Modeling the U.S. Rooftop Photovoltaics Market
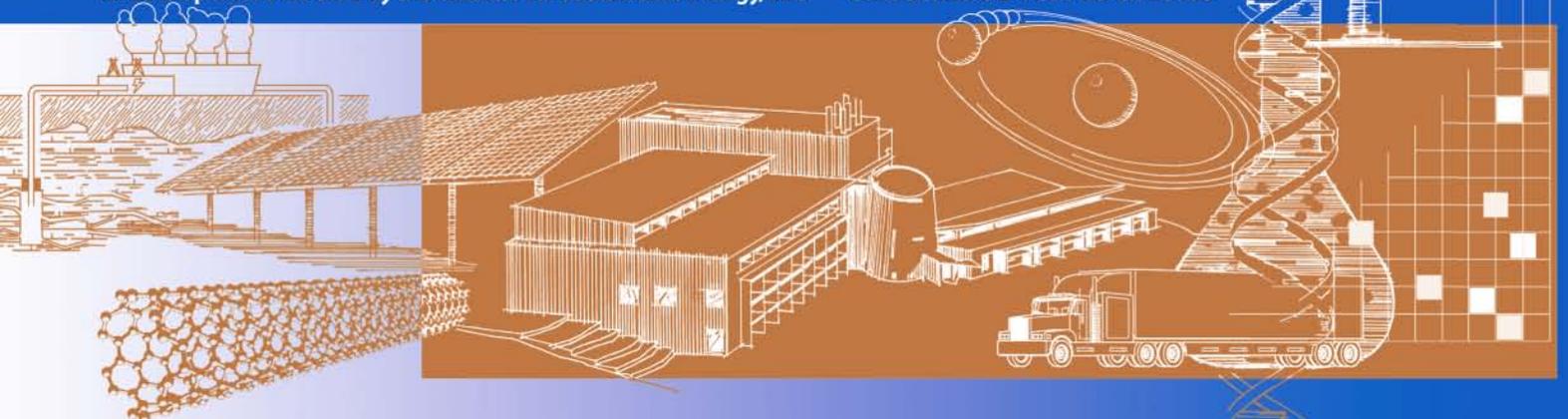
Easan Drury, Paul Denholm and Robert Margolis

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Modeling the U.S. Rooftop Photovoltaics Market

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ABSTRACT

Global rooftop PV markets are growing rapidly, fueled by a combination of declining PV prices and several policy-based incentives. The future growth, and size, of the rooftop market is highly dependent on continued PV cost reductions, financing options, net metering policy, carbon prices and future incentives. Several PV market penetration models, sharing a similar structure and methodology, have been developed over the last decade to quantify the impacts of these factors on market growth. This study uses a geospatially rich, bottom-up, PV market penetration model—the Solar Deployment Systems (SolarDS) model developed by the National Renewable Energy Laboratory—to explore key market and policy-based drivers for residential and commercial rooftop PV markets. The identified drivers include a range of options from traditional incentives, to attractive customer financing options, to net metering and carbon policy.

1. INTRODUCTION

Global PV capacity exceeded 15 GW by the end of 2009 *(1)*, of which, approximately 1 GW was installed in the United States *(2)*. Distributed rooftop PV currently represents the largest segment of the U.S. and global PV markets, in large part because these systems earn retail electricity rates, and avoid transmission and distribution losses. Much of this recent growth has been fueled by declining PV prices and policy-based incentives. The United States has a patchwork of federal, state, and utility-scale incentives that have stimulated regional PV markets, but not the national markets seen in Germany, Japan and Spain.

PV market penetration models have been developed over the past two decades to evaluate the impacts of declining PV costs, electricity rates and rate structures, net metering policy, carbon prices, and incentives. PV market penetration models frequently focus on the distributed rooftop PV market and share a similar modeling framework *(3-7)*. PV models typically start by characterizing regional PV economic performance (based on local PV output, electricity rates, incentives, etc.), then relate PV economic performance to customer adoption.

