The Effect of Photovoltaic Module Efficiency on Installed System Costs and Markets in Residential Rooftop Installations in the United States

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1 National Renewable Energy Laboratory
2 Nielson Scientific
3 United States Department of Energy
4 Rensselaer Polytechnic Institute

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15013 Denver West Parkway
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We would like to acknowledge Billy Roberts for creating the maps included in this publication. We would also like to acknowledge James Zahler and Michael Haney for insightful conversations on this topic.

List of Acronyms

BOS	balance-of-system
dGen	Distributed Generation Market Demand
c-Si	crystalline silicon
kW	kilowatt
kWh	kilowatt-hour
LiDAR	light detection and ranging
NEM	net energy metering
NPV	net present value
NREL	National Renewable Energy Laboratory
PV	photovoltaic

Executive Summary

A defining characteristic of photovoltaic (PV) panels is their efficiency. Higher-efficiency panels produce more power (kW) and energy (kWh) per area of panels. A significant amount of PV research and development has focused on improving module efficiencies, with groups competing to achieve even incremental increases in record device efficiency, but questions remain about exactly how valuable higher efficiency is in mainstream PV markets. In this report, we analyze how efficiencies influence installed system costs and potential markets for residential rooftop systems throughout the United States, providing insights on how improvements in efficiency might serve as a lever for reaching cost and deployment targets. Residential rooftops were selected as the first market for analysis because they have higher balance-of-system costs and are more likely to have limited roof area, increasing the value of efficiency compared to other sectors. This is particularly true in the United States, where residential PV soft costs are still higher than in many areas of the world. We first analyze installed system cost versus efficiency using a bottom-up cost model and illustrating the key drivers of cost versus efficiency. In calculating installed system costs, we look at a scenario in which module price per watt is fixed versus efficiency. While there is evidence that today module prices tend to increase with efficiency, there is insufficient and inconsistent information on how module pricing varies with efficiency in the market. Using a fixed module price per watt avoids the need to assume this relationship and allows us to isolate the effects of efficiency on system costs. To better understand how module prices could change with efficiency, we calculate break-even module prices at different efficiency levels.

An important result of our bottom-up system cost analysis is understanding the degree to which installed system cost savings vary, depending on if a household is area-constrained in terms of its ability to host enough on-site PV to offset the desired amount of building electricity consumption. In the area-constrained scenario, the customer is not able to fit as much solar on their rooftop to offset their annual electricity consumption or maximize their economic return. In this case, the number of panels is fixed, but system size in kW grows with efficiency. In the not-area-constrained, or *usage-constrained* scenario, there is ample roof space, and as efficiency grows, the system size in kW is fixed, but the number of panels installed decreases. Usage-constrained scenarios are also referred to as "designated power" or "fixed power" cases. We show that the impact of efficiency on installed cost is much greater for the area-constrained scenario because of economies of scale associated with the larger system size, although some savings is also achieved in the usage-constrained case due to the lower number of panels installed. In the area-constrained scenario, we looked at weighted-average U.S. costs for an example system and saw that in the scenario where module prices ($\$/W_{DC}$) are fixed with efficiency, a 14% savings in installed costs could be achieved by increasing efficiency from 20% to 25%. Increasing the efficiency further from 25% to 30% results in an additional 11% savings, and increasing from 25% to 35% results in a 19% savings. With efficiencies below 15%, the system costs are higher even if the module is free. These savings and cost penalties can vary somewhat, depending on the available rooftop area and inverter type used as well as the customer acquisition model, overhead structure, and other factors specific to a given company. We also saw that the installed system cost savings in dollar per watt varies significantly across the United States because some states have higher fixed costs per system (e.g., permitting cost, portions of labor cost), which are more dramatically decreased by the increased system-rated power associated with high-efficiency panels in area-constrained scenarios.

Next, we compare the installed costs versus efficiency modeled using our bottom-up cost model versus efficiency in both the area-constrained and usage-constrained cases to the results with the prevailing, simplified model used in the literature to estimate cost versus efficiency. This simplified efficiency model results in only one curve of cost versus efficiency and does not differentiate between the area-constrained and usage-constrained cases. We find that the single curve associated with the simplified model reflects the area-constrained case fairly well, but significantly overestimates the savings expected for the usage-constrained scenarios. Additionally, compared to the bottom-up model, the simple efficiency model still slightly overestimates the savings that can be achieved by increasing efficiency as well as the cost penalty for lower efficiency modules compared to the bottom-up model in the area-constrained case.

Importantly, if high-efficiency modules have a price premium ($\$/W_{dc}$), as is often the case in the market today, then the savings due to increased efficiency would be reduced or possibly eliminated. We have calculated the break-even module price premium comparing higher efficiency panels against today's standard-efficiency panels. This analysis focuses purely on installed *costs*. Whether these savings are seen by customers will depend on how installers price their systems. Market reports indicate that there is an inverse relationship between system size (in kW) and price in residential markets ("EnergySage" 2020; Barbose and Darghouth 2019). However, high-module prices per watt for high-efficiency panels or higher system prices associated with "premium" high-efficiency systems have also been observed.

Finally, we calculate the fraction of physically area-constrained residential rooftops in the United States. Whether a system is "physically area-constrained" is determined by the ability of PV that fits on a given rooftop to fully offset annual electricity consumption, and is consistent with net energy metering approaches as well as other scenarios where it is desirable to fully offset load. This could include scenarios where buildings must be net-zero energy. We observe that approximately 60% of rooftops are physically area-constrained at 17% module efficiency, with the fraction of area-constrained rooftops varying from 20% to over 80%, depending on the specific state. The variation between states is driven by differences in the distribution of roof areas as well as differences in electricity consumption. For example, states with milder climates tend to be less area-constrained since they do not use as much air conditioning, and areas in the southeastern United States are more likely to use electric heating than other regions. The fraction of area-constrained systems is expected to grow significantly if high levels of electrification of building and/or transportation loads occur in the future, suggesting a potential increase in the market demand for high-efficiency panels, depending on net metering policies and adoption of behind-the-meter energy storage. High-efficiency modules can help alleviate these area constraints and drive higher adoption in U.S. markets if high-efficiency panels can be manufactured at a low enough price.

This analysis is a step toward understanding the potential market for high-efficiency solar panels. Additional analysis is needed to fully understand how high-efficiency panels could influence adoption in different scenarios. The influence module efficiency and installed system price on adoption was initially investigated in Ramdas, Horowitz, and Sigrin (2019). Based on the results of our analysis in this report, indicating that electrification can significantly affect the fraction of area-constrained rooftops in the United States, future work is needed to understand how the impacts of efficiency on adoption could change with high levels of electrification. Finally, further investigation is required to understand how the value of efficiency could change with combined effects of electrification with the potential for the sunsetting of net energy metering and increased energy storage adoption.

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1 Introduction

A defining characteristic of photovoltaic (PV) panels is their efficiency. Higher-efficiency panels produce more power (kW) and energy (kWh) per area and per panel. A significant amount of PV research and development has focused on improving module efficiencies, with groups competing to achieve even incremental increases in record device efficiency, but questions remain about exactly how valuable higher efficiency is in mainstream PV markets. This includes the effect of module efficiencies on installed system costs and adoption potential. In this report, we analyze how efficiencies influence installed system costs and potential markets for residential rooftop systems throughout the United States, providing insights on how improvements in efficiency might serve as a lever for reaching cost and deployment targets. Residential rooftops were selected as the first market for analysis because they have higher balance-of-system (BOS) costs and are more likely to have limited roof area, increasing the value of efficiency compared to other sectors. This is particularly true in the United States, where residential PV soft costs are still higher than in many areas of the world.

Modules used in mainstream PV markets are typically 14%- to 22%-efficient, but available technologies can range in efficiency from less than 5% to over 35% under one sun illumination. III-V materials, which make up the highest efficiency devices, are currently too expensive for use outside of niche markets where high performance is essential, for example in space applications. Lower- (<14%) efficiency modules, on the other hand, can be low cost, but the low efficiency results in prohibitively high installed system cost, limiting their overall cost competitiveness; low-efficiency modules are not typically installed in practice today. In this report, we will provide analysis on the break-even cost for high-efficiency panels in residential markets, as well as the efficiency level below which modules would have to be free in order to achieve installed system cost parity with a 17.5%-efficiency standard crystalline silicon (c-Si) panel. The spectrum of efficiencies analyzed in this report and how they map to commercially available or theoretically (although undemonstrated) efficiencies achievable using different technologies is illustrated in Figure 1.

