# SOLAR GENERATION MARKET RESEARCH

## Task 1: Solar Market Assessment and Cost Projections

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**PREPARED FOR**

Portland General Electric

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# 1.0 Executive Summary

Portland General Electric (PGE) has a strong history of supporting many forms of distributed and renewable resources, including roof-top and utility-scale solar photovoltaic (PV) generation. While the utility already has some solar on its system, PGE's 2013 Integrated Resource Plan's (IRP) Action Plan included additional investigations for PGE to further explore solar in Oregon. In particular, the IRP called for a market assessment using technical, financial, and achievable screens of potential distributed solar generation within PGE's service area and utility-scale solar within the state of Oregon. Throughout this report, "potential" represents an upper-bound based on underlying assumptions. PGE retained Black & Veatch to complete these potential assessments and also to prepare cost forecasts for solar PV.

Multiple scenarios were tested, and the estimated potential in terms of installed capacity under technical, financial, and achievable screens are summarized in the table below. As is common in the solar industry, distributed solar systems are reported according to their direct current (dc) capacity rating, while utility-scale systems are reported based on their alternating current (ac) ratings.

**Table 1-1 Summary of Solar Potential Assessment**

| POTENTIAL | TECHNICAL SCREEN | FINANCIAL SCREEN BY 2035 | ACHIEVABLE SCREEN BY 2035 |
|---|---|---|---|
| Distributed (MWdc) | 2,810 | 1,410 | 125 to 223 |
| Utility-Scale (MWac) | 56,000 | 7,500 to 17,500 | 100 to 369 |
| MWdc = megawatts direct current<br>MWac = megawatts alternating current | | | |

This report outlines Black & Veatch's cost estimates for solar PV systems, assessment of distributed solar potential, and assessment of utility-scale solar potential. Key findings are described in this executive summary.

## 1.1 SOLAR PV COST ESTIMATES

Black & Veatch developed cost estimates for representative distributed and utility-scale solar PV systems for 2015 and forecasted those costs on an annual basis through 2035. The main body of the report includes an overview of solar technologies, a discussion of Black & Veatch's cost estimating approach, cost estimates for distributed systems, and cost estimates for utility-scale systems.

Since 1998, rooftop PV system prices throughout the United States have fallen on average between 6 and 8 percent per year. The once seemingly aggressive goals of the US Department of Energy's (DOE's) SunShot Initiative now appear within reach because of (1) the rapid and prolonged decline in the prices of PV modules and other system components and (2) the potential to reduce labor and other "soft costs" as demonstrated by best practices in more mature PV markets.

Black & Veatch developed forecasts of installed PV costs for every year through 2035. One of the major assumptions of the forecast is that installed PV prices will meet the DOE's SunShot Initiative targets in 2025, resulting in a large decline from today's costs. Table 1-1 summarizes Black & Veatch's 2015 and 2035 cost estimates for distributed and utility-scale PV systems. Figure 1-1 shows the cost trend through 2035. By the end of the period, Black & Veatch forecasts costs to drop for all system types to between $0.9 and $1.3 per watt direct current (Wdc) (2014$). Residential system costs are projected to drop by approximately 65 percent, commercial system costs by approximately 55 percent, and utility-scale systems by approximately 45 percent. It is important to note that this figure is shown in 2014 dollars, and inflation will increase these costs in nominal dollar terms. In nominal terms, costs plateau around 2025, with small continued improvements in costs offset by inflationary increases.

More details on the cost estimating approach, background, and a breakdown into major system components is provided in the main body of this report. A table of the annual projection of costs is provided in Appendix A.

**Table 1-2 Summary of Distributed and Utility-Scale Solar PV Cost Estimates for 2015 and 2035 Installation (2014$)**

| SYSTEM CHARACTERISTICS | | TOTAL INSTALLED COST ($/$W_{DC}$), 2014$ | |
|---|---|---|---|
| APPLICATION | SIZE ($kW_{DC}$) | 2015 | 2035 |
| ***Distributed*** | | | |
| Residential rooftop | 4 | $3.74 | $1.31 |
| Commercial/industrial rooftop | 50 | $2.62 | $1.18 |
| Commercial/industrial rooftop | 250 | $2.50 | $1.17 |
| ***Utility-Scale*** | | | |
| Fixed-tilt, ground-mount | 7,000 | $1.96 | $1.06 |
| Fixed-tilt, ground-mount | 28,000 | $1.77 | $0.96 |
| Fixed-tilt, ground-mount | 140,000 | $1.71 | $0.92 |
| kWdc = kilowatt direct current | | | |

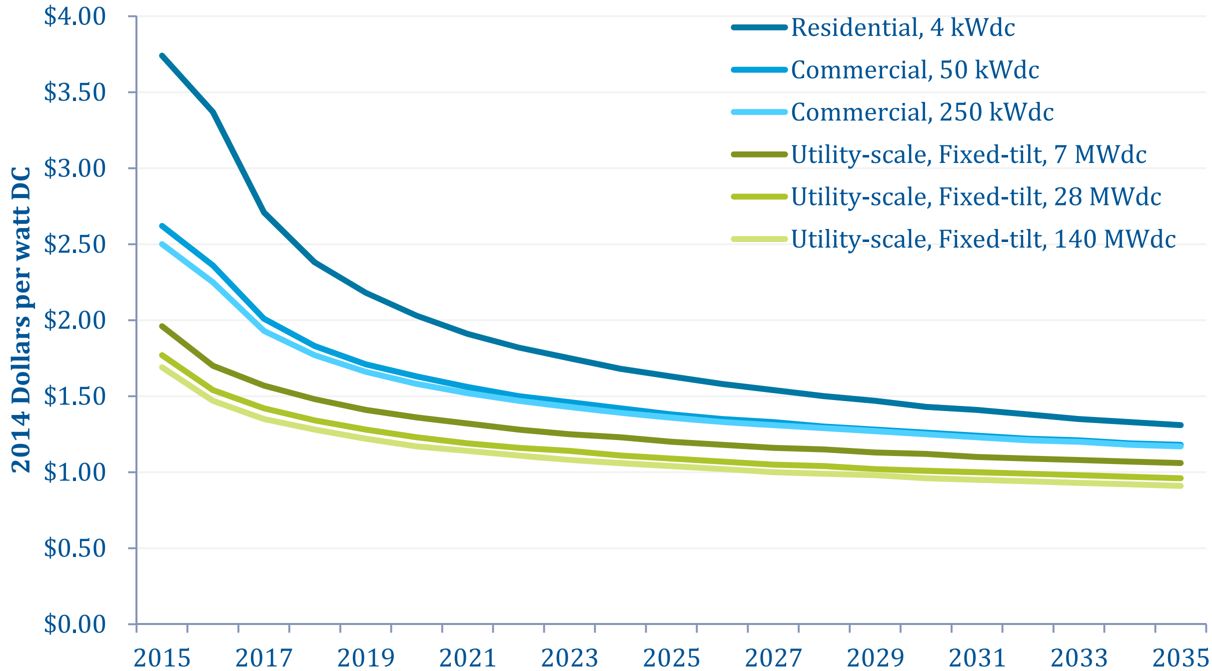
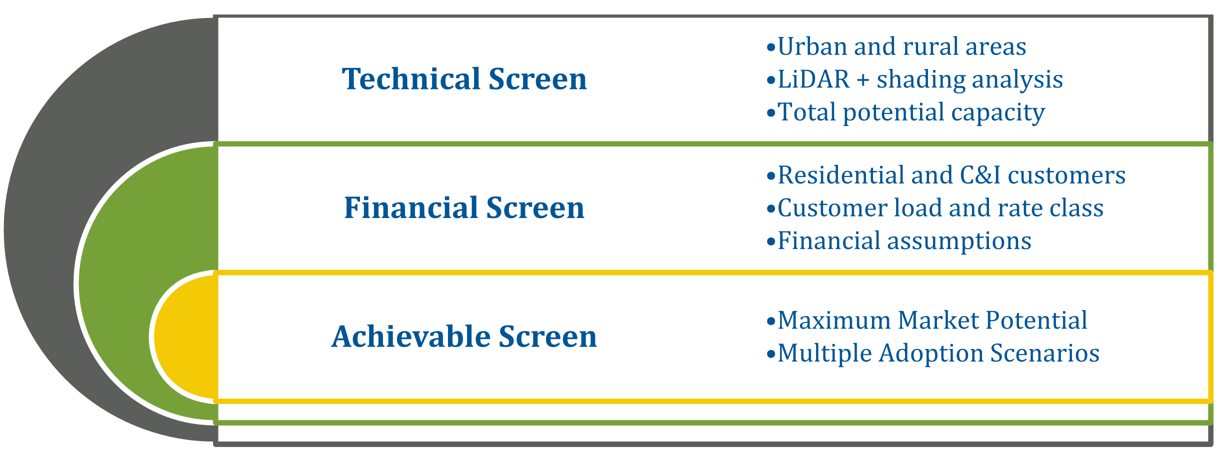



**Figure 1-1 Solar Cost Projections (2014$/Wdc)**

## 1.2 DISTRIBUTED SOLAR POTENTIAL ASSESSMENT

The distributed solar assessment focused on identifying the potential for solar installed on customer rooftops within PGE's service territory in northwest Oregon. Black & Veatch implemented an innovative approach to assess the technical potential using Light Detection and Ranging (LiDAR) data to evaluate the available area of individual buildings across PGE's service territory, studied the financials of each of these systems, and considered market penetration and other factors in determining the amount of distributed solar PV that could practically be achieved.

The approach used to quantify the technical, financial, and achievable potential for distributed systems is summarized as follows; additional details are provided in the main body of the report.



The technical screen used LiDAR data to provide detailed evaluation of 1.2 billion square feet of rooftop space representing over 400,000 buildings. A summary of the technical screen results by property type is provided in Table 1-3. The total technical potential of the areas assessed using LiDAR data was 1,800 MWdc. The technical screen estimate was scaled up for portions of the PGE territory where LiDAR data were not able to be used. After scaling up to cover the entire PGE service territory, the total technical potential amounted to 2,810 MWdc. About 30 percent of this amount is residential (single-family and multi-family), while the rest comprises commercial, industrial, and public/semi-public properties.