This paper describes the common structure of PV market penetration models, with a focus on the SolarDS model developed by the National Renewable Energy Laboratory. SolarDS is used to evaluate rooftop PV market drivers, and to identify market- and policy-based 'levers' that could be used to effectively stimulate PV markets. These 'levers' include options ranging from traditional incentives, to attractive customer financing options (e.g. Property-Assessed Clean Energy financing for residential customers), to net metering and carbon policy.

2. SolarDS
2.1. PV Revenue

The revenue generated by a PV system in a given location is characterized by combining regional PV output with local electricity rates. Regional PV output is calculated at different resolutions depending on the modeling framework. SolarDS simulates 'typical' hourly PV output in 216 model regions (Figure1) using Typical Meteorological Year (TMY3) stations from the National Solar Radiation Database *(8)*. PV output is calculated for several

orientations including flat-mounted modules, and tilted modules (tilt angle equal to latitude) with azimuth orientations ranging from ±90° from south in 30° increments. Alternating current (AC) PV output is calculated for each location and orientation using the PVFORM/PVWATTS model *(9)*, which calculates PV efficiency based on hourly temperature and wind speed, and accounts for losses in converting direct current (DC) PV output to AC electricity using a derate factor (representing losses in the inverter, transformer, wiring, module mismatch, panel soiling, etc.). Here and elsewhere, see *(7)* for a more detailed description of the SolarDS model.

PV performance is associated with adjacent census blocks, which are used to generate the 216 solar resource regions shown in Figure 1.
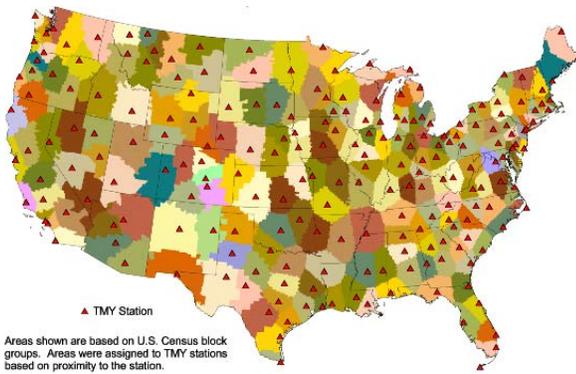
Figure 1. Solar resource regions used in SolarDS. The 216 TMY stations are shown by triangles.

Local electricity rates are challenging to characterize due to the large variation in rates and rate structures used by U.S. utilities. Retail electricity rates vary significantly both within and among states. SolarDS captures both the distribution in customer rate types (flat, time of use (TOU), and demand-based rates) and the distribution of rate prices for each state. The distribution of customer rate structures is determined using tariff sheets from the largest service provider in each state. The distribution of electricity rates is calculated using Energy Information Administration (EIA) form 861 data *(10)*, which provides total revenue and sales for over 3000 utility service providers in the U.S. Electricity rates are projected through 2030 using the Annual Energy Outlook 2009 (AEO2009) *(11)*.

Figure 2 illustrates the distribution of retail electricity rates for residential customers in five U.S. states, and the differences among states. A PV investment is much more attractive for the fraction of customers paying the highest rates, and SolarDS is able to simulate increased PV adoption in these regions.
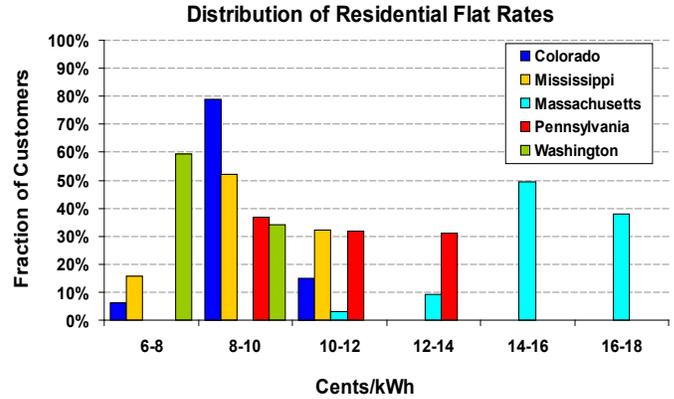
Figure 2. Retail electricity rates from over 3000 utilities are used to calculate state-based electricity rate distributions.

