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-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.

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.

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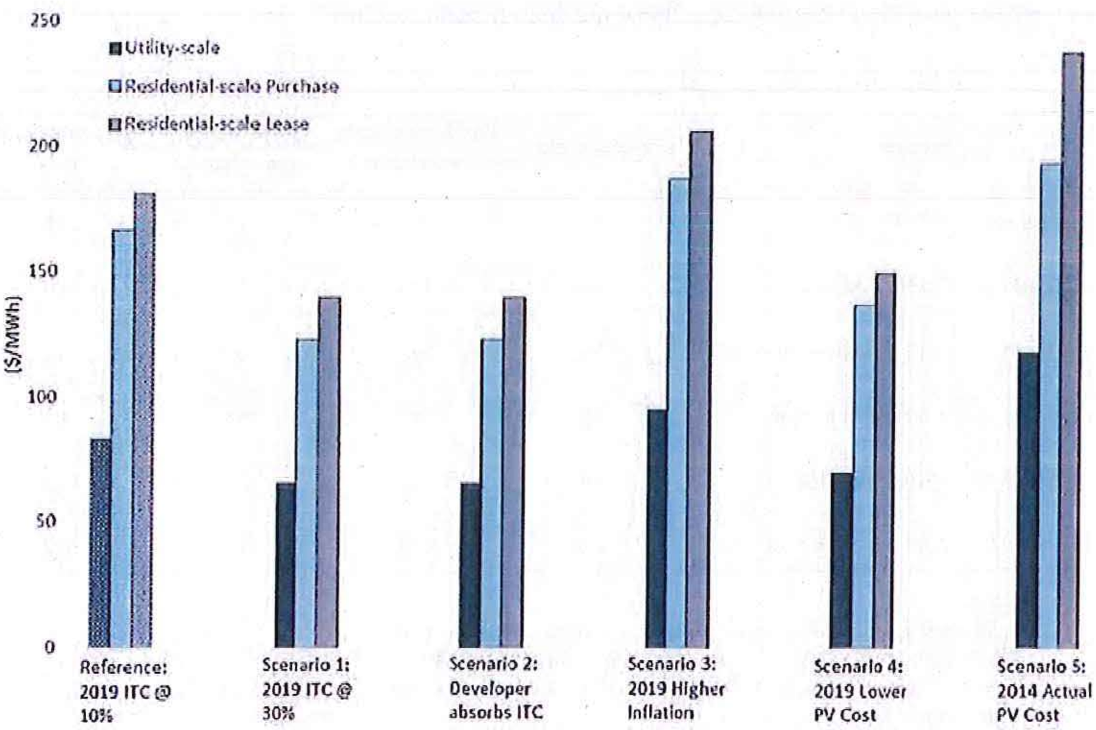
5 EIA Electric Power Monthly, January 2015, Table 5.3.

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.

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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

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[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

[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.

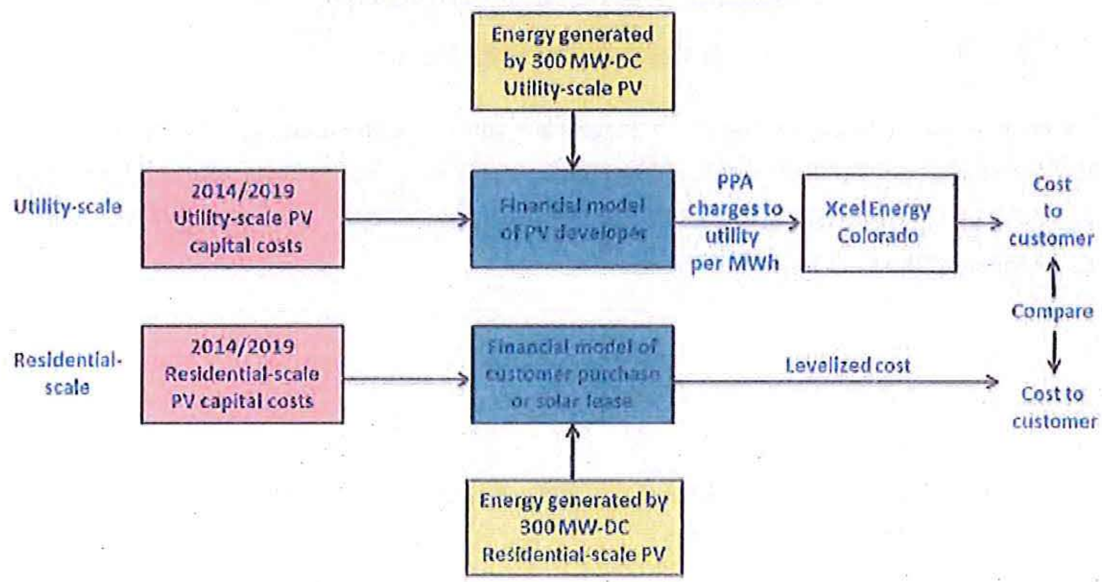
utility- and residential-scale systems in the Reference Case and across these Scenarios. In Section IV, we discuss the likely effects on our primary conclusions of factoring monetized non-generation costs and non-monetized costs, *i.e.*, societal benefits or externalities, into the analysis.