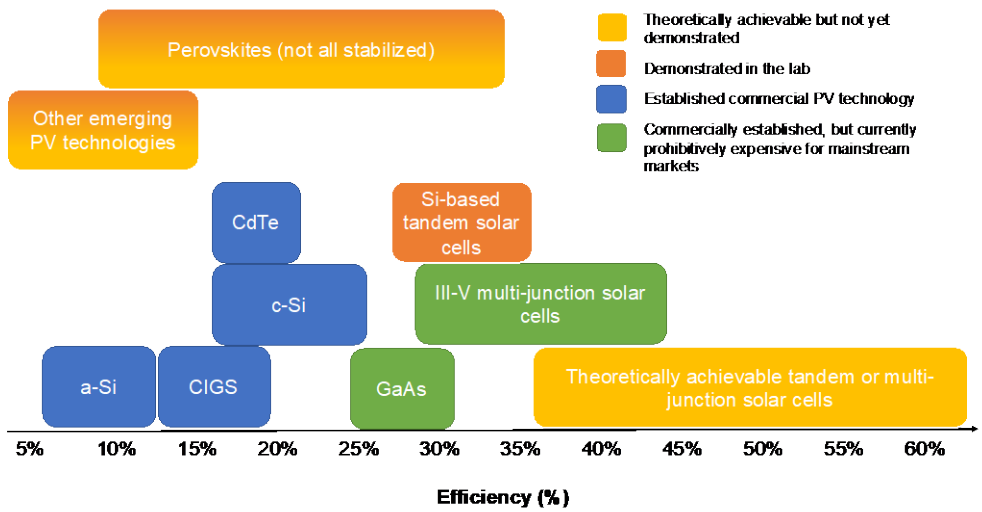

Figure 1. Spectrum of module efficiencies analyzed in this report and the technologies capable of achieving those efficiencies. The boxes indicate ranges for each technology. The boxes for perovskites and other emerging technologies have a gradient to indicate that the range shown includes both efficiencies that are theoretically achievable but not yet demonstrated as well as those that have been demonstrated to some extent in a laboratory environment.

In evaluating the potential system-level cost effects of these emerging high-efficiency technologies (or lower-cost, lower-efficiency technologies), the researchers have typically assumed that the relationship between module efficiency and system costs is straightforward—that certain costs are dependent on power rather than area (e.g., inverter costs), and some are a function of area (e.g., installation labor, BOS material costs). Specifically, in the literature (Sofia et al. 2018; Bobela et al. 2017; Yu, Carpenter, and Holman 2018), the dependence of PV-installed system costs has been modeled using these high-level cost categorizations as follows:

$$C_{system}\left[\frac{\$}{W}\right] = \frac{C_A}{\eta * 1{,}000[W/m^2])} + C_P\left[\frac{\$}{W}\right] \quad \text{(Eq. 1)}$$

where η is the rated module efficiency, 1,000 W/m^2 represents the irradiance under standard test conditions, C_A are costs categorized as area-dependent, and C_P are costs categorized as power-dependent. Costs most frequently characterized as area-dependent (and thus strongly dependent on efficiency) include all BOS equipment and labor and land costs, with some literature also (incorrectly) including permitting, inspection, and interconnection; installer overhead and profit; and sales tax (i.e., all BOS costs except the inverter) as area-dependent for rooftop markets. These models also do not differentiate between area- versus usage-constrained scenarios (Section 2). However, as we will see in this report, the effects of efficiency in the area-constrained scenario are much more pronounced. While some prior literature has mentioned this difference between area-constrained and usage-constrained (also referred to as "power-constrained") cases (Basore 2014; Nanayakkara et al. 2017), these papers have not compared the installed cost versus efficiency in each scenario, and Nanayakkara et al. (2017) also utilized a simplified model of installed cost versus efficiency.

These simplified cost categorizations and models are used where more detailed bottom-up cost models—which are time-intensive to build and maintain, requiring significant PV system expertise and a broad set of industry contacts—are not available, but these simplifications fail to capture the complexity of how efficiency affects cost. Here, we compare the results from our more detailed bottom-up cost models in both area- and usage-constrained cases (see *Methods*) to those obtained with this simplified model in order to gain insights into their potential accuracy in different scenarios. We also move beyond the literature by assessing the fraction of area-constrained residential rooftops in the United States to give insights into the potential geographies where system cost savings and the ability to increase system size associated with higher-efficiency PV technologies would be most beneficial. Prior work has delved more deeply into the market potential by estimating how customer adoption of PV varies with module efficiency and capital cost (Ramdas, Horowitz, and Sigrin 2019).

2 Definition of Area-Constrained and Usage-Constrained Systems

We can categorize rooftop[1] PV systems into a set of cases:

- ***Area-constrained***, wherein a rooftop limits the size of the PV system that can be installed to something less than the economic optimum.
- ***Usage-constrained***, wherein a rooftop has sufficient space to host a PV system of the desired size, and the size of the system is instead based on the electricity usage of the building onto which the system is deployed to maximize the net-energy-metering benefit or enable net-zero electricity usage.
- ***Capital-constrained***, in which the PV system is limited by the total upfront cost of the system compared to the available capital for purchase.
- ***Power-limited,*** in which a customer would be able to install a larger kW-sized system, but are unable to do so because of a strict kW threshold for the PV system size, for example, due to interconnection rules.

The capital-constrained case is highly dependent on the means of a specific household or business at a given point in time and can be alleviated to some extent by using leasing or other third-party ownership models. The power-limited case is not uncommon for utility-scale systems, but is relatively rare for residential systems, where PV size is typically instead limited to not exceed the estimated kWh annual consumption in most states' interconnection rules. Here, we focus on the two other cases: area-constrained and usage-constrained. Usage-constrained, capital-constrained, and power-limited scenarios are all effected by module efficiency similarly because they all result in a system being designed to match a designated power rather than a designated area.

In the **area-constrained** case for residential rooftop systems, the roof is too small to fit as many standard-efficiency panels as needed to fully offset the home's electricity consumption or otherwise maximize economic return. This means that the PV system area and module count are fixed (assuming the area of the modules is also fixed) as efficiency varies. Thus, when low-efficiency panels are used, the system will have a lower-rated power (in kW) and when high-efficiency panels are used, the system will have a larger- (kW) rated power. As we will see in detail, this allows users to spread many of the

[1] These categorizations could also apply to ground-mounted systems, wherein land area limits the PV system size.

installed costs over a larger number of watts resulting in a larger system-cost savings. In contrast, in the **usage-constrained** case, where the roof is not area-constrained, the system size in kW is *fixed* as efficiency varies, while the area of modules (and the number of modules when module area is fixed) installed instead increases with low-efficiency modules and decreases with high-efficiency modules. In residential markets in the United States, the size of the system (kW) is typically set based on the electricity consumption of the building with the goal of offsetting annual electricity consumption. This is due to the prevalence of net energy metering (NEM) and net billing policies that provide electricity bill credits for electricity produced by the PV system up to the amount of consumption on a monthly or annual basis, with minimal or no compensation for additional energy delivered. If metering policies evolve in the future, that could change the way systems are sized and should be explored more in future work.

Figure 2 shows how system power rating versus efficiency compare for an area-constrained versus a usage-constrained scenario in an example where the roof is 28 m^2, and the desired system-rated power in the usage-constrained case is 6 kW. The ripples on the curve for the usage-constrained case arise from the discrete nature of the modules. Figure 3 shows how module count varies with efficiency for the same example. This figure illustrates how the module count of area-constrained systems is fixed while module count decreases for usage-constrained scenarios as efficiency increases.