Net metering policy must also be assumed when calculating PV revenue. If a customer is using more electricity than provided by their PV system in a given hour, PV electricity offsets electricity purchases, and receives retail electricity rates. However, if the customer is using less electricity than their PV system provides in a given hour, the additional PV electricity will be exported to the grid. In regions offering full net metering, this surplus PV generation receives retail electricity rates. In regions without full net metering, the value of surplus energy can range from zero, to the cost of avoided fuel use and operations and maintenance (O&M) costs, to retail electricity rates. SolarDS allows the user to specify net metering assumptions, and the value of surplus electricity. The results shown later represent full net metering scenarios, and scenarios where surplus electricity is valued at the cost of avoided natural gas use[1].

Lastly, if carbon emissions are priced through a carbon tax or cap and trade structure, the cost of burning carbon-based fuels will increase. This cost will likely be passed on to the customer, resulting in higher retail electricity rates and higher PV revenues. SolarDS characterizes this additional revenue by combining a user-defined carbon price with the carbon intensity of conventional electricity generation in each region.

2.2. PV Costs
The cost of a PV system includes the initial investment in system hardware (module, inverter, and balance of systems costs), and the variable operations and maintenance (O&M) costs. PV costs are expected to decrease substantially over the next few decades by increasing module efficiencies, and by reducing module costs, balance of systems costs, and supply chain margins as the industry grows and matures. Figure 2 shows PV cost projections from the EIA (used to generate AEO2009 scenarios *(11)*), the U.S. Department of Energy (DOE) Solar Energy Technology Program (SETP)

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[1] Natural gas is frequently at the margin during hours of peak PV output.

cost targets, and a recent DOE expert elicitation of PV costs *(12)*. The DOE elicitation included PV experts ranging from industry to academia.

Residential PV System Costs
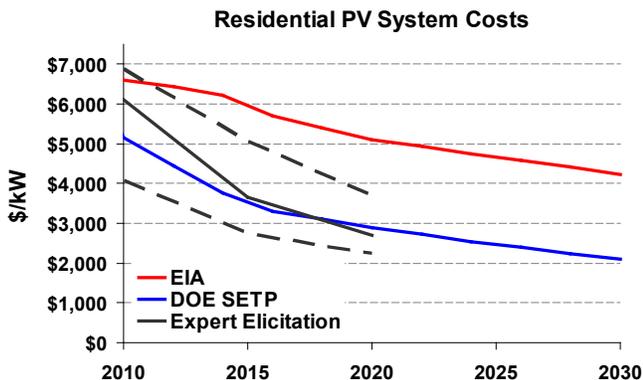
Figure 3. Residential PV cost projections. The solid black line represents median PV cost estimates from the DOE elicitation (50% of participants thought costs would be higher and 50% lower). The upper dashed line represents a cost projection where 10% of participants thought costs would be higher, and the lower dashed line represents costs where 10% of participants thought costs would be lower.

Commercial PV System Costs
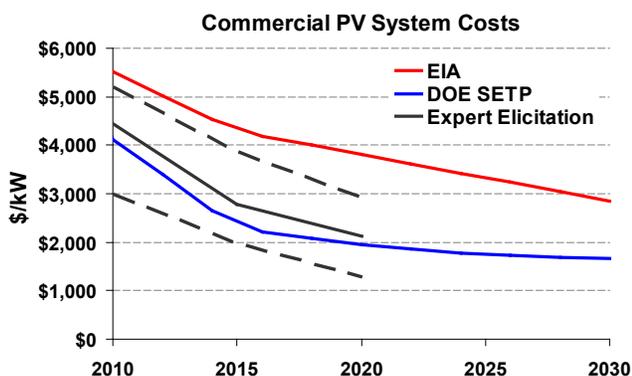
Figure 4. Same as Figure 3, but for commercial PV systems.

