Power to the Customer: Differentiating Rooftop and Utility-scale Solar

Prepared for:

Sunrun, Inc.

Prepared by:

Crossborder Energy

Authors:

R. Thomas Beach
Patrick G. McGuire
Andrew B. Peterson

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*2560 Ninth Street * Suite 213A * Berkeley, California 94708 * tomb@crossborderenergy.com*

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R. Thomas Beach, Patrick G. McGuire, and Andrew B. Peterson
Crossborder Energy

Executive Summary

This white paper presents an updated consideration of the benefits and costs of distributed, behind-the-meter, "rooftop" solar facilities in comparison to large, central station, "utility-scale" solar projects. In several states, utilities and ratepayer advocates have argued that utility-scale solar can provide the same benefits as rooftop systems, but at a lower cost due to the economies of scale of utility-scale projects. This paper argues that this simple comparison fails to consider important differences between these two types of solar resources, differences based on where these resources are located and how customers are able to choose them. We update the benefit/cost comparison between these two types of solar (including the costs of financing), provide new perspectives on the value of customers' freedom to choose to adopt rooftop solar, and discuss how rooftop solar combined with on-site storage will leverage additional benefits for the electric system that cannot be supplied by utility-scale solar plus storage.

We have previously examined this argument quantitatively, in a white paper prepared in 2014 that compared both the benefits and costs of rooftop and utility-scale solar using data from Colorado.[1] That paper found that utility-scale solar offers higher capacity factors and lower capital costs due to economies of scale, compared to rooftop systems. However, this advantage is offset by rooftop solar's more valuable location at the point of end-use, by its ability to meet the demand for 100% renewable power at a lower cost to the customer than the typical utility "green pricing" program, by the reliability benefits of rooftop solar when paired with storage, and by the greater societal and customer choice benefits of rooftop. To the extent that these added benefits of rooftop could be quantified, they essentially offset the cost advantage of utility-scale systems.

A report prepared by the Brattle Group for a utility-scale solar developer, with support from the Edison Electric Institute and Xcel Energy, has also addressed this issue in Colorado, concluding that the per kWh costs of utility-scale solar are significantly lower than for rooftop.[2] However, the Brattle Study appears to calculate utility-scale costs using an overestimation of the proportion of utility-scale projects that use tracking. Moreover, it did not examine quantitatively certain key differences, including:

- the general body of ratepayers pays directly for only a portion of rooftop costs, i.e. just for the portion of rooftop output that is exported to the grid;

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1 "Relative Benefits and Costs of Rooftop and Utility-scale Solar" (Crossborder Energy, July 28, 2014).
2 "Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area" (Brattle Group for First Solar, July 2015). Hereafter, "Brattle Study.."

- the location of rooftop facilities allows them to avoid line losses and reduce infrastructure costs for transmission and distribution (T&D);

- rooftop solar can be deployed more quickly;

- customer-sited and customer-driven rooftop solar responds directly to customers' desire to use a higher penetration of renewable generation;

- there are incremental benefits from the pairing of rooftop solar and on-site storage; and

- there are important differences between these resources in their societal and customer choice benefits.

This updated white paper focuses on this comparison using benefits and costs specific to Arizona, where regulators have decided to use the costs of utility-scale solar as a factor in pricing the exported power from rooftop solar facilities.[3] We caution that the benefits and costs will vary from state to state and utility to utility; nonetheless, our analyses for Colorado and now for Arizona are designed to provide a fuller perspective on how to compare different types of solar resources. Accordingly, this paper not only updates our prior analysis using Arizona data, but also extends our earlier work to include new perspectives on this important comparison.

Table ES-1 summarizes the findings of our updated analysis, and lists the additional quantifiable benefits of rooftop solar beyond those provided by utility-scale facilities.

Table ES-1: *Summary of Location and Choice Benefits of Rooftop Solar*

Benefit	**Value** *(cents per kWh)*
Locational Benefits	
Avoided line losses	+0.6
Avoided transmission capacity	+1.2
Avoided distribution capacity	+1.5 to +4.0
Subtotal – direct locational benefits	+3.3 to +5.8
Added benefits when paired with storage	+5.0
Land use benefits	varies widely
Choice Benefits	
Accelerate renewable deployment • Increase electrification • Exceed RPS requirements • Avoid Green Pricing premiums • Includes local economic benefits vs. utility-scale	+7.4
Lower cost third-party financing vs. rate base for utility-owned solar	Lower LCOE by 15% to 20%

[3] See the Arizona Corporation Commission's (ACC) order approved December 20, 2016 in its "Value of Solar" Docket E00000J-14-023.

The table shows that rooftop solar provides additional benefits by avoiding the transmission and distribution (T&D) infrastructure that is necessary to deliver utility-scale solar power to customers. Both types of solar generation provide substantial environmental benefits to the public, but rooftop solar offers additional benefits from the reduced land use impacts. Rooftop solar also provides greater benefits when it is paired with on-site storage. Finally, rooftop solar development is driven by the choices of individual customers who wish to be served by a higher penetration of renewable energy. The value of customer choice should not be minimized; in Arizona, it has resulted in Arizona Public Service (APS) exceeding its renewable energy standard (RES) goals. The value of this additional renewable energy would be lost if only utility-scale solar resources are developed to meet RES requirements.

Utility-scale solar remains less expensive than rooftop solar, although this difference is narrowing, as we discuss in the next section. The additional benefits of rooftop solar shown in Table ES-1 are sufficient to make up for this difference, such that we continue to conclude that both rooftop and utility-scale solar should have central roles in the transition to a clean, sustainable, and resilient electric industry.

1. Rooftop and Utility-scale Costs

a. The difference between these costs continues to narrow.

Economies of scale in installation, plus the greater use of tracking systems, result in lower costs per unit of solar output for large, utility-scale solar facilities. However, data on solar costs shows that the difference in costs between rooftop and utility-scale facilities is steadily decreasing.

Lawrence Berkeley National Lab's (LBNL) annual reports on rooftop and utility-scale solar installation costs show that the difference between residential rooftop and utility-scale solar costs has decreased by 50% over the last five years, and the difference between small commercial rooftop (under 500 kW) and utility-scale solar costs has dropped by 67%. Further, in 2015 there was essentially no difference in cost between large (over 500 kW) distributed solar facilities and utility-scale projects. These trends are illustrated in **Figure 1** below.[4] Data from 2016 reported by the Solar Energy Industries Association (SEIA) through the third quarter of 2016 shows that the difference between residential and utility-scale costs remains in the range of $1.50 to $2.00 per watt DC, with residential costs now falling to $3 per watt DC and utility-scale costs below $1.50 per watt DC.[5]