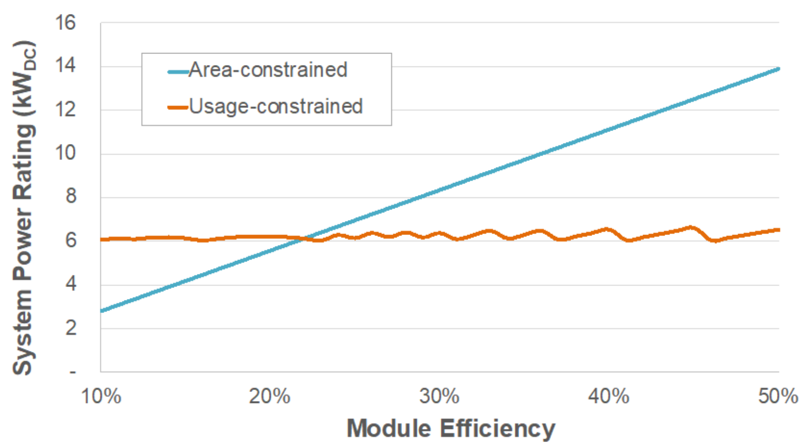

Figure 2. A comparison of system power rating versus module efficiency for area-constrained and usage-constrained (not area-constrained) systems for a rooftop with a 28-m^2 area and a desired system-rated power of 6 kW. The same module area (1.63 m^2) was assumed in both cases, and it was assumed module area was fixed as a function of efficiency.

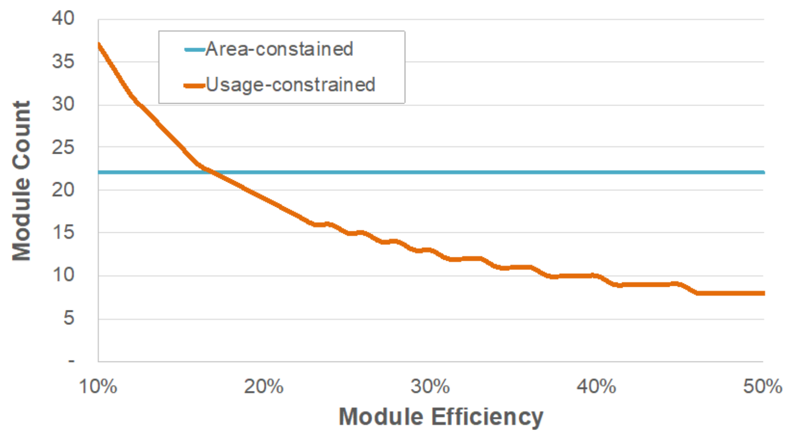

Figure 3. A comparison of module count versus module efficiency for area-constrained and usage-constrained (not area-constrained) systems for a rooftop with a 28-m^2 area and a desired system-rated power of 6kW. The same module area (1.63 m^2) was assumed in both cases, and it was assumed module area was fixed as a function of efficiency.

The way to calculate whether a particular customer is area- or usage-constrained when using standard-efficiency panels is as follows:

1. Estimate the *annual electricity consumption, $E_{consumed}$,* of the customer in kWh. This is typically done by looking at electricity bills and seeing what typical usage is in each month (installers often do this, too, when they are sizing residential PV systems).

2. Estimate the *electricity yield, EY,* standard-efficiency solar panels over a year in *kWh/kW*.

3. Calculate the rated power of the system, $P_{desired}$ (kW), that would allow the solar system to offset electricity consumption on an annual basis using this equation:

$$P_{desired}(kW) = \frac{E_{consumed}(kWh)}{EY\left(\frac{kWh}{kW}\right)} \qquad \text{(Eq. 2)}$$

4. Calculate the power, $P_{standard}$, that would be produced by standard-efficiency modules ($\eta_{standard}$) given the roof area (A_{roof}) using Eq. 3. Take care that the full area of the roof is not used, but only the area minus any required setbacks and area that is unusable due to excessive shading.

$$P_{standard}(kW) = 1{,}000\ W/m^2 \cdot \eta_{standard} \cdot A_{roof} \qquad \text{(Eq. 3)}$$

5. If $P_{standard} < P_{desired}$, then the customer is area-constrained.

As we will see in subsequent sections, whether a system is area-constrained has a strong effect on both how efficiency impacts installed cost and on-market adoption of high-efficiency panels.

3 Methods

3.1 Installed System Cost Modeling

We utilize a bottom-up approach for installed system cost modeling, wherein each step in the installation process is mapped out, and the materials, equipment, and labor requirements for that step are documented. We then have costs of material, equipment, and labor per unit from a combination of primary interviews with installers and standard construction cost references (Mewis 2019). Costs for all steps are summed, and then overhead costs and additional costs such as sales tax are added. Recently, we have also begun modeling customer acquisition and overhead costs using a bottom-up approach, calculating national average costs, weighted by the type of customer acquisition, installer, and permitting requirements, as well as associated costs currently in the marketplace. More details of the overall installed system modeling methodology are included in Fu, Feldman, and Margolis (2018). However, compared to prior published reports of cost versus efficiency using that model, our analysis here incorporates three key improvements to capture efficiency impacts:

1. Revisions to how an installed system power rating is calculated in the area-constrained case, as well as the addition of a usage-constrained scenario.

2. Revisions to how customer acquisition and overhead costs depend on efficiency. These were previously fixed in \$/W as efficiency increased, but our analysis includes the per-system and per-company portions of these costs directly and then calculates the \$/W costs using Eq. 4:

$$C\left[\frac{\$}{W_p}\right] = \frac{C_s\left[\frac{\$}{system}\right]}{\frac{W_p}{system}} + \frac{C_c\left[\frac{\$}{company}\right]}{\frac{W_p}{company/year}} \quad \text{(Eq. 4)}$$

where C_s are the per-system components of overhead and customer acquisition costs, C_c are the per-company components of customer acquisition and overhead costs, and W_p is the watt rating of the PV systems. We assume that the number of systems installed is 46,011/year and 175/year for a large national and small local installer, respectively. This is based on the average of data collected of typical annual installations for large and small installers. The typical number of annual installations for small installers is based on primary interviews conducted with installers. In practice, there is a range of systems installed by installer as well as by year. The data on annual installations for large installers come from dividing the MWs installed by residential installers available in public documents by the average system power rating used in our report. We assume the average power rating of usage-constrained installation, W_U, is 6.18 kW (Fu, Feldman, and Margolis 2018), and use that to calculate an average system area based on a module packing factor of 88%. That area is then used to calculate a new average system power rating with a given efficiency input, W_A, for the area-constrained portion of the company's portfolio by multiplying by 1,000 W/m^2 and the efficiency. The total system-installed watts per year is then given by Eq. 5:

$$\frac{Watts}{company/year} = f_A \cdot W_A + (1 - f_A) \cdot W_U \quad \text{(Eq. 5)}$$

where f_A is the fraction of area-constrained systems in the company's portfolio. We assume that f_A is 60% based on our analysis in the subsequent section of this report.

This methodology is an approximation, and in reality, this calculation as well as the fraction of area-constrained systems and average system power ratings vary company to company and in different regions of the United States. However, this allows us to at least capture how efficiency can influence per-company costs using typical values across the country as a whole.

3. Power electronics costs were also previously fixed in $/W as efficiency or system power rating changed. We revised this approach so that costs were either calculated per module (for microinverters), per system (for string inverters), or both per module and per system (for direct current to direct current [DC-DC] optimizers). For per-module costs, the total cost per system was obtained by multiplying by the number of modules per system. Then $/W for all cases was obtained by dividing the cost per system for the power electronics by the watts per system. We also adjusted the model to account for the discrete nature of string inverter power ratings available in the market. We selected the power rating of the inverter such that the DC-to-alternating current (AC) ratio remained at or below 1.3 for each system; once this limit was reached, we moved to the next largest standard power rating for the inverter. This resulted in the DC-to-AC ratio varying as system power rating increased for a given inverter power rating, as occurs in practice. The resulting inverter sizes and cost-versus-system power rating are shown below in Figure 4.

