC output power. On the other hand, the limiting factor for residential-scale PV is often the size of the roof and the rated AC output power of the inverter is matched to the panel size. We account for this by selecting a DC to AC size ratio (i.e., the ratio of rated DC power of the panel and rated output power of the inverter) of '1' and '1.2' for residential-scale PV and utility-scale PV, respectively (see Table 1-2). The 1.2 value is selected as a typical value.[1]

Table 1-2: DC to AC size ratio for residential-scale and utility-scale PV.

	Residential-Scale	**Utility-Scale**
DC to AC Size Ratio, P_{dc0} / P_{ac0}	1	1.2

[1] The adequacy of this 1.2 value was confirmed by First Solar in an email communication from October 2, 2014.

Derate Factor due to System Losses

PVWatts applies derate percentages in order to account for a reduction of the production level due to system losses, such as soiling, shading, etc. Each of these derate percentage has a default value in PVWatts, which can be user-modified within a pre-determined range (from 0% to 100%). Note that PVWatts updated these default values in September 2014 and the default values listed below are based on this update.

1) **Soiling** of PV panels due to dirt, snow, and other particles on the panel surface can decrease PV production. In PVWatts, the default value for the derate percentage due to soiling is 2%.
2) **Shading** of PV panels from nearby objects such as trees or buildings can decrease PV production. In PVWatts, the default value for the derate percentage due to shading is 3%.
3) **Snow** covering PV panels. In PVWatts, the default value for the derate percentage due to snow is 0%.
4) **Module mismatch** is caused by PV modules that have slightly different current-voltage characteristics due to manufacturer tolerances, which can result in an efficiency reduction. In PVWatts, the default value for the derate percentage due to the module mismatch is 2%.
5) **Losses in DC and AC wiring**, that is, wiring between modules, wiring between the PV array and inverter, wiring between the inverter and the local utility service, etc. In PVWatts, the default value for the derate percentage due to losses in DC and AC wiring is 2%.
6) **Losses in connections**, that is, resistive losses in parts that electrically connect elements of the system. In PVWatts, the default value for the derate percentage due to connections is 0.5%.
7) **Light-induced degradation**, that is, degradation of photovoltaic cells during the first few months of operation causing a reduction of the arrays power output. In PVWatts, the default value for the derate percentage due to light-induced degradation is 1.5%.
8) **Actual PV module nameplate DC rating**, which may be different from the manufacturer-specified nameplate rating. In PVWatts, the default value for the derate percentage due to differences in module nameplate DC rating is 1%.
9) **Aging of the PV modules** primarily due to weathering can result in performance losses over time. In PVWatts, the default value for the loss due to aging of the modules is 0.
10) **System downtime** due to maintenance, utility outages, or other operational factors. In PVWatts, the default value for the derate percentage due to system downtime is 3%.

The total derate percentage $dp_{\text{System Losses}}$ due to system losses can be calculated from the individual derate percentages (dp_{soiling}, dp_{shading}, etc.) as follows:

$$dp_{System\ Losses} = 100\% \cdot \left[1 - \left(1 - dp_{soiling}\right) \cdot \left(1 - dp_{shading}\right) \cdot \left(1 - dp_{snow}\right) \dots\right]$$

For instance, the derate percentage calculate from the default values $dp_{System\ Losses,default}$ is

$$dp_{System\ Losses,default} = 100\% \cdot [1-(1-0.02)\cdot(1-0.03)\cdot(1-0)\cdot(1-0.02)\cdot(1-0.02)\cdot(1-0.005)\cdot(1-0.015) \cdot(1-0.01)\cdot(1-0)\cdot(1-0.03)] = \mathbf{14.1}\%$$

In this study, we apply the derate percentages for the system losses as listed in Table 1-3. The resulting derate percentages and derate factors for the system losses are also listed in the table.

Table 1-3: Derate percentages due to system losses applied in this study.

ID	Effect	Derate %, Residential-Scale	Derate %, Utility-Scale	Justification
1	Soiling	4%	2%	PVWatts default value for utility-scale PV. Higher derate percentage for residential-scale PV is an estimate in an attempt to account for the fact that residential-scale PV panels have a tendency of having more soiling.
2	Shading	8%	2%	Utility-scale installations have some shading between panels (at early and late hours), but typically no shading from other objects (trees, buildings, etc.). Residential-scale PV can have significant shading from other objects. [9] observed that 63% of residential-scale systems and 20% of non-residential-scale systems are prone to more than minimal shading[1].
3	Snow	5.5%	1%	Utility-scale installations are likely to be cleaned on a routinely basis, while residential-scale installations are likely to be cleaned less frequently. [10] measured the snow losses in Colorado for residential-scale PV over a two year period and found that the average snow losses were 5.5% (ranging from 1.9% to 9.3%).
4	Module Mismatch	2%	2%	PVWatts default value

[1] Although the referenced study was conducted in urban Southern California, it stands to reason that there are no significant location differences between shading losses in this area and the Denver area. The PVWatts default value for shading is 3%, but, based on the referenced study, shading losses for residential PV appear to be both substantially larger than (1) the 3% default value and (2) shading losses for utility-scale PV. Our estimates of 8% and 2% for residential PV and utility-scale PV shading losses, respectively, reflect these observed relationships.

5	Wiring Losses	2%	2%	PVWatts default value
6	Connections	0.5%	0.5%	PVWatts default value
7	Light Degradation	1.5%	1.5%	PVWatts default value
8	Nameplate Rating	1%	1%	PVWatts default value
9	Aging	0%	0%	PVWatts default value
10	Downtime	3%	2%	PVWatts default value for residential-scale systems. Slightly lower derate percentage for utility assumed as performance issues will likely be detected earlier.
Derate Factor, System Losses		78.3%	85.9%	

Changes in PV Production due to Other Factors

In addition to derating due to system losses, PV Watts also accounts for the decrease of production due to inverter inefficiencies and ambient temperature. The factors that account for these effects are listed in Table 1-4. We are using these factors in our calculation of the capacity factors for utility-scale and residential-scale PV.

The employed panel technology also has an effect on the energy yield (i.e., how many kWh are generated per installed kW). The newest version of PVWatts allows selecting between Crystalline-Silicon (c-Si) panels and thin film technology panels. c-Si have an energy yield that is different from PV panels produced using thin film technology. There is some controversy regarding the actual difference in yield between these two technologies. Some early researcher claims that thin film modules have a yield that is 5-20% higher than c-Si modules [11] [12]. Newer research indicates that these claimed differences are exaggerated as they stem from testing that does not appropriately account for real-world conditions, such as (1) coupling between intensity, (2) temperature, and (3) light spectrum in real outdoor climates [13]. Attempts to accurately quantify any energy yield differences between c-Si and thin film technologies have proven difficulty as the typical uncertainty of an energy yield comparison, which was determined to be +-5%, outweighs energy yield differences between the two technologies [14]. In light of this newer research that suggest that only very small energy yield differences between c-Si and thin film technologies exist, which are difficult to quantify, and considering the comparative nature of our study (i.e., technology differences would not come into play if the same technology is used for both PV categories), we ignore energy yield differences due to different PV technologies in our study.

Note that we assume that PV panels employed for utility-scale PV are c-Si ‘premium’ grade panels and the ones used for residential-scale PV are c-Si ‘standard’ grade panels. In our model, this only affects the changes of PV panel energy yield due to deviations of the ambient temperature[1] from the rated temperature (i.e., 25°C): -0.47% per °C for standard panels and -0.35% per °C for premium panels. However, the difference in capacity factor due to this assumption is very small: 32.48% for standard panels at the Sunspot2 location and 32.39% (see Section 2.3) for premium panels at the same location. Interestingly, standard panels yield a slightly higher capacity factor. This is because PV panels operate more efficiently at lower temperature and this efficiency increase is larger for standard panels. Apparently, the ambient temperature at the PV locations were mostly below rated temperature, which resulted in the observed overall increase of capacity factor for standard panels. Note that if the panels were mostly operating at above rated temperature, PV panel performance would decrease and premium panel energy yield would decrease less compared to the yield of standard panels resulting in a slightly superior performance of premium panels.

Table 1-4: Factors used to account for inverter efficiency and ambient temperature.

Effect	Factor, Residential-Scale	Factor, Utility-Scale	Justification
Inverter Efficiency	94%	96%	PVWatts default value for utility-scale PV. Smaller inverters employed for residential-scale PV are slightly less efficient.
Ambient Temperature	-0.47% per C°	-0.35% per C°	PVWatts default value for standard crystalline silicone PV modules (assumed for residential-scale PV) and premium crystalline silicone PV modules (assumed for utility-scale PV).

[1] In our model, we used the ambient temperature recorded by NREL at the same measurement station at which the irradiance data were recorded.

DC Power to AC Power

The inverter model adopted in this study to convert the DC power output of the PV array to AC power is the same model that is used in PVWatts [3]. Sandia National Laboratory developed this model originally and it was employed in Sandia's PVFORM V3.3 simulation program [15] [16]. The Sandia model accounts for efficiency changes of the inverter due to different load conditions, which it accomplishes by curve fitting a set of efficiency measurements of typical inverters during load conditions at which the inverter-operates within the range of 10% to 100% of rated DC power. The curve fitted to the typical data at operating condition η_{op} is the following third-order polynomial:

$$\eta_{op} = 0.774 + 0.663 \cdot f - 0.952 \cdot f^2 + 0.426 \cdot f^3 \qquad \text{for} \qquad 0.1 \leq f \leq 1$$

where f is the part-load operation fraction, which is defined as the ratio of the derated DC power P'_{DC} (i.e., the DC power produced by the PV module, accounting for the decreased production levels due to the effects described in the previous section) and the effective inverter DC rating $P_{inv,dc0}$. The effective inverter DC rating can be calculated from the full-load inverter efficiency η_{rated} and the AC nameplate rating of the inverter P_{ac0}:

$$P_{inv,dc0} = \frac{P_{ac0}}{\eta_0}$$

For DC power operating conditions below 10%, i.e., operating conditions that are outside the range of the data set, a linear behavior is assumed:

$$\eta_{op} = |-0.015 + 8.46 \cdot f| \qquad \text{for} \qquad 0 < f < 0.1$$

With the parameters calculated above, the AC power output of the PV system P_{ac} can be readily calculated as follows:

$$P_{ac} = 0 \qquad \text{for} \qquad f = 0$$

$$P_{ac} = P'_{dc} \cdot \eta_{op} \cdot \frac{\eta_0}{\eta_{ref}} \qquad \text{for} \qquad 0 < f \leq 1$$

$$P_{ac} = P_{ac0} \qquad \text{for} \qquad f > 1$$

where η_{ref} is the reference efficiency fixed at 0.91, which corresponds to the efficiency of the data set from which the operating efficiency curve were derived.

1.3 Data Selection for Utility-Scale PV

It is apparent from the solar data documented in Appendix E of this report that there is abundant solar irradiance data available for the Denver area, but very limited irradiance and production level data for utility-scale PV plants located outside Denver. Specifically, no irradiance/production level data for the Comanche PV plant located in Pueblo 90 miles south of Denver are available for the study year of 2013. However, solar irradiance data from this location are available prior to June 16, 2011. In the absence of 2013 data for the Comanche location, we selected the following approach:

1) Select the NREL irradiance data collected at the measurement station (1) that is closest to the Comanche station, (2) for which the data collection period overlaps with the one for the Comanche station, and (3) for which production data are available for the entire year of 2013. This station is the Sunspot2 station (data ID 10 in Appendix E) about 50 miles from the Comanche station. The overlapping time period is from December 1, 2010 to May 31, 2011.
2) Select the NREL irradiance data collected at the Comanche station (data ID 8 in Appendix E) for the same time period (from December 1, 2010 to May 31, 2011).
3) Apply a calibration factor to Sunspot2 irradiance data so that the clear-sky irradiance at the Sunspot2 location matches the clear-sky irradiance at the Comanche location. The goal of this step is to minimize any differences between the two locations due to differences in measurement equipment and regional differences. The applied calibration factor was determined to be 0.944
4) Calculate the capacity factor for the two locations based on the irradiance data from step 2) and step 3).

Using the procedure described above, the capacity factor calculated for the Comanche location is 22% and the capacity factor calculated for the Sunspot2 location is 23%. We consider these capacity factors to be very close and, consequently, it is appropriate to use the calibrated Sunspot2 irradiance data as a proxy for the irradiance conditions at the Comanche station during the year 2013. For illustrative purposes, we are comparing irradiances measured at the two locations in Figure 1-1. The data were measured with a one minute resolution (top part of the figure) and downsampled to 15-minute resolution data (bottom part of the figure). The figure shows that for the clear sky day (5/27/2011) the irradiances are essentially identical. For the cloudy day (5/26/2012) there are some discrepancies, but the irradiance profiles from the two locations generally follow a similar pattern, which supportive to our conclusion that the Sunspot2 data can serve as a proxy for the Comanche data. Note that the capacity factors calculated from the one-minute data is identical to the capacity factor calculated from the 15-minute data for the respective location, which indicates that 15-minute data is sufficient for determining aggregate annual PV production.