Figures 3 and 4 illustrate different evolutions of PV costs for residential and commercial systems. The DOE SETP cost targets are more aggressive, but could be met my incremental improvements in manufacturing processes (and costs), and decreasing supply chain inefficiencies. We use this range of PV costs to explore the sensitivity of the rooftop PV market to future costs reductions in section 3.

The majority of PV customers finance their PV system. SolarDS models the annual cost of PV ownership using the financing assumptions in Table 1. For residential systems, both standard financing assumptions and attractive financing assumptions (Property Assessed Clean Energy (PACE) *(13)*) are explored in section 3.

Table 1. Financing parameters

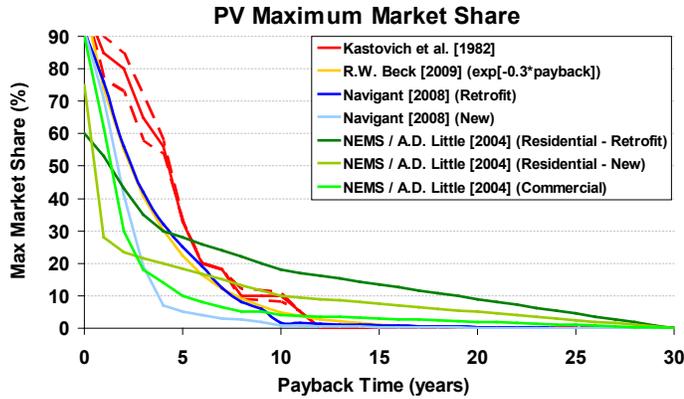|	Residential (new / retrofit)	Residential (PACE-style[1])	Commercial
Loan Rate (real)	5% / 5%	3.9%%	5%
Loan Term (years)	30 / 15	20	20
Down Payment	20%	1%[2]	20%
Depreciation	-	-	MACRS
Federal Tax	28-33%	28-33%	35%
State Tax	by state	by state	by state
Federal Incentives	30% ITC through 2016	30% ITC through 2016	30% ITC through 2016; 10% after 2016
State Incentives[3]	by state	by state	by state

[1]Based on financing terms from *(13)*.
[2]Although systems financed using PACE loans frequently do not require a down payment, a small down payment is included here to capture loan fees.
[3]From the www.dsireusa.org database.

2.3. Simulating PV Adoption

Potential PV customers frequently use economic performance metrics to evaluate a PV investment. Survey studies have suggested that residential customers typically use the payback time metric to evaluate whether or not they will invest in an energy saving device *(5,6,14)*. Because of this, PV market penetration models typically use PV payback times to simulate customer adoption, not because they represent the most accurate indicator of investment value, but because they best characterize the decision making process used by potential customers. SolarDS calculates residential PV payback times using the time-to-net-positive-cashflow metric, which represents the first year that the revenue generated by a PV system exceeds the cost of ownership *(4,6,7)*. SolarDS calculates commercial payback times based on the Internal Rate of Return (IRR) earned by the PV system. The commercial payback time represents the amount of time required for an investment accruing at the system IRR to double in value *(3,7)*. Simple payback times—roughly defined by the cost of a system divided by its annual revenue—have also been used in previous rooftop PV simulations *(e.g. 5)*, however simple payback times are not able to capture the impacts of customer financing options. Both the time-to-net-positive-cashflow metric, and the IRR-based metric were chosen here to best represent the decision making process used by potential residential and commercial customers.

PV adoption rates are simulated using a semi-empirical relationship between PV payback time and maximum customer adoption fraction, and a market diffusion rate which characterizes how quickly a potential PV market is attained. The maximum customer adoption fraction, or market share, is approximated based on previous survey studies *(14)*, and expert elicitations from industry participants *(5,15)*. Figure 5 shows maximum market share relationships derived and used in previous studies.

PV Maximum Market Share

Legend:
- Kastovich et al. [1982]
- R.W. Beck [2009] (exp[-0.3*payback])
- Navigant [2008] (Retrofit)
- Navigant [2008] (New)
- NEMS / A.D. Little [2004] (Residential - Retrofit)
- NEMS / A.D. Little [2004] (Residential - New)
- NEMS / A.D. Little [2004] (Commercial)

Figure 5. Relationship between PV payback times and maximum market share, representing the fraction of customers likely to invest in PV for a range of payback times.