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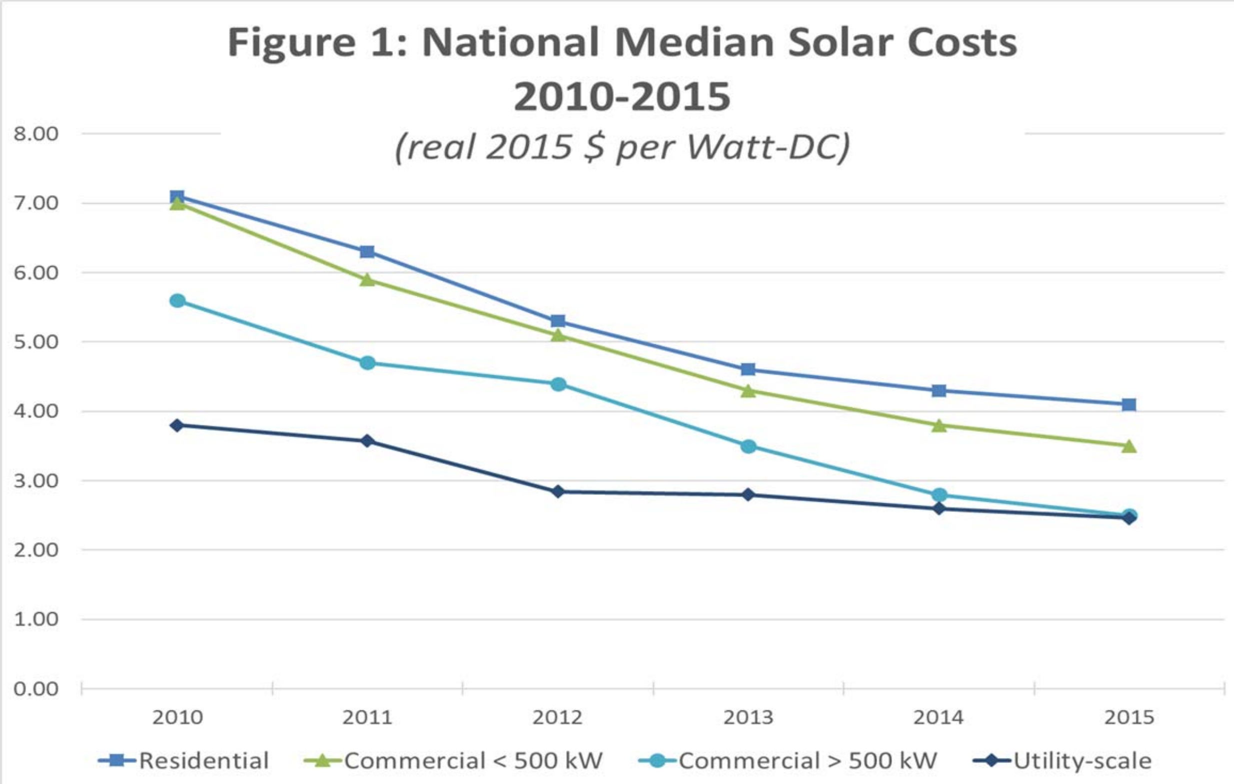
4 See LBNL, *Tracking the Sun IX* (August 2016), Figures 6 and 7, available at https://emp.lbl.gov/publications/tracking-sun-ix-installed-price.

5 See SEIA, *Solar Market Insight Report 2016 Q4*, at Figure 2.3, available at http://www.seia.org/research-resources/solar-market-insight-report-2016-q4.



The primary drivers for the decreasing differential in installed costs over the last five years are the significant reductions in the installation and "soft" costs for rooftop systems. In the U.S., there remains room for further narrowing of these costs, as shown by the much lower costs for residential solar in other developed markets such as Germany and Australia, where residential prices in 2015 were just $1.70 and $1.80 per watt-DC, respectively, which was <u>below</u> utility-scale costs in the U.S.[6]

b. The Brattle study exaggerates the cost difference.

Brattle used costs for utility-scale solar that include a mix of both fixed and tracking systems.[7] However, Brattle also assumed that the output from utility-scale projects in Colorado is 100% from tracking systems.[8] Thus, for a portion of its sample, Brattle used costs for fixed arrays but assumed the production of trackers. This inconsistency underestimates the cost of utility-scale solar, as the most recent LBNL data shows that tracking systems are about 11% more expensive, on a $ per watt basis.[9]

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6 See LBNL, *Tracking the Sun IX*, at pp. 1-2 and 22-24.

7 For example, Brattle relied on LBNL data on utility-scale solar costs from Figure 29 of LBNL's *Tracking the Sun VII* report. See Figure 6 of the Brattle report. As shown in the data for Figure 30 of the LBNL *Tracking the Sun VII* report, the data that Brattle used is for a mix of fixed and tracking systems (roughly two-thirds fixed and one-third tracking for 2011-2013 systems), with the costs for the tracking systems 5% to 17% higher than the fixed systems.

8 Brattle Report, at p. 26, footnote 24.

9 LBNL, *Utility-scale Solar 2015* (August 2016), at data table for Figure 10, comparing tracking and fixed-tilt costs for 2013-2015.

Further, Brattle's projection of utility-scale capacity factors of 24% in Colorado are 50% above Brattle's assumed 16% capacity factor for rooftop solar. These projections are based on simulated output, not on actual production data.[10] Actual solar generation data from California, which has over 9 GW of utility-scale solar and almost 5 GW of rooftop solar, shows capacity factors of 27% for utility-scale solar (based on CAISO generation data from 2015-2016) and 21% for rooftop systems (from the five years of output data on CSI systems with performance-based incentives).[11] This actual solar output data indicates a significantly smaller difference in output between utility-scale and rooftop systems than modeled by Brattle. Similarly, based on actual generation, APS is reporting capacity factors of 33% for its utility-scale solar and 26% and 28% for residential and commercial rooftop solar, respectively.[12] This smaller difference in capacity factors is due, in part, to a significant portion of utility-scale solar projects being fixed arrays, and not 100% trackers as assumed by Brattle.

2. Utility-scale and Rooftop Solar Provide Different Products, at Different Locations

Rooftop and utility-scale solar do not provide the same energy product. The majority of the output of a rooftop solar facility provides power directly to end-use loads, behind the meter, where it displaces retail power from the utility. The rest of the power is exported to the distribution grid, where as a matter of physics it immediately serves neighboring loads, also displacing retail power from the utility.[13] The rooftop solar customer using distributed generation (DG) is compensated for this power at the retail rate, through net energy metering (NEM). In contrast, utility-scale solar supplies wholesale power to the utility, delivering power to the transmission system.

The most significant difference between these products is that the retail, rooftop product has been delivered to end use loads, whereas the wholesale, utility-scale product has not. Thus, for an apples-to-apples comparison with rooftop solar, the cost of utility-scale power to the ultimate consumer needs to include the marginal cost of delivery. The correct delivery cost to use in this comparison is not necessarily the utility's delivery rate, that is, what it charges to provide transmission and distribution (T&D) service. Instead, the correct rate to use in this comparison is the utility's marginal costs for T&D service. These are the line losses and T&D infrastructure costs which the utility avoids if rooftop solar supplies a customer and his neighbors, thus avoiding the

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[10] See Brattle Report, at pp. 24-26.