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.

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.

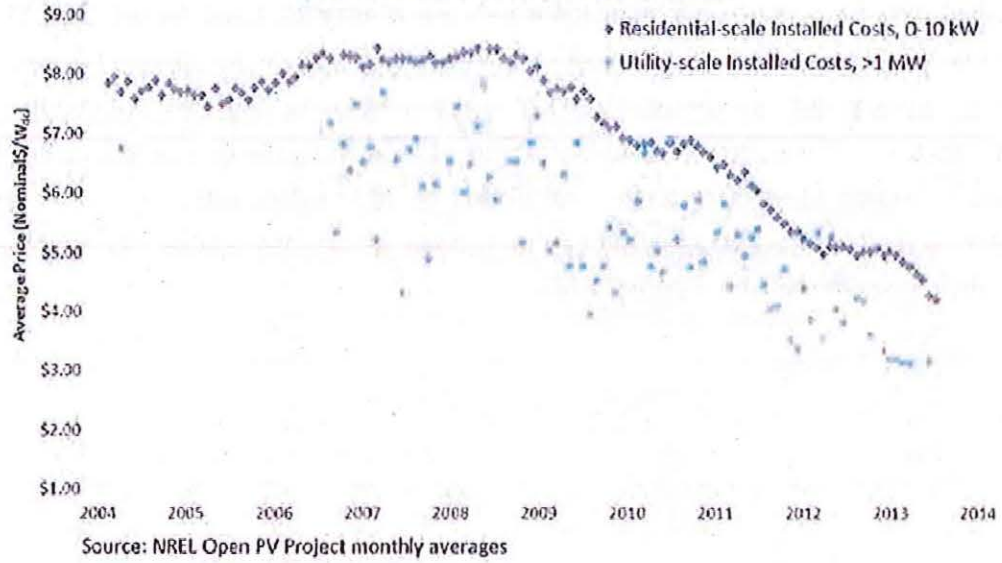
The NREL Open PV dataset was used to estimate costs for both 2014 and 2019. Open PV presents installed costs for over 315,000 installations between January 2004 and August 2014. This data was first sorted into different categories based on the capacity of the installation. For this portion of the analysis, 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

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[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:

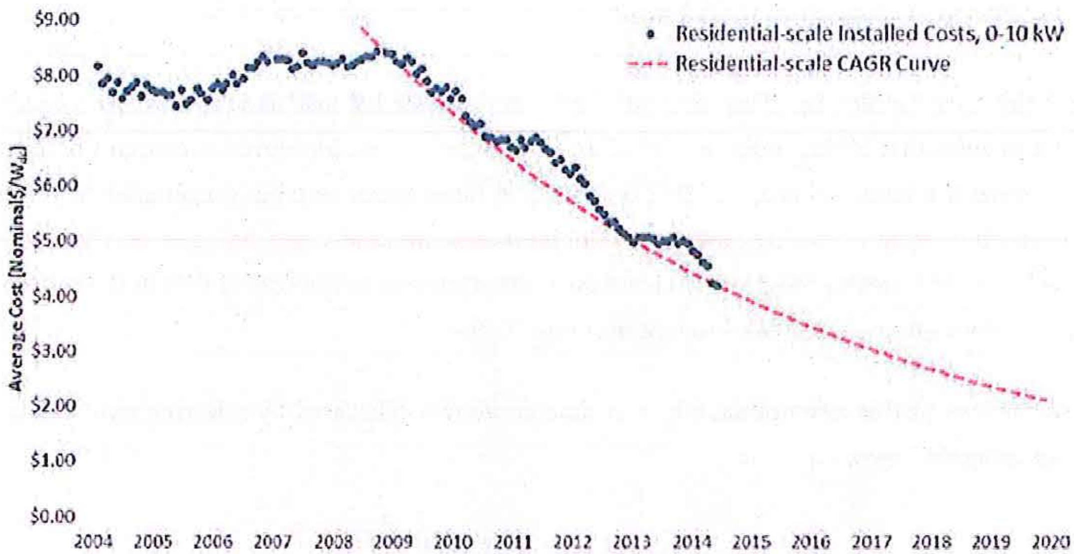
$$Decline\ Rate = \left[\frac{MP_1}{MP_2}\right]^{\frac{1}{(Date_1 - Date_2)}}$$

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-DC by June of 2019.