**Table 1-3 Identified Distributed Solar PV Technical Potential**

| PARAMETER | LIDAR-ASSESSED AREA TOTAL CAPACITY (MWDC) | PGE SERVICE TERRITORY TOTAL CAPACITY (MWDC) |
|---|---|---|
| Single Family Residential | 451 | 631 |
| Multi-Family Residential | 125 | 167 |
| Commercial | 586 | 874 |
| Industrial | 575 | 869 |
| Public/Semi-Public | 62 | 270 |
| **Total** | **1,800** | **2,810** |

For the financial screen, site-specific characteristics were developed to calculate the expected payback of individual buildings, accounting for solar generation profile, project size, and customer type. A detailed financial analysis was performed for hundreds of thousands of sites for four financial cases (Table 1-4). For the 2016 cases, this case included all incentives that are available to solar by customer type including federal investment tax credit (ITC of 30%) and accelerated depreciation, Oregon state tax credit for residential customers, and ETO funding. The 2016 case used the forecasted installed cost in 2016. The 2035 cases assumed no incentives would be available except for accelerated depreciation and included the 2035 forecasted installed cost. These two cost years were tested under utility rate increase conditions of Consumer Price Index (CPI) and CPI+1. Commercial and residential customers were calculated separately given different financial treatment and incentives in the years 2016 and 2035, under two rate increase scenarios (CPI and CPI+1 percent). .

**Table 1-4 Financial Cases for Solar Distributed Generation**

| CASES | CPI | CPI+1 |
|---|---|---|
| 2016 | All incentives are available. 2016 cost assumptions. Utility rate escalates at CPI. | All incentives are available. 2016 cost assumptions. Utility rate escalates at CPI+1 percent. |
| 2035 | No incentives are available, except accelerated depreciation. 2035 cost assumptions. Utility rate escalates at CPI | No incentives are available, except accelerated depreciation, 2035 cost assumptions. Utility rate escalates at CPI+1 percent |

In addition to the financial analysis, multiple factors were considered in the screening. Projects were resized to match designated load profiles, so systems would not over-generate under the net metering tariff. Multi-family dwellings were excluded because there are challenges in installing systems for shared usage. Furthermore, since installing solar PV on rooftops is a long-term commitment that both residential and commercial renters are unlikely to pursue, ownership factors were applied as an additional screen to represent the portion of the property type that were owner-occupied. The resulting potential is estimated to be 1,410 MWdc. This figure comprises 415 MWdc of residential capacity and 995 MWdc of commercial capacity (commercial plus industrial and public/semi-public).

Incentives have long been an important part of the financials of PV, and Oregon has had some of the highest incentives for solar PV in the country. For example, the combined federal, state, and Energy Trust of Oregon (ETO) incentives can reduce the installed cost of PV in Oregon by approximately 55 to 75 percent. This reduction strongly influences the payback of systems in 2016. It was assumed that by 2035 no incentives (tax credits or state incentives) would be available, since the market should be mature and self-sustaining by that time. While Black & Veatch forecasts sharp declines in solar PV cost of 55 to 65 percent for distributed PV systems by 2035, these reductions are not enough to counteract the loss of incentives in many cases. Thus, the net cost after incentives to customers in real terms is actually lower in 2016 than it would be in 2035 for most cases. This effect had a major impact on the payback periods that were calculated for the financial screen.

Black & Veatch calculated customer payback for hundreds of thousands of customer systems over multiple scenarios. The distributions of payback periods are differentiated by residential and commercial customers for each of the financial cases tested.

Figure 1-2 is a sample comparing commercial payback distribution in 2016 and 2035 for the CPI+1 rate scenario. This chart represents the total MW of rooftop solar potential by increment of payback period (0.1 years). For both residential and commercial customers under both CPI and CPI + 1 scenarios, the distribution of payback periods are higher in 2035 than in 2016, as demonstrated in Figure 1-2. The results show that while the cost of solar is assumed to decline significantly by 2035, the modest rise in utility rates in both cases is not sufficient to offset the lack of incentives. Therefore, the payback periods increase significantly in 2035. Payback distribution charts for additional cases are available in the main body of the report.

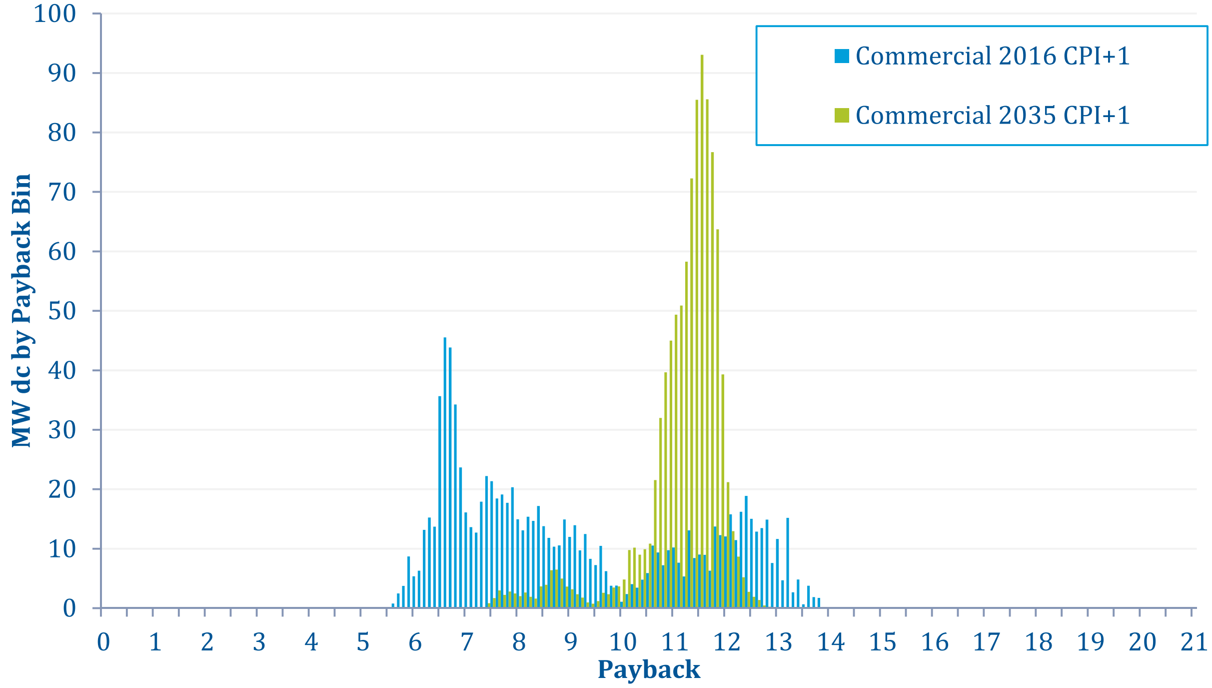



**Figure 1-2 Commercial Systems Payback Period (CPI+1)**

However, while the financial calculations show paybacks of less than 20 years for all systems, this does not necessarily translate to adoption by customers. There are numerous factors that influence a customer's decision to adopt a technology beyond financial viability.

In order to determine achievable potential within the study period, Black & Veatch used survey-based data to translate the payback distributions of customer systems to maximum market potential and then forecasted the adoption of solar over the study period. . Using the results of surveys of residential and commercial customers' preferences for adopting solar and distributed generation, NREL (residential) and Navigant (commercial) developed maximum market penetration curves that indicate the likelihood of market penetration given a certain amount of payback for that customer class. The survey data specifies what portion of a group of customers, given a certain payback outlook, would actually adopt the technology--the shorter the payback period, the more likelihood of adoption. The portion that would adopt makes up the maximum market potential. The maximum market potential was calculated for each customer class using the payback distributions for the 2016 and 2035 cases under the two rate increase assumptions (CPI and CPI+1). Therefore, four different maximum market potentials were calculated.

The resulting cumulative maximum market potential for each of the cases tested is shown in Table 1-5. These totals include already installed systems in PGE territory. Current and estimated 2015 commercial and residential rooftop installations total 47.9 MW.

**Table 1-5 Summary of Maximum Market Potential for DG Solar (MWdc)**

| | CPI | | CPI+1 | |
|---|---|---|---|---|
| | **2016** | **2035** | **2016** | **2035** |
| Residential | 180 | 102 | 192 | 145 |
| Commercial | 70 | 14 | 81 | 37 |
| **Total** | **250** | **116** | **273** | **182** |
| **Remaining Potential (Less Current and 2015 Installations)** | **202** | **68** | **225** | **134** |

Taking the remaining potential, Black & Veatch then developed estimates of annual adoption based on a range of market adoption scenarios. Forecasts were developed on an annual basis from the year 2016 through 2035. Black & Veatch took two approaches to capture the range of potential adoption of solar over time: bottom-up (technology adoption limited) and top-down (ETO funding constrained).

1. **Technology Adoption Limited:** The first approach is a bottom-up approach using the previously discussed payback analysis and survey data to determine maximum achievable market potential and applying a technology adoption curve to simulate annual adoption going forward. In these scenarios, since the payback distribution is higher in 2035 than in 2016, the maximum achievable market actually declines.

2. **ETO Funding Constrained:** For the top-down approach, Black & Veatch opted to test alternative scenarios where the payback, thus the maximum market potential,over time, is maintained at the same level as in 2016. This is done through adjusting ETO incentive levels ($/W) on an annual basis under various tax incentive and rate increase conditions.

For the technology adoption limited approach, cumulative adoption flattens out around 2028 as the customers who would adopt have already adopted solar, and the financials of solar limit further growth of the market. The maximum adoption of solar over the study period is 164 MWdc in the CPI+1 scenario.