[11] CAISO generation data is from the CAISO's "Renewables Watch" data (at http://www.caiso.com/market/Pages/ReportsBulletins/DailyRenewablesWatch.aspx). CAISO system solar capacity is based on the CAISO's "Master CAISO Control Area Generating Capability List" for November 2, 2016. Rooftop solar output data for PBI systems can be found at https://www.californiasolarstatistics.ca.gov/data_downloads/, see the CSI Measured Production Data Set.

[12] Based on 2017-2021 forecasted generation data in APS's 2017 Renewable Energy Standard Plan, filed with the ACC on July 1, 2016 (Docket No. E-01345A-16-0238).

[13] It is only at relatively high penetrations of rooftop solar, as have been experienced in some locations in Hawaii, that significant amounts of rooftop solar are at times backfed upstream through the distribution substation.

need for the utility to provide delivery service from a more remote utility-scale solar producer or other wholesale generator.[14]

a. The significant cost of transmission to deliver utility-scale solar

Utility-scale solar projects require transmission to deliver this power to the utility's load centers. New transmission can be expensive, and can require many years to site, permit, and build. It is well known that the availability of adequate transmission is a critical issue for the development of utility-scale solar and wind resources in the western U.S. Transmission bottlenecks can constrain a utility's ability to access utility-scale solar. As an example, APS has been building, in phases, a new 500 kV line from the Yuma area to the Palo Verde hub and then to the Phoenix load center, with a stated purpose of accessing solar and natural gas resources in the Yuma and Palo Verde areas.[15] Adequate transmission also has been a central issue in California's ambitious Renewable Portfolio Standard program, whose goals are now 33% renewable generation by 2020, and 50% by 2030.[16]

The table below shows representative transmission capacity costs for new utility-scale solar that is located at a distance from utility load centers, using data from the recent APS transmission plans, as well as comparable transmission costs from other states.

Table 1: *Utility-scale Solar Transmission Costs (cents per kWh)*

Resource	Transmission Cost (c/kWh)
Arizona[17]	
New 500 kV lines to access gas and solar	1.2
California 50% RPS data[18]	
In-state renewables	3.4
Small-scale solar	2.1
Colorado SB 100 data[19]	
San Luis-Comanche line (access 1,400 MW of solar)	1.0

14 The Brattle Report, at pp. 38-39, acknowledges that rooftop solar may avoid transmission costs, and cites the avoided transmission costs for Public Service of Colorado (PSCo) that we calculated in our 2014 critique of Xcel Energy's *Distributed Solar Study*, both filed in Colorado PUC Docket No. 11M-426E. Brattle argues that these avoided costs are not large enough to bridge the cost divide between utility-scale and rooftop solar.

15 See APS Renewable Transmission Plan and its recent 10-year Transmission Plans.

16 Some utility-scale solar projects in California have been developed on an "energy-only" basis as a result of their inability to secure firm transmission capacity to deliver their power on a firm basis.

17 Based on the costs per kW of the North Gila to Palo Verde 500 kV line and the segments of the Palo Verde to Morgan 500 kV line, which APS has justified as accessing new solar and gas resources. We use a 11.05% fixed charge rate and an assumed 32% capacity factor for utility-scale solar. The fixed charge rate is from an SAIC Energy, Environmental and Infrastructure LLC study for APS, *2013 Updated Solar PV Value Report* (May 2013), at Table 3-2.

18 See Energy and Environmental Economics (E3), *A 50% Renewable Portfolio Standard in California* (E3, February 2014), at p. 58 and Tables 10 and 29, hereafter "E3 50% RPS Study."

19 The capital costs for the San Luis line were converted to cents per kWh assuming a 7.4% levelized carrying charge for transmission and that utility-scale solar resources operate at a 25% capacity factor.

Clearly, transmission costs are significant, although they are also location-specific. In addition, line losses on the T&D system are significant, and are avoided by rooftop solar. APS has estimated that its marginal line losses avoided by solar DG are 12%, or 0.6 cents per kWh assuming utility-scale solar costs of 5 cents per kWh.[20]

Rooftop solar is sited in the built environment in the load center and therefore avoids transmission costs and line losses. For residential customers, about one-half of the output of rooftop systems is consumed on-site by the solar host. The other half of the power is exported and, at today's relatively low penetrations of solar, is consumed by the host customer's neighbors on the distribution system, thereby avoiding line losses and displacing power that would have to be imported from more remote generators. As a result, rooftop solar makes capacity available on the upstream transmission and distribution systems that can be used to serve other customers, to import other power supplies, and to meet load growth.

b. DG can accelerate distribution and grid modernization at a lower cost for consumers.

Today, the primary impact of the development of rooftop solar DG is to reduce the overall level of the utilities' loads. In this way it is similar to other demand-side resources. Over the long-run, these lower loads will reduce the utility's need to invest in distribution infrastructure. Customer-sited DG thus combines with other customer investments in energy efficiency (EE) and demand response (DR) to allow the utility to avoid investments in distribution capacity.[21] As a result, the avoided distribution capacity costs from rooftop solar are not zero.

These distribution benefits can be measured, at the utility-wide level, by the utility's long-run marginal cost of distribution capacity, which can be calculated using a regression of distribution investments as a function of load growth. This effectively separates that portion of overall distribution investments that are driven by load growth from those that are pursued for other reasons, such as reliability, replacement, or grid modernization.[22] Solar PV's share of the

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20 See R.W. Beck, *Distributed Renewable Energy Operating Impacts and Valuation Study* (January 2009), hereafter, the "*R.W. Beck Study*," at Table 4-3. Other studies use system average line losses, but this does not reflect the fact that solar DG output is produced when system loads, and losses, are higher. It also does not consider that marginal line losses are higher than average losses. The Beck Study includes a full discussion and analysis of the loss issue, at pages 4-4 to 4-8.

21 These benefits are largely counterfactual; in other words, they result from the long-term demand trajectory of the utility being significantly lower as a result of demand-side EE, DR, and DG resources than a "business as usual" trajectory that will not actually be experienced. Such "avoided cost" benefits will rarely show up publicly, or even in utility rate cases, as DG (or DR or EE) replacing or deferring a specific distribution investment. Instead, the utility planning process will respond over time to a lower level of demand and will need to build less infrastructure, as a result of the development of demand-side resources.

22 It is important to recognize that distribution investments can have a variety of benefits, and it is often inaccurate to say that a particular distribution project is only being pursued for reliability, for example. A new substation can provide benefits from added load-serving capacity even if its principal justification

load reduction benefits can be determined by calculating a "load match factor" that captures the ability of solar DG to reduce the peak distribution system loads that drive load-related distribution investments.[23]

Recent studies of avoided distribution capacity costs resulting from rooftop solar have used the correlation between solar output and distribution substation peak loads (or class loads as a proxy) to calculate load match factors for distribution capacity. These factors are then applied to an estimate of marginal distribution capacity costs derived from data on utility distribution investments. This approach has resulted in significantly higher estimates of avoided distribution capacity costs than prior studies, because it captures the ability of widespread DG deployment to reduce the distribution-level loads that drive the overall level of long-term distribution additions.[24] **Table 2** summarizes the results of several recent studies using this approach.