In looking at the resulting dependencies of power electronics cost per watt arising from these model revisions (Figure 4 and Figure 5), it is interesting to note, making the simplifying assumption that these costs are power related appears to closely reflect reality and can serve as a good approximation.

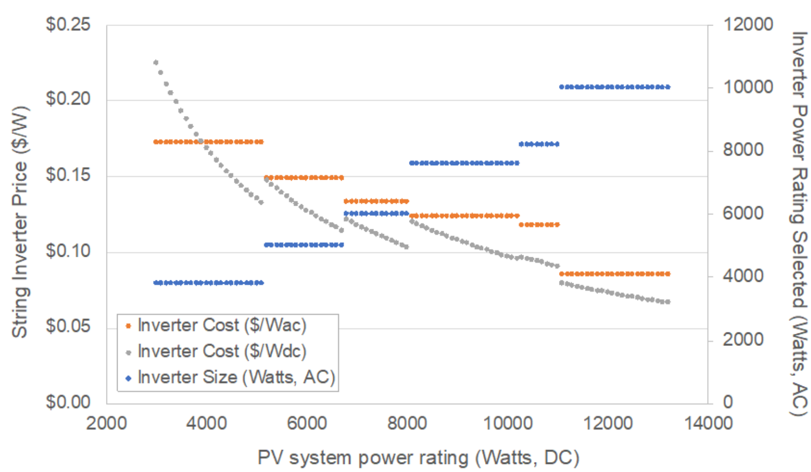

Figure 4. String inverter costs input to our installed cost model as a function of PV system power rating

For microinverters and DC-DC optimizers, there was also a scaling of price per unit with the inverter watt ratings. These were derived by assembling online prices of different wattage inverters from major suppliers and then using regression to generate an estimate dependence of cost-on-watt rating. The overall inverter costs at each rating were then scaled according to the discounts that can be achieved with bulk ordering, as determined via interviews with installers and equipment providers. The final costs used in this model for microinverters are shown in Figure 5.

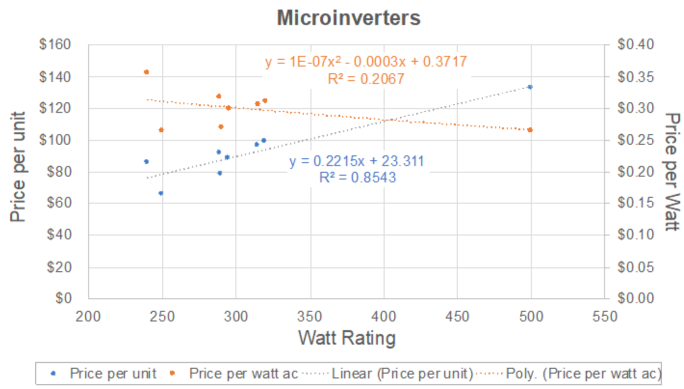

Figure 5. Microinverter costs used in this study as a function inverter watt rating. Inverter prices were collected in 2019.

A summary of the dependence of different system cost categories on system parameters in our model is shown in Figure 6. This figure illustrates the complexity of how costs depend on different factors. Costs may be fixed per watt, per module, per system, or per company. For example, modules themselves are often priced per watt, so they have a cost per watt, but the labor cost to drill holes to attach each module as well as the materials used to attach the modules are typically fixed per module. Many cost categories (BOS, power electronics, installation labor, and equipment/vehicle depreciation, as well as customer acquisition costs) depend on multiple variables, reflecting the fact that the dependency for individual cost items within these higher-level cost categorizations vary. There are, for example, one (or maybe two) string inverters per system, so the majority of string inverter costs are per system. However, the price of each string inverter also depends somewhat on the watt rating. Similarly, some labor costs are fixed per system (e.g., the cost to drive out to the site, plan the site, get on the roof, etc.), while others depend on the number of modules installed (e.g., labor time to attach the panels). The grey and red shading in Figure 6 shows which of these cost categories are fixed in area-versus usage-constrained systems, respectively.

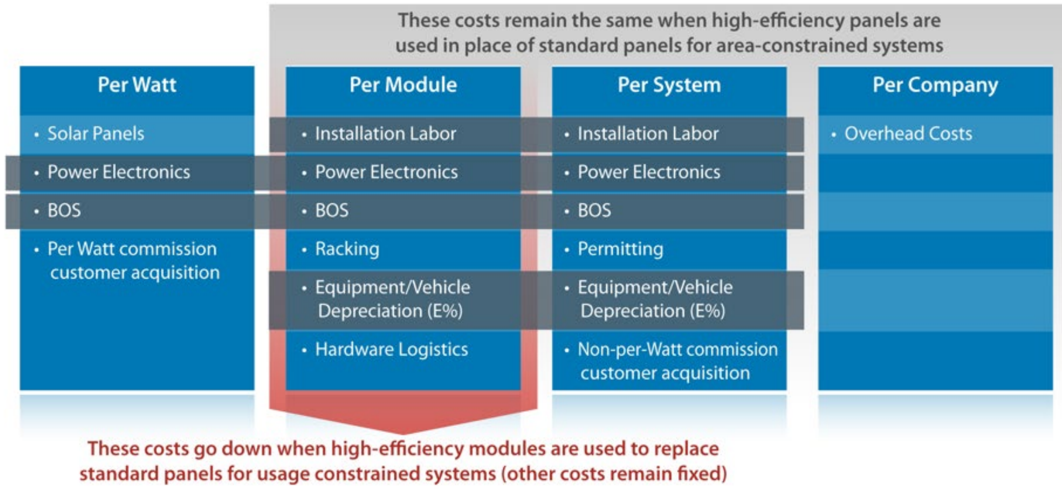

Figure 6. Dependence of PV-installed system cost categories on different variables. Costs may be fixed per watt, per module, per system, or per company. Some cost categories depend on multiple variables (e.g., they have a component of costs that are fixed per watt and some that are fixed per system) because of the differing dependencies of individual cost items within each category. These dependencies assume area per module is fixed with efficiency.

3.2 Estimating the Fraction of Area-Constrained Residential Rooftops in the United States

In this section, we describe our methodology for estimating the fraction of physically area-constrained rooftops across each state. We used light detection and ranging (LiDAR) data to estimate the area of rooftops for residential customers across the United States. These data come from the National Renewable Energy Laboratory's (NREL's) Distributed Generation Market Demand (dGen) model (Sigrin et al. 2016). Due-north-facing sections of the roofs are excluded from the useable area, while all other faces are included. In reality, panels are occasionally still installed on north-facing roof sections, and thus our analysis may be somewhat conservative in the total amount of roof area available. However, the energy production from north-facing roofs can be considerably lower, depending on the tilt, and thus placing panels on these planes will not alleviate area constraints as effectively. Additionally, currently there are few systems installed on northwest or northeast roof faces, which are included in our analysis. In this analysis, any area that is shaded is excluded, as described in (Sigrin et al. 2016).

Figure 7. Coverage of LiDAR data used in calculating the fraction of area-constrained rooftops and in customer adoption modeling. Reproduced from (Gagnon et al. 2016).

The LiDAR data are mapped to dGen *agents*, which are statically representative of groups of customers. Each agent is also associated with an 8,760 (hourly, annual) load profile which can be summed to obtained annual kWh of electricity consumed.[2] These data come from the U.S. Energy Information Administration's Annual Energy Outlook. In calculating the fraction of area-constrained systems, we then use this roof area and load data to calculate whether a given agent is area-constrained using the steps outlined in Section 3 (Eqs. 2 and 3).

We conducted sensitivity analysis, comparing results with 1 agent, 3 agents, and 10 agents per county and found that the results with 3 and 10 agents were within less than 1% for the fraction of area-constrained systems. However, computational time increased linearly with the number of agents per county. Thus, we chose to model three agents per county for all dGen analysis in this report to balance accuracy and computational requirements. Three agents per county corresponds to 9,021 agents modeled for the United States as a whole.

We analyzed both the fraction of area-constrained systems with current electricity consumption levels as well as possible future scenarios with high electrification of both building and transportation loads. Load data for the high-electrification scenario are based on modeling conducted for NREL's Electrification Futures Study (Mai et al. 2018). Figure 8 shows how the sales share of electric technologies for vehicles, space heating, and water heating evolves over time in the reference and high-electrification scenarios.