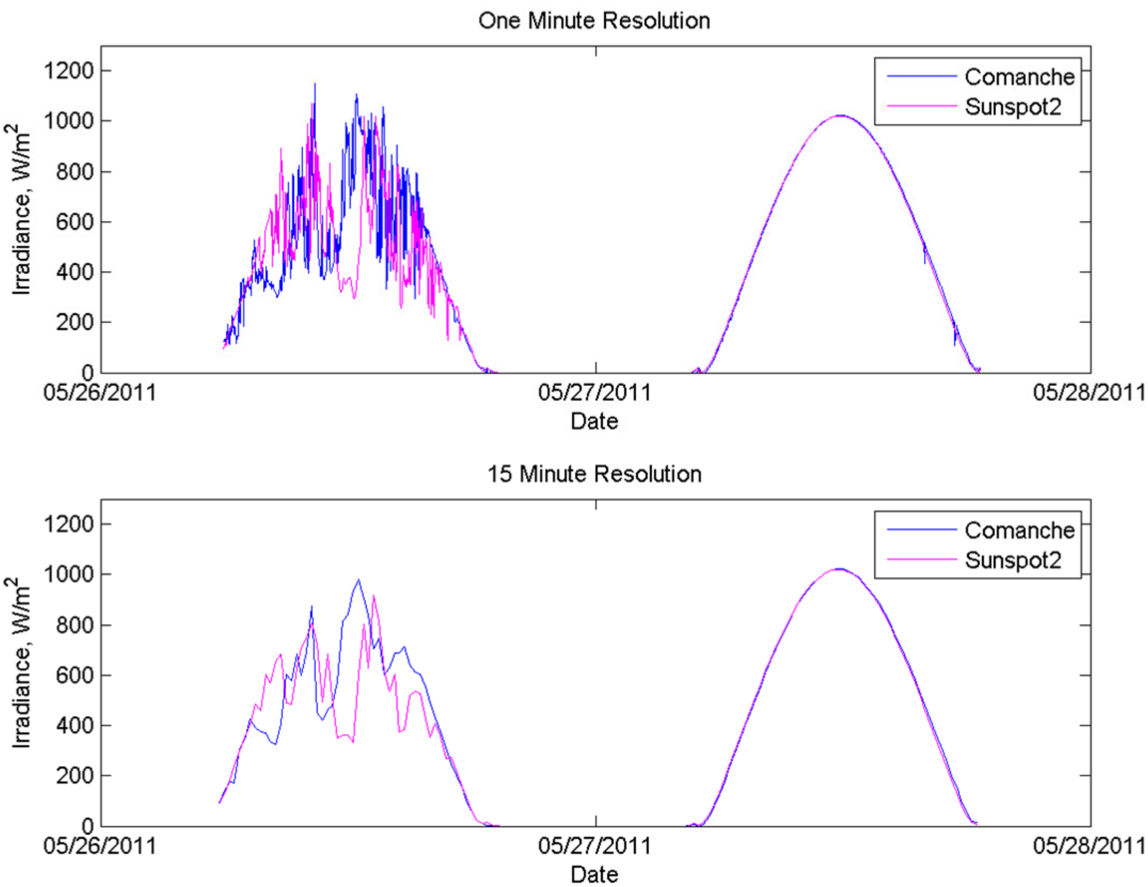

Figure 1-1: Irradiance data measured at the Comanche and Sunspot2 stations for two days in May, 2011. One minute data and 15 minute data.

1.4 Geospatial Diversity of Residential-scale PV Installations

In this section, we describe our approach for accounting for the geospatial diversity of residential-scale PV installations. Our reasoning for using this method is that it improve the accuracy of the analysis compared to an analysis that assigns a single irradiance profile to all PV systems, which is commonly done in PV impact studies[1]. The grouping methodology employed here has been peer-reviewed by Dr. Jan Kleissl of the University of California in San Diego. The peer-review, which also contains additional details on the issue that warrants such a method, is documented in Appendix C.

[1] Note that this grouping methodology is not widely used and no information is available by how much the accuracy is improved by employing the grouping method because reference data to compare our simulation results to and that would allow us to quantify the improvement are not available.

1.4.1 Background

Characteristics of residential PV include (1) the individual PV units are finely distributed, and (2) the variations in output of individual PV units are correlated to a variable degree as a function of geographic separations between their locations. During clear-sky conditions, the output of all PV on a feeder will follow approximately the same smooth diurnal curve over the course of the day. During solidly-overcast conditions, the output is also relatively smooth, following a scaled (20% - 40%) proportion of the clear-sky curve. Impacts of distributed residential-scale PV on voltage during these totally-clear and totally-overcast conditions can be readily evaluated by conventional distribution power flow analysis techniques because the PV output can be accurately represented as a modifier of the load pattern (i.e., a “negative load”).

It is during partly-cloudy conditions that the output of a PV unit is highly variable. The variations in output of an individual PV unit are the result of cloud shadows passing over that location. The size of a typical cloud shadow, during partly-cloudy conditions, is typically much smaller than the geographic footprint of a typical distribution feeder. Therefore, the shadow will usually only affect a portion of the total PV capacity on the feeder at any given time, assuming the PV penetration consists of finely-distributed small residential-scale units. As the shadows move across the landscape at the speed of the wind at cloud height (most typically in the range of 10 – 80 km/h), different areas of the feeder will be shadowed at different times. It is also likely that a feeder’s geographic area may experience multiple shadows simultaneously, and as a shadow moves off of the feeder footprint on the downwind side, another shadow may move on to the footprint on the upwind side. The net result is that there will be diversity in the PV output variations.

The diversity of finely-distributed residential-scale PV output variations need to be appropriately considered when performing PV impact assessment in order to provide results that are neither extremely pessimistic nor extremely optimistic. The degree of PV output correlation is a function of distance between units; neighboring PV units are highly correlated because they experience the same cloud shadows nearly simultaneously. On the other hand, PV units that are distant from each other will have short-term variability that is essentially uncorrelated.

A study performed by the National Renewable Energy Laboratory has shown that the coefficient of correlation for 130-second PV output variations drops below 50% in 200 - 300 meters, but correlation for five minute variations remains above the same amount for separations up to approximately 1 km [17]. A more generic, but apparently universal formula for the correlation between sites was derived at the University of California, San Diego as $\rho = e^{-d / (0.5 \text{ ucl } t)}$, where ucl is the cloud velocity, d is the distance between sites, and t is the time scale of the fluctuations.

Thus, on a feeder-wide basis, the aggregate PV output may be greatly smoothed by this geo-spatial diversity, while aggregate output within local areas will remain highly variable. Phase balance is also affected because single-phase laterals tend to serve concentrated geographic areas. Clouds may shadow whole laterals at a time, causing erratic changes in phase balance.

As a result of this geo-spatially dependent correlation of PV output variations, the impacts of high-penetration residential-scale PV on distribution voltage, phase balance, and equipment duty cannot be adequately assessed by conventional techniques and tools. Using a single PV output pattern for all PV units within a feeder will result in voltage variability severity far exceeding that which will occur in reality. While highly conservative, the results will either drive unnecessary system upgrades or unnecessary restrictions on PV interconnection. On the other hand, applying an aggregated output pattern to all PV units will be very optimistic and may not expose significant impacts that may actually occur.

A very rigorous approach to making an assessment of finely-distributed PV impacts is by modeling all of the individual PV units, as well as the progression of cloud shadows over the feeder footprint, in an extended Quasi-Steady-State (QSS) load flow simulation. EnerNex has recently performed such an analysis as part of a research project for the California Solar Initiative [18]. Cloud patterns and movement in this study were derived from actual conditions using a recently-developed sky camera and image processing system developed by the University of California at San Diego.

1.4.2 Grouping Methodology to Account for Geospatial Diversity

The very rigorous approach described in the previous section is very time consuming and requires very specialized and comprehensive high-resolution (temporal and spatial) data, which are not available for this study. A more practical approach that can be done with the data available is to divide distribution system into zones, each of a certain geographic extent. A common PV output pattern will be applied to all PV injections within the zone. Different zones will use different patterns which might be totally uncorrelated, although some realistic correlation may exist if the locations of the zones follow a similar pattern as the locations of the sensors that measure the irradiance data.

1.4.2.1 *Mapping Sensor Map to Distribution Feeder Map*

In this study, we will employ data from four NREL measurement stations that are located in or near Denver (Data IDs 1, 2, 5, and 6 in Appendix E). The data were recorded with a one-minute and one-hour time step. The following three figures illustrate the methodology described above. Figure 1-2 shows a diagram of one of the analyzed distribution feeders in the Xcel Energy service territory. Existing PV installations are indicated by circles, with the size of the circle being indicative of the size of the PV installation. Figure 1-3 illustrates the mapping of the sensor locations to load buses on the analyzed feeder. The left side of the figure shows a map of the larger Denver area with the sensors locations indicated. The right side of the figure shows a map of the feeder also shown in Figure 1-3. Note that the footprint of the left map with the actual sensor locations is much larger than the footprint of the map on the right side and, consequently, we need to scale down the sensor map in order make it fit the distribution feeder map. The scaled-down map retains the general shape of the sensor map. This process is illustrated in Figure 1-3. For instance, sensor 1 at the south-east corner of the sensor map maps to a sensor on the south-east corner of the distribution feeder map.

1.4.2.2 *Zoning PV Buses*

The next step is to zone the PV buses based on their proximity to a sensor. For instance, a bus at the southernmost part of the system belongs to the Sensor 1 zone (light blue) and a PV system installed on this bus will be fed with the irradiance data measured by Sensor 1. The right side of Figure 1-3 shows all zoned buses (irrespective of whether the bus has a PV system, or not) with the different zones indicated by different colors. Figure 1-4 show all zoned buses with PV systems (i.e., only the buses that have a PV system are zoned).

As mentioned above, the relative distances of the sensors corresponds to the relative locations of the PV groups, although the absolute distances between sensors are scaled down to fit the smaller footprint of the feeder. This results in some correlation between irradiance profiles captured by the different sensors. As argued in Section 1.4.1, increasing the separation distance between PV systems results in a decrease of the correlation of the generation output and, consequently, capturing this correlation exactly becomes less important. The described method will capture some correlation and will improve by accounting for the diversity effect to some extend (as opposed to almost all other PV system impact studies, which completely ignore the diversity effect).

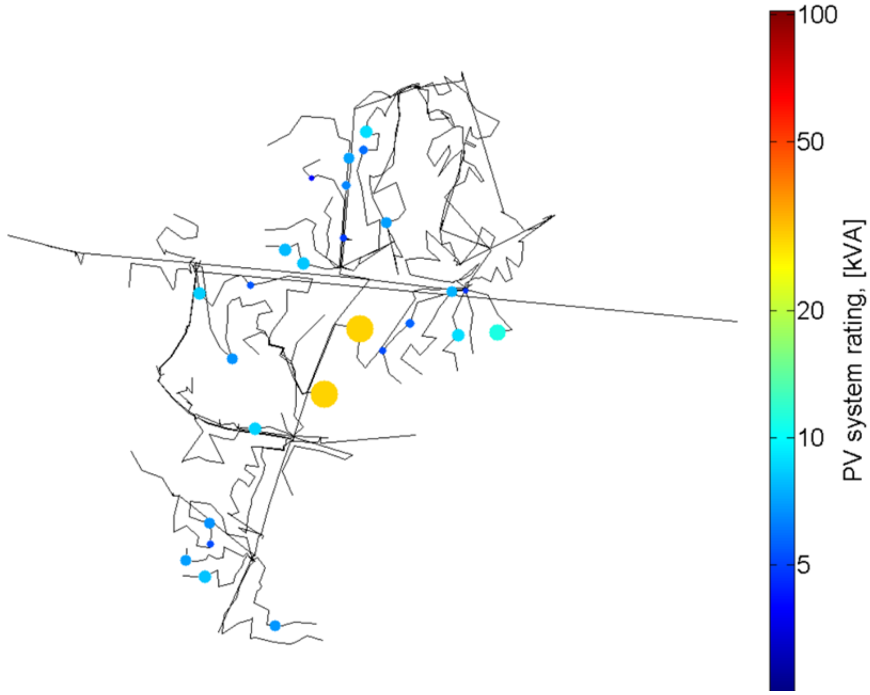

Figure 1-2: Diagram of distribution feeder located in the Xcel Energy service territory with location and size of existing PV systems (as of 2013).