Table 2: *Studies of Avoided Distribution Capacity Costs*

State	Study	Date	Avoided Distribution Capacity Costs *(cents/kWh)*
AZ	Crossborder-TASC[25]	2016	1.5 (residential) 4.0 (commercial)
NH	Crossborder-TASC[26]	2016	2.3 (average for three NH utilities)
CA	CPUC-E3 / Public Tool Model[27]	2015	2.9 (average for three CA utilities)

The distribution benefits of solar DG and other demand-side resources are location-specific, but this is not a reason to assign them an overall value of zero until they can be

is reliability or replacement of aging equipment.

[23] In addition, recent work has highlighted how the impacts of DG and storage on distribution capacity also can be evaluated by looking at their impact on the thermal loads in distribution transformers, rather than on peak power flows. The focus on thermal demand can increase avoided T&D capacity by one-third, in comparison to evaluations based on peak power flows. See the Solar City white paper, *Enhancing Methodologies for Valuing Transmission and Distribution Capacity*, available as Exhibit RH-4 to the Direct Testimony of Ryan Hanley of Solar City, presented in Public Utilities Commission of Nevada Docket No. 16-06-006, dated October 7, 2016.

[24] The older studies of the distribution benefits of rooftop solar are referenced and discussed in the Rocky Mountain Institute's meta-analysis of these benefit-cost studies.
See Rocky Mountain Institute, *A Review of Solar PV Benefit and Cost Studies* (July 2013), at page 31, available at http://www.rmi.org/Knowledge-Center/Library/2013-13_eLabDERCostValue. Generally, the distribution capacity benefits in these studies were in the range of 0 to 1 cents per kWh.

[25] See Crossborder Energy, *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service (Updated APS DG Study)*, at Table 6, filed on behalf of The Alliance for Solar Choice in the ACC Value of Solar case (Docket No. E-00000J-14-0023).

[26] See Crossborder Energy, *The Benefits and Costs of Distributed Solar Generation in New Hampshire*, at Appendix D, Table D-7 of Exhibit RTB-1, filed on behalf of The Alliance for Solar Choice in the New Hampshire Public Utilities Commission Docket No. DE 16-576.

[27] Based on the marginal sub-transmission and distribution costs of the California electric utilities and the CPUC-E3's Public Tool model of the benefits and cost of net metering in California. The Public Tool is described and is available at http://www.cpuc.ca.gov/General.aspx?id=11285.

assessed on a location-specific basis. Instead, the more accurate and equitable approach is to assess these benefits now on an overall "system" basis, and then to proceed in the future, as DG penetration grows, to develop a more location-specific assessment of avoided distribution costs. States such as California and New York are taking steps in this direction, with California's Distribution Resource Plans and New York's Reforming the Energy Vision (REV) initiative.

Renewable DG is now being installed on the distribution system in the context of many initiatives underway across the U.S. to modernize the electric grid. Grid modernization will expand the electric system's capabilities to handle not only renewable DG but also a wide variety of other new distributed energy loads & resources – new DR programs such as programmable thermostats, electric vehicle (EV) charging, and distributed storage, for example. Solar DG is the customer's central, "gateway" investment that can unlock the customer's interest and investment in these customer-focused clean energy technologies that will be integral to a modern grid infrastructure.[28]

From the perspective of the utilities and customers who do not invest in DG, there are other significant benefits of grid modernization, including the following:[29]

1. Reducing the frequency and effects of outages, by allowing greater visibility for system operators into local grid conditions and reducing response times to customer outages;

2. Optimizing demand to reduce system and customer costs;

3. Improving utility workforce and asset management, such as reduced costs for distribution maintenance;

4. Developing a charging infrastructure for EVs - a major new market for electricity;[30]

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[28] Studies have shown that solar customers adopt more energy efficiency measures than other utility customers. For example, see:

- The *2009 Impact Evaluation Final Report* on the California Solar Initiative, prepared by Itron and KEMA and submitted in June 2010 to Southern California Edison and the Energy Division of the California Public Utilities Commission. See pages ES-22 to ES-32 and Chapter 10. Also available at the following link: http://www.cpuc.ca.gov/workarea/downloadasset.aspx?id=7677.
- Center for Sustainable Energy, *Energy Efficiency Motivations and Actions of California Solar Homeowners* (August 2014), at p. 6, finding that more than 87% of solar customers responding to a survey had installed or upgraded one or more energy efficiency technologies in their homes. Also available at https://energycenter.org/sites/default/files/docs/nav/policy/research-and-reports/Energy%20Efficiency%20Motivations%20and%20Actions%20of%20California%20Solar%20Homeowners.pdf.

[29] *See*, for example, *Investigation by the Department of Public Utilities Upon its Own Motion into Modernization of the Electric Grid*, Massachusetts Department of Public Utilities ("DPU") order D.P.U. 12-76-B, at pp. 7-15 (Jun. 12, 2014).

[30] There is a strong correlation between EV ownership and solar DG installation – a 2014 survey of California EV owners found that 32% of EV owners have installed solar and an additional 16% plan to do so. See https://cleanvehiclerebate.org/eng/vehicle-owner-survey/feb-2014-survey.

5. Opportunities to reduce stationary source air emissions through further electrification of buildings and industrial processes; and

6. Allowing deployment of distributed storage, which in turn has numerous potential benefit streams – energy arbitrage, capacity deferral, ancillary services, enhanced reliability and resiliency, and power quality.

7. Providing voltage support and enhancing conservation voltage reduction (CVR) programs through the use of smart inverters.[31]

As a result, states have recognized that there are many reasons to modernize the grid, and many benefits from doing so beyond the traditional need to meet load growth. Moreover, there is significant potential for the intelligent deployment of DG to reduce the costs associated with grid modernization. Solar City recently released a white paper, *A Pathway to a Distributed Grid*, which quantifies the net benefits of distributed energy resources ("DER") – including both DG and other distributed resources such as smart inverters, storage, energy efficiency, and controllable loads – and shows that they are a cost-effective, least-cost approach to grid modernization.[32] This report shows that distributed energy resources (DERs), including rooftop solar, have the potential to replace a portion of the real-world grid modernization projects that Pacific Gas and Electric has proposed in its 2017 General Rate Case, at a lower net cost to the utility's ratepayers. Thus, rooftop solar can be an integral part of a cost-effective grid modernization program, even if the key drivers and benefits of such a program for ratepayers go well beyond simply serving load growth.

3. Rooftop solar customers can expand their system for a low incremental cost close to that of utility-scale solar.

Most studies of how to achieve deep reductions in carbon emissions by mid-century recognize that the most likely path will involve increasing the use of clean electricity as the source of primary energy for buildings and transportation. For example, the California Air Resources Board's 2014 update to its *AB 32 Scoping Plan* observes that meeting California's ambitious goal to reduce GHG emissions to 80% below 1990 levels by 2050 will require the widespread electrification of the state's transportation, building, and industrial sectors.[33] This is also the conclusion of academic researchers who have modeled how the state can reach its 2050 goal.[34]

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[31] Based on an analysis from Solar City using the results of its smart inverter field demonstration projects, smart inverters used for CVR can produce an incremental 0.4% energy consumption savings, with the associated greenhouse gas emissions reductions, as reported in a white paper from Solar City Grid Engineering and the Natural Resources Defense Council, *Distributed Energy Resources in Nevada: Quantifying the net benefits of distributed energy resources* (May 2016), available at. http://www.solarcity.com/sites/default/files/SolarCity-Distributed_Energy_Resources_in_Nevada.pdf.