[2] Roof area and annual electricity consumption are not currently correlated in dGen's agent creation process.

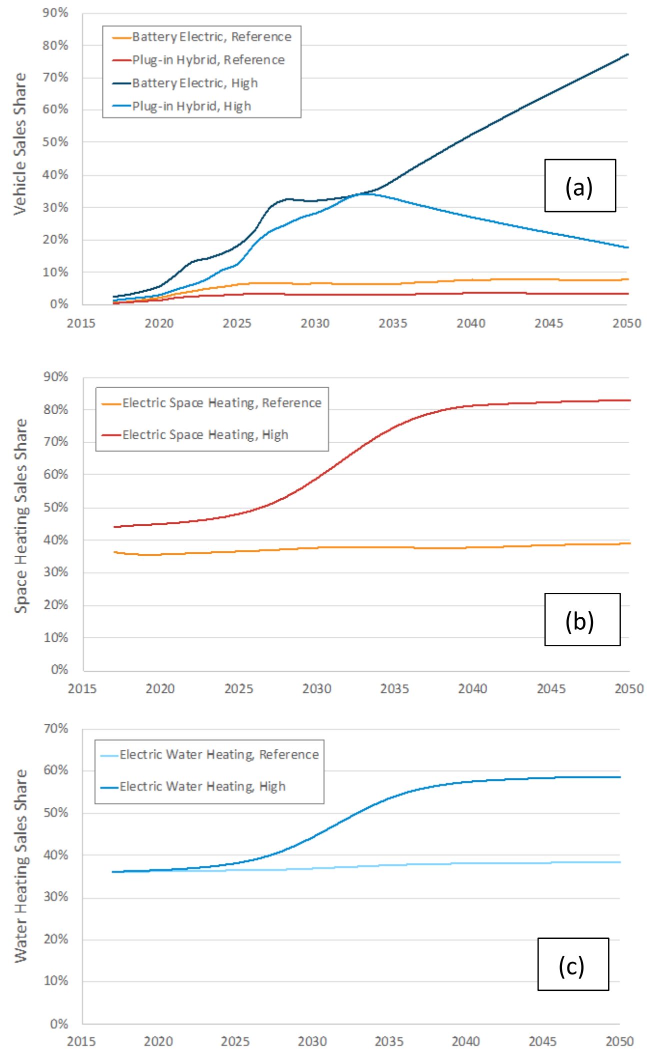

Figure 8. Sales share of (a) electric and hybrid vehicles, (b) electric space heating, and (c) electrical water heating in the reference and high-electrification scenarios through 2050

This approach of estimating *physically* area-constrained systems should be distinguished from that of estimating the fraction of *economically* area-constrained systems. Estimating the fraction of physically area-constrained systems should be considered only a preliminary step in understanding the market for high-efficiency solar panels. This issue and the distinction between physically and economically area-constrained rooftop are further discussed in Section 4.2.

4 Results and Discussion

4.1 Installed System Cost Analysis

Modeled installed system costs for area-constrained and usage-constrained systems with string inverters for an example system are shown in Figure 9. The differences between large national integrators and small local installers are also shown. As shown in the figure, the total costs between these two groups are very similar in our models. However, the breakdown of costs differs, with small local installers having lower overhead costs but higher materials costs due to their purchasing of goods in smaller volumes. Customer acquisition costs are fixed per system in our model (the dependence can vary depending on the business model; see Discussion). This means that customer acquisition costs per watt in the area-constrained case decrease in efficiency, and thus the system power rating in kW increases. Because of this, the small local installers, which have lower per-system customer acquisition costs, are cheaper for smaller system-rated powers; however, at large system-rated powers, the savings on materials for larger national integrators dominates, resulting in a slightly lower system cost. Because the difference between large and small installers' costs overall is so small, we do not distinguish between these two installer types for the remainder of the paper.

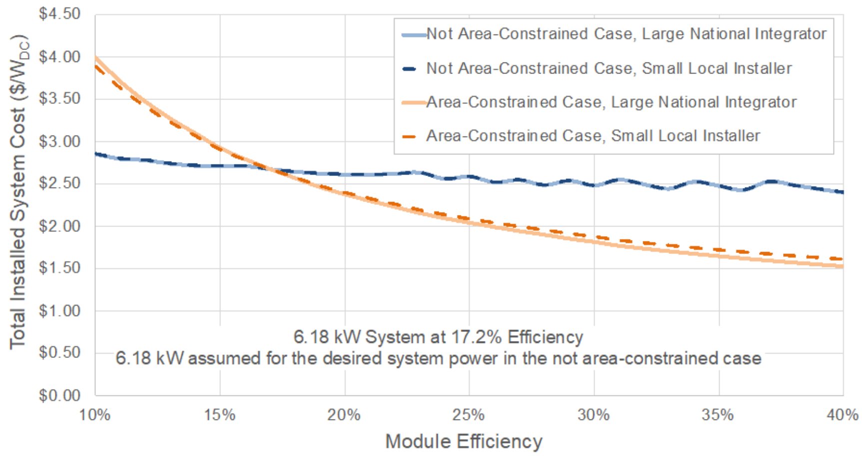

Figure 9. Installed system costs in area-constrained and usage-constrained scenarios for the case where string inverters are used, and the module costs are fixed per watt. This example is shown for a system with a desired power of 6.18 kW for the usage or not-area-constrained case and 37 m^2 of usable roof area. The exact curves will vary, depending on the desired power and available roof area.

A much larger difference in cost per watt is driven by whether the system is usage- or area-constrained, with area-constrained systems seeing much larger system-rated powers with increased efficiency as well as a steeper increase in costs with low-efficiency panels. This is because the magnitude of costs that decreased by increasing the system power rating (kW) is greater than the magnitude of costs resulting from a decrease in the number of modules installed. This essential reflects economies of scale with costs being spread over a larger number of watts. This can be understood intuitively by looking at Figure 10, which shows a dramatic decrease in installed cost per watt with an increasing system power rating as calculated using our bottom-up cost model. The trend of lower system costs with higher system power ratings is consistent with market pricing data for residential systems available in ("EnergySage" 2020; Barbose and Darghouth 2019).

This monotonic decrease of this curve holds regardless of the efficiency of the panels—a 7-kW system with standard-efficiency c-Si panels will have lower installed costs than a 3-kW system with standard-efficiency c-Si panels. Higher-efficiency panels allow more watts in a smaller space, so that if a household is area-constrained, their system will be larger and able to take advantage of these economies of scale.

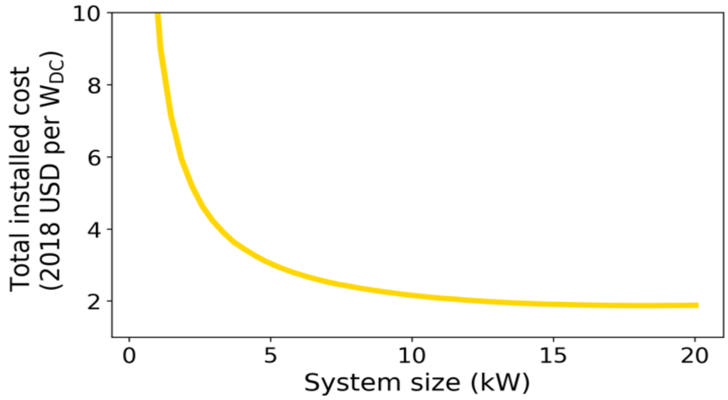

Figure 10. Dependence of installed system costs on system power rating in the scenario where module prices ($/W) are fixed versus system power rating. This curve is independent of whether a system is area-constrained or usage-constrained.

The relative savings depends on the type of power electronics used in the installation.