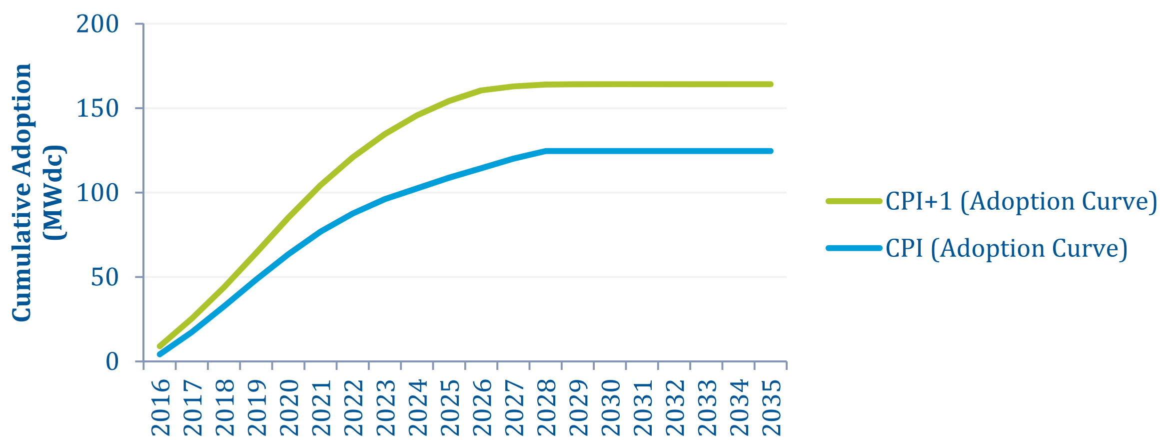


**Figure 1-3 Technology Adoption Limited Cumulative DG Adoption**

The technology adoption limited approach is a bottom-up analysis based on market adoption concepts. Another approach, which is a top-down approach, is to assume that ETO funding influences market adoption. The ETO, funded through system benefits charges (SBC), currently provides incentives to most projects installed in Oregon. ETO's budget is set on an annual basis and greatly impacts the net cost to customers and, thus, the adoption of solar in Oregon. Several funding scenarios were evaluated with and without additional federal and state tax credits. The assumed objective for these scenarios is that the ETO would provide enough incentives ($/W) to maintain similar payback levels as those modeled for the 2016 case for residential and commercial customers. The one limitation is that the absolute annual ETO funding is capped, which limits the MW of projects that the annual budget can support. The resulting cumulative adoption over time is shown on Figure 1-4, with maximum adoption of 224 MWdc in the CPI+1 (tax credits) scenario. Note adoption is slower and less when there are no tax credits available because higher ETO incentives ($/W) are needed to offset upfront costs, which means less MW can be funded, given a fixed annual ETO funding cap tied to SBC.

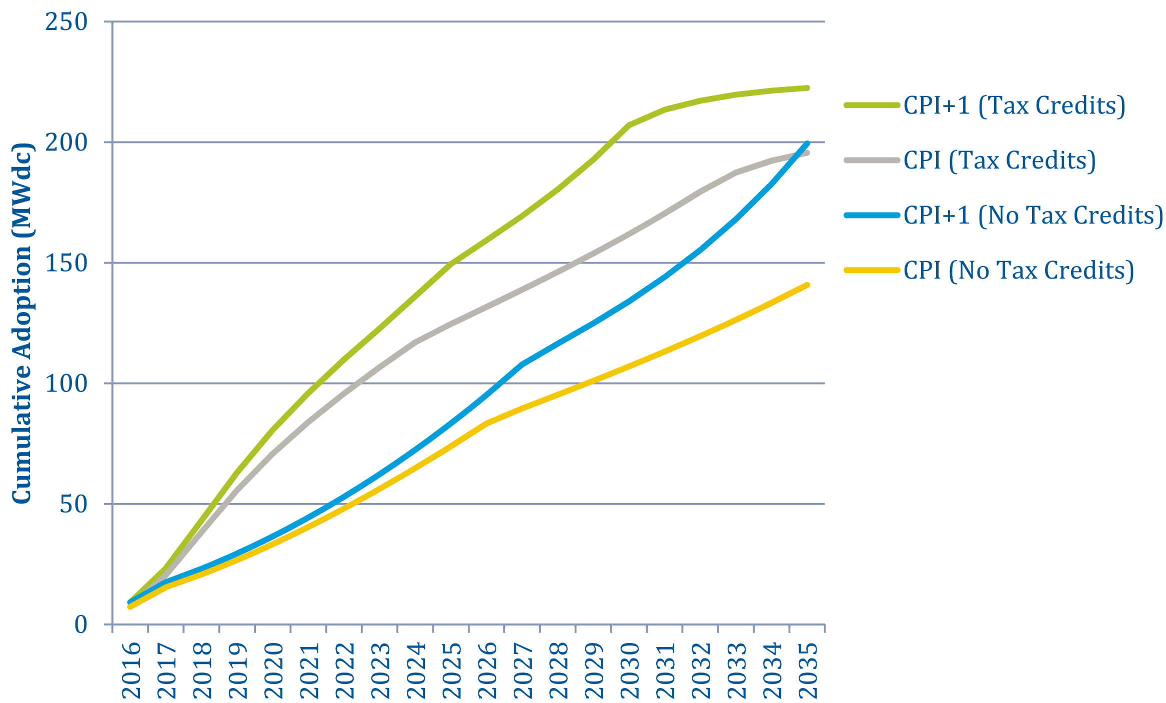



**Figure 1-4 ETO Funding Constrained Solar DG Cumulative Adoption (2016-2035)**

## 1.3 UTILITY-SCALE SOLAR POTENTIAL ASSESSMENT

The utility-scale solar potential assessment focused on areas across Oregon for projects ranging from 5 to 250 MWac. Black & Veatch first identified potential sites by excluding land areas based on certain environmental considerations, proximity to existing transmission, technical limitations, and other parameters. Next, a financial screen was applied to these sites by comparing each site's levelized cost of energy (LCOE) to PGE's long-term qualified facility (QF) rates, without considering transmission capacity availability. To arrive at an achievable potential, an additional screen was applied to these sites, assuming firm transmission availability constraints on existing transmission lines would limit delivery to PGE's service territory and size of projects that can interconnect. This assumes no new transmission is built in Oregon.

The technical screen found a total of over 56 GWac of solar potential in Oregon after limiting the maximum size of systems that can interconnect to transmission lines for each transmission voltage level.

For the financial screening, Black & Veatch calculated the levelized cost of energy (LCOE) for each project site for the years 2016 to 2035 with and without the federal investment tax credit (ITC) of 10 percent. Project costs include total installed cost for the respective year being analyzed, generation tie to the transmission system, substation costs to upgrade an existing substation or build a project-specific substation, ongoing operation and maintenance (O&M) including property taxes, and transmission tariffs/wheeling costs and losses to deliver energy to PGE's service territory. Supply curves based on LCOE were created for each year. Figure 1-5 and Figure 1-6 show sample supply curves for the years 2016, 2017, 2025, and 2035. It is important to note that the financial screen does not consider available firm transmission capacity for delivery to PGE's service territory.

