NATIONAL RENEWABLE ENERGY LABORATORY

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Implications of Scheduled ITC Reversion for RPS Compliance: Preliminary Results

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INTRODUCTION

This poster displays DRAFT initial results of a forthcoming NREL analysis. This analysis investigates whether the scheduled investment tax credit (ITC) reversion from 30% to 10% for businesses beginning in 2017 could result in an increase the use of alternative compliance payments (ACPs) in lieu of solar renewable energy credits (SRECs) for renewable portfolio standard (RPS) compliance. The analysis models the effect of a 10% ITC on power purchase agreement (PPA) prices for non-residential systems in the eight states with solar carve-outs and solar ACPs (see Figure 1).

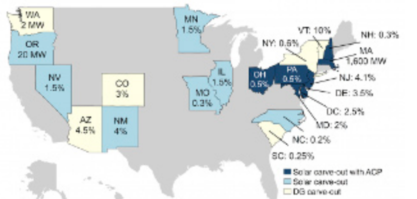

Figure 1. State solar and distributed generation (DG) carve-out programs.

Source: Based on data from Database of State Incentives for Renewables and Efficiency (DSIRE 2015)

The objectives of this analysis are two-fold: 1) to investigate future trends in carve-out compliance based on market forecasts of installed capacity (GTM, 2015) and required RPS demand (BNEF, 2015); 2) to account for the effects of a 10% ITC on PPA rates in the eight states with solar carve-outs and solar ACPs.

METHODS

PPA rates were modeled for a 1 megawatt (MW) commercial-scale project in NREL's System Advisor Model (SAM) using inputs sourced from interviews, published studies, and NREL internal data. Modeled PPA prices were compared to state-level commercial retail electricity rates as published by the Energy Information Administration (EIA)* and escalated over the 20-year PPA period by the compound annual growth rate (CAGR) in national commercial retail electricity rates as projected by EIA (0.79%) in its Annual Energy Outlook (AEO) 2015 Reference Case.

To model the effect of SREC pricing on current PPA prices, we obtained historical spot prices from a proprietary trading platform and discounted the most recent spot price by 10% for a three-year payment stream. We assumed an SREC price equal to 20% of the state's solar ACP for years four through ten. After year ten, we assumed an SREC price of $0. This methodology was based on interviews with SREC trading professionals.

The analysis is limited by access to current and forecasted SREC market data, as well as state-specific commercial solar market costs and trends. We did not model deployment of commercial-scale solar, but rather examined projected scenarios for solar PPA prices compared to commercial retail electricity rates.

OBSERVATIONS

Based on forecasts from Greentech Media Research and Bloomberg New Energy Finance, most states with carve-outs and ACPs are projected to install sufficient capacity to meet long-term solar carve-out targets, even after the ITC reversion in 2017. However, our PPA analysis suggests that some states with relatively low commercial electricity rates and SREC prices will see further stress on solar project economics in a 10% ITC environment. If SREC prices in excess of the ACP are required to support project economics in a given state, then development could contract. According to a PPA sensitivity analysis performed in SAM, such conditions may lead to heightened use of solar ACPs in MD, OH, and PA (Figure 2).

The ITC reversion is not the only factor which could influence carve-out compliance. Other considerations such as carve-out size, net metering, and rate redesign can all significantly impact the economic viability of solar energy in a given state. The interplay of these factors will be critical in determining which states will remain supportive of distributed solar deployment.

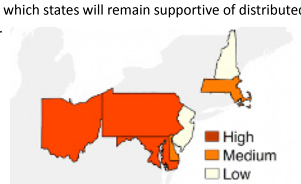

Figure 2. State potential to use solar ACPs to meet solar carve-out compliance

*EIA state electricity rates include demand charges and other charges that solar energy does not fully offset. EIA rates were chosen as a high-level indicator of solar competitiveness in a given state, as a detailed construction of volumetric charges for individual utilities was beyond the scope of this analysis. The margins between modeled PPA rates and the EIA electricity rates illustrated in Figures 5 and 6 partly account for the effects of the gap between volumetric and capacity-based charges implied in the aggregated EIA rates.

PROJECTING CARVE-OUT COMPLIANCE

Solar carve-outs for states with ACPs require about 3,700 MW of new capacity by 2030 (as of January 1, 2015) to provide sufficient capacity for long-term compliance in the eight states we examine (Figure 3). Our projections of required capacity represent the minimum new capacity required for compliance entities to meet carve-out targets through in-state SRECs. The actual amount required will vary as some states allow the use of out-of-state SRECs and not all SRECs generated will be available for compliance purposes.

We projected two scenarios based on market forecasts: a base case assuming a 57% reduction (GTM, 2015) in annual installed capacity post-ITC reversion, and a low projection assuming the annual install rate would be half of market forecasts beyond the 57% reduction post-ITC reversion. Most of these states are projected to install sufficient capacity to meet long-term targets (Figure 4). The scheduled ITC reversion could affect carve-out compliance in several states. Carve-outs require more than a threefold increase in installed capacity in DC, DE, MD, and OH. The ITC reversion could also affect compliance in Massachusetts where the carve-out explicitly requires new installed capacity.