Figure 11 shows the costs with microinverters versus string inverters for the usage-constrained case compared to the area-constrained case with our current estimated (extrapolated) costs for higher-power microinverters. The cost savings with efficiency increases slightly when microinverters are used for the usage-constrained scenario and decreases slightly when microinverters are used for the area-constrained scenario. This is because microinverters and DC-DC optimizers have a per-module component to their costs, reducing the number of units (modules) per install with efficiency increases, thus decreasing costs in the usage-constrained case. However, this effect competes against the increase in microinverter per-unit costs with higher power modules (Figure 5), making the difference in the shape of the cost curve with efficiency in the usage- versus area-constrained case between inverter types small; as discussed in 3.1, this suggests that these costs are essentially power related. There is significant uncertainty in how microinverter prices will evolve with high-power modules; at 30% efficiency, the module ratings for 1.63-m^2 panels are approximately 571 W, higher than what we see in the market today. Even higher-power microinverters for today's panels could come down in price if the volume of high-efficiency panels increased.

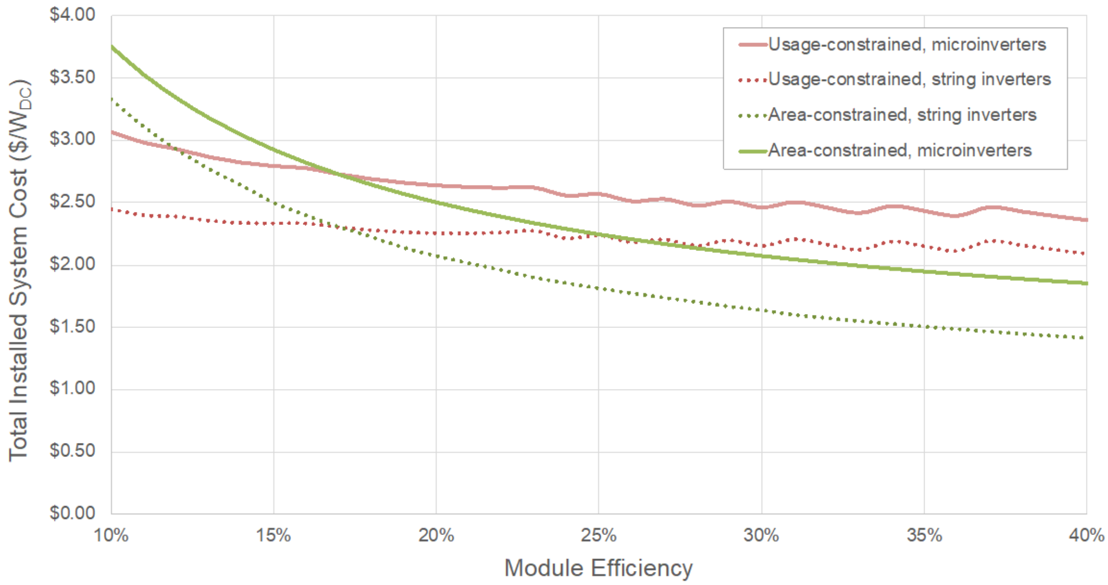

Figure 11. Installed system costs in usage- and area-constrained scenarios with microinverters versus string inverters when the module costs are fixed per watt. Results are shown for a market-weighted average of installer types (small, local, and large nation integrators) in the United States. Results indicate the scenario where module prices are fixed per watt as efficiency increases.

4.1.1 Break-Even Module Prices

The module prices required to break even, with the 2018 benchmark system having 17% efficiency with a $0.35/W U.S. module price as a function of efficiency, are shown below in Figure 12. These break-even module prices are based purely on the installed system cost, not the levelized cost of energy or other economic or market factors. The break-even module prices are less than the difference between the installed system cost savings at one efficiency and another because some costs are a percentage mark-up on the total installed cost. These include sales tax, some profit and overhead, and some supply chain costs. It is important to note that these break-even module prices are based on the assumption that the modules are purchased in the United States; U.S. module prices for both multi and mono c-Si are substantially higher than global prices (Feldman, O'Shaughnessy, and Margolis 2020), and so the ex-factory gate pricing that could be tolerated is lower. In 2019's third and fourth quarters, U.S. module average selling prices for multi c-Si were $0.31/W and mono c-Si were $0.45/W, compared to global average prices between $0.20–$0.21/W add $0.22–$0.24/W for multi and mono c-Si, respectively ("ITRPV 2020 Presentation - USA" 2020; Feldman, O'Shaughnessy, and Margolis 2020). Average mass production efficiencies for p-type PERC, PERT, PERL, and Topcon cells with multi c-Si were 18.3%, compared to 20.0% for the same with mono c-Si. These compare to the results of break-even prices in our model (shown in Figure 12), as follows:

- We see a break-even module price at 20% efficiency (mono c-Si average) of $0.49/W, compared to the $0.45/W average selling price in the United States.
- We see a break-even module price at 18.3% efficiency (multi c-Si average) of $0.395/W, compared to the $0.31/W average selling price in the United States.

- Our model suggests that the price for a 20% module to break even with an 18.3% module priced at \$0.31/W is \$0.38/W, which corresponds to a \$0.07/W premium, compared to the \$0.14/W premium for mono c-Si versus multi c-Si observed in U.S. average pricing. This suggests that a premium may be charged beyond the installed system cost savings, although looking only at averages makes this difficult to assess.

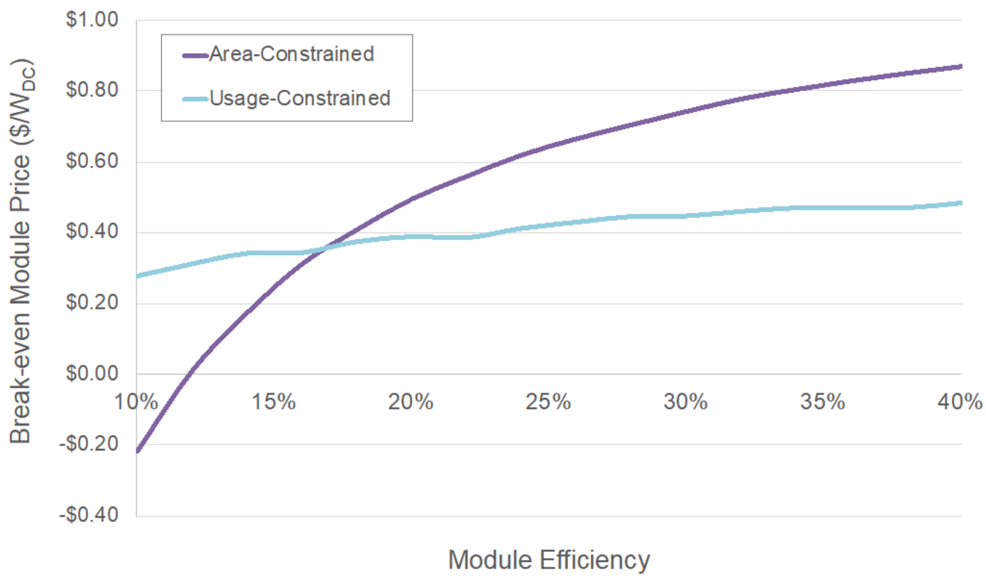

Figure 12. Break-even module prices as a function of efficiency for the area-constrained and usage-constrained scenarios

4.1.2 Comparison to Simplified Models of Cost Versus Efficiency

Figure 13 compares the cost versus efficiency in the usage- and area-constrained scenarios modeled using our bottom-up cost model compared to the results when the simple efficiency model in Eq. 1 is used. This example shows the case for a string inverter, but as we saw in Figure 11, the shape of the curve of cost versus efficiency with microinverters versus string inverters is similar. Figure 13 shows that the simple efficiency model in Eq. 1 is a much better approximation of the area-constrained case than the usage-constrained case, but still overestimates both the savings from increased efficiency and the cost increase with lower-efficiency panels compared to the full bottom-up model presented here. However, it may be possible to develop an additional, simplified efficiency model that better reflects the costs in the usage-constrained scenario and does not require time-intensive, detailed bottom-up cost modeling. This would be beneficial in allowing researchers to more quickly and easily generate and update their own analyses of the value of efficiency to evaluate research and development directions.