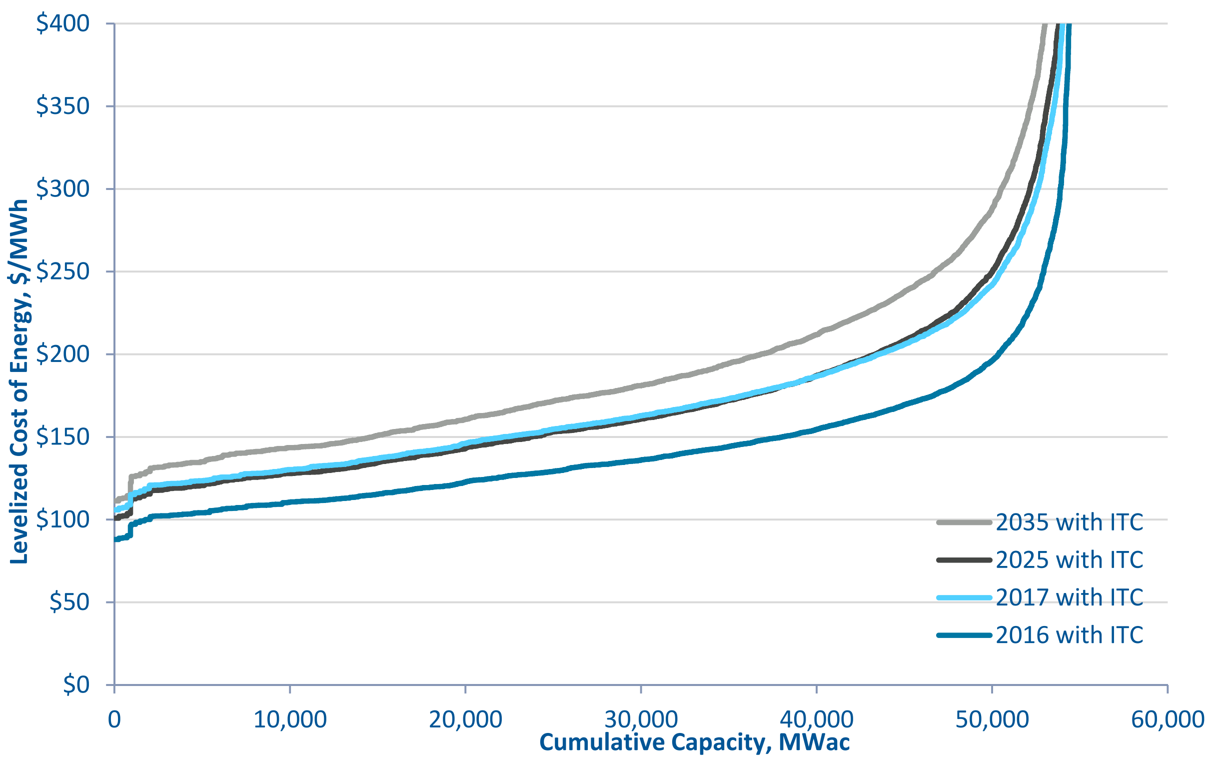



**Figure 1-5 Utility Solar Supply Curve With ITC (10% after 2016)**

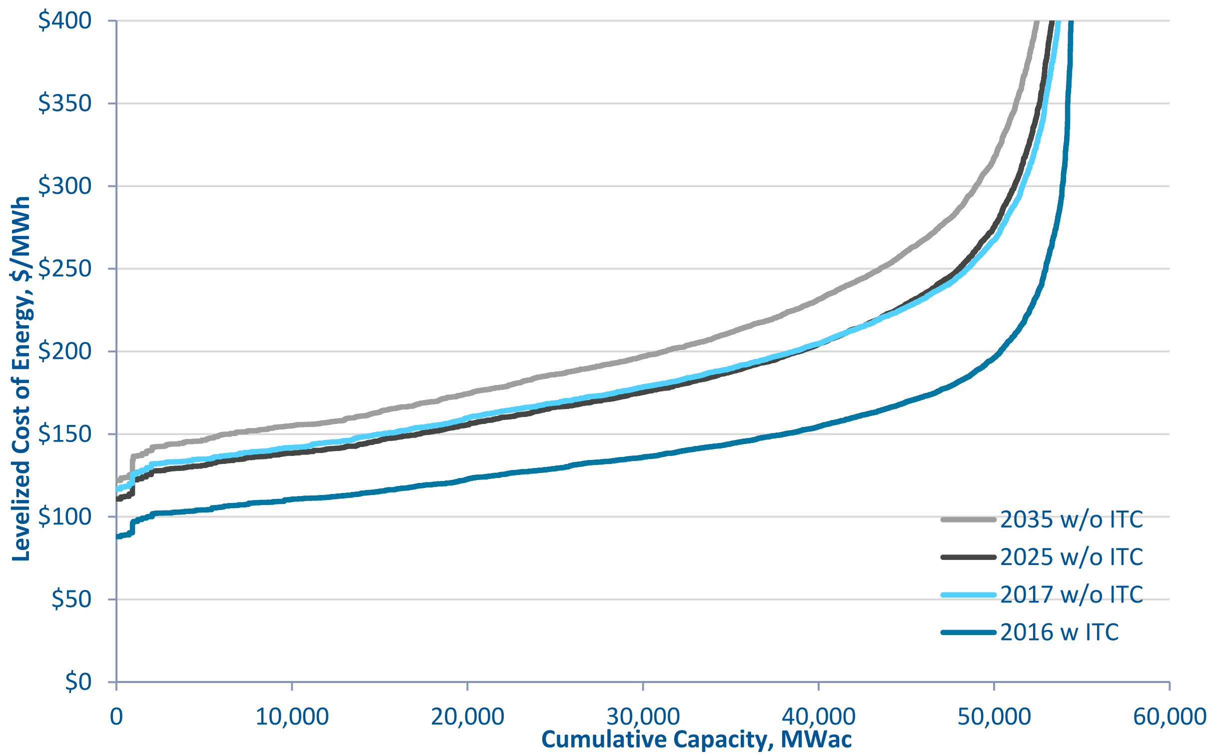



**Figure 1-6 Utility Solar Supply Curve Without ITC**

The LCOE supply curves were compared to the long-term levelized price for variable solar under PGE's long-term QF rates. The amount of capacity with LCOE lower than levelized QF rates increases over time as solar PV costs are forecasted to decline, along with increasing levelized cost of QF prices. The resulting potential by year with this financial screen is shown on Figure 1-7. By 2035, 7.5 gigawatts (GW) (no ITC) and 15.5 GW (ITC) of potential are considered financially viable. There is significantly less potential if no ITC is available.

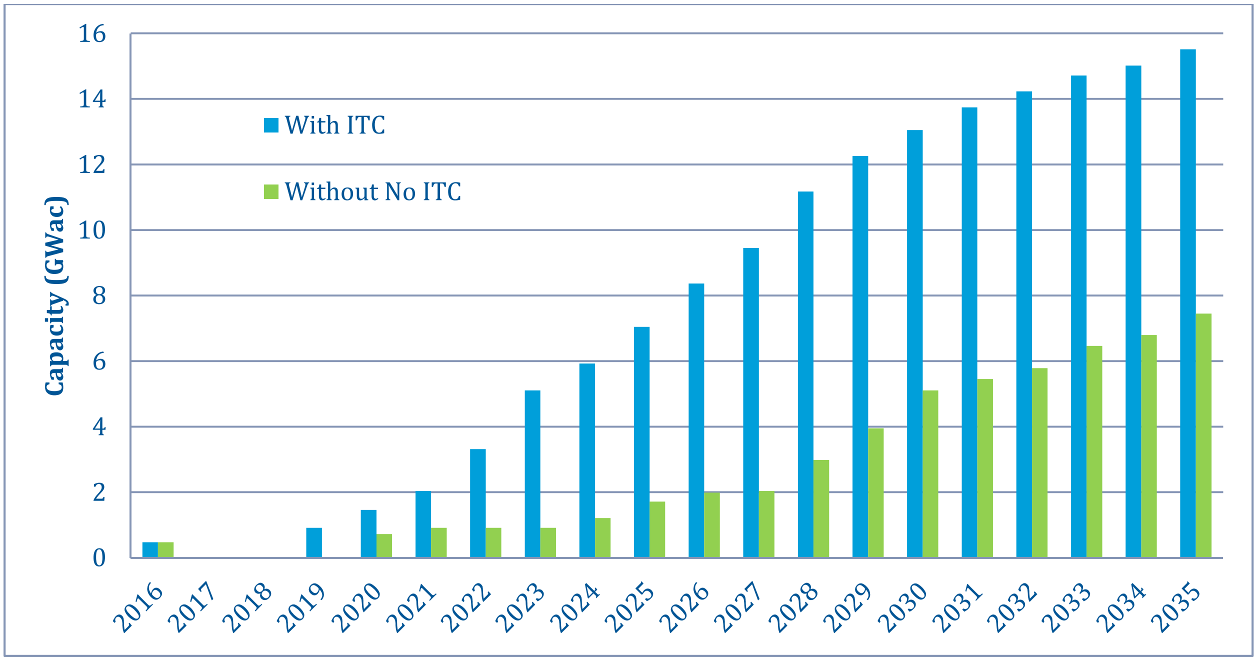



**Figure 1-7** **Annual Maximum Potential with Financial Screen (No Transmission Constraints) for Utility-Scale Solar PV**

The financial screen did not consider transmission constraints to deliver the power to PGE's service territory. To estimate achievable potential for utility-scale solar, Black & Veatch assumed that the primary constraint is transmission availability. While transmission could be upgraded to deliver solar PV, such upgrades would be relatively expensive given the low utilization rate of solar. With input from PGE, several transmission zones were established for areas where PGE's staff estimated firm transmission capacity that may be available for delivery to PGE's service territory. Projects were also resized in order to meet these constraints, which impacted the cost of the PV systems. Sites were then identified that were less than the levelized QF price for each year. The cumulative solar penetration, with and without ITC, is shown on Figure 1-8. When the ITC is not available, no projects are financially viable until 2035, the last year in the study period, when 100 MWac of PV becomes financially viable. For the With ITC case, 369 MWac of total capacity are installed by the end of the study period.

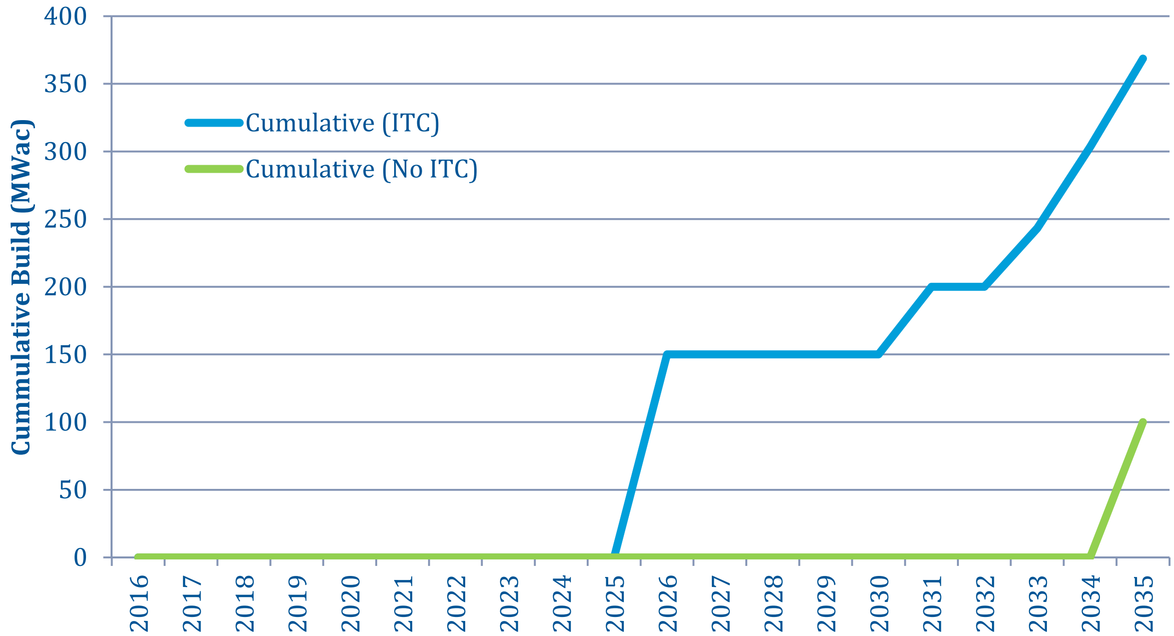



**Figure 1-8 Cumulative Utility-Scale Solar Achievable Potential**

## 1.4 SUMMARY CONCLUSIONS

The technical potential for distributed solar is significant in PGE's service territory, but continued incentives or alternative financing, such as leasing, will be needed to sustain higher levels of adoption. The study findings indicate that, given forecasted capital costs, the market potential by 2035 will continue to require incentives or alternative financing, at some level to support growth of the market. Otherwise, without additional incentives or alternative financing, the maximum market potential is constrained, meaning there is a limited pool of customers who would choose to adopt solar PV despite solar being financially viable.

Thus, additional incentives that can drive the net cost to customers down further or alternative financing mechanisms, such as third-party leasing, may help expand the market potential and should be studied further. Black & Veatch acknowledges that third-party leasing of systems, where customers do not have to pay an upfront cost, are becoming more prevalent in PGE's service territory. However, given the observed pricing behavior of third-party participants, such as Solar City, resulting in negative earnings, it was not possible to model third party ownership (TPO) financials in a reasonable manner. Furthermore, it was not possible to rely on historical data, as the historical annual dc capacity installed for both residential and commercial customers have not really increased in the past few years, despite increasing TPO participation. This is primarily due to external market constraints including ETO funding and the Solar Payment Option (SPO) programs.