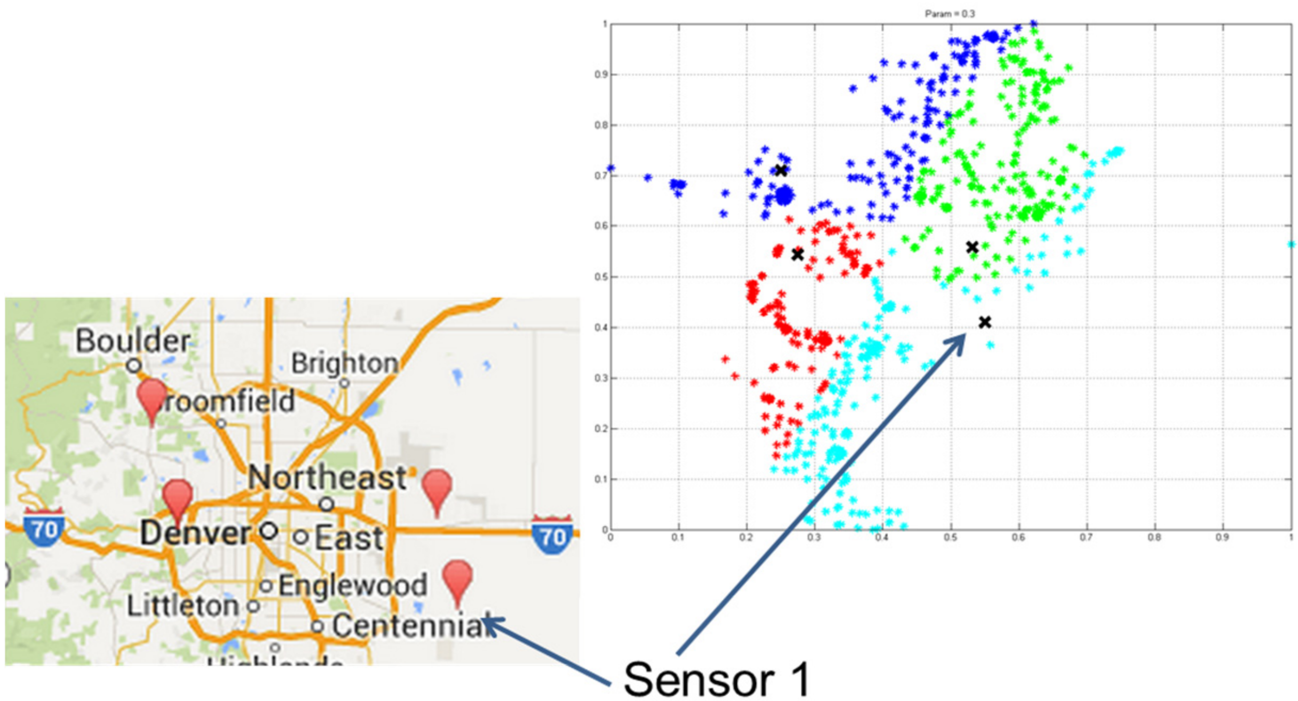

Figure 1-3: Mapping solar irradiance sensors to load buses on the feeder shown in Fig. 3-1.

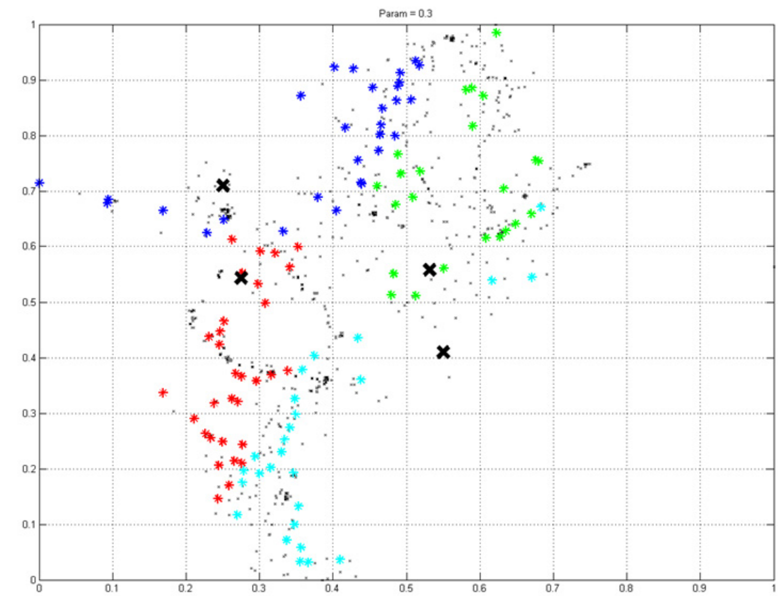

Figure 1-4: Mapping solar irradiance profiles to PV systems for a future high PV penetration scenario in which all PV systems are installed on phase B.

2 PV Production

In this section, we document our solar data selection effort and present the result of our calculations of PV production and the resulting capacity factors for residential-scale PV and utility-scale PV, using 2013 as a representative year.

2.1 Review of Solar Data

We identified and reviewed, with support from two solar experts, a large number of solar data sets (irradiance and production) for suitability for our study. The identified/reviewed data sets (1) are from NREL's solar irradiance database, which includes solar irradiance from a number of locations in the Denver area and outside Denver (29 locations total) and (2) were provided by Xcel Energy and included production and irradiance data from 54 locations. Appendix E includes a complete list of the identified/reviewed data sets.

2.2 Production of Residential-scale PV

In this section, we document the results of our effort to convert the irradiance data from the selected four NREL measurement stations to PV production data for residential-scale PV employing the methodologies described in Section 1. We calculated capacitor factors and energy productions for residential-scale PV from these four data sets. The blended results were used as input to the economic analysis.

Table 2-1 lists the data sets used to derive the production data. Note that a complete data set was not available for the NWTC location – only Global Horizontal Irradiance (GHI) data and temperature. We substituted the data we required for our conversion process with data from the closest measurement station, which was the BMS station. It stands to reason that the error introduced by the substitution is very minor because (1) GHI data are available for the NWTC location and this parameter is most critical for the production calculation because it is the accumulation of direct and diffuse irradiances on the sensor surface and (2) the NWTC and BMS locations are relatively close (about 12 miles), so BMS data should be very similar to the NWTC data that were not measured.

Table 2-1: NREL Solar Data used in the study to characterize production of residential-scale PV. All data sets have a 1-minute temporal resolution and comprise the entire year of 2013.

ID	Label	Location	Data Used	Link
1.2	NWTC	NWTC M2 Tower (5 miles south of Boulder) 39° 54' 38.34" N, 105° 14' 5.28" W	Global Horizontal Temperature	www.nrel.gov/midc/nwtc_m2/
2.2	BMS	NREL Solar Radiation Research Laboratory Baseline Measurement System (BMS), Golden 39.742° N 105.18° W	Global Horizontal (TSP1) Direct Normal (NIP1) Direct Extraterrestrial Diffuse Horizontal (PSP) Zenith Angle Azimuth Angle Airmass (PV) Temperature	http://www.nrel.gov/midc/srrl_bms/
5	SolarTAC	Solar Technology Acceleration Center (SolarTAC), Aurora 39.75685° N 104.62025° W	Global Horizontal Direct Normal Diffuse Horizontal Zenith Angle Azimuth Angle	http://www.nrel.gov/midc/solartac/
6	Lowry	Lowry Range (a few miles east of Denver) 39.60701° N 104.58017° W	Global Horizontal Direct Normal Diffuse Horizontal Zenith Angle Azimuth Angle Airmass Temperature	http://www.nrel.gov/midc/lrss/

In Figure 2-1 and Table 2-2, we present the results of our capacity factor and energy production calculations for residential-scale PV and, for comparison, for utility scale PV, which are used in the economic evaluation. Figure 2-1 shows the power produced by PV installations located at the four locations as predicted by our model described in Section 1.2. The figure shows the model-predicted power production for January 1 and January 2 of the year 2013 for the purpose of illustration, but we actually obtained the power production profile at all four locations for each day in the year 2013. The focus in this section is on the power produced by residential-scale PV installations, but we also included the power production profiles for utility-scale PV installations (with and without tracking) in the figure for comparison. Table 2-2 shows that for three of the four locations, the capacity factors are 16%, 29%, and 22% for residential-scale PV, utility-scale PV with single-axis tracking, and utility-scale PV without tracking. The factors are slightly higher for the fourth location. The residential-scale PV capacity factor for the economic analysis is the average value of the four residential-scale PV capacity factors, which is 16%

The differences in capacity factors between PV types result in even larger percentage differences for the energy production, as documented in Table 2-2. It is apparent from the comparison, that the capacity factor of the utility-scale single-axis tracking PV system is significantly (+13%) larger than the capacity factor of the residential-scale PV system (given the same input irradiance data) with a significant portion of the difference being attributable to tracking (i.e., the difference of capacity factors for a utility-scale PV plant without tracking compared to residential-scale PV is only +6%).

Note that in this section, we use the same irradiance data as input to our capacity factor / energy calculations for residential-scale PV and utility-scale PV (but used different assumptions for the conversion process, as documented in Section 1.2) in order to facilitate a direct comparison of the effect of the assumptions we used for the two PV categories. However, while our calculations of the capacitor factor / energy are accurate for the residential-scale PV case because the irradiance data are from the urban Denver area where residential-scale PV systems are located at, the capacity factor / energy presented here for the utility-scale PV are based on irradiance data collected at locations at which utility-scale PV would not typically be located.

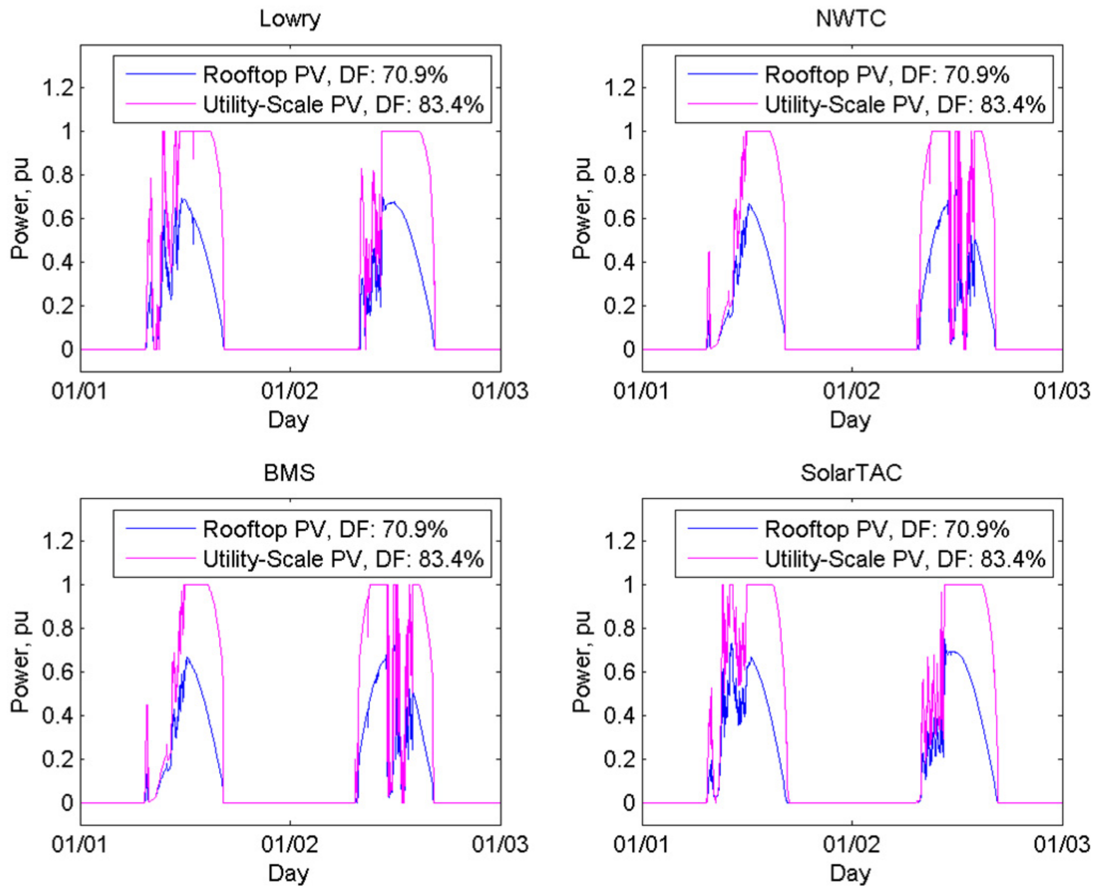

Figure 2-1: Comparison of production from residential-scale PV and utility-scale PV for the first two days in the year of 2013. The derating factors are given in the figure legends.

Table 2-2: Capacity factors and aggregated energy produced annually by 300 MW of PV for the four residential PV measurement stations.