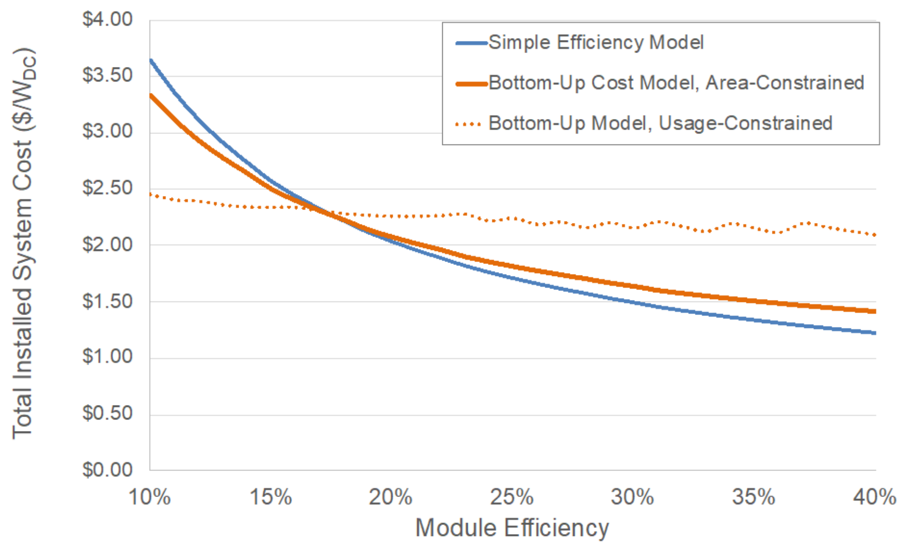

Figure 13. Comparison of the total installed system cost versus module efficiency using bottom-up cost models compared to the simple efficiency model in the scenario where module prices ($/W) are fixed versus efficiency. Example is shown for the case where string inverters are used.

4.2 Fraction of Physically Area-Constrained Residential Rooftops in the United States

Figure 14 shows both the fraction of physically area-constrained residential rooftops and modeled installed cost savings for all states in the continental United States. The map shows the fraction of area-constrained systems with current electricity consumption and a 17%-efficient solar module, typical for current residential installations. The map illustrates that the fraction of area-constrained systems varies across the United States, as do the installed cost savings. In California, for example, only about 25% of residential rooftops are area-constrained because of the relatively lower electricity consumption in this state. Other states, particularly in the southeastern part of the country, have over 80% area-constrained rooftops because of their higher loads, due partly to the higher prevalence of electric space heating as well as air conditioner use.

As mentioned above, whether a rooftop is "physically area-constrained" is determined by the ability of PV that fits on a given rooftop to fully offset annual electricity consumption, and is consistent with NEM approaches as well as other scenarios where it is desirable to fully offset load. This does not consider if the household is area-constrained or not based on the economics. This is an important distinction, because in some cases the homeowner may not be able to offset their electricity consumption fully with solar and currently available technology, but it may not make economic sense for them to fully offset their consumption anyway based on the local electricity prices, net metering policies, or other factors. Thus, a household could be physically area-constrained but not economically area-constrained.

Ramdas, Horowitz, and Sigrin (2019) offers some insight into how adoption—which considers these economic factors—could be influenced by efficiency by conducting customer adoption modeling using dGen. The results indicate that across the country, increases in efficiency lead to increased adoption if the installed system price is the same. If installed system cost savings can be realized, adoption could increase further; however, if there is a premium on the installed cost for high-efficiency systems resulting, for example, from higher module prices per watt, the adoption advantage can disappear.

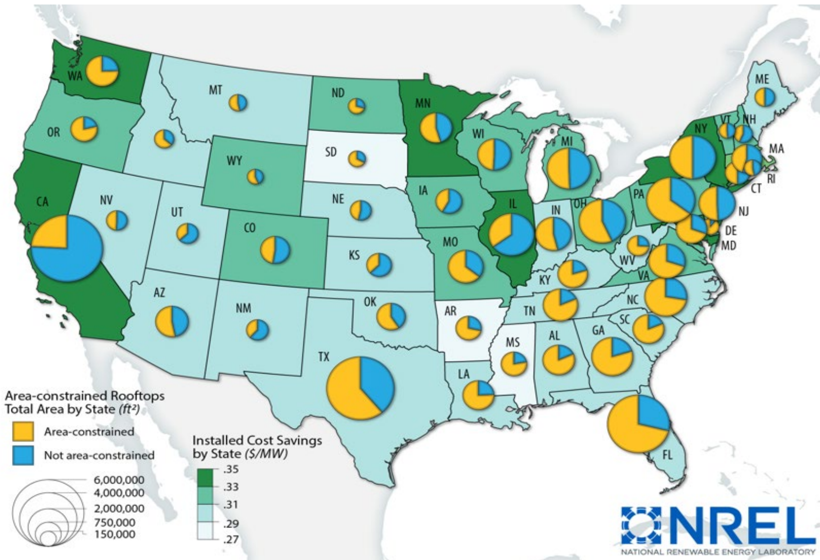

Figure 14. Fraction of physically area-constrained residential rooftops with a 17%-efficiency solar module and current electricity consumption. Installed cost savings are shown for going from a 17%- to a 22.7%-efficient module in each state.

Despite these nuances, it is still interesting to consider the fraction of physically area-constrained rooftops and how these could evolve over time if high levels of electrification occur as a first attempt to understand the market for high-efficiency panels because metering policies and electricity tariffs that influence the fraction of economically area-constrained systems are in flux. Figure 15 shows that with high levels of electrification for both building and transportation loads, the fraction of area-constrained rooftops in the United States would increase over time at a 17% module efficiency. The increase is more dramatic between 2030 and 2050 when the markets for electric vehicles, space heating, and water heating are expected to grow significantly in the high-electrification scenario. Figure 16 shows how increasing module efficiency could help reduce the fraction of physically area-constrained systems in the 2030 high-electrification scenario across the United States.

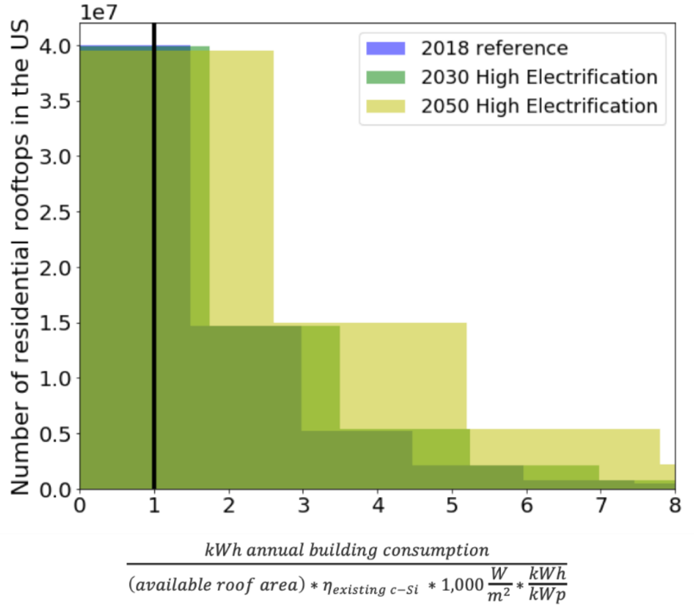

Figure 15. Evolution in the fraction of area-constrained systems in the United States over time in the case of high electrification of building and transportation loads if a 17% module efficiency is assumed

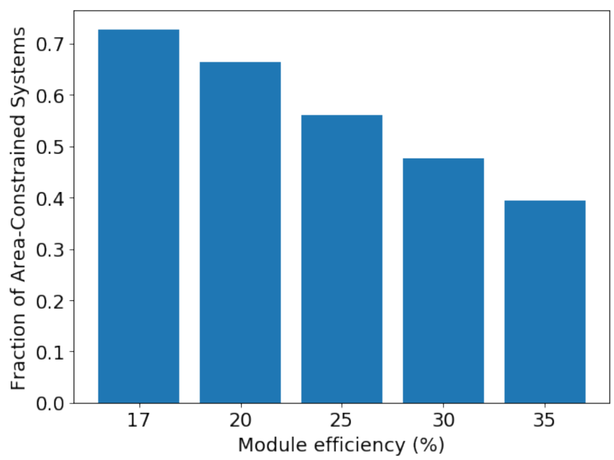

Figure 16. Change in the fraction of physically area-constrained households across the United States versus efficiency in a high-electrification scenario in 2030

This large increase in the fraction of area-constrained systems can be intuitively understood by examining how the loads for individual households could change with electrification. Figure 17 shows this for a typical household in Kansas City, Missouri, and the Appendix includes similar figures for Portland, Oregon, and Daggett, California. In Kansas City, where gas heating is more common than electric heating, and heating needs during the winter can be high, converting to electric space heating is the largest factor. Overall, electrifying the household's vehicles and all its energy use would result in a 3.3X increase in electricity consumption.