Lastly, based on recent surveys conducted by NREL on market penetration using alternative financial metrics, such as bill reduction, the survey results indicate less than 20 percent market penetration for bill savings of less than 20 percent (Figure 1-9) for residential customers.[1] There was not a similar survey conducted for commercial customers. Due to the sensitivity of the overall study results to the Maximum Market Penetration Curves developed by NREL and Navigant (and R.W. Beck), Black & Veatch recommends PGE perform a similar survey for its customer base (residential and commercial) for both payback and percent bill savings.

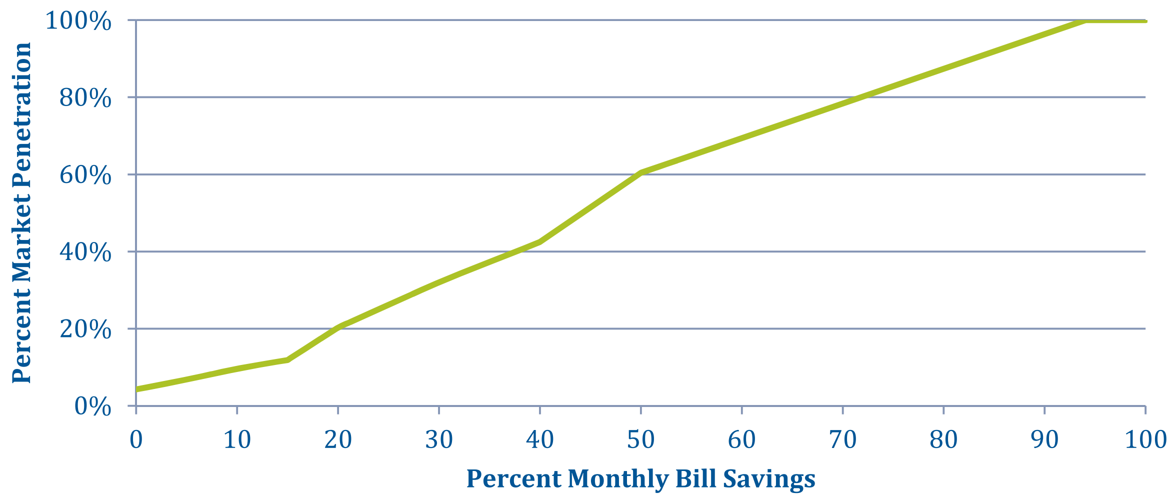



**Figure 1-9 2014 NREL Solar PV Market Penetration Curve Based on Monthly Bill Savings Survey of Residential Customers (Source: NREL)**

Additionally, it is important to note that the technical potential estimate is based on assessment of the current building stock within PGE's territory. New construction could cause the technical, financial, and achievable potential to increase over time. A number of other factors could also influence capacity over time, including the following:

- Modifications to the existing building stock.
- Growth/removal of trees and other shading sources.
- Improvements in solar panel efficiency, which would improve panel density per area.
- Changes in permitting/zoning requirements and restrictions.
- Innovations in mounting structures, such as lower cost solar carports.

Black & Veatch recommends that PGE regularly update the technical potential estimate and consider these factors in future studies.

[1] NREL provided maximum market penetration curves for residential sector only to Black & Veatch. Surveys were performed in 2014 and assessed market penetration based on payback, monthly bill savings, internal rate of return, and net present value. Data is not yet published.

For utility-scale solar, the long-term QF pricing for variable solar appears not to be sufficient to drive long-term large-scale solar adoption in Oregon when the ITC is not available. If the ITC is available at 10 percent, cost-effective solar becomes possible by 2026. Additional penetration may be possible if developers are willing to build projects for less than the assumed return requirements of 6.5 percent, capital costs are lower than forecasted, or more value is placed on large-scale solar than just QF pricing.

The tables below summarize the achievable potential identified by Black & Veatch for both distributed-scale and utility-scale systems.

**Table 1-6 Annual Solar Distributed Generation Adoption (MWdc)**

| | CPI (ADOPTION CURVE) | CPI+1 (ADOPTION CURVE) | CPI (ETO FUNDING - NO TAX CREDITS) | CPI+1 (ETO FUNDING - NO TAX CREDITS) | CPI (ETO FUNDING – WITH TAX CREDITS) | CPI+1 (ETO FUNDING – WITH TAX CREDITS) |
|---|---|---|---|---|---|---|
| 2016 | 4.2 | 9.0 | 7.3 | 9.2 | 7.3 | 9.2 |
| 2017 | 13.2 | 16.4 | 8.1 | 8.3 | 13.1 | 14.1 |
| 2018 | 15.2 | 18.6 | 5.3 | 5.5 | 17.9 | 19.8 |
| 2019 | 15.9 | 20.2 | 6.0 | 6.3 | 17.4 | 20.0 |
| 2020 | 14.9 | 20.9 | 6.6 | 7.1 | 15.1 | 17.5 |
| 2021 | 13.4 | 19.3 | 7.1 | 7.8 | 13.1 | 15.3 |
| 2022 | 10.7 | 16.5 | 7.6 | 8.6 | 11.8 | 13.9 |
| 2023 | 8.5 | 13.8 | 8.1 | 9.3 | 10.9 | 13.0 |
| 2024 | 6.4 | 11.1 | 8.6 | 10.1 | 10.3 | 13.3 |
| 2025 | 6.3 | 8.5 | 9.1 | 10.9 | 7.6 | 13.4 |
| 2026 | 5.6 | 6.3 | 9.5 | 11.8 | 7.1 | 9.9 |
| 2027 | 5.7 | 2.3 | 6.2 | 12.7 | 7.1 | 10.1 |
| 2028 | 4.5 | 1.1 | 5.7 | 8.6 | 7.3 | 11.0 |
| 2029 | 0.0 | 0.2 | 5.8 | 8.4 | 7.7 | 12.4 |
| 2030 | 0.0 | 0.0 | 5.9 | 9.1 | 8.1 | 14.2 |
| 2031 | 0.0 | 0.0 | 6.2 | 10.1 | 8.5 | 6.4 |
| 2032 | 0.0 | 0.0 | 6.4 | 11.3 | 9.1 | 3.7 |
| 2033 | 0.0 | 0.0 | 6.7 | 12.7 | 7.9 | 2.5 |
| 2034 | 0.0 | 0.0 | 7.1 | 14.6 | 4.9 | 1.7 |
| 2035 | 0.0 | 0.0 | 7.4 | 16.9 | 3.3 | 1.1 |
| **Total** | **124.6** | **164.2** | **140.8** | **199.5** | **195.6** | **222.5** |

**Table 1-7 Annual Build-Out of Utility-Scale Solar PV**

| YEAR | ANNUAL BUILD (ITC) MWAC | ANNUAL BUILD (NO ITC) MWAC |
|---|---|---|
| 2016 | | |
| 2017 | | |
| 2018 | | |
| 2019 | | |
| 2020 | | |
| 2021 | | |
| 2022 | | |
| 2023 | | |
| 2024 | | |
| 2025 | | |
| 2026 | 150 | |
| 2027 | | |
| 2028 | | |
| 2029 | | |
| 2030 | | |
| 2031 | 50 | |
| 2032 | | |
| 2033 | 43 | |
| 2034 | 60 | |
| 2035 | 65 | 100 |
| **Total** | **369** | **100** |

# 2.0 Introduction

Portland General Electric (PGE) retained Black & Veatch to provide an assessment of the potential for distributed solar photovoltaic (PV) generation within PGE's service area in northwest Oregon and utility-scale solar PV throughout Oregon. This report outlines the solar potential in each size range and also presents forecasts of solar costs.

This introductory section provides a background to the project and an overview of the report organization.

## 2.1 BACKGROUND

Portland General Electric (PGE) has a strong history of supporting many forms of distributed and renewable resources, including roof-top and utility-scale solar photovoltaic (PV) generation. PGE has approximately 55 megawatts direct current (MWdc) of distributed generation solar on the PGE system consisting of multiple programs. PGE has had a net-metering program since 1999 and participates in the state of Oregon's Solar Volumetric Incentive and Payments Program (effectively a feed-in tariff, or "FIT" program), for which it has a 16 MWdc cap. PGE has also developed several solar PV projects, including two solar highway projects: a 104 kilowatt direct current (kWdc) system that was the first solar highway project in the nation and a 1.75 MWdc project (Baldock Solar Highway). In partnership with customers, PGE is developing 3.5 MWdc of rooftop solar. In addition to DG solar resources, PGE purchases utility-scale solar PV generation totaling 14 MWdc.

PGE's 2013 Integrated Resource Plan (IRP) recommended studies and research initiatives to assess the market potential, business models, and policies that support installation of cost-effective distributed generation, in particular solar. "Potential" represents an upper-bound based on underlying assumptions. As part of the initiative, PGE identified the following areas of study:

1. Assessment of technical, financial, and achievable potential of distributed solar within PGE's service area and utility-scale solar within the state of Oregon.
2. Assistance in developing a methodology and models to calculate the costs and benefits of distributed and utility-scale solar ("value of solar") to the utility and customers that mitigates cost shifts between customers.

Black & Veatch was retained by PGE to support Task 1. Task 2 is reported in a separate document. As part of Task 1, Black & Veatch also provided current and forecasted costs for distributed and utility-scale solar projects. This report summarizes the findings of these analyses.