	Lowry		NWTC		BMS		SolarTAC	
	Capacity Factor							
Residential-Scale	16%		16%		16%		17%	
Utility-Scale (Single-Axis Tracking)	29%		29%		29%		31%	
Utility-Scale (No Tracking)	22%		22%		22%		24%	
	Energy Produced Annually, 300 MW Installation							
Residential-Scale	424 GWh		429 GWh		427 GWh		459 GWh	
Utility-Scale (Single-Axis Tracking)	775 GWh	+83%	759 GWh	+77%	758 GWh	+77%	816 GWh	+78%
Utility-Scale (No Tracking)	590 GWh	+39%	590 GWh	+37%	587 GWh	+38%	636 GWh	+38%

2.3 Production of Utility-Scale PV

In this section, we present the result of our calculations of utility-scale PV production data from NREL's irradiance data for the year 2013. The assumption is that the utility-scale PV plants use single-axis-tracking PV systems that are overbuilt by 120%, that is, the DC rating of the panels are rated 1.2 times larger than the AC rating of the inverters (see Section1.2.4). We used the one-minute irradiance data measured in 2013 at the Sunspot2 location 150 miles south-east of Denver as a proxy for the irradiance conditions in 2013 at the Comanche location 90 miles south of Denver and downsampled it to 15 minute data. Refer to Section 1.3 for additional information and justification of this approach.

Figure 2-2 shows the incident irradiance on the panel of a single-axis PV system located at the Sunspot2 location for three days in February 2013. For comparison, we also included the incident irradiance at the BMS location, which is located in the Denver area. The figure shows incidence irradiance during cloudy (February 11 and February 13) and clear-sky (February 12) conditions at both locations. The irradiances at both locations during the clear-sky day are essentially identical, which is an expected result and confirms the consistency of the NREL data and the validity of our approach to use the Sunspot2 data as a proxy for the Comanche data.

Figure 2-3 shows the power generated by single-axis PV systems that are overbuilt by 120%. The figure shows power production at the BMS and Sunspot2 locations for the same three days as the previous figure that shows incident irradiances. The power production profiles resemble the incident irradiance profiles, except for the flat area at the top of the power production profile, which is due to inverter saturation and a consequence of the 120% PV panel overbuilding.

Table 2-3 shows the capacity factors and the energy produced by PV systems with an aggregate AC rating of 300 MW. The PV systems are single-axis-tracking and no-tracking utility scale plants located at the BMS and Sunspot2 locations. The capacity factor for the BMS and Sunspot2 locations are 29% and 32%. The 3% difference is likely due to (1) normal weather variation at the two locations and/or (2) a systematic difference that is a consequence of weather conditions at the Sunspot2 location that are more favorable for PV production. The latter is in line with the notion that PV plants are built at locations outside urban areas where weather conditions were determined in the planning stage of the prospective plant to be more favorable.

The capacity factor for each of the two single-tracking PV plants is 7% larger than the capacity factor of the respective no-tracking plant as apparent from the table. Consequentially, the annual energy produced by each of the two single-axis plants is 29% larger than the energy produced by the respective no-tracking plant. Note that the capacity factors and energy productions we calculated from annual 1-minute are identical to the ones we calculated from the upsampled 15-minute data.

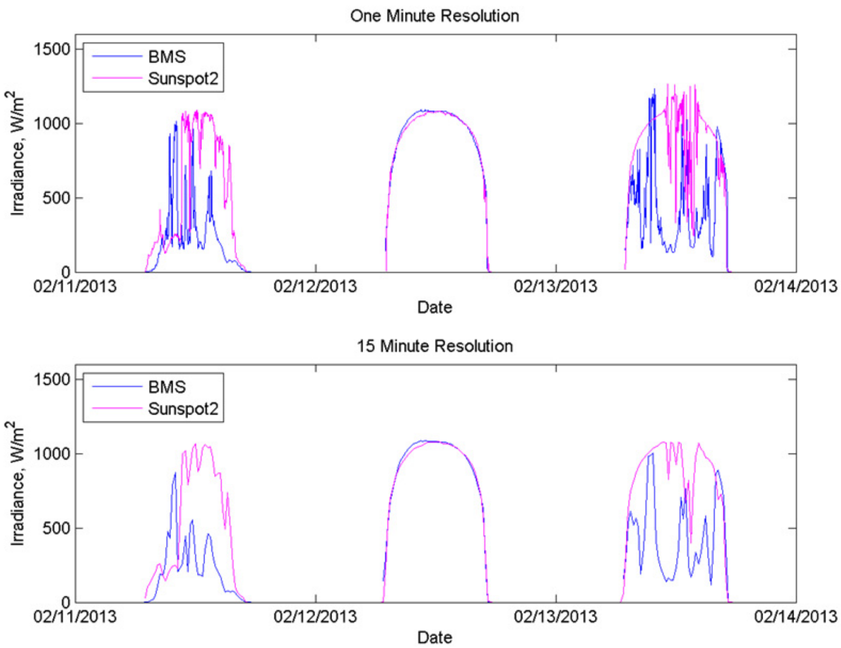

Figure 2-2: Incident irradiances on panels of single-axis PV systems located at the BMS and Sunspot2 locations for three days in February 2013.

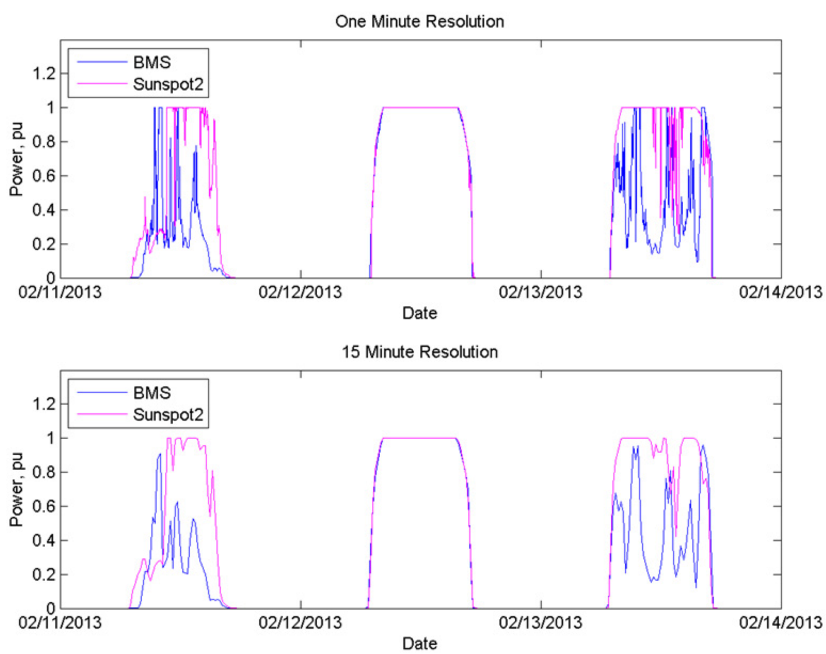

Figure 2-3: Power generated by single-axis PV systems at the BMS and Sunspot2 locations for three days in February 2013.

Table 2-3: Capacity factors and aggregated energy produced annually by 300 MW of PV for a PV measurement station in the Denver area (BMS) and a measurement station 150 miles south-east of Denver (Sunspot2).

	BMS		Sunspot2	
	Capacity Factor			
Utility-Scale (Single-Axis Tracking)	29%		32%	
Utility-Scale (No Tracking)	22%		25%	
	Energy Produced Annually, 300 MW Installation			
Utility-Scale (Single-Axis Tracking)	758 GWh	+29%	854 GWh	+29%
Utility-Scale (No Tracking)	587 GWh	0%	662 GWh	0%

3 Summary and Conclusion

In this report we document the methodologies used to convert the solar irradiance data to production data, which is used in the distribution and transmission analysis. In addition, we document our approach for (1) accounting for the spatial diversity of PV systems on distribution systems and (2) allocating future PV to distribution feeders.

A key finding of documented in this report is that the capacity factor of the utility-scale single-axis tracking PV system is significantly (+13%) larger than the capacity factor of the residential-scale PV system (given the same input irradiance data) with a significant portion of the difference being attributable to tracking (i.e., the difference of capacity factors for a utility-scale PV plant without tracking compared to residential-scale PV is only +6%). The differences in capacity factors result in even larger percentage differences for the annual energy production, as documented in Section 2. Note that this comparison uses the same input irradiance data, which were collected at four locations that are typical for locations at which residential-scale PVs are installed. In Section 2.3, we present results from capacity factor and energy calculations based on irradiance data collected at a location outside Denver, which is more typical for a location of a utility-scale PV plant. The calculated utility-scale PV plant capacity factor is 32%, i.e., the capacity factor is twice as large as the 16% capacity factor for residential-scale PV.

We also calculated the capacity factors at the four residential-scale locations using utility-scale assumptions. These capacity factors ranged between 29% and 31%, that is, slightly less than the 32% capacity factor for utility-scale PV at the typical utility-scale PV location (presumably due to more favorable environmental conditions at the utility-scale PV location). Note that using the slightly higher 32% capacity factor calculated at the utility-scale PV location for the economic analysis can be justified as utility-scale PV is often deployed at locations that have more favorable environmental conditions than residential-scale PV locations. However, we decided against this and instead used the utility-scale capacity factors calculated using the environmental data at the typical residential-scale locations for the economic analysis. The rational for this decision is that using capacity factors from the same location (1) facilitated a more direct comparison between the two PV types and (2) avoided a bias towards utility-scale PV.

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Appendix A Point GHI-to-Average GHI

The 2013 Sandia report "Simulating Solar Power Plant Variability: A Review of Current Methods" reviews six methodologies that can be employed to convert measured GHI data to plant-average GHI. The plant-average GHI can be used as input to models that convert GHI levels to irradiances incident on the PV panels (see Section 1.2.3). Three of the reviewed methods use irradiance data measured with a point sensor located at a single location on the ground, two of the reviewed methods use irradiances that were derived from satellite imagery[1], and one method uses power measurements from a proxy plant. Each of the methods is described below.

1) Ground-Measured-Irradiance to PV production using
    a. **Time Averaging**: This method uses measured point irradiance data as input and captures spatial smoothing due to the PV array size by employing a simple temporal smoothing technique. This technique applies a moving average of length $\bar{t}$ to the point irradiance data. $\bar{t}$ can be calculated from the PV plant footprint and the velocity of the cloud. The footprint of the plant is assumed to be square-shaped. Cloud velocities vary over time and can be obtained from measurements or numerical models [19].
    b. **Low-Pass Filter**: This method developed by Marcos et al. [20] uses measured point irradiance data as input and captures temporal smoothing due to the PV array size by applying a low-pass filter to the point irradiance data. This method was derived from frequency analysis of point irradiance data and PV production data. The frequency analysis showed that the low-frequency content[2] of point irradiance data and production data are very similar. On the other hand, the irradiance data had higher bandwidth[3] compared to the PV production data. The higher bandwidth is indicative of temporal smoothing due to panel size. In essence, PV production data can be predicted by applying a low-pass filter to point irradiance data thereby creating a waveform with a similar frequency content as the actual PV production data. The cutoff frequency f_c of the applied filter can be calculated from an empirically derived best-fit curve that uses the footprint A of the PV plant as input: $f_c = \frac{0.02}{\sqrt{A}}$.
    c. **Wavelet Variability Model**: The Wavelet Variability Model (WVM) developed by Lave et al. [4] at the University of California, San Diego uses the top hat wavelet transform to account for spatial smoothing in the conversion process from point

[1] The GOES satellites cover most of North America at a spatial resolution of 0.01° by 0.01° (approximately 1 km by 1 km at 23° latitude) and a temporal resolution of 30 minutes.
[2] The low-frequency content is due to variability with long time scale, such as changes in irradiance due to the diurnal solar cycle.
[3] The high-frequency content is due to variability with short time scale, such as changes in irradiance due to moving clouds.

irradiance data to PV plant production data. This method decomposes the irradiance data into wavelet modes, which account for cloud-induced fluctuations at each timescale. The steps for this method are described below:

i. Determine the clear sky index by normalizing the measured irradiance data by the expected clear sky irradiance data. The converted time series has a value of ‘one’ during clear-sky condition and a value between zero and one during overcast sky condition.

ii. Decompose the clear-sky index into wavelet modes w_(t^*) (t) at timescales t* using the top hat wavelet transform.

iii. Determine the Variability Reduction VR, that is, the amount of smoothing applied to each wavelet mode by (1) calculating the correlations ρ for each pair of PV modules within the plant, (2) aggregating the correlations for all pairs, and (3) calculating the Variability Reduction VR at each timescale.

iv. Calculate scaled wavelet modes w_(t^*)^P (t) of the entire power plant by dividing each wavelet modes w_(t^*) (t) determined in step 2 by the square root of the respective VR(t*) determined in step 3.

v. Calculate the clear-sky index of area-averaged irradiance over the whole PV plant by applying an inverse wavelet transform to the scaled wavelet modes w_(t^*)^P (t) determined in step 4.

vi. Calculate the averaged irradiance by multiplying the averaged clear sky index with the expected clear sky irradiance.