Figure 5 shows that there are significant differences in assumed market sizes for PV systems with both long (>10 years) and short (<10 years) payback times. Some relationships show virtually no PV adoption for systems with payback times greater than 12 years, while others show some adoption for payback times greater than 20 years. One challenge in defining potential PV market share based on payback times is that these relationships are dynamic, and will change over time based on demonstrated technology improvements, general customer awareness and acceptance, and access to financing (in particular, new financing methods like PACE). While improving our understanding of the relationship between PV economic performance and customer adoption is the focus of ongoing research, we explore the sensitivity of model simulations to market adoption assumptions in section 3.

The rate at which durable goods attain market share, or diffuse into a potential market, has been actively researched for several decades. SolarDS characterizes the rate of customer adoption using Bass diffusion dynamics *(16)*, where diffusion is driven both by early adopters (using a coefficient of innovation), and by late adopters (using a coefficient of imitation). Diffusion models and coefficients are critically important for short-term simulations (<10 years), but not as important for longer-term simulations (~20 years or greater) where potential markets have been diffused into.

The final step in simulating the rooftop PV market is to calculate capacity additions from customer adoption characteristics. This is done using a residential and commercial building stock database, and statistically filtering this database to remove shaded roofs, obstructed roof space, and roofs that are unsuitable for PV adoption *(5,7)*. The remaining building stock is scaled by associated market adoption fractions, using a distribution of customer-

and building-dependent PV system sizes (residential systems have mean sizes of approximately 4-5kW, and commercial systems have means sizes of approximately 75-100 kW, depending on the deployment scenario). Using this methodology, the technical potential of the residential and commercial rooftop PV markets are approximately 300 GW each *(7)*.

3. RESULTS

To explore the evolution of residential and commercial rooftop PV markets in the U.S., and evaluate the sensitivity of these markets to a range of future PV cost reductions and policy-based incentives, we ran several SolarDS scenarios varying the input parameters listed in Table 2. We varied PV prices from an upper bound of the PV costs used by EIA in the AEO 2009 projections *(11)*, to a lower bound of PV costs from the DOE SETP targets. We use two customer adoption relationships, including the relationship used in National Energy Modeling System (NEMS) *(15)* to simulate AEO projections, and the relationship used in the Navigant Consulting, Inc. PV market penetration model *(5)*. We calculate penetration using the standard financing assumptions listed in Table 1, and explore the impact of PACE-style financing parameters following *(13)*. We also evaluate a range of policy-based options, including the impacts of pricing carbon emissions, adding full net metering, and extending the 30% federal ITC through 2030.

Table 2. Market drivers explored in SolarDS

|	Lower Penetration	Higher Penetration
PV Price	EIA prices used in the AEO 2009 projection	DOE Solar Energy Technology Program cost targets
Market Penetration Assumption	NEMS [EIA, 2004]	Navigant [Paidipati et al. 2008]
Financing Parameters	Standard loan terms for residential and commercial	PACE loan terms for residential Standard loan terms for commercial
Net Metering	No net metering; surplus electricity valued at reduced natural gas use	Full net metering; surplus electricity valued at retail electricity rates
Carbon Price	No carbon price	Carbon price set to $15/ton CO_2 in 2012, then increases linearly to $50/ton CO_2 by 2025. Stays fixed at $50/ton CO_2 through 2030.
Incentives	ITC through 2016	ITC through 2030

Varying these six input assumptions resulted in a wide range of modeled PV markets, with 20 to 280 GW of installed rooftop PV capacity by 2030. Figure 6 shows the evolution of the rooftop PV market for 10 scenarios, where