## 2.2 REPORT ORGANIZATION

Following this introduction, the report presents three main sections as follows:

- **Solar PV Cost Projections:** Black & Veatch developed total installed cost estimates for representative distributed and utility-scale solar PV systems for 2015 installation and forecasted those costs yearly through 2035. This section includes a basic overview of solar technologies, a discussion of Black & Veatch's cost estimating approach, cost estimates for distributed systems, and cost estimates for utility-scale systems.
- **Distributed Solar Potential Assessment:** The distributed solar assessment focused on identifying the potential for solar installed on customer rooftops within PGE's service territory. Black & Veatch implemented an innovative approach to assess the technical rooftop solar potential using Light Detection and Ranging (LiDAR) data to evaluate each individual building site across PGE's service territory, studied the financial viability of each of these systems, and considered market penetration and other factors in determining the dc capacity of distributed solar PV that could practically be achieved through 2035.
- **Utility-Scale Solar Potential Assessment:** The utility-scale solar analysis assessed potential project areas in Oregon ranging from 5 to 250 MWac. For the utility-scale system analysis, Black & Veatch first identified potential sites by excluding land areas based on certain environmental considerations, proximity to existing transmission, technical limitations, and other parameters. Next, a financial screen was applied to these sites by comparing each site's levelized cost of energy (LCOE) to PGE's long-term qualified facility (QF) rates, without considering transmission capacity availability. To arrive at an achievable potential, an additional screen was applied to these sites assuming firm transmission availability constraints on existing transmission lines would limit delivery to PGE's service territory and size of projects that can interconnect.

In addition to these three main report sections, several appendices include additional technical and modelling data for reference.

The achievable potential estimates for DG and utility-scale solar were developed for the time period of 2016 to 2035, based on the forecasted cost estimates and other adoption factors. This report summarizes the Black & Veatch analysis and results for both distributed and utility-scale solar PV resources. A separate report discusses non-solar distributed generation resources.[2]

[2] "Non-Solar Distributed Generation Market Research," Black & Veatch, 2016.

# 3.0 Solar PV Cost Projections

Black & Veatch developed total installed cost projections for distributed and utility-scale solar PV systems. Estimates were made for systems installed in 2015 and forecasted for each year through 2035. To provide context for these estimates, this section begins with a basic overview of solar technologies. This is followed by a discussion of the cost estimating approach used, the estimates for distributed systems, and the estimates for utility-scale systems.

## 3.1 SOLAR TECHNOLOGY OVERVIEW

Solar PV systems consist primarily of solar modules, inverters, and racking systems. Sample components for distributed (typically roof-mounted) PV systems and utility-scale (typically ground-mounted) PV systems are shown in Figure 3-1 and Figure 3-2.

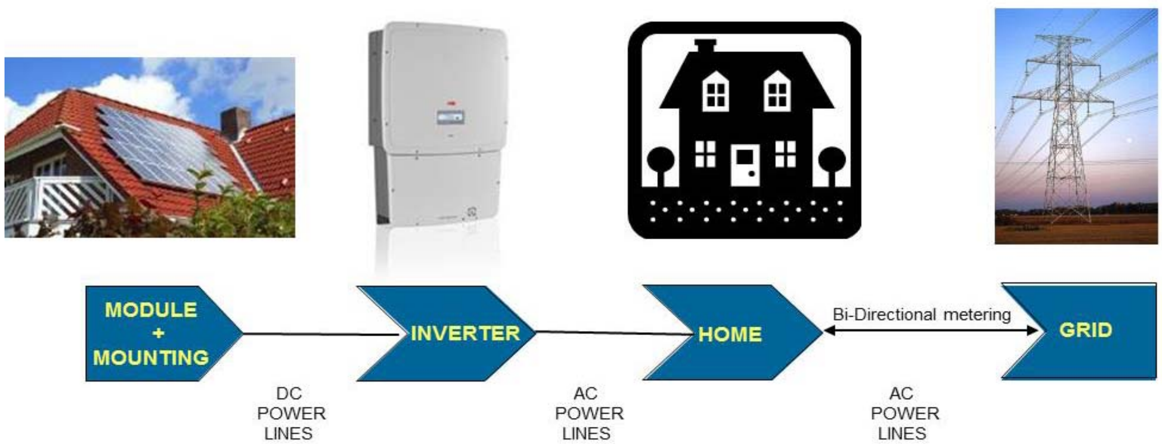



**Figure 3-1 Example Components for Distributed Solar PV System**


**Figure 3-2 Example Components for Utility-Scale Solar PV System**

There are three main types of module technologies[3]: monocrystalline, polycrystalline, and thin film, in order of their efficiency from highest to lowest. Less efficient technologies do not necessarily mean inferior performance; aside from some slight variations in performance curves, the main difference is that less efficient technologies require more surface area for the same amount of output. The selection of a particular module technology depends on the cost of the technology and presence of site space constraints.

Inverters convert the direct current (dc) output of solar modules to alternating current (ac), so that the power can be utilized by the electrical grid and most electrical devices. Solar system nameplate capacity may be reported in dc or ac, representing the capacity of modules and capacity of inverters, respectively.

Racking systems refer to the support system for solar modules. There are two main types of racking systems: fixed tilt and single-axis tracking. The latter tracks the sun's movement from east to west. There are dual-axis tracking systems[4] that track the sun's shift north to south as well, but these systems are more costly and less common in the industry. Due to the ability to track the sun, the single-axis tracking systems can produce more energy on average than fixed-tilt systems, but the tracking systems cost more. Therefore, regardless of the module technologies or racking systems selected, the levelized cost of energy (LCOE) for these various combinations are typically similar.

It should be noted that racking systems can be built over parking lots as well. These are often referred to as carport systems. The expense to build the elevated structures for these carport systems is higher than rooftop systems in most cases and, therefore, Black & Veatch assumed these types of systems would not be considered cost competitive compared to rooftop systems. For this reason, parking lots were not included in the technical screen.

For the purposes of this study, Black & Veatch chose to analyze polycrystalline modules mounted in a fixed-tilt orientation. This is a common technology and mounting orientation and, therefore, considered representative of the other options for characterization purposes.

## 3.2 GENERAL COST ESTIMATING APPROACH

Black & Veatch identified key factors driving the cost projection of solar in the global, national, and regional markets. Cost projections were developed for both distributed solar in PGE's service territory and utility-scale solar in Oregon. These estimates are specific to the region and based on forecasts for the main solar cost components, including the following:

- PV modules.
- PV inverters.
- Other PV balance-of-system hardware (racking/mounting/trackers, combiner boxes, wiring, transformers, communications and control systems, etc.).
- Grid interconnection.

[3] Concentrating photovoltaics (CPV) are applicable in locations with high direct insolation. Oregon is not considered an applicable location for CPV technologies, and this technology is therefore not discussed.

[4] Dual-axis tracking systems are not often used for flat plate PV and therefore are not discussed.

- "Soft" costs (land costs, permitting, customer acquisition, engineering, procurement, and construction [EPC] costs, financing, etc.).
- Installation labor costs.

To establish a starting point for the solar PV cost projection, Black & Veatch used proprietary conceptual cost estimating tools to generate bottom-up cost estimates for both rooftop solar and ground-mount utility scale systems for several representative sizes. The conceptual cost estimate tools were derived from Black & Veatch procedures and experience generating and reviewing firm-price bids to engineer, procure, and construct utility scale PV solar. Inputs for the analysis were based on recent quotations for equipment and recent experience regarding labor requirements and reflect projects to be installed in 2015.

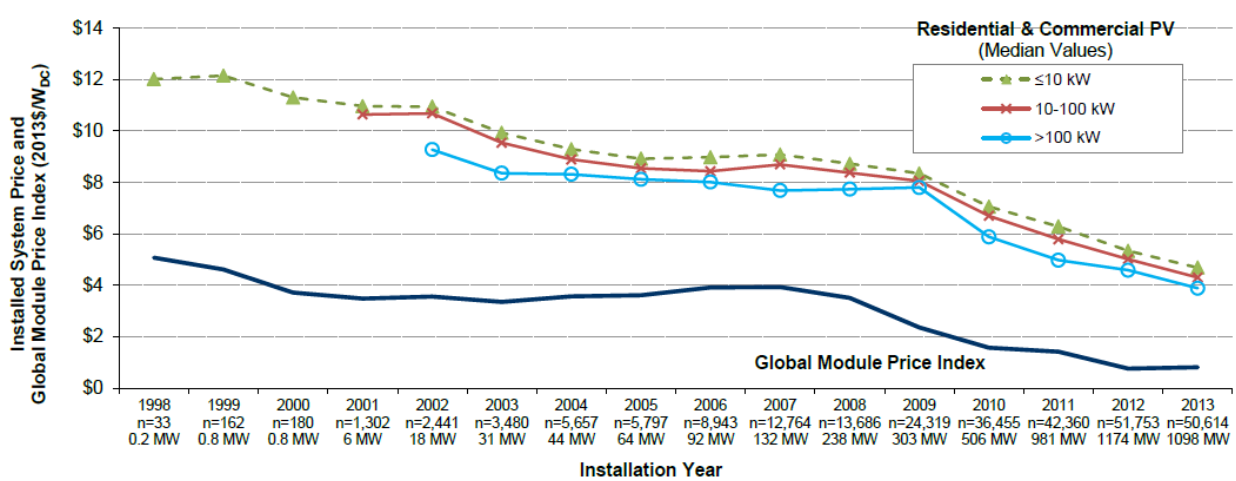
The 2015 costs served as the starting point for forecasted solar PV costs from 2016 to 2035.

## 3.3 DISTRIBUTED SOLAR PV COST PROJECTIONS

This section provides cost projections for distributed solar PV, namely, rooftop solar systems. Historical and current costs are presented first, followed by Black & Veatch's projections for costs through 2035.

### 3.3.1 Historical and Present Distributed Solar PV Cost

Since 1998, rooftop PV system prices throughout the United States have fallen on average between 6 and 8 percent per year. The decrease is due primarily to lower module and other equipment costs. This rate of price reduction has increased in recent years. Prices fell between 12 and 15 percent from 2012 to 2013 alone. Rooftop solar prices in Oregon tend to track above the national average and have also dropped significantly since 2008. Figure 3-3 illustrates the installed prices for rooftop solar PV over time.




Note: Median installed prices are shown only if 15 or more observations are available for the individual size range. The Global Module Price Index is SPV Market Research's average module selling price for the first buyer (P. Mints).

**Figure 3-3 Median Reported Installed Prices of Residential and Commercial PV Systems over Time (source: US DOE)**

Oregon prices for residential and commercial customers have also fallen over time as well, as shown on Figure 3-4. This figure shows that since 2007, reported residential PV costs in Oregon have dropped approximately 50 percent from around $9/Wdc to about $4.5/Wdc in 2014. Reported commercial system costs have dropped even further, starting at over $9/Wdc in 2007 and dropping to less than $4/Wdc in 2014.