2) Satellite-derived irradiance to PV production using

a. **SolarAnywhere High Resolution Data**: Clean Power Research sells SolarAnywhere High Resolution data. These data are derived from GOES satellite data continuously collected from 1998 onward. The GOES data capture one image every 30 minutes to derive irradiance data with one-minute resolution. The spatial resolution of the irradiance data is approximately 1 km^2, which, as noted in [2], is approximately the size of a 30 MW utility-scale PV plant. The variability of the PV production levels at short time scales may be underestimated due to (1) the upsampling process used to derive the one-minute data and (2) the relatively large spatial resolution of the data.

b. **Western Wind and Solar Integration Study II Data**: Hummon et al. [21] derived one-minute data from the same GOES satellite data set used as input to the SolarAnywhere model, although the data are limited to the year 2007. Upsampling to one-minute resolution was achieved by supplementing the data set with ground-measured irradiance data collected at 7 sites at one-minute resolution and categorizing the ground-based irradiance profiles into five sky condition classifications. A statistical method was used to map the cloud pattern captured on the satellite image to a sky condition.

3) **Power measurements for a proxy plant**. In this method, power measurements from an existing PV plant are used as a proxy for the studied plant. The accuracy of this method is highly dependent on the proxy plant data that are available. For instance, data from a

proxy plant that is similar in size and geographically close to the plant under study can be a good approximation of the prospective production levels of the study plant. If such proxy data are not available, then it is important to match the important plant parameters, such as meteorological conditions, topographical features, and plant footprint when using the proxy method.

Appendix B Average GHI-to Incidence Irradiance

In this section, we describe a simplified method for calculating the incident irradiance on a fixed surface as documented in Luque and Hegedus, 2011 [22]. This methodology achieves sufficiently accurate results by boiling down the calculation to a small number of parameters to which the results are most sensitive to and which are readily available. This method does not include the effect of shading (we treat this effect separately, as explained in Section1.2.4), but soiling is accounted for by selecting appropriate coefficients that vary with degree of dirt on the panel surface. However, [22] only gives coefficients for medium-soiled PV panels and, consequently, incident irradiances for unsoiled or heavily soiled PV panels cannot be accurately calculated with the information provided in the reference.

Many PV systems employ panels that are oriented at a specific fixed angle. However, as shown in [22], the clearness index does not have a significant impact on the optimal inclination angle β_{opt}, which provides maximum energy yield and, consequently, β_{opt} can be calculated with sufficient accuracy using

$$\beta_{opt} = 3.7 + 0.69 \cdot |\phi|$$

where ϕ is the latitude of the panel location. This equation was derived from linearly fitting the optimum angle vs latitude dependencies for 30 locations around the world. The authors note that the linear fit of this equation is not very strong but that the energy calculation is insensitive to angle variation within the error range, that is, a deviation of the calculated optimal angle and the true optimal angle at a given location has a negligible impact on the calculated energy.

Similarly, the following second-order polynomial equation can be fitted well ($R^2 > 0.98$) to a number of curves from various location around the world:

$$\frac{G_{dy}(\beta)}{G_{dy}(\beta_{opt})} = 1 + p_1 \cdot (\beta - \beta_{opt}) + p_2 \cdot (\beta - \beta_{opt})^2$$

where G_{dy} is the irradiance for an arbitrary or optimum panel inclination angle β and β_{opt}, respectively. The coefficients p_1 and p_2 are $4.46 \cdot 10^{-4}$ and $-1.19 \cdot 10^{-4}$, respectively.

The irradiance for a surface tilted at an optimal angle can be calculated readily calculated from the two equations above using the latitude of the panel location and the GHI as input, noting that the GHI is the irradiance on a horizontal surface, that is, $G_{dy}(\beta=0)=GHI$ [23].

$$G_{dy}(\beta_{opt}) = \frac{GHI}{1 - p_1 \cdot \beta_{opt} + p_2 \cdot \beta_{opt}{}^2}$$

The reality is that PV panels installed on rooftops are not necessarily tilted at an optimal angle due to constraints given by the roof geometry. Consequently, the azimuth α, that is, the angle clockwise from true north that the PV panel faces, needs to be accounted for.

$$G_{effdy}(\beta,\alpha) = G_{dy}(\beta_{opt}) \cdot \left(g_1 \cdot (\beta - \beta_{opt})^2 + g_2 \cdot (\beta - \beta_{opt}) + g_3\right)$$

where

$$\boldsymbol{g_i} = \begin{bmatrix} g_1 \\ g_2 \\ g_3 \end{bmatrix} = \begin{bmatrix} g_{11} \cdot |\alpha|^2 & g_{12} \cdot |\alpha| & g_{13} \\ g_{21} \cdot |\alpha|^2 & g_{22} \cdot |\alpha| & g_{23} \\ g_{31} \cdot |\alpha|^2 & g_{32} \cdot |\alpha| & g_{33} \end{bmatrix}$$

The coefficients $\mathbf{g}_{ij}$ vary with the level of soiling on the PV surface. For a panel with medium soiling, they are

$$\boldsymbol{g}_{ij} = \begin{bmatrix} 8 \cdot 10^{-9} & 3.8 \cdot 10^{-7} & -1.218 \cdot 10^{-4} \\ -4.27 \cdot 10^{-7} & 8.2 \cdot 10^{-6} & 2.892 \cdot 10^{-4} \\ -2.5 \cdot 10^{-5} & -1.034 \cdot 10^{-4} & 0.9314 \end{bmatrix}$$

Appendix C Peer Review of Grouping Methodology

This appendix documents the peer reviews by Professor Jan Kleissl of the University of California in San Diego and Professor Steven Hegedus of the University of Delaware.

C.1 Peer review, Professor Jan Kleissl

On June 19, 2014 I was provided a draft report entitled "Summary of Solar Data and Description of Solar Irradiation to PV Production Conversion Methodologies" by Dr. Jens Schoene from EnerNex, LLC. The objective of the study is to compare the cost impacts on a host utility when adding either (1) utility scale, (2) community scale, or (3) rooftop PV of equal amounts to their service territory.

One of the differences between the three scenarios is the amount of geographic diversity in solar irradiance and it is important to prescribe realistic irradiance input data to each PV system in the study. In other words, PV systems that are further apart will be less correlated and therefore produce a smoother aggregate irradiance signal that presents less challenges for PV integration. For example, geographic diversity reduces voltage fluctuations and tap changes on distribution feeders. Geographic diversity also reduces solar forecast error and therefore reduces load following and regulation capacity needs.

The study considers future high PV penetration scenarios and therefore existing data is insufficient to prescribe realistic irradiance inputs for each PV system. Consequently, for each of the three categories of PV systems, one year of future production levels need to be derived from today's solar irradiance data and assumptions about PV growth. The EnerNex report documents the solar data made available to EnerNex and present the methodologies to obtain a complete one-year set of 2013 PV production levels for all PV scenarios from available irradiance data.

Generally the following solutions exist to generate such data:

Use satellite or sky imager solar resource data. While geostationary satellite data covers the entire US, it is limited to 1 km resolution images taken every 30 minutes, Clean Power Research has derived an accurate approach to interpolate satellite solar resource data to 1 min. This approach was considered, but dismissed due to the prohibitive cost of the data. Similarly, solar data can be simulated with numerical weather models, but these models are not as accurate as satellite data and again this approach is costly.

Georeference existing PV and solar irradiance data and interpolate it to the sites to be modeled. If a large number of measurement stations are available per feeder as in the EPRI Distributed PV Monitoring project (http://dpv.epri.com/), this approach is simple and reasonably accurate. However, in the more common case with sparse irradiance this approach dramatically overestimates correlation between PV systems (especially if nearest-neighbor interpolation is used that results in many systems experiencing the same irradiance profile) or underestimates local variability (if linear interpolation is used).

Sufficient data that would justify approach (2) are rarely available and such data also do not exist for the EnerNex project. Despite the significant shortcomings, approach (2) is still very common in solar integration studies. In this project EnerNex has taken a superior approach that is still simple yet reasonably realistic. As shown in Fig. 3-2 in the EnerNex report, 1 min solar irradiance data *from four sites distributed across the Denver area is spatially downscaled assuming that the four site were located within the feeder footprint. Then nearest-neighbor interpolation is applied, i.e. all PV systems closest to a virtual sensor site are assigned the irradiance from the sensor. In this way all irradiance profiles in the vicinity are identical, while far away systems experience very different irradiance profiles. Fig. 1 shows the effective correlation function assumed by this approach. Fluctuations on feeder branches that are within one sensor footprint are overestimated. On the other hand, the essentially uncorrelated signal from other systems may cause realistic correlations when the entire feeder is considered.*

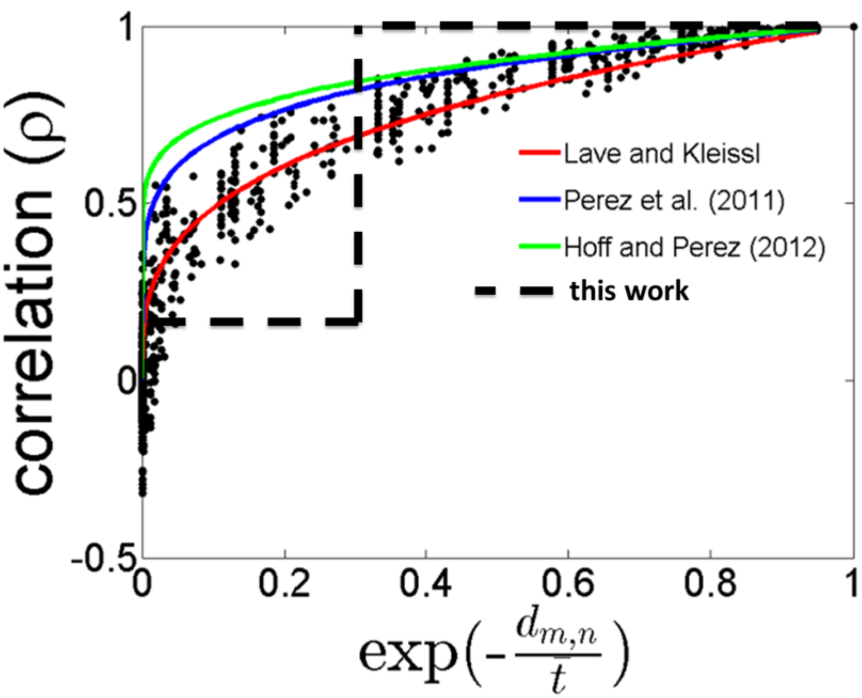

Fig. 1: Measured correlation between irradiance fluctuations at time scale t between sites spaced by $d_{m,n}$. If the distance is large or the time scale is small exp($d_{m,n}$ / t) goes to zero and the correlation is small. Colored lines show different correlation functions derived by Perez et al. and Kleissl's group at UC San Diego. The black dashed line shows an estimate of the effective correlation function assumed in the present work. Small-distance correlation is perfect (1) and therefore overestimated, while large distance correlation is small and underestimated.

Summary

Spatial diversity within the study footprint is accounted for using a creative yet simple approach that improves upon the common practice to use a single irradiance curve for all PV systems. More sophisticated approaches and/or the purchasing more data would yield more realistic results, but both are cost-prohibitive.

I have reviewed the report and found it to be well-written, clear, and the assumptions to be accurate within the limitations mentioned earlier. Technical suggestions for improvement were made directly into the document, e.g. related to transposition models, direct and diffuse irradiance, and clear sky index. All issues and suggestions were appropriately addressed by

EnerNex. These comments will also allow more accurate estimates of the differences in energy produced among the three scenarios.

C.2 Peer review, Professor Steven Hegedus

Review of "Economic Impact of Utility-Scale, Community-Scale, and Residential-Scale Solar PV" for Brattle Group and EnerNex

I have carefully read the Report. In general it seems to lay out a very reasonable plan to utilize existing data to extrapolate to predict PV array output, despite limits in the availability of the irradiance data. I list my comments and concerns below. They are listed not by importance but in order as presented in the report. One concern is about mixing data taken with different or unknown irradiance monitors, and the other is about a slight but systematic bias in favor of utility scale against residential distributed.

1. In general, I think that data from many of the locations listed in Tables 2-1 and 2-2 will be of little value, for multiple reasons: a) Many of them say "data collected with different sensor surfaces". Without any further information, I am assuming the typical industry standards where POA sensors are Si photodiodes while most meterological stations use pyranometers. These devices have different spectral, thermal and angle-of-incidence sensitivity; i.e.pyranometers will record 3-4% higher irradiance due to their wider spectral range[i]. Si photodiodes are often not calibrated to the same standards as the pyranometers. Thus, it will be inaccurate to mix or try to establish correlation between datasets from different locations if they have different sensors. One could apply a simple scaling parameter to make first order correction for the expected average difference between sensors. Also Si photodetectors have faster response and will record faster transients and peak power events compared to slower pyranometers. This has neglible impact on the daily energy or irradiance but impacts the peak power spikes; b) different time scales also give different degrees of spatial correlation. The longer the time period for averaging, the larger the correlation distance and the 'smoother' the data; You have data from seconds, minutes and hours; and c) Many of the sites have only a few months of data. Locations 1-8 of Table 2-2 have only 1 week.