[32] This Solar City white paper is available at http://www.solarcity.com/sites/default/files/SolarCity_Distributed_Grid-021016.pdf.

[33] CARB, *First Update to the Climate Change Scoping Plan: Building on the Framework* (May 2014), at 36-37, available at https://www.arb.ca.gov/cc/scopingplan/2013_update/first_update_climate_change_scoping_plan.pdf.

[34] Academic publications on this topic include the following:

With electricity's share of primary energy use growing, there is the potential for customers to install larger rooftop solar arrays, at an incremental cost that is closer to utility-scale costs, to allow them to charge electric vehicles at home and to replace natural gas-fired water and space heaters with efficient electric heating. The cost-effectiveness of these incremental rooftop resources are further enhanced by the fact that this power would be already delivered at or very close to these new loads, thus avoiding significant T&D costs.

For example, we examined the potential for an incremental expansion of a residential rooftop system to be used to charge an electric vehicle (EV), displacing gasoline. We assume that a residential customer in Phoenix adds enough incremental solar capacity to fuel a typical EV travelling 10,000 miles per year. **Table 3** shows the key assumptions and results of our analysis.

Table 3: *Using Incremental Solar for EV Charging*

Key Assumptions	Input
Incremental solar cost	$2.50 per W-DC
Incremental solar capacity	1.8 kW-DC
Phoenix solar output	1,470 kWh/kW-DC
EV efficiency	3.3 miles/kWh
Mileage of equivalent gasoline car	35 miles/gallon
Current gasoline price in Phoenix	$2.05 per gallon
Results	**Value**
Incremental solar cost – first year	7.8 cents/kWh
Equivalent gasoline cost for EV charging	$0.83/gallon
First year gasoline savings (10,000 miles/year)	$300
Annual GHG emission reductions	2.3 tonnes

The incremental solar cost we use is above today's utility-scale solar costs,[35] but results in a charging cost that is competitive with off-peak charging at APS's off-peak time-of-use rate, which is what an EV customer would pay if the power were supplied by either incremental utility-scale solar or marginal power production using predominantly natural gas. This example shows that a vibrant rooftop market can provide an economical means to expand electrification that is cost-competitive with the use of utility-scale solar for the same purpose.

• Williams, J. H., et al. 2011. "The Technology Path to Deep Greenhouse Gas Emissions cuts by 2050: The pivotal role of electricity." Science Express 335 (6064): 53–59. http://www.sciencemag.org/content/335/6064/53.
• Wei, M., et al. 2013. "Deep carbon reductions in California require electrification and integration across economic sectors." Environmental Research Letters 7: 1–9. http://iopscience.iop.org/1748-9326/8/1/014038/.

[35] We use an incremental cost of $2.50 per kW-DC, assuming a current cost of $3.00 per kW-DC and an incremental cost for a 2 kW addition that is $0.50 per kW-DC lower. This incremental cost is based on LBNL 2015 data for residential solar costs for systems of various sizes. See LBNL, *Tracking the Sun IX,* at the data table for Figure 16, for systems from 2 kW to 12 kW in size.

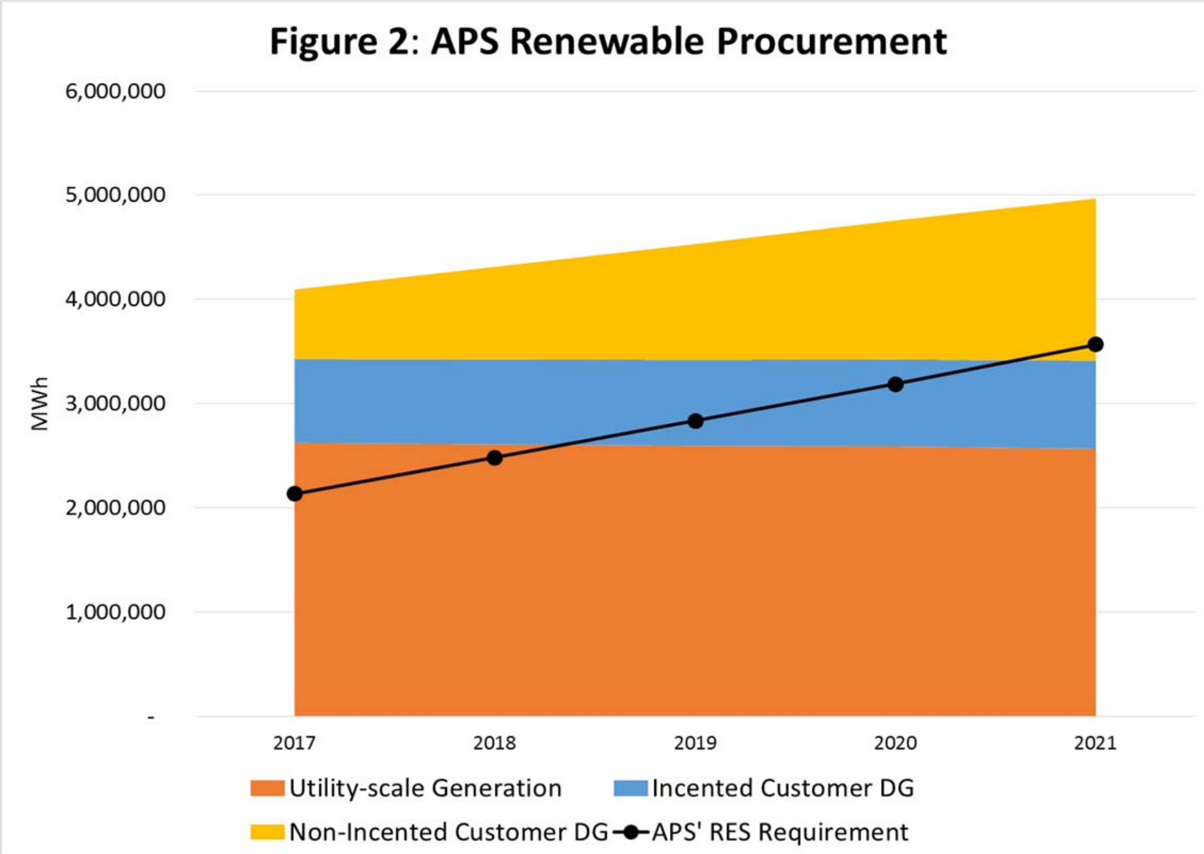
4. Rooftop solar is driven by customer demand, not RPS mandates. Customer choice of rooftop solar accelerates renewable energy adoption.