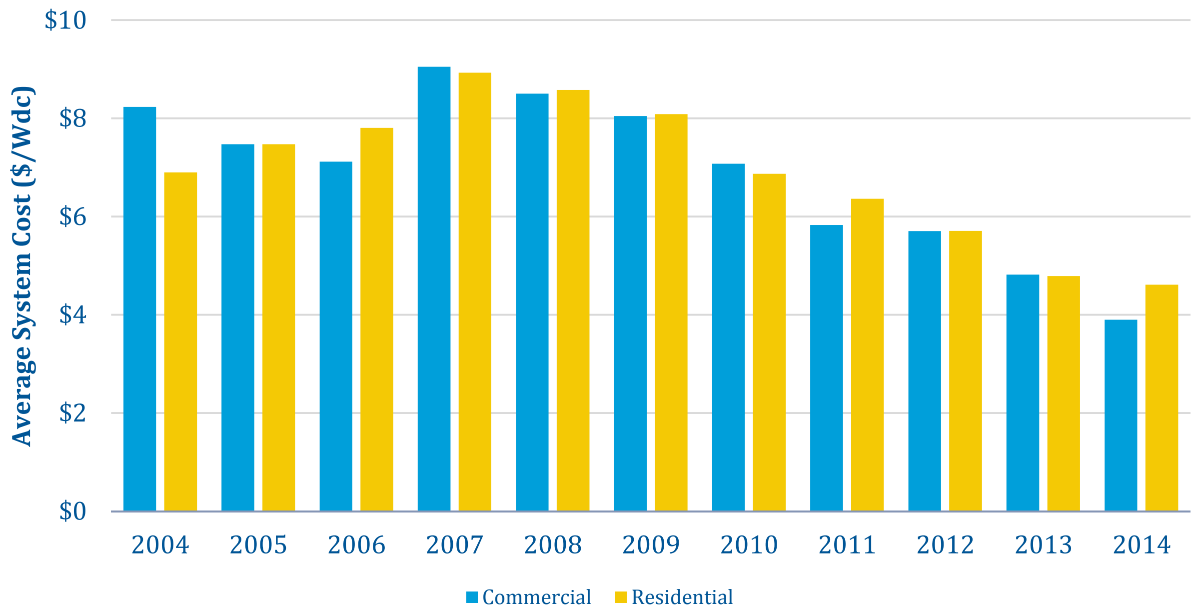



**Figure 3-4** **ETO-Funded Installed PV System Average Costs in PGE Service Territory (Data Source: ETO)**

As shown in Figure 3-5, the pace of installations, including both ETO funded and Solar Payment Option (SPO) projects, for residential systems has averaged about 5 MWdc per year for the past 4 years. In contrast, commercial system installation rates have slowed, averaging only about 2 MWdc per year over the past 2 years, after peaking at about 7 MWdc of annual installations in 2012, when the Oregon tax incentive for commercial customers expired.

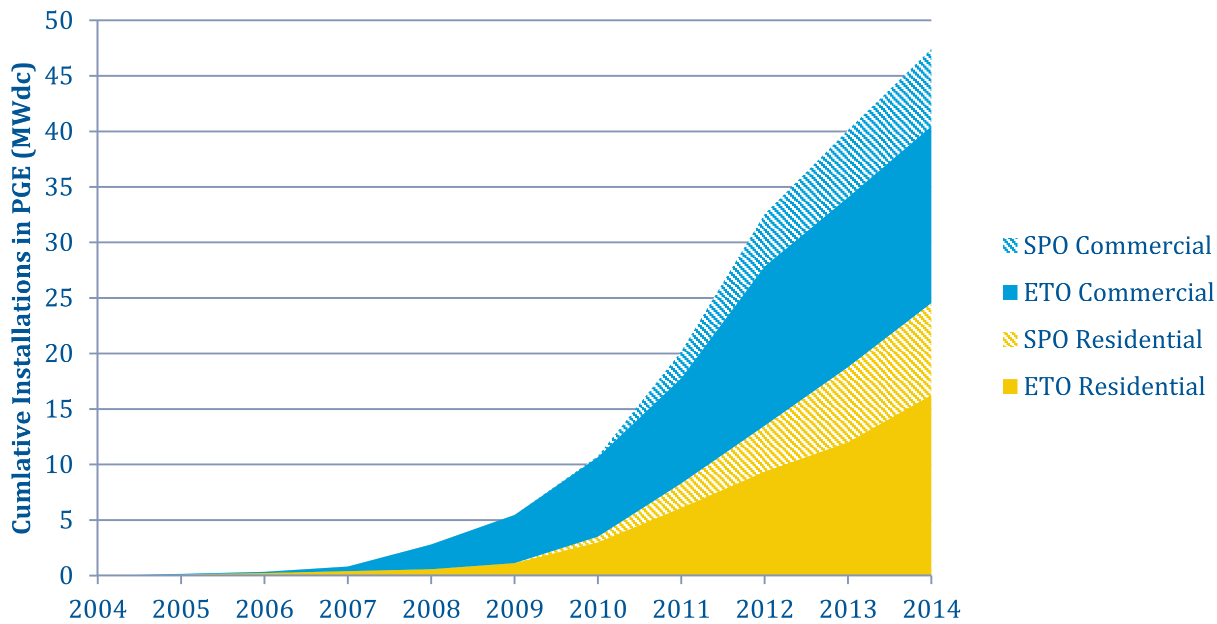
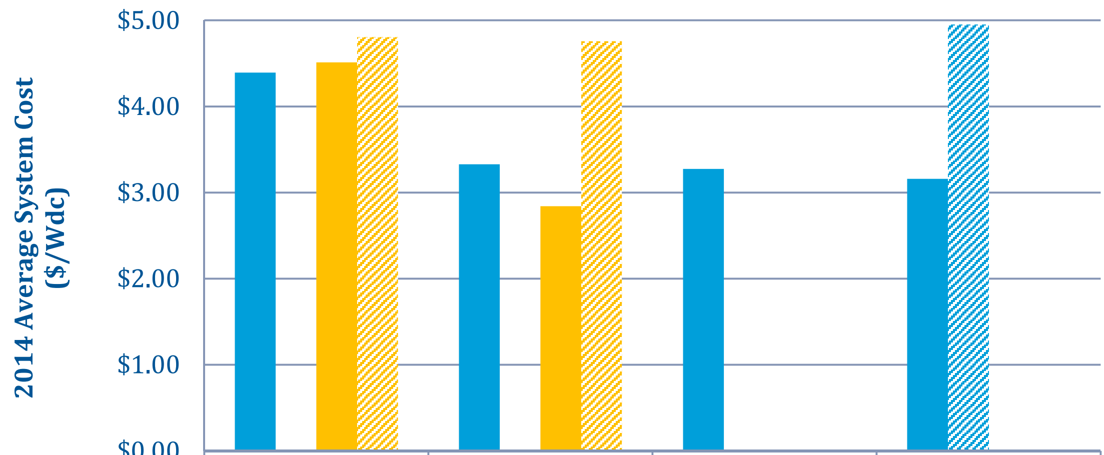



**Figure 3-5** **ETO Funded and SPO Cumulative Installations in PGE Territory**

Interestingly, under the ETO incentive program, third-party owners (TPOs) make up over 80 percent of the capacity installed in 2014 for residential installations and 30 percent of commercial installations. While TPO models are more prevalent, there is insufficient historical data to conclude whether TPO is driving market growth.

The TPOs typically report generically higher cost information to the ETO than direct sales, thus increasing the reported average installation cost of residential systems.[5] Figure 3-6 shows the average system costs for 2014 separately by direct sales customers and TPOs. For the purposes of this study, the direct sale customers are the more relevant comparison, with average system costs ranging from $2.84 to $4.51/Wdc for smaller systems and $3.16 to $3.27/Wdc for large systems.

[5] Since TPOs do not sell the solar system to the host, their basis for reporting costs is not as straightforward as direct sales installations. There are a variety of reasons that TPO reported costs are typically higher than direct sales, including the basis used for tax credits, perceived fair market value, etc.




| | 1-10 | 10-25 | 25-100 | >100 |
|---|---|---|---|---|
| Commercial-Direct | $4.39 | $3.33 | $3.27 | $3.16 |
| Commercial TPO | | | | $4.95 |
| Residential - Direct | $4.51 | $2.84 | | |
| Residential-TPO | $4.81 | $4.76 | | |

Size Bins (kWdc)

**Figure 3-6 ETO 2014 Reported Installed Costs by System Size (kWdc) and Ownership (Source: ETO)**

To estimate current PV costs, Black & Veatch developed a bottom-up cost estimate for distributed solar. This was then compared to market data from the ETO's PowerClerk database to ensure that the estimate was consistent with the actual installed costs being observed in the market. The key design and cost assumptions were based on current market conditions, product availability, and conventional system design, as follows:

- For the purpose of the estimate, typical equipment was assumed to consist of Canadian Solar polycrystalline silicon modules, ABB inverters, and Unirac/Quick Mount (for pitched residential rooftops) or AET Rayport (for flat commercial rooftops) racking or equivalent equipment.
- Current EPC module cost is $0.90/Wdc.
- Average system cost assumes a moderate level of complexity for installation:
  - For residential systems, this is characterized by contiguous arrays, two-story residential roofs, roof pitches between 6:12 and 9:12, and within 50 feet of a 240 volt (V) single-phase service panel/utility meter.
  - For commercial roofs, this is characterized by arrays routed around heating, ventilating, and air conditioning (HVAC) and other rooftop obstructions, flat roofs, and within 250 feet of a single- or three-phase 208, 240, or 480 V service panel/utility meter.

- Estimates of EPC indirect costs were based on Black & Veatch experience and industry-accepted assumptions.
- Other soft costs are based on general industry practice of 50 percent margin above total EPC costs. Soft costs include any permitting fees, administrative costs, financing and contracting costs, design and engineering costs, customer acquisition costs, incentive application fees, interconnection fees, taxes, insurance, contingency, and profit, as well as the costs associated with project delays due to permitting or interconnection issues.