EnerNex response: The table lists all data we have available, but we will not be using all of the data – only data from selected locations and for the year 2013. I am not concerned about the accuracy of the NREL data listed in Table 2.1 because (1) NREL went to great length to calibrate the sensors and ensuring the accuracy of the data and (2) the sensors should be the same type for the year 2013 (although we probably should check with NREL that this is indeed the case). The data listed in Table 2.2 is mostly production data, so the concern regarding the accuracy of the irradiance sensors does not apply.

2. You have a great interest in location 8 in Table 2-1 (Comanche Station) which is 90 miles south of Denver and in very different terrain from Denver front range but is lacking data

for 2013. What about location 7 (South Park) which is 40 miles and has good data covering 17 years including 2013?

EnerNex response: Geologically, the two sites are quite different – South Park is grassland at 3 km elevation, while Pueblo is semi-arid desert land at 1.5 km. In our view, Pueblo is a good representation for a preferred location for a PV plant that takes advantage of the utility-scale PV feature to have greater site location flexibility. Also, more parameters are measured at Comanche Station.

3. In Table 2-2, location 9 (SolarTac) has 3 years of irradiance (including all of 2013). It is in Aurora near airport relatively removed from metro NREL/Golden area where many of the sites are. Why not average that on hourly or minute bases to get typical average to compare to other locations like you propose for Comanche Station.

EnerNex response: SolarTAC has only 1-hour data.

4. In Table 2-2, locations 23-37 have PV performance, irradiance, and temperature for all of 2013. They should provide a good data set for establishing correlation distances assuming they were of similar PV technology, and have been monitored and logged similarly. But this depends on the actual distances between them. I am curious why you did not mention greater interest using them more deliberately? You could also apply your model to see how well it predicts the actual output at those locations.

EnerNex response: We are unsure about the quality of the data. There are concerns that the sensors might not have been maintained well (regular cleaning, kept shade free, etc.). On the other hand, the NREL data is high quality, so these data are preferred. I agree that these data would be useful for determining correlations, but doing this would be out of scope (unfortunately, as it would be very interesting).

5. In section 3 'Methodologies', you say that utility scale PV might have more clear sky since they tend to be located outside the polluted sky of downtown metro areas. Do you have real data to support this? My recollection of CO is that Denver used to have winter smog problem due to inversion layer (which is getting better since they established 'code red' days to ban wood stoves) but outside of metro Denver in the winter, the skies are pretty clear most of the year. This is limited empirical data from my annual visits to NREL or other mountain locations for vacation, and talking to locals.

EnerNex response: No, we do not have data to support this and it would be nice to have data to determine what difference smog really makes. Clearly, it makes some difference but it likely has a minor effect on the irradiance. However, the solar data we will be using should have the pollution effect included as the irradiance is measured on the ground (after the sun rays make it through the smog). The effect is mentioned in the report to make the point that it is not advisable to take irradiance data measured in downtown Denver and apply it to a utility-scale plant outside Denver.

6. Regarding 3.2.1 ‘Background’, what parameter is being typically reported from your meteorological stations? I thought GHI is the most commonly and easily measured solar irradiance parameter? Where are you getting the clearness index from?

EnerNex response: The parameters mentioned in this section are available from NREL for the stations we have selected for our analysis.

7. In a related concern, in 3.2.2 you are going to obtain the newer parameter ‘clear sky index’ by “normalizing measured irradiance data by the EXPECTED clear sky irradiance”. Where are you getting the expected clear sky data from? Without diffuse or DNI, how do you determine clearness index? It seems like you need to calculate your own clear sky index but if you already have DNI and GHI, then you don’t need it. Otherwise, you are in a logically inconsistent loop, requiring the data you don’t have to calculate the data don’t have. Probably I am missing something about the procedure or definitions. Also the statement ‘convert measured irradiance levels to average GHI to account for spatial smoothing’ is very unclear to me. The measured irradiance IS the GHI. How does this accomplish smoothing?

<u>EnerNex response:</u> The irradiance data were measured with a sensor that has a small footprint – it does not account for a large footprint of the plant. The “small-footprint” data are referred to in the report as point GHI and the PV plant irradiance data as average GHI.

8. Regarding Table 3-1, the parameter ‘Tilt of Single Axis Tracking (Baxis)’ of 25° seems a bit too high. I realize this would give very high annual yield, nearly same as two axis tracker, but it would also require lots more space to avoid shading and it would require more robust mounting hardware to meet wind load requirements. However, a common single axis tilt tracker is the Sunpower T20 with 20° tilt as stated in your reference (I assign that article for my class reading!) so I guess 25° is acceptable.

<u>EnerNex response:</u> The referenced article also mentions systems with 30° tilt, so 25° seems to be a good compromise.

9. Regarding table 3-2, your use of -0.5%/C for temperature derate was certainly justified several years ago. However, now, more and more Si module manufacturers are figuring out how to increase Voc which has indirect impact on reducing the TC. Many Si modules now have < -0.4%/C. And CdTe from First Solar has significantly smaller value, -0.25%/C. You might want to tweak that parameter down a little to represent today’s modules.

<u>EnerNex response:</u> Thank you for the information. I change the values to -0.4 for residential and -0.25% for commercial and utility-scale. Do you think this is OK?

10. The procedure for scaling data from years other than 2013 to allow comparison to 2013 seems reasonable to me.

<u>EnerNex response:</u> Glad to hear that. We had to get a bit creative there (due to the dearth of data).

11. Discussion of effect of partial shading due to clouds in 3-4 is very ambiguous without knowing the spatial dimensions involved. It seems to me you are biased towards the utility scale against the residential here since all of your discussion of negative consequences of cloud transients apply to the residential case assuming they are on one feeder. There are certainly reports of utility scale project of same MW as you are considering experiencing severe transients due cloud motion[ii],[iii]. As the area of the residential network is considerably more dispersed, the correlation will decrease and the transients will be smaller than a concentrated 1-100 MW utility scale array. First Solar reports that its 290 MW Aqua Caliente array field is less sensitive to clouds than a smaller utility array due to its enormous size.

<u>EnerNex response:</u> We do believe that cloud transients have a larger effect on distribution feeder with regards to voltage control, power quality, etc. Also, as observed at First Solar's Aqua Caliente plant larger size arrays are less sensitive to clouds due to the smoothing effect. We will be accounting for the smoothing effect when we process the solar data.

12. The x and y axes of figures 3-2 and 3-3 are unlabeled and I can't figure out from the text what they should be.

<u>EnerNex response:</u> This is a map of the distribution feeder. The scale of the feeder is not relevant as the explanation is only conceptual. Admittedly, the reviewed draft did not explain our methodology very well, so I understand the confusion of the reviewer. We reworded this paragraph – hopefully the explanation is clear now.

Appendix D Solar Modeling Tools

D.1 PVWatts

NREL offers the PVWatts Viewer application on their website (http://gisatnrel.nrel.gov/PVWatts_Viewer/index.html), which is a tool that facilitates an evaluation of the economics of small-scale PV based on site-specific meteorological data, customizable energy rates, and customizable characteristics of the PV system (Rating, DC/AC Derate Factor). From the NREL website:

> *NREL's PVWatts calculator determines the energy production and cost savings of grid-connected photovoltaic (PV) energy systems throughout the world. It allows homeowners, installers, manufacturers, and researchers to easily develop estimates of the performance of hypothetical PV installations.*
>
> *The PVWatts calculator works by creating hour-by-hour performance simulations that provide estimated monthly and annual energy production in kilowatts and energy value. Users can select a location and choose to use default values or their own system parameters for size, electric cost, array type, tilt angle, and azimuth angle. In addition, the PVWatts calculator can provide hourly performance data for the selected location.*
>
> *Using typical meteorological year weather data for the selected location, the PVWatts calculator determines the solar radiation incident of the PV array and the PV cell temperature for each hour of the year. The DC energy for each hour is calculated from the PV system DC rating and the incident solar radiation and then corrected for the PV cell temperature. The AC energy for each hour is calculated by multiplying the DC energy by the overall DC-to-AC derate factor and adjusting for inverter efficiency as a function of load. Hourly values of AC energy are then summed to calculate monthly and annual AC energy production.*
>
> *The PVWatts calculator is available in two versions. Site Specific Data Calculator (http://www.nrel.gov/rredc/pvwatts/site_specific.html) allows users to select a location from a map or text list of pre-determined locations throughout the world. Grid Data Calculator (http://www.nrel.gov/rredc/pvwatts/grid.html) allows users to select any location in the United States.*
>
> *The PVWatts calculator was developed by NREL's Electricity, Resources, and Building Systems Integration Center*

The Site Specific Data Calculator (Version 1) and the Grid Data Calculator (Version 2) will no longer be supported after June 2014. The latest version of PVWatts was released in March, 2014 and is currently in Beta (http://pvwatts.nrel.gov/).

D.2 SAM

NREL developed the System Advisor Model (SAM, https://sam.nrel.gov/), which allows for the evaluation of cost and performance of renewable energy projects using computer models developed at NREL, Sandia National Laboratories, the University of Wisconsin, and other organizations. SAM includes a library that includes coefficients to represent the characteristics of various renewable technologies (e.g., photovoltaic modules and inverters, parabolic trough receivers and collectors, wind turbines, and biopower combustion systems). Weather conditions can be incorporated by (1) selecting a weather data file from a list or (2) using a custom data file. For PV, The former option draws solar data from the NREL Solar Prospector mapping tool (http://maps.nrel.gov/node/10), which contains hourly solar resource data for the years 1998 to 2005 derived from satellite measurements [24]. NREL validated the SAM-predicted power production levels for nine PV systems against measured power production levels and found that the annual power levels for all systems are in agreement within ±3% [25].

Appendix E Solar Data

E.1 NREL Data

Table 0-1 gives an overview of the NREL data, which we identified and reviewed for suitability for our study. Six locations are in the larger Denver area.

Table 0-1: NREL Solar Data for Colorado

ID	Location	Data Type	Temp. Res	Recording Period	Link
1.1	NWTC M2 Tower (5 miles south of Boulder) 39° 54' 38.34" N, 105° 14' 5.28" W	Global Meteorological	10 min 1 h	9/24, 1996 - 8/23, 2001	www.nrel.gov/midc/nwtc_m2/
1.2		Global Global (accumulated) Meteorological	1 min 1 h	Since 8/24, 2001 (ongoing)	
2.1	NREL Solar Radiation Research Laboratory, Golden 39.742° N 105.18° W	Large database of different irradiance types (global, reflected, direct) collected with different sensor surfaces Meteorological	1 min 5 min 1 h	July 15, 1981 to 5/31, 2012	http://www.nrel.gov/midc/srrl_bms/
2.2		Large database of different irradiance types (global, reflected, direct) collected with different sensor surfaces Meteorological	1 min 1 h	Since 6/1, 2012 (ongoing)	
3.1	NREL Solar Measurement Grid, Golden From NREL site: “NREL Grid is just a "test" grid to prove the concept. The calibration and cleanliness of the sensors are not maintained”	Large database of different irradiance types (global, reflected, direct) collected with different sensor surfaces	1 min 1 h	9/17, 2009 – 2/9, 2010	http://www.nrel.gov/midc/nrel_grid/
3.2		Large database of different irradiance types (global, reflected, direct) collected with different sensor surfaces	1 sec	2/10, 2010 – 8/26, 2013	
3.3		Global Horizontal Global on surface tilted by	1 sec	Since 8/27, 2013 (ongoing)	

		40° from horizontal			
4	Vehicle Testing and Integration Facility (VTIF), Golden 39.74211° N 105.17514° W (same location as 3)	Global Horizontal Direct Normal Diffuse Horizontal Meteorological	1 min 1 h	Since 4/1, 2012 (ongoing)	http://www.nrel.gov/midc/vtif_rsr/
5	Solar Technology Acceleration Center (SolarTAC), Aurora 39.75685° N 104.62025° W	Global Horizontal Direct Normal Diffuse Horizontal Meteorological	1 min 1 h	Since 2/11, 2011 (ongoing)	http://www.nrel.gov/midc/solartac/
6	Lowry Range (a few miles east of Denver) 39.60701° N 104.58017° W	Global Horizontal Direct Normal Diffuse Horizontal Meteorological	1 min 1 h	5/30, 2008 - 1/30, 2014	http://www.nrel.gov/midc/lrss/
7	South Park (40 miles south-west of Denver) 39° 16' 22" N 105° 37' 29" W	Global Meteorological	5 min	Since 3/28, 1997 (ongoing)	http://www.nrel.gov/midc/spmd/
8	Comanche Station, Pueblo (90 miles south of Denver) 38.2098° N 104.5724° W	Global Horizontal Direct Normal Diffuse Horizontal Meteorological	1 min 1 h	6/20, 2007 – 6/16, 2011	http://www.nrel.gov/midc/xecs/
9	Sun Spot One, San Luis Valley (150 miles south of Denver) 37.56100° N 106.0864° W	Global Horizontal Direct Normal Diffuse Horizontal Meteorological	1 min 1 h	6/10, 2008 – 11/8, 2010	http://www.nrel.gov/midc/ss1/
10	Sun Spot Two, Swink (150 miles south east of Denver) 38.01221° N	Global Horizontal Direct Normal Diffuse Horizontal Meteorological	1 min 1 h	Since 11/10, 2010 (ongoing)	http://www.nrel.gov/midc/ss2/