The Brattle Study joins many utilities in arguing that both rooftop and utility-scale solar provide similar societal benefits per kilowatt-hour of output. For example, both produce similar reductions in carbon emissions and criteria air pollutants, lower water use, and provide benefits from fuel hedging and market price mitigation.[36] However, even if utility-scale and rooftop solar provide similar societal benefits, there is now significant evidence that rooftop solar can provide these benefits more rapidly, compared to limiting solar development just to wholesale utility-scale projects developed in response to a state's RPS program. Driven by customer choice, this acceleration has a significant value.

Another way to look at this benefit is to recognize that utility-scale solar is not a substitute for rooftop solar if additional utility-scale solar is not going to be built because RPS goals have been reached. APS provides a good example of a utility where rooftop solar has driven an acceleration of renewable development well beyond the state's RPS requirements:

- Arizona's current Renewable Energy Standard (RES, i.e. RPS) goal is 7% of sales in 2017, with the RES percentage increasing by 1% per year to 10% in 2020 and 15% in 2025. APS expects to use renewable generation to serve 12% of sales in 2017 and 15% in 2021. This over-achievement will be driven largely by continued strong growth in rooftop solar installed without RES-linked incentives, as shown by the yellow area in the **Figure 2**. Arizona has a separate requirement for distributed energy (DE, i.e. DG) deployment, which is 30% of the overall RES requirement in each year. Figure 2 also shows that DG development in APS's territory is expected to be far greater than the state's RES requirement for DG.

36 See Brattle Study, at pp. 40-44.



- There is nothing in APS's 2014 Integrated Resource Plan (IRP) or draft 2017 IRP which indicates that rooftop and utility-scale solar are substitutes for each other. So, if APS installs less rooftop solar, it is not committed to installing more utility-scale solar, or vice versa. APS's own testimony in the Value of Solar docket assumes that the output from DG solar avoids the cost of APS's marginal fuel, which is natural gas.[37] There is no RES requirement in Arizona to mandate the substitution of utility-scale for rooftop solar if the latter is not developed, and APS is in compliance with the existing RES goals.

- Rooftop solar is driven by customer choice and customers' investment, and can occur more quickly than utility-scale development, because the development and permitting time from sale to commercial operation is so much shorter than for utility-scale projects. Large scale solar projects also face constraints from the need to provide additional bulk transmission capacity, which can take years to site and build.

The conclusion from the strong growth in rooftop solar is that APS's customers want to be served with more renewable energy than the RES requirements, which were established in legislation enacted a decade ago in 2007. Rooftop solar has been available to meet this strong customer demand for a higher penetration of renewables, without an RPS cost premium and indeed with the potential for long-term customer savings.

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[37] Direct testimony of Leland Snook for APS, at p. 17 ("The method described above uses the filed avoided fuel costs for all kWh produced by the rooftop solar system.").

The problem which utilities face is that, even if utility-scale solar is less expensive than the utility's overall portfolio of generation, they are unlikely to offer to serve customers with 100% utility-scale renewable energy unless they can charge a premium to their existing rates. If the utilities were to offer customers 100% utility-scale renewable energy at a discount to their existing rates, the utilities would be overwhelmed by the demand from customers who, as polling data shows, express strong support for renewable energy across the political spectrum.[38] As a result, utility "green pricing" programs all charge a premium even though the cost of renewables in many states is now at or below the all-in costs of fossil generation.[39] For example, the three largest investor-owned utilities in Arizona charge an average premium of 1.7 cents per kWh for additional renewable generation. Such premium pricing has limited the success of green pricing programs. In 2017, APS's Green Choice program (which charges the lowest premium in the state of 1.0 cent per kWh above the retail rate) will supply less than 10% of the renewable generation provided by the customer-sited DG installations in APS's service territory.

All Arizona citizens realize the substantial environmental and societal benefits of this accelerated renewable development driven by DG, even though the capital is provided by either customers or third parties, who also bear the installation and operational risks of this generation. This contrasts with utility-scale solar, whose installation costs and risks are assumed by all ratepayers. In 2017, the additional 1,960 GWh of renewable generation above the RES requirement on the APS system will have societal benefits of $145 million, based on the 20-year levelized societal benefits of 7.4 cents per kWh calculated in our 2016 *Updated APS DG Study*.[40] Essentially, this quantifies the value of choice – of customers choosing to make their own investments to accelerate the deployment of renewable generation in Arizona.

Finally, APS ratepayers only pay directly for the portion of the DG generation that is exported to the grid, typically about 50% to 60% of the output, depending on the system size.[41] In contrast, APS ratepayers must pay directly for 100% of the costs of wholesale utility-scale solar in order to obtain the same environmental benefits per kWh.

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38 See, for example, this Pew Research Center survey, http://www.pewinternet.org/2016/10/04/public-opinion-on-renewables-and-other-energy-sources/.

39 See Department of Energy's survey of the premiums for utility green pricing programs, at http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml.

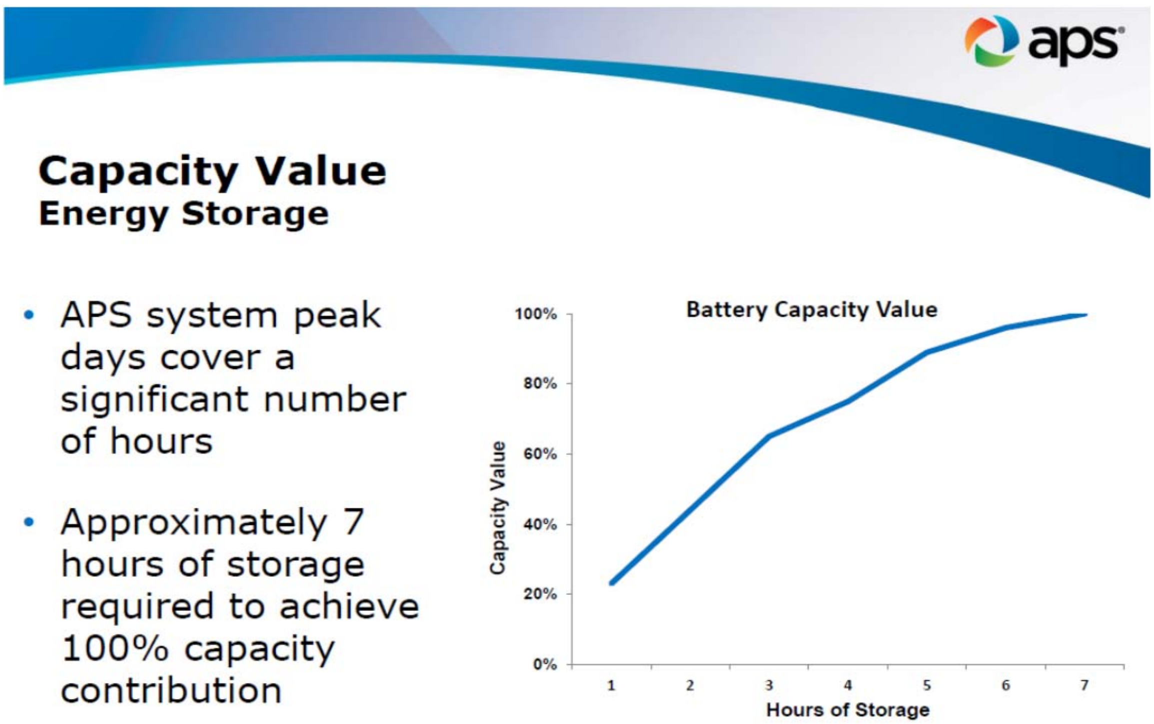
40 See *Updated APS DG Study*, pp. 17-20, adjusted to reduce local economic benefits for the difference between residential/small commercial and utility-scale solar, as discussed below in Section 8.