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the input parameters that improve PV economics were added sequentially. Lowering PV prices increases the rooftop PV market from approximately 20 to 80 GW by 2030. Allowing residential customers to use PACE-style financing increases the rooftop PV market by another 20 GW. Adding full net metering and pricing carbon emissions increases the market by another 60 to 100 GW. And extending the 30% federal ITC brings the cumulative market to 215 – 280 GW by 2030. Figure 6 shows rooftop PV projections calculated using both the customer adoption relationship from Navigant *(5)* (solid lines) and from NEMS *(15)* (dashed lines). While the different customer adoption relationships lead to significant differences in PV market projections on the order of 20%, they do not drive the modeled PV markets to the extent of other input variables like PV price projections.
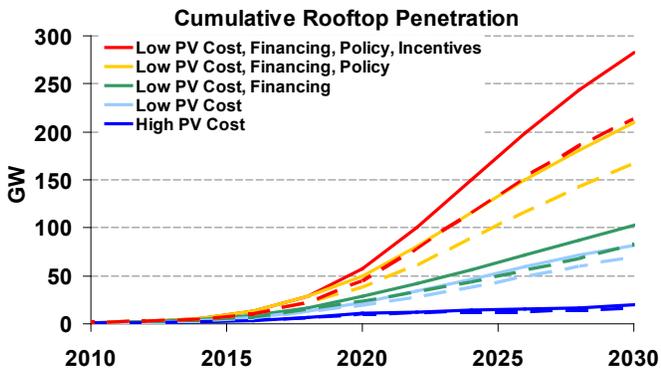

Figure 6. Evolution of the rooftop PV market for several scenarios where input parameters that increase PV economic performance are applied sequentially. The solid lines show PV projections calculated using the customer adoption relationships from Navigant *(5)*, and the dashed lines use customer adoption relationships from NEMS *(15)*.

Figure 7 shows the impact of varying each input assumption individually. Lowering PV cost has the largest impact on increasing PV penetration, followed by improving PV economics through policy options (adding full net metering, and pricing carbon emissions) and extending the federal ITC. Switching to PACE-style financing parameters affects only residential systems (as modeled here), and shows the least impact when applied individually. Several input assumptions show significantly less impact when applied individually (Figure 7) than when applied sequentially (Figure 6). For example, improving PV economics by assuming full net metering and by pricing carbon emissions increase total market size on the order of 10-20 GW when applied individually, but increase market size up to 100 GW when applied after PV cost reductions and PACE-style financing assumptions have already been applied. This is caused, in part, by the non-linear customer adoption relationships, as shown in Figure 5.
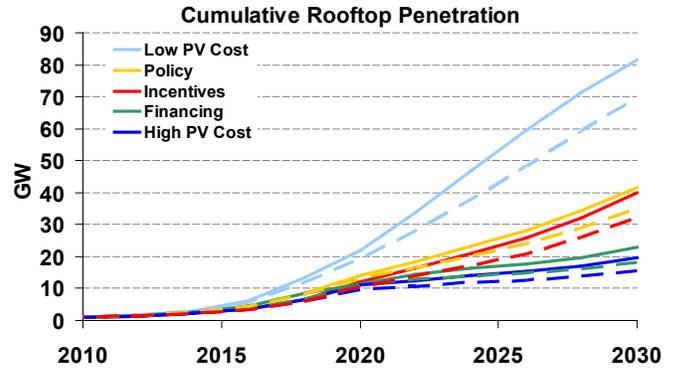
Figure 7. Evolution of the rooftop PV market for several scenarios where input parameters that increase PV economic performance are applied individually. The solid lines show PV projections calculated using the customer adoption relationships from Navigant *(5)*, and the dashed lines use customer adoption relationships from NEMS *(15)*.

Figure 8 explores the different sensitivities of the residential and commercial rooftop PV markets to varying input assumptions. These scenarios are calculated using the customer adoption relationships from Navigant *(5)*, and by sequentially applying input parameters that increase PV economic performance. Figure 8 shows that achieving PV cost reductions in line with DOE SETP targets is sufficient to induce very robust growth in the commercial rooftop PV market, but significantly less rapid growth in the residential market. Additional market or policy based 'levers' would be required to stimulate the residential market to reach similar levels of penetration as the commercial market. Improving residential financing options using a PACE-style model, increases the modeled residential (and total) market by approximately 20GW by 2030. Additional policy based incentives, including full net metering, pricing carbon emissions, and extending the federal ITC through 2030 lead to substantially larger increases in the residential than the commercial market.