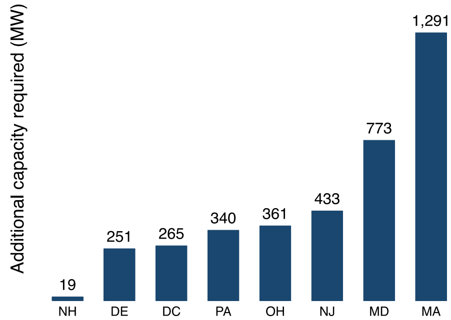

Figure 3. Additional capacity required to meet peak carve-out target by state.

Source: Based on data from a BNEF 2015 analysis

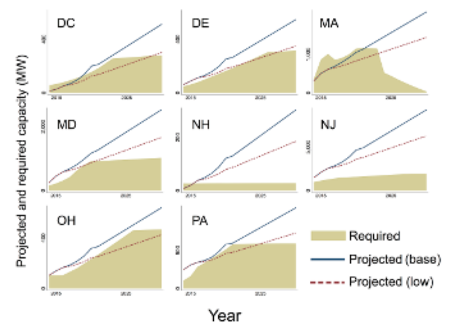

Figure 4. Projections of installed capacity (cumulative MW) plotted with capacity required to meet solar carve-out targets. Scales are not constant.

Source: Based on data from a BNEF 2015 and a GTM 2015 analysis

THE EFFECTS OF AN ITC REVERSION ON RPS COMPLIANCE

In assessing initial results, we assume that for solar to remain economic in a given market in 2017, year-one PPAs will need to be executed at a ≥10% discount to the local commercial electricity rate. This will allow for the PPA price to escalate by up to 1.3% for 20 years and still remain below the prevailing electricity rate (given a 20-year CAGR in commercial electricity rates of 0.79%). We also use the following assumptions in SAM:

System Size	1 MW
Offtaker	Commercial entity
Installed Cost	$2.30/W - $2.50/W
Cost of Capital (IRR)	8%
Developer Margin	$0.40/W

We identified three areas of project cost reduction that could potentially keep PPA prices competitive with commercial electricity rates in a 10% ITC environment: installed cost (reductions in module prices and balance of system costs, as well as developer efficiencies, and other factors); cost of capital (a 1% reduction through continued investor comfort with the solar asset class, among other factors); and developer margin. ** For states where even aggressive reductions in these cost components could not yield a competitive PPA price, we estimated the SREC price necessary to achieve a 10% discount off of the 2015 electricity rate.

Figures 5 and 6 present the results of the analysis for two illustrative states: New Jersey and Maryland. In New Jersey, a 10% ITC results in a year-one PPA price below the prevailing electricity rate, though only at a 3% discount. With the above-mentioned reductions in installed cost and cost of capital , solar developers in New Jersey may remain competitive with utility electricity even without reducing their margins.

In Maryland, however, lower commercial electricity and SREC prices drive tighter economics, even with a 30% ITC. With the 10% ITC, PPA prices appear roughly $0.02 above the commercial electricity rate. The above reductions in installed cost and cost of capital yield a year-one PPA price just 3% below the prevailing electricity rate with a 10% ITC in 2017. This discount is notably less than the 10% discount margin assumed in this analysis as a minimum threshold for project viability. To reach a 10% discount to commercial electricity rates, an SREC price of $210 per megawatt-hour (MWh) was required (assuming a three year contract), which exceeds the 2017 solar ACP in Maryland (set at $200/MWh). With such a ceiling on incentive levels, and a relatively low commercial electricity rate, it is possible that compliance entities in Maryland may make more ACP payments in a post-ITC market, which could result in reduced solar deployment in the state.

**These reductions were applied uniformly across all states, regardless of market context. Reductions were based on numbers compiled from several published sources, NREL interviews, nd NREL internal data.

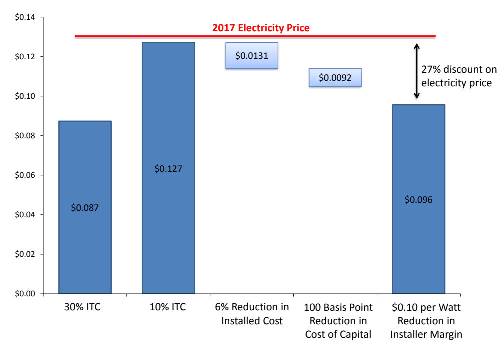

Figure 5. Modeled PPA prices for New Jersey

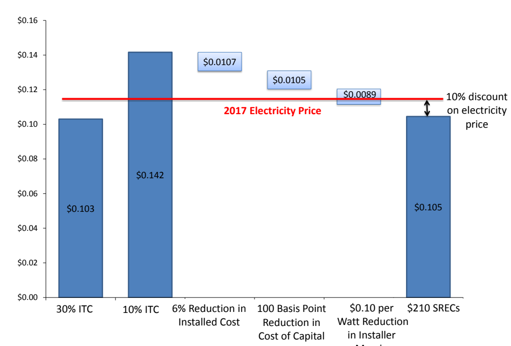

Figure 6. Modeled PPA prices for Maryland

This poster displays draft research from a forthcoming NREL analysis report.

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