41 Billing data produced in discovery in the ongoing APS general rate case (Arizona Corporation Commission Docket No. E-01345A-16-0036) for the 26,000 residential solar DG customers on the APS system in the 2015 test year show that 44% of the average solar customer's production in 2015 served their on-site load, with 56% exported to the grid. The percentage of exports for APS is larger than for other utilities because APS uses two-channel meters that instantaneously measure exports and imports. See *Direct Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association* (Docket No. E-01345A-16-0036), filed February 3, 2017, at page 8.

5. DG solar plus storage leverages greater benefits than utility-scale plus storage.

Utilities often highlight the anticipated decline in solar's value as more solar capacity is added, due to the shift in the hours of highest "net loads"[42] into the late afternoon and evening when solar output is declining. However, this picture will change fundamentally with the pairing of solar plus storage. Importantly, the benefits of pairing solar plus storage are significantly greater for rooftop solar than for utility-scale projects, for the following reasons:

- DG solar plus storage can increase the ability of distributed generation to defer investments in T&D capacity, in addition to avoiding a higher level of generation capacity costs. In contrast, storage sited with utility-scale solar only provides generation-related benefits. With storage, solar becomes a dispatchable resource whose output can be targeted to the times when the power has the greatest value to the grid, and can avoid capacity-related costs for T&D as well as generation. The following figure is from a recent APS presentation on its draft 2017 IRP, and shows the utility's recognition that adding adequate storage will firm the capacity value of solar.



- Based on the avoided generation and T&D capacity costs calculated in our *Updated APS DG Study*, and assuming that the addition of four hours of storage will increase south-facing residential solar's capacity value to 75% of nameplate (as shown in the APS figure above), rooftop solar paired with storage will provide benefits that are 10.3 cents per kWh higher than solar alone, while utility-scale solar plus on-site storage will increase in value by just 5.3 cents per kWh. These calculations are shown in **Table 4**.

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[42] Net load is defined as the end use load less variable wind and solar generation.

Table 4: *Increased Benefits of Solar plus Storage for APS*

Capacity Component	**Marginal Cost w/losses** *($/kW-yr)*	**Solar Capacity Value as % of Nameplate**	**Solar Output** *(kWh/kW-AC)*	**Avoided Cost** *($/MWh)*
	A	**B**	**C**	**1000 x A x B / C**
Generation – applies to both utility-scale and DG				
No storage	237.3	36.2%	1,730	50
With storage	237.3	75%	1,730	103
Increase due to storage				53
Transmission – applies to DG				
No storage	43.3	36.2%	1,730	9
With storage	43.3	75%	1,730	19
Increase due to storage				10
Distribution – applies to DG				
No storage	127.0	20.1%	1,730	15
With storage	127.0	75%	1,730	55
Increase due to storage				40
Added benefits of solar plus storage				
For Utility-scale solar – generation alone				53
For DG solar – generation plus T&D				103

- Finally, DG solar plus storage enhances reliability and resiliency at the end-use level. Storage plus solar can maintain service to critical loads during grid outages. Most electric system interruptions do not result from high demand on the system, but from weather- or disaster-related transmission and distribution system outages. In these more frequent events, renewable DG paired with on-site storage can provide customers with a short-term back-up supply of electricity for critical applications should the grid suffer an outage of any kind. This benefit of enhanced reliability and resiliency has broad societal benefits as a result of the increased ability to maintain government, institutional, and economic functions related to safety and human welfare during grid outages.

6. DG solar has access to lower cost financing than rate-based solar.

Utility-scale solar can be owned and operated either by merchant generation companies who sell the power to a utility under a power purchase agreement (PPA) or by the utilities themselves. The costs of utility-owned generation are recovered through the utility's rate base, earning the utility's regulated return on that rate base. The rate base for a generation asset depreciates over the life of the asset, resulting in cost recovery that is front-loaded into the early years of the asset's life. In comparison, the pricing in typical PPAs for renewable resources are levelized over the contract life.

There also can be differences in the cost of capital and the tax benefits available to merchant generators and utilities. Generally, utility cost recovery through rate base is more expensive than merchant PPAs, for several reasons. The first is the front-loaded nature of cost recovery through rate base. The second reason is the higher Weighted Average Cost of Capital (WACC) that regulators have approved for regulated utilities, compared to competitively-sourced capital from the efficient capital markets that fund merchant assets and rooftop solar. **Table 5** below highlights this difference, estimating that the lower cost of capital of independently-owned assets, compared to regulated assets with higher-than-market allowed ROEs, reduces the levelized cost of energy (LCOE) of solar by 12%. Said another way, energy procured through independently owned solar assets costs 12% less than if a utility were to rate-base the asset.

Table 5: *Exemplary WACCs for Independently-owned and Regulated Utility Assets43*

Owner	Capital Cost	Capital Structure
Regulated Utility Solar Assets		
Approved Return on Equity	10.0%	57%
Cost of Debt	4.0%	43%
WACC	6.8%	
Solar Assets owned by Independent Parties		
Cost of Equity	10.0%	35%
Cost of Debt	5.0%	65%
WACC	5.6%	
Difference in Cost of Capital	1.2%	
Resulting difference in LCOE	**-12.0%**	

Similarly, the LCOE model developed by Energy and Environmental Economics (E3) for the Western Electricity Coordinating Council calculates LCOEs for either utility or merchant cost recovery.[44] Based on the E3 models, utility-owned LCOEs with rate base cost recovery are typically 15% - 20% more expensive than merchant plant LCOEs over comparable 25- or 30-year periods.

Utilities can access the lower cost of third-party financing by purchasing utility-scale solar from third-party developers, instead of building such plants themselves. However, rooftop solar still provides an advantage by avoiding investments in utility-owned T&D whose costs clearly must be financed at a higher cost through rate base. Moreover, there are lower cost financing options available to rooftop customers, such as when homeowners are willing to pay cash for a DG system or to use home equity loans whose interest is often tax-deductible. In these ways, DG solar brings new, lower-cost capital to the utility system than the combination of utility-scale solar plus a utility-owned, rate-based T&D system to deliver that power.

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[43] The capital structure for utilities is derived using the S&P 500 Utility index, weighted by market capitalization, as of December 31, 2016. The capital structure for merchant solar assets is based on typical project finance structures. The cost of utility debt is estimated to be 4%, slightly higher than the current market capitalization weighted statistic of 3.5% for the S&P 500 Utility index as of December 31, 2016, owing to a shorter-term debt profile than comparable project-level debt for solar assets arranged in typical transactions by comparable parties.