	103.61696° W				
11	NREL PVDAQ Residential#1a Rating (DC): 2.912 kW 39.7214° N 105.0972° W	DC Current DC Voltage DC Power POA Irradiance	1 min	1/21/2010 – 9/3/2013	
12	NREL PVDAQ Residential#1b Rating (DC): 2.72 kW 39.7214° N 105.0972° W	DC Current DC Voltage DC Power POA Irradiance	1 min	1/21/2010 – 9/3/2013	
13	NREL PVDAQ Residential#2 Rating (DC): 5.17 kW 39.766° N 105.2387° W	Not publicly accessible			
14	NREL PVDAQ CIS#1 Rating (DC): 1.12 kW 39.7404° N 105.1774° W	AC Current AC Power AC Voltage Ambient Temperature	15 min	1/9/2006 – 4/21/2009	http://maps.nrel.gov/pvdaq
		DC Current DC Voltage DC Power POA Irradiance	1 min	Since 1/10/2010 (Ongoing)	
15	NREL PVDAQ CIGS#11 Rating (DC): ??? 39.7405° N 105.1774° W	AC Current AC Power AC Voltage Ambient Temperature DC Current DC Voltage DC Power POA Irradiance	1 min	Since 6/29/2012 (Ongoing)	

		Power Factor			
16	NREL PVDAQ CIGS#12 Rating (DC): 1.82 kW 39.7405° N 105.1774° W	AC Current AC Power AC Voltage Ambient Temperature DC Current DC Voltage DC Power POA Irradiance Power Factor	1 min	Since 9/27/2012 (Ongoing)	
17	NREL PVDAQ x-SI#1 Rating (DC): 1 kW 39.7406° N 105.1774° W	AC Current AC Power AC Voltage Ambient Temperature DC Current DC Voltage DC Power POA Irradiance Power Factor	15 min 1 min	6/26/2007 – 6/3/2009 Since 1/21/2010 (Ongoing)	
18	NREL PVDAQ Ribbon Si#1c Rating (DC): 1.4 kW 39.7407° N 105.1773° W	Not publicly accessible			
19	NREL PVDAQ Silicor Materials Rating (DC): 2.4 kW 39.7404° N 105.1772° W	AC Current AC Power AC Voltage Ambient Temperature DC Current DC Voltage DC Power POA Irradiance	1 min	Since 11/8/2010 (Ongoing)	

		Power Factor			
20	NREL PVDAQ CIGS#7 Rating (DC): ??? kW 39.7404° N 105.1771° W	Not publicly accessible			
21	NREL PVDAQ CIGS#3 Rating (DC): ??? kW 39.7404° N 105.1771° W	Not publicly accessible			
22	NREL PVDAQ CIGS#5 Rating (DC): ??? kW 39.7404° N 105.1771° W	Not publicly accessible			
23	NREL PVDAQ CIGS#8 Rating (DC): ??? kW 39.7404° N 105.1771° W	Not publicly accessible			
24	NREL PVDAQ CIGS#9 Rating (DC): ??? kW 39.7404° N 105.1771° W	Not publicly accessible			

25	NREL PVDAQ CIGS#4 Rating (DC): ??? kW 39.7404° N 105.1771° W	Not publicly accessible			
26	NREL PVDAQ a-Si #2 Rating (DC): 1.2 kW 39.7405° N 105.1728° W	Not publicly accessible			
27	NREL PVDAQ Research Support Facility II Rating (DC): 408.24 kW 39.7409° N 105.1711° W	AC Current AC Power AC Voltage Ambient Temperature DC Current DC Voltage DC Power POA Irradiance Wind Speed	15 sec	Since 1/9/2012 (Ongoing)	
28	NREL PVDAQ Visitor Parking Structure Rating (DC): 524.16 kW 39.7407° N 105.1694° W	AC Power DC Power DC Current DC Voltage	15 sec	Since 7/26/2011 (Ongoing)	
29	NREL PVDAQ Parking Garage Rating (DC): 1153.488 kW 39.7388° N 105.1732° W	AC Power DC Power DC Current DC Voltage Current Shaded Current Unshaded	15 sec	Since 3/29/2013 (Ongoing)	

E.2 Data provided by Xcel Energy

Table 0-2 lists the solar data provided by Xcel Energy.

Table 0-2: Xcel Energy Solar Data for Colorado

ID	Location	Data Type	Temp. Res	Recording Period
1	SolarTAC	• Irradiance	• 1 hour	2/11/2011 – 2/11/2014
2	SolarTAC	• DC Power	• 1 min	01/01/2013 – 01/31/2013
3	Xcel Energy Colorado Rating (DC): 101.660 kW Zip: 80219	• kW	• 4 min	9/19/2013 – 12/31/2013
4	Xcel Energy Colorado Rating (DC): 101.660 kW Zip: 80205	• kW	• 4 min	9/19/2013 – 12/31/2013
5	Xcel Energy Colorado Rating (DC): 80.730 kW Zip: 80219	• kW	• 4 min	9/19/2013 – 12/31/2013
5	Xcel Energy Colorado Rating (DC): 101.660 kW Zip: 80204	• kW	• 4 min	9/19/2013 – 12/31/2013
6	Xcel Energy Colorado Rating (DC): 101.660 kW Zip: 80204	• kW	• 4 min	9/19/2013 – 12/31/2013
7	Xcel Energy Colorado Rating (DC): 101.660 kW Zip: 80223	• kW	• 4 min	9/19/2013 – 12/31/2013
8	Xcel Energy Colorado Rating (DC): 101.660 kW Zip: 80205	• kW	• 4 min	9/19/2013 – 12/31/2013

9	Xcel Energy Colorado Rating (DC): 101.660 kW Zip: 80211	• kW	• 4 min	9/19/2013 – 12/31/2013
10	Xcel Energy Colorado Rating (DC): 95.680 kW Zip: 80219	• kW	• 4 min	9/19/2013 – 12/31/2013
11	Xcel Energy Colorado Rating (DC): 101.660 kW Zip: 80219	• kW	• 4 min	9/19/2013 – 12/31/2013
12	Xcel Energy Colorado Rating (DC): 101.660 kW Zip: 80205	• kW	• 4 min	9/19/2013 – 12/31/2013
13	Xcel Energy Colorado Rating (DC): 101.660 kW Zip: 80219	• kW	• 4 min	9/19/2013 – 12/31/2013
14	Zip: 80205 Rating (DC): ??? kW	• Power Factor • Apparent Power • Reactive Power • AC Voltage • AC Current • AC Power • Irradiance • Humidity • Ambient Temperature • Cell Temperature	• 15 min	01/01/2013 – 12/31/2013

15	Zip: 80224 Rating (DC): ??? kW	• Power Factor • Apparent Power • Reactive Power • AC Voltage • AC Current • AC Power	• 15 min	10/30/2012 – 12/31/2013
		• Irradiance • Humidity • Ambient Temperature • Cell Temperature	• 15 min	01/01/2013 – 12/31/2013
16	Zip: 80206 Rating (DC): ??? kW	• Power Factor • Apparent Power • Reactive Power • AC Voltage • AC Current • AC Power • Irradiance • Humidity • Ambient Temperature • Cell Temperature	• 15 min	01/01/2013 – 12/31/2013
17	Zip: 80249 Rating (DC): ??? kW	• Power Factor • Apparent Power • Reactive Power • AC Voltage • AC Current • AC Power	• 15 min	01/31/2013 – 12/31/2013

		• Irradiance • Ambient Temperature • Cell Temperature	• 15 min	02/28/2014 – 03/28/2014
18	Zip: 80123 Rating (DC): ??? kW	• Power Factor • Apparent Power • Reactive Power • AC Voltage • AC Current • AC Power • Irradiance • Humidity • Ambient Temperature • Cell Temperature	• 15 min	01/31/2013 – 12/31/2013
19	Zip: 80249 Rating (DC): ??? kW	• DC Power • Inverter Efficiency • AC Voltage • AC Current • AC Power • DC Current • DC Voltage • Irradiance • Ambient Temperature • Cell Temperature	• 15 min	01/01/2013 – 12/31/2013

20	Zip: 80249 Rating (DC): ??? kW	• Power Factor • Apparent Power • Reactive Power • AC Voltage • AC Current • AC Power • Irradiance • Ambient Temperature • Cell Temperature	• 15 min	01/01/2013 – 12/31/2013
21	Zip: 80239 Rating (DC): ??? kW	• DC Current • DC Voltage • Irradiance • Ambient Temperature • Cell Temperature	• 15 min	01/01/2013 – 12/31/2013
22	Zip: 80230 Rating (DC): ??? kW	• DC Power • Inverter Efficiency • AC Voltage • AC Current • AC Power • DC Current • DC Voltage • Irradiance • Ambient Temperature • Cell Temperature	• 15 min	01/31/2013 – 12/31/2013
23	Zip: 80205 Rating (DC): ??? kW	• Power Factor • Apparent Power • Reactive Power • AC Voltage • AC Current • AC Power	• 15 min	01/31/2013 – 12/31/2013

		• Irradiance • Humidity • Cell Temperature		
24	Zip: 80249 Rating (DC): ??? kW	• Power Factor • Apparent Power • Reactive Power • AC Voltage • AC Current • AC Power • Irradiance • Humidity • Ambient Temperature • Cell Temperature	• 15 min	01/31/2013 – 12/31/2013
25	Zip: 80239 Rating (DC): ??? kW	• Power Factor • Apparent Power • Reactive Power • AC Voltage • AC Current • AC Power • Irradiance • Ambient Temperature • Cell Temperature	• 15 min	01/01/2013 – 12/31/2013
26	Zip: 80224 Rating (DC): ??? kW	• Power Factor • Apparent Power • Reactive Power • AC Voltage • AC Current • AC Power	• 15 min	01/01/2013 – 01/31/2013

		• Irradiance • Humidity • Ambient Temperature • Cell Temperature		
27	Zip: 80239 Rating (DC): ??? kW	• DC Power • Inverter Efficiency • AC Voltage • AC Current • AC Power • DC Current • DC Voltage • Irradiance • Ambient Temperature • Cell Temperature	• 15 min	01/01/2013 – 12/31/2013
28	Zip: 80210 Rating (DC): ??? kW	• Power Factor • Apparent Power • Reactive Power • AC Voltage • AC Current • AC Power • Irradiance • Humidity • Ambient Temperature • Cell Temperature	• 15 min	01/01/2013 – 12/31/2013

29	CES Project Meter 1 Rating (DC): 4.9 kW	• Voltage • Power	• 1 sec	2013
30	CES Project Meter 2 Rating (DC): 7 kW	• Voltage • Power	• 1 sec	2013
31	CES Project Meter 3 Rating (DC): 2.1 kW	• Voltage • Power	• 1 sec	2013
32	CES Project Meter 4 Rating (DC): 4.2 kW	• Voltage • Power	• 1 sec	2013
33	Zip: 80225	• Power	• 4 min	9/19/2013 – 12/31/2013

34	Zip: 80225	• Power	• 4 min	9/19/2013 – 12/31/2013
35	Zip: 80225 Rating (DC): 255 kW	• Power	• 15 min	01/01/2013 – 12/31/2013
			• 4 min	9/19/2013 – 12/31/2013
36	Zip: 80225 Rating (DC): 484 kW	• Power	• 15 min	01/01/2013 – 12/31/2013
			• 4 min	9/19/2013 – 12/31/2013
37	Zip: 80225 Rating (DC): 147 kW	• Power	• 15 min	01/01/2013 – 12/31/2013
			• 4 min	9/19/2013 – 12/31/2013
38	Zip: 80225 Rating (DC): 363 kW	• Power	• 15 min	01/01/2013 – 12/31/2013
			• 4 min	9/19/2013 – 12/29/2013