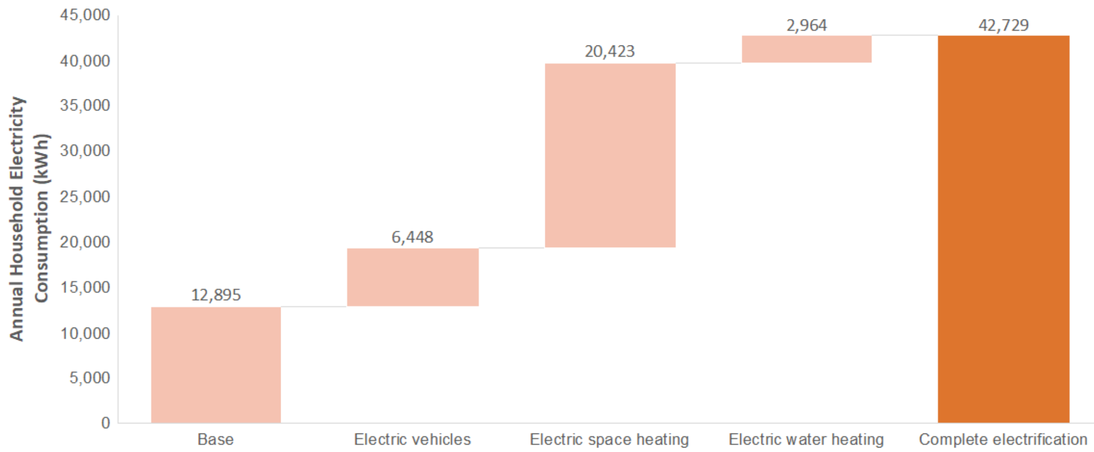

Figure 17. Increase in annual household electricity consumption for an example home in Kansas City, Missouri, with electrification

5 Conclusions and Future Work

We have presented a bottom-up analysis of installed system cost versus efficiency for residential rooftop PV systems in the United States, focusing on the scenario where module prices ($/W) are fixed as efficiency increases. We have distinguished between installed cost savings in area-constrained versus usage-constrained scenarios and shown that the impact of efficiency on installed cost is much greater for area-constrained systems. In the area-constrained scenario, we looked at weighted-average U.S. costs for an example system and saw that if module prices ($\$/W_{DC}$) are fixed with efficiency, a 14% savings in installed costs could be achieved by increasing efficiency from 20% to 25%, with 11% and 19% additional savings going from 25% to 30% and 25% to 35%, respectively. These savings can vary somewhat, depending on the available rooftop area and inverter type used, the customer acquisition model and overhead structure, and other factors specific to a given company. We also saw that the installed system cost savings varies significantly across the United States because of different cost structures in each state. Importantly, the savings can be eliminated if high-efficiency panels have a module price premium, as can often be the case in the market today, and we have calculated the module price needed to break even with installed costs using today's standard-efficiency panels. This analysis focused purely on installed *costs*, and whether these savings are seen by customers will depend on how installers price their systems and if they reflect how costs change with panel efficiency and/or system-rated power. We also calculated the fraction of physically area-constrained residential rooftops in the United States. We saw that approximately 60% of rooftops are physically area-constrained today, with the fraction of area-constrained rooftops varying from 20% to over 80%, depending on the specific state. The fraction of area-constrained systems is expected to grow significantly if high levels of electrification of building and/or transportation loads occur in the future. Increasing the efficiency of solar modules can alleviate these physical area constraints. This analysis is a step toward understanding the potential market for high-efficiency solar panels. However, additional analysis is needed to understand the fraction of economically area-constrained systems, how this fraction is affected by changes in NEM policies, and, broadly, the potential effects on adoption to better understand this market.

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Appendix

This section shows how the electricity consumption for typical households in Daggett, California, and Portland, Oregon, could change with complete electrification of both building and transportation loads.

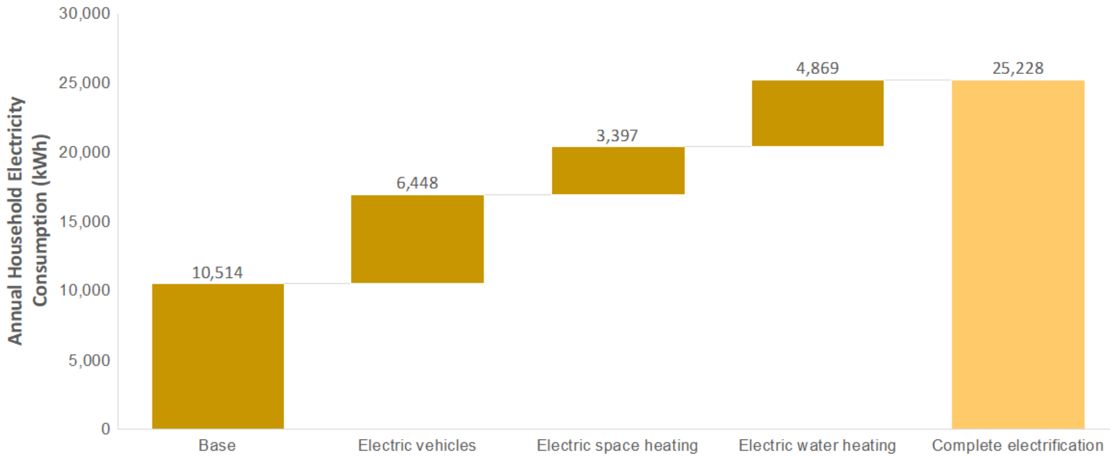

Figure 18. Effects of complete electrification on electricity consumption for a typical household in Daggett, California

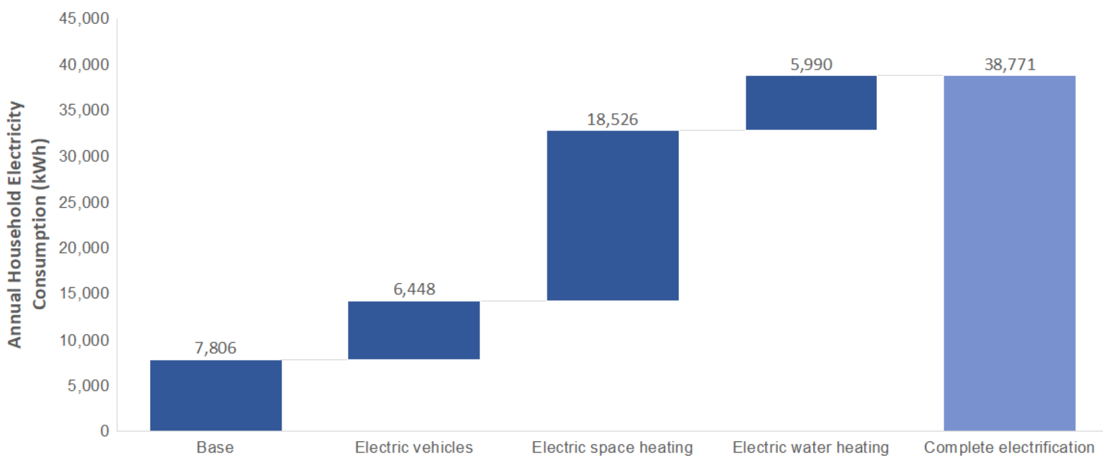

Figure 19. Effects of complete electrification on electricity consumption for a typical household in Portland, Oregon