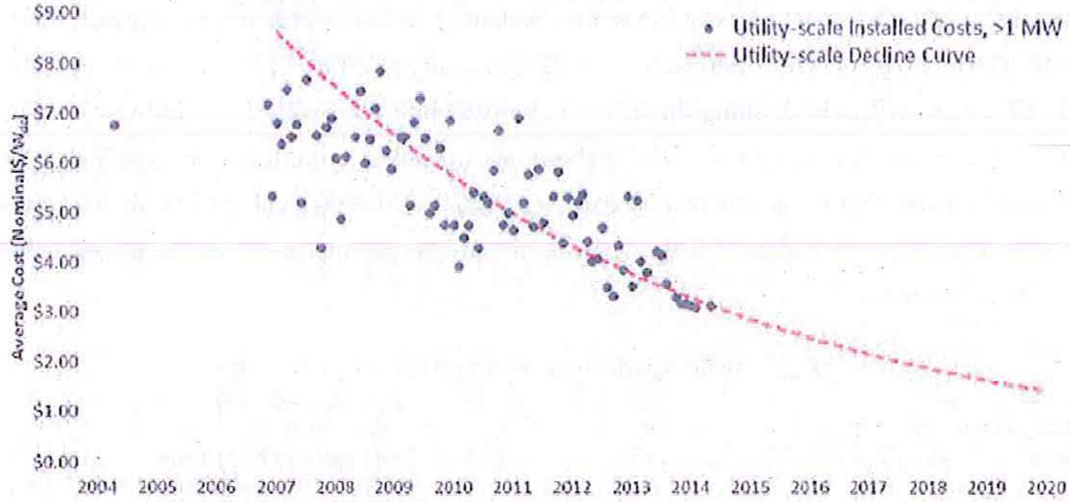
Table 7: Residential-Scale Cost Decline Calculations

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

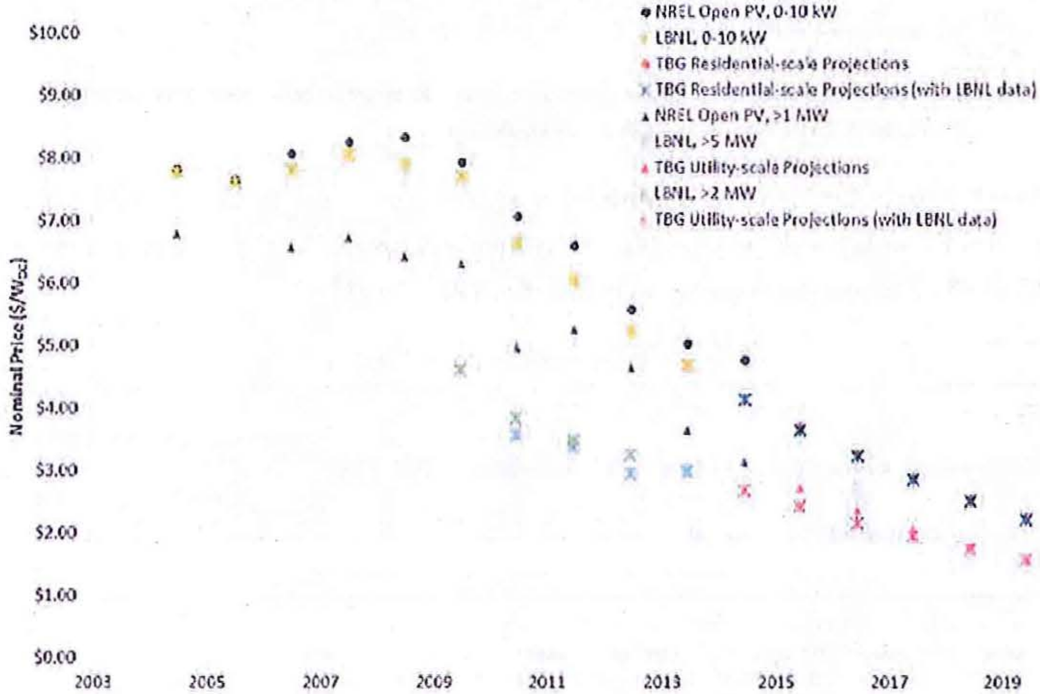
Start Date for Decline Rate	Start Cost for Decline Rate ($/W-DC)	End Date for Decline Rate	End Cost for Decline Rate ($/W-DC)	Monthly Decline Rate for Utility-scale	Utility-scale value on 6/1/2019 ($/W-DC)	EOS adjusted Utility-scale Value on 6/1/2019 ($/W-DC)
[1]	[2]	[3]	[4]	[5]	[6]	[7]
Feb-2009	$6.55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

[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/200/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

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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]

[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]

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[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[a] 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_{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)

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[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						$1.50		
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	$2.83	$2.57	$2.35	$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 - $1.53			
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-DC):

- 2014 Residential-scale PV: $4.25/W-DC;
- 2014 Utility-Scale PV: $2.88/W-DC;
- 2019 Residential-scale: $2.25/W-DC; and
- 2019 Utility-Scale: $1.43/W-DC.

APPENDIX B

EnerNex Report-

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