39	Zip: 80225 Rating (DC): 280 kW	• Power	• 15 min	01/01/2013 – 12/31/2013
			• 4 min	9/19/2013 – 12/31/2013
40	Zip: 80225 Rating (DC): 497 kW	• Power	• 15 min	01/01/2013 – 12/31/2013
			• 4 min	9/19/2013 – 12/31/2013
41	Zip: 80225 Rating (DC): 497 kW	• Power	• 15 min	01/01/2013 – 12/31/2013
			• 4 min	9/19/2013 – 12/31/2013
42	Zip: 80225 Rating (DC): 465 kW	• Power	• 15 min	01/01/2013 – 12/31/2013
			• 4 min	9/20/2013 – 12/31/2013
43	Zip: 80225 Rating (DC): 573 kW	• Power	• 15 min	01/01/2013 – 12/31/2013

			• 4 min	9/19/2013 – 12/31/2013
44	Zip: 80225	• W/m^2	• 15 min	01/01/2013 – 12/31/2013
			• 4 min	9/19/2013 – 12/31/2013
45	Zip: 80225 Rating (DC): 489 kW	• Power	• 15 min	01/01/2013 – 12/31/2013
			• 4 min	9/19/2013 – 12/31/2013
46	Zip: 80225 Rating (DC): 489 kW	• Power	• 15 min	01/01/2013 – 12/31/2013
			• 4 min	9/19/2013 – 12/31/2013
47	Zip: 80225 Rating (DC): 492 kW	• Power	• 15 min	01/01/2013 – 12/31/2013
			• 4 min	9/19/2013 – 12/31/2013
48	Zip: 80225	• Power	• 15 min	01/01/2013 – 12/31/2013

	Rating (DC): 495 kW		• 4 min	9/19/2013 – 12/31/2013
49	Zip: 80225 Rating (DC): 533 kW	• Power	• 15 min	01/01/2013 – 12/31/2013
			• 4 min	9/19/2013 – 12/31/2013
50	Zip: 80225 Rating (DC): 381 kW	• Power	• 15 min	01/01/2013 – 12/31/2013
			• 4 min	9/19/2013 – 12/31/2013
51	Zip: 80225 Rating (DC): 393 kW	• Power	• 15 min	01/01/2013 – 12/31/2013
			• 4 min	9/19/2013 – 12/31/2013
52	Zip: 80225	• W/m^2	• 15 min	01/16/2013 – 12/31/2013
			• 4 min	9/19/2013 – 12/31/2013

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Prog. Photovolt: Res. Appl. 2008; 16:249–259
[iii] Kankiewicz, Sengupta, Moon "Observed impact of transient clouds in utility scale PV fields" Proceeding ASES 2010.

APPENDIX C

Solar Financing Model Assumptions and Results

Table C.1: Reference Case (2019 ITC at 10%)

2019 ITC @10%		Utility: ITC Monetized by Tax Equity	Residential: ITC Monetized by Tax Equity	Residential: Customer Purchase
Assumptions				
Installed Cost (DC)	$/ kW	1,430	2,250	2,250
DC Overbuild	%	20%	0%	0%
DC to AC Conversion	%	96%	94%	94%
Inflation	%	2%	2%	2%
FOM	$/ kW-Year	26	26	26
Contract/ Asset Life**	Years	25	25	25
Debt Life***	Years	15	15	15
Capacity Factor (AC)	%	29.06%	16.24%	16.24%
Annual Derate Factor	%	0.50%	0.50%	0.50%
SREC Price (10 Years)	$/kWh	-	0.001	0.001
Tax Rate	%	40%	40%	40%
Investment Tax Credit	%	10%	10%	0%
Accelerated Depreciation	MACRS	5	5	-
Cost of Debt	%	8.0%	8.0%	3.8%
Cost of Tax Equity	%	8.0%	8.0%	0.0%
Cost of Developer Equity	%	12.0%	12.0%	0.0%
Capital Structure - Gross				
Debt***	%	47%	47%	100%
Tax Equity****	%	35%	35%	0%
Developer Equity****	%	18%	18%	0%
Total	%	100%	100%	100%
Average DSCR***	EBITDA/ DS	1.5	1.5	1.0
Revenue Requirement				
Levelized Nominal	$/kWh	0.083	0.182	0.167
Discount Rate	%	7.6%	7.6%	7.6%
PVRR	$M	556	812	752

** Assumes asset reverts to customer at zero cost at contract end

*** Assumed to be backlevered if tax equity in capital structure

**** Monetizes ITC, as relevant. Tax equity modeled as partnership flip @ 10 years.

Table C.2: Scenario 1 (2019 ITC at 30%)

		Utility	Residential	
2019 ITC @ 30%		ITC Monetized by Tax Equity	ITC Monetized by Tax Equity	Customer Purchase
Assumptions				
Installed Cost (DC)	$/ kW	1,430	2,250	2,250
DC Overbuild	%	20%	0%	0%
DC to AC Conversion	%	96%	94%	94%
Inflation	%	2%	2%	2%
FOM	$/ kW-Year	26	26	26
Contract/ Asset Life**	Years	25	25	25
Debt Life***	Years	15	15	15
Capacity Factor (AC)	%	29.06%	16.24%	16.24%
Annual Derate Factor	%	0.50%	0.50%	0.50%
SREC Price (10 Years)	$/kWh	-	0.001	0.001
Tax Rate	%	40%	40%	40%
Investment Tax Credit	%	30%	30%	30%
Accelerated Depreciation	MACRS	5	5	5
Cost of Debt	%	8.0%	8.0%	3.8%
Cost of Tax Equity	%	8.0%	8.0%	0.0%
Cost of Developer Equity	%	12.0%	12.0%	0.0%
Capital Structure - Gross				
Debt***	%	33%	33%	100%
Tax Equity****	%	55%	55%	0%
Developer Equity****	%	13%	13%	0%
Total	%	100%	100%	100%
Average DSCR***	EBITDA/ DS	1.5	1.5	1.0
Revenue Requirement				
Levelized Nominal	$/kWh	0.066	0.140	0.123
Discount Rate	%	7.6%	7.6%	7.6%
PVRR	$M	438	625	554

** Assumes asset reverts to customer at zero cost at contract end

*** Assumed to be backlevered if tax equity in capital structure

**** Monetizes ITC, as relevant. Tax equity modeled as partnership flip @ 10 years.

Table C.3: Scenario 2 (2019 Developer absorbs ITC)

		Utility	Residential
2019 Developer absorbs ITC		ITC Absorbed by Developer	ITC Absorbed by Developer
Assumptions			
Installed Cost (DC)	$/ kW	1,430	2,250
DC Overbuild	%	20%	0%
DC to AC Conversion	%	96%	94%
Inflation	%	2%	2%
FOM	$/ kW-Year	26	26
Contract/ Asset Life**	Years	25	25
Debt Life***	Years	20	20
Capacity Factor (AC)	%	29.06%	16.24%
Annual Derate Factor	%	0.50%	0.50%
SREC Price (10 Years)	$/kWh	-	0.001
Tax Rate	%	40%	40%
Investment Tax Credit	%	10%	10%
Accelerated Depreciation	MACRS	5	5
Cost of Debt	%	5.5%	5.5%
Cost of Tax Equity	%	8.0%	8.3%
Cost of Developer Equity	%	12.0%	12.0%
Capital Structure - Gross			
Debt***	%	61%	61%
Tax Equity****	%	0%	0%
Developer Equity****	%	39%	39%
Total	%	100%	100%
Average DSCR***	EBITDA/ DS	1.4	1.4
Revenue Requirement			
Levelized Nominal	$/kWh	0.066	0.140
Discount Rate	%	7.6%	7.6%
PVRR	$M	438	625

** Assumes asset reverts to customer at zero cost at contract end

*** Assumed to be backlevered if tax equity in capital structure

**** Monetizes ITC, as relevant. Tax equity modeled as partnership flip @ 10 years.

Table C.4: Scenario 3 (2019 Higher Inflation)

		Utility	Residential	
2019 Higher Inflation		ITC Monetized by Tax Equity	ITC Monetized by Tax Equity	Customer Purchase
Assumptions				
Installed Cost (DC)	$/ kW	1,430	2,250	2,250
DC Overbuild	%	20%	0%	0%
DC to AC Conversion	%	96%	94%	94%
Inflation	%	4%	4%	2%
FOM	$/ kW-Year	26	26	26
Contract/ Asset Life**	Years	25	25	25
Debt Life***	Years	15	15	15
Capacity Factor (AC)	%	29.06%	16.24%	16.24%
Annual Derate Factor	%	0.50%	0.50%	0.50%
SREC Price (10 Years)	$/kWh	-	0.001	0.001
Tax Rate	%	40%	40%	40%
Investment Tax Credit	%	10%	10%	0%
Accelerated Depreciation	MACRS	5	5	-
Cost of Debt	%	10.0%	10.0%	5.8%
Cost of Tax Equity	%	10.0%	10.0%	0.0%
Cost of Developer Equity	%	14.0%	14.0%	0.0%
Capital Structure - Gross				
Debt***	%	48%	48%	100%
Tax Equity****	%	35%	35%	0%
Developer Equity****	%	18%	18%	0%
Total	%	100%	100%	100%
Average DSCR***	EBITDA/ DS	1.5	1.5	1.0
Revenue Requirement				
Levelized Nominal	$/kWh	0.095	0.206	0.187
Discount Rate	%	9.6%	9.6%	9.6%
PVRR	$M	538	785	716

** Assumes asset reverts to customer at zero cost at contract end

*** Assumed to be backlevered if tax equity in capital structure

**** Monetizes ITC, as relevant. Tax equity modeled as partnership flip @ 10 years.

Table C.5: Scenario 4 (2019 Lower PV Cost)

		Utility	Residential	
2019 Lower PV Cost		ITC Monetized by Tax Equity	ITC Monetized by Tax Equity	Customer Purchase
Assumptions				
Installed Cost (DC)	$/ kW	1,140	1,800	1,800
DC Overbuild	%	20%	0%	0%
DC to AC Conversion	%	96%	94%	94%
Inflation	%	2%	2%	2%
FOM	$/ kW-Year	26	26	26
Contract/ Asset Life**	Years	25	25	25
Debt Life***	Years	15	15	15
Capacity Factor (AC)	%	29.06%	16.24%	16.24%
Annual Derate Factor	%	0.50%	0.50%	0.50%
SREC Price (10 Years)	$/kWh	-	0.001	0.001
Tax Rate	%	40%	40%	40%
Investment Tax Credit	%	10%	10%	0%
Accelerated Depreciation	MACRS	5	5	-
Cost of Debt	%	8.0%	8.0%	3.8%
Cost of Tax Equity	%	8.0%	8.0%	0.0%
Cost of Developer Equity	%	12.0%	12.0%	0.0%
Capital Structure - Gross				
Debt***	%	47%	47%	100%
Tax Equity****	%	35%	35%	0%
Developer Equity****	%	18%	18%	0%
Total	%	100%	100%	100%
Average DSCR***	EBITDA/ DS	1.5	1.5	1.0
Revenue Requirement				
Levelized Nominal	$/kWh	0.069	0.149	0.137
Discount Rate	%	7.6%	7.6%	7.6%
PVRR	$M	463	668	617

** Assumes asset reverts to customer at zero cost at contract end

*** Assumed to be backlevered if tax equity in capital structure

**** Monetizes ITC, as relevant. Tax equity modeled as partnership flip @ 10 years.

Table C.6: Scenario 5 (2014 Actual PV Cost)

		Utility	Residential	
2014 Actual PV Cost		ITC Monetized by Tax Equity	ITC Monetized by Tax Equity	Customer Purchase
Assumptions				
Installed Cost (DC)	$/ kW	2,880	4,250	4,250
DC Overbuild	%	20%	0%	0%
DC to AC Conversion	%	96%	94%	94%
Inflation	%	2%	2%	2%
FOM	$/ kW-Year	26	26	26
Contract/ Asset Life**	Years	25	25	25
Debt Life***	Years	15	15	15
Capacity Factor (AC)	%	29.06%	16.24%	16.24%
Annual Derate Factor	%	0.50%	0.50%	0.50%
SREC Price (10 Years)	$/kWh	-	0.010	0.030
Tax Rate	%	40%	40%	40%
Investment Tax Credit	%	30%	30%	30%
Accelerated Depreciation	MACRS	5	5	-
Cost of Debt	%	8.0%	8.0%	3.8%
Cost of Tax Equity	%	8.0%	8.0%	0.0%
Cost of Developer Equity	%	12.0%	12.0%	0.0%
Capital Structure - Gross				
Debt***	%	32%	33%	70%
Tax Equity****	%	55%	55%	30%
Developer Equity****	%	13%	13%	0%
Total	%	100%	100%	100%
Average DSCR***	EBITDA/ DS	1.5	1.5	1.0
Revenue Requirement				
Levelized Nominal	$/kWh	0.117	0.237	0.193
Discount Rate	%	7.6%	7.6%	7.6%
PVRR	$M	781	1,061	869

** Assumes asset reverts to customer at zero cost at contract end

*** Assumed to be backlevered if tax equity in capital structure

**** Monetizes ITC, as relevant. Tax equity modeled as partnership flip @ 10 years.

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