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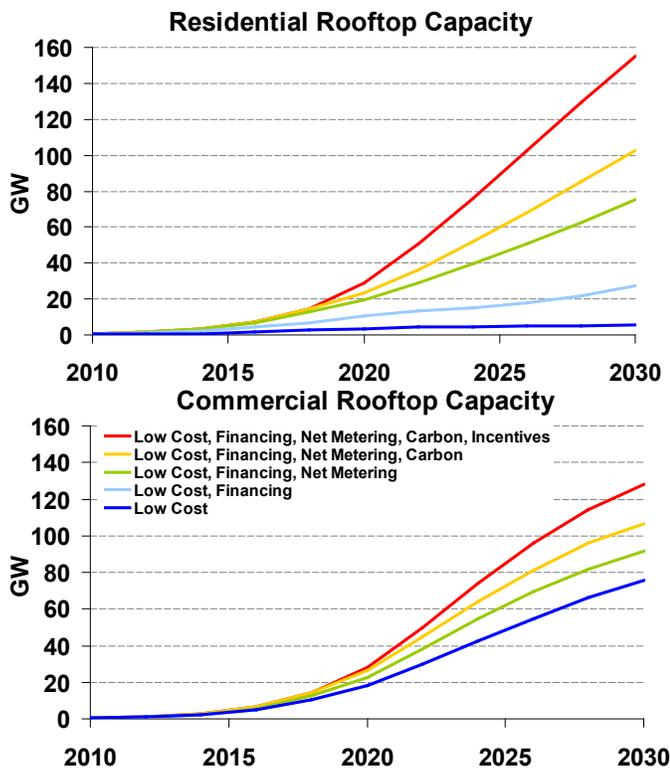
Figure 8. Cumulative installed rooftop PV capacity for a range of scenarios, calculated using DOE SETP PV costs, and sequentially applying input parameters that improve PV economic performance.

The commercial PV market (as modeled) requires fewer incentives to show vigorous growth, primarily because of four factors: (1) larger commercial PV systems cost less per kW than smaller residential systems; (2) commercial customers are eligible for a 10% federal ITC after the 30% ITC expires in 2016; (3) commercial customers can depreciate their PV investment using a 6-year capital recovery schedule (following the Modified Accelerated Cost Recovery System – or MACRS); and (4) the use of an IRR-based payback metric leads to shorter payback times than the time-to-net-positive cash flow metric under several scenarios[2]. These factors combine, allowing commercial markets to grow strongly if PV cost reductions achieve DOE SETP targets, while residential markets require additional cost reductions and/or incentives to reach similar levels of penetration. However, since the technical potential of commercial and residential markets are similar (approximately 300 GW each *(7)*), the commercial market begins to saturate more quickly, making the commercial market less sensitive to adding several incentives in tandem.

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[2] This is primarily caused by the assumption in calculating IRRs that capital can be reinvested at a rate of return equal to the system IRR. Revenue from the federal ITC and accelerated depreciation is implicitly assumed to be reinvested at very high rates for systems with high IRRs.

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Global rooftop PV markets are growing rapidly, fueled by a combination of declining PV prices and several policy-based incentives. The future growth, and size, of the rooftop market is highly dependent on continued PV cost reductions, financing options, net metering policy, carbon prices and future incentives. Several PV market penetration models, sharing a similar structure and methodology, have been developed over the last decade to quantify the impacts of these factors on market growth. This study uses a geospatially rich, bottom-up, PV market penetration model--the Solar Deployment Systems (SolarDS) model developed by the National Renewable Energy Laboratory-- to explore key market and policy-based drivers for residential and commercial rooftop PV markets. The identified drivers include a range of options from traditional incentives, to attractive customer financing options, to net metering and carbon policy.

15. SUBJECT TERMS
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