[44] This *WECC Generation Costing Tool* model is available on the E3 website at https://ethree.com/public_projects/renewable_energy_costing_tool.php.

7. DG utilizes the built environment, reducing the amount of land used for energy production.

Distributed generation makes use of the built environment in the load center – typically roofs and parking lots – without disturbing the existing use for the property. In contrast, central station renewable plants require larger single parcels of land, and are more remotely located where the land has other uses for agriculture, grazing, recreation, or wildlife habitat. The land must be removed from this prior use when it becomes a solar farm. Central-station solar photovoltaic plants with fixed arrays or single-axis tracking typically require 7.5 to 9.0 acres per MW-AC, or 3.3 to 4.4 acres per GWh per year.[45]

The lost value of the land depends on the alternative use to which it could be put. There is obviously a wide range of land values. The U.S. Department of Agriculture has reported the average rental value of pastureland and irrigated farmland in Arizona in 2016 to be $2 and $222 per acre, respectively.[46] These values can be much higher in other states – for example, these values are $16 and $440 per acre in California. Land is much more expensive in metropolitan areas, with one source reporting an average metropolitan land value of $100,000 per acre in Arizona.[47] If the 1,470 GWh of rooftop solar production that APS expects on its system in 2017 were instead ground-mounted in the metro Phoenix area, the value of the land required would approach $600 million.

8. Communities enjoy unique local economic benefits from rooftop solar.

While distributed generation has higher costs per kW than central station renewable or gas-fired generation, the higher costs – principally for installation labor, permitting, permit fees, and customer acquisition (marketing) – are spent in the local economy, and thus provide a local economic benefit in close proximity to where the DG is located. These local costs are an appreciable portion of the "soft" costs of DG. Utility-scale solar plants have significantly lower soft costs, per kW installed, and often are not located in the same local area where the power is consumed.

There have been a number of recent studies by the national labs on the soft costs of solar DG, as the industry has focused on reducing such costs, which are significantly higher in the U.S. than in other major international markets for solar PV. The following **Table 6** presents recent data, from detailed surveys of solar installers conducted by the National Renewable Energy Lab (NREL), on residential and large commercial soft costs that are likely to be spent in

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45 S. Ong *et al.*, "Land-Use Requirements for Solar Power Plants in the United States" (NREL, June 2013), at Table ES-1.

46 United States Department of Agriculture, National Agricultural Statistics Service, Quick Stats, at https://quickstats.nass.usda.gov/results/58B27A06-F574-315B-A854-9BF568F17652#7878272B-A9F3-3BC2-960D-5F03B7DF4826. Given the significant environmental opposition to utility-scale solar development on unoccupied federal lands, this is a reasonable, even conservative proxy for the value of the open land used for utility-scale solar development.

47 See http://datatoolkits.lincolninst.edu/subcenters/land-values/land-prices-by-state.asp.

the local area where the DG customer resides.[48] Conservatively, if we take the large commercial soft costs to be representative of utility-scale costs, then the 17% difference between residential and large commercial soft costs, as a percentage of overall system costs, represents the added local economic benefit of rooftop systems in comparison to utility-scale solar.

Table 6: *Residential vs. Large Commercial Local Soft Costs*

Local Costs	Residential		Large Commercial	
	$/watt	**%**	**$/watt**	**%**
Total System Cost	5.22	100%	4.05	100%
Local Soft Costs				
Customer acquisition	0.48	9%	0.03	1%
Installation labor	0.55	11%	0.17	5%
Permitting & interconnection	0.10	2%	0.00	0%
Permit fees	0.09	2%	0.04	1%
Total local soft costs	**1.22**	**23%**	**0.24**	**6%**

These economic benefits occur in the year when the DG capacity is initially built. We have converted these benefits into a $ per kWh benefit over the expected DG lifetime that has the same NPV in 2016 dollars. We also use more current DG capital costs than the system costs used in the LBNL and NREL studies. The result is an economic benefit of 2.9 cents per kWh of DG output. Finally, as discussed in Section 4, the growth in DG in Arizona above the RES requirements means that the state has benefitted from this local economic activity to a greater extent than if Arizona had limited DG development only to enough solar to meet the RES DG set-aside requirements.

9. Summary & Conclusion

The location of rooftop solar on the customer's premises and its deployment at the customer's choosing are the key factors that differentiate rooftop from utility-scale solar. Although utility-scale solar has lower installed costs as a result of economies of scale and higher capacity factors, this advantage is decreasing as the soft costs of rooftop solar have declined. There is significant potential to further reduce this difference, as shown by the experience in other countries and by the fact that large solar DG systems now have comparable costs to utility-scale solar.

The following table summarizes the additional benefits that rooftop solar offers as a result of its location and its deployment through customer choice, using the values that we have calculated for Arizona.

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[48] B. Friedman et al., *Benchmarking Non-Hardware Balance-of-System (Soft) Costs for U.S. Photovoltaic Systems, Using a Bottom-Up Approach and Installer Survey – Second Edition* (National Renewable Energy Lab, October 13, 2013), at Table 2. See also J. Seel, G. Barbose, and R. Wiser, *Why Are Residential PV Prices So Much Lower in Germany than in the U.S.: A Scoping Analysis* (Lawrenece Berkeley National Lab, February 2013), at pp. 26 and 37.

Table 7: *Summary of Location and Choice Benefits of Rooftop Solar*

Benefit	Value *(cents per kWh)*
Locational Benefits	
Avoided line losses	+0.6
Avoided transmission capacity	+1.2
Avoided distribution capacity	+1.5 to +4.0
Subtotal – direct locational benefits	+3.3 to +5.8
Added benefits when paired with storage	+5.0
Land use benefits	varies widely
Choice Benefits	
Accelerate renewable deployment • Increase electrification • Exceed RPS requirements • Avoid Green Pricing premiums • Includes local economic benefits vs. utility-scale	+7.4
Lower cost third-party financing vs. rate base for utility-owned solar	Lower LCOE by 15% to 20%

The table shows that the direct locational benefits of rooftop solar account for much of the cost difference between rooftop and utility-scale solar. While both types of solar generation provide substantial environmental benefits to the public, there are significant additional, quantifiable locational benefits from the reduced land use impacts of rooftop solar and the greater benefits from pairing rooftop solar with on-site storage. Finally, rooftop solar is developed through the choices of customers, allowing electric consumers to exercise fully their freedom to choose to be served from a higher penetration of clean energy resources for an expanding share of their primary energy needs. The value of this choice can be substantial, as illustrated by the choices to adopt rooftop solar that have resulted in APS far exceeding its RES goals. These additional benefits would be foregone if only utility-scale solar resources are developed. Distributed solar should not be undervalued by equating it to utility-scale solar when there are substantial differences between the two sources of electricity. Our conclusion remains that both types of solar should have central roles in the transition to a clean, sustainable, and resilient electricity infrastructure.

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