Cost estimates were generated for 4 kWdc (residential), 50 kWdc, and 250 kWdc (commercial) rooftop systems of moderate or "average" difficulty. These sizes fall within the range of typical distributed generation grid-tied systems.

It is important to note that installed PV prices vary widely in Oregon and throughout the United States because of such factors as brand-value, extended warranties, third-party ownership models, and other factors not captured by cost per watt. Prices are also influenced by both consumer savvy and contractor practices. The assumptions provided in this report are considered representative of the market, but actual costs could be significantly above or below these estimates.

Black & Veatch's estimate for rooftop solar PV costs is summarized in Table 3-1. The table provides a breakdown by major components and major soft costs.

**Table 3-1 Distributed Solar PV Cost Estimate Breakdown for 2015 Installation (2014$)**

| | PITCHED ROOF –3.6 $KW_{AC}$ (4 $KW_{DC}$) | | FLAT ROOF – 45 $KW_{AC}$ (50 $KW_{DC}$) | | FLAT ROOF –225 $KW_{AC}$ (250 $KW_{DC}$) | |
|---|---|---|---|---|---|---|
| PARAMETER | $ | $/$W_{DC}$ | $ | $/$W_{DC}$ | $ | $/$W_{DC}$ |
| Modules | 3,600 | 0.90 | 45,090 | 0.90 | 225,180 | 0.90 |
| Inverter(s) | 1,380 | 0.34 | 10,770 | 0.21 | 53,830 | 0.20 |
| Racking | 820 | 0.21 | 11,210 | 0.22 | 55,980 | 0.22 |
| Balance of System | 880 | 0.22 | 3,610 | 0.07 | 10,300 | 0.05 |
| Installation | 1,740 | 0.44 | 13,120 | 0.27 | 50,460 | 0.23 |
| Total Direct Cost | 8,420 | 2.11 | 83,800 | 1.67 | 395,760 | 1.60 |
| EPC Indirects | 1,550 | 0.39 | 9,680 | 0.20 | 45,670 | 0.19 |
| **Total EPC Costs** | **9,950** | 2.49 | **93,480** | 1.87 | **441,430** | 1.79 |
| Soft Costs | 4,980 | 1.25 | 37,390 | 0.75 | 178,400 | 0.71 |
| **Total Cost** | **14,950** | 3.74 | **130,870** | 2.62 | **619,840** | 2.50 |

### 3.3.2 Projected Distributed PV System Costs

Black & Veatch developed a forecast of future PV system costs. The once seemingly optimistic US Department of Energy's (DOE's) SunShot Initiative targets now appear within reach because of (1) the rapid and prolonged decline in the prices of PV modules and other system components and (2) the potential to reduce labor and other soft costs as demonstrated by best practices in more mature PV markets (e.g., Germany).

Assumptions for Black & Veatch's forecast include the following:

- Installed PV prices will approach the DOE's SunShot Initiative targets in 2025.
- "Learning curve," economies of scale, and incremental cost and technology improvements will continue throughout the projection period at a diminishing rate. As the rate of improvement declines, inflationary pressure will push up on prices in nominal terms.
- No disruptive or revolutionary technology breakthroughs will occur during the projection period, although incremental improvements in module efficiency are implicit in the forecasted cost.
- PV labor, material, and other costs will approach their theoretical minimums between 2030 and 2035.
- Wide variations in installed costs will continue because of differences in contractor operating margins as well as differences in system features not captured by $/W.
- Variations in prices caused by time lags between contract and completion dates are reflected in the model.
- Between 2016 and 2017, Black & Veatch expects a precipitous drop in prices for residential customers if the federal investment tax credit (ITC) is not renewed at the current level of 30 percent, as residential installers will need to offer more competitive pricing to maintain a similar net cost after incentives to customers.

Figure 3-7 shows the Black & Veatch forecast for sample distributed PV systems through 2035. By the end of the forecast period, Black & Veatch forecasts costs will have dropped to between $1.1 to $1.3/Wdc (2014$). Residential system costs are projected to drop by approximately 65 percent, while commercial system costs will drop between 50 and 55 percent. It is important to note that this figure is shown in 2014 dollars, and inflation will increase these costs in nominal dollar terms. In nominal terms, costs plateau around 2025, with the small continued improvements offset by inflationary increases. A table of the annual projection of costs is provided in Appendix A.

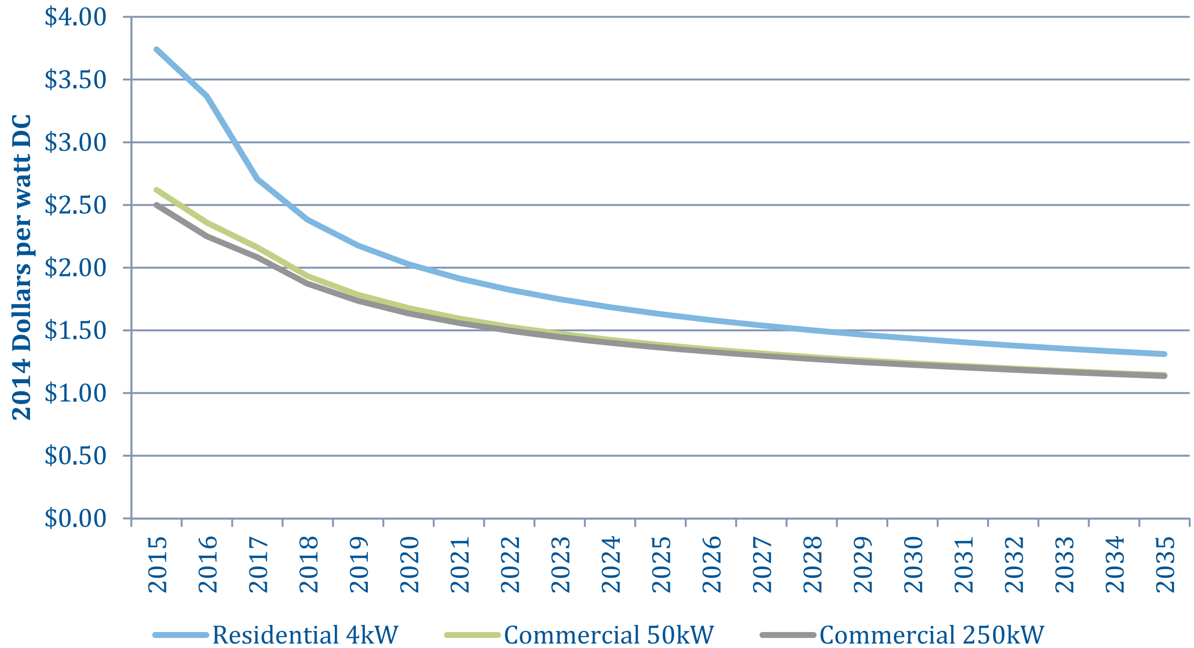



**Figure 3-7 Rooftop Solar PV Cost Projections from 2015 to 2036**

## 3.4 UTILITY SCALE SOLAR PV COST PROJECTIONS

This section provides cost projections for utility-scale, ground-mount solar systems. Historical and current costs are presented first, followed by Black & Veatch's projections for costs through 2035. This section also provides assumptions for transmission costs.

### 3.4.1 Historical and Present Utility-Scale Solar PV Cost

As shown on Figure 3-8 ground-mount solar system costs have dropped precipitously in the past 5 years. This has been the result of the mass production of solar PV equipment and the cost reduction realized from the installation of gigawatts of utility scale installations. Cost for ground-mount systems has fallen in Oregon as well. The recent Steel Bridge Solar proposal in Oregon was the lowest reported in Oregon at $1.98/Wdc for a 3.0 MWdc (2.4 MWac) system with a commercial operation date in 2015.[6]

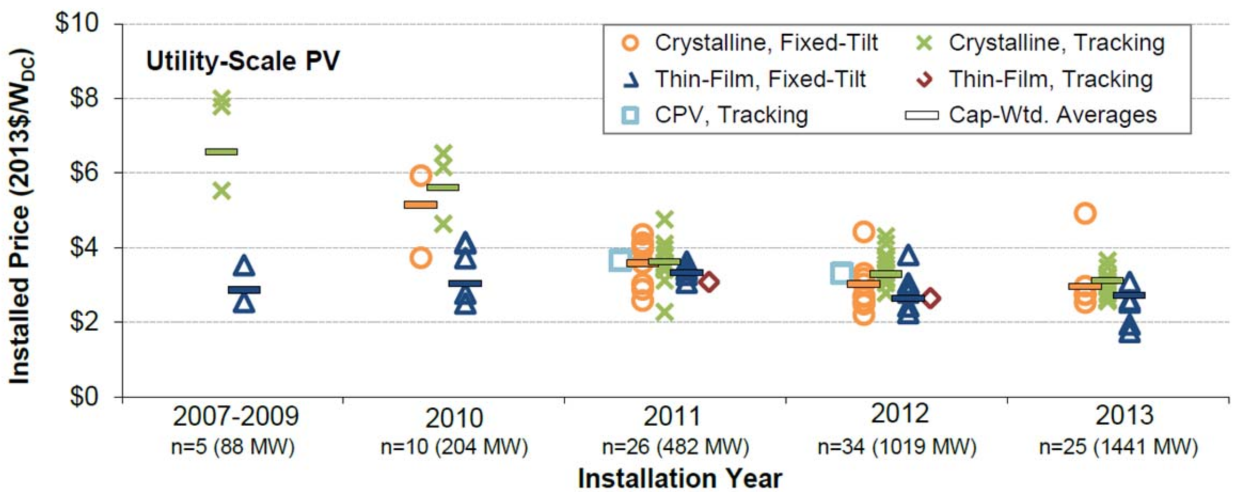



**Figure 3-8 Cost Decline of Utility-Scale Solar PV in the US between 2007 and 2013 (Source: Lawrence Berkeley National Laboratory/DOE)** [7]

To estimate current PV costs, Black & Veatch developed a bottom-up cost estimate for utility-scale solar. Inputs for the analysis were based on recent quotations for equipment and recent experience regarding labor requirements. The most critical cost input is the assumption of $0.72 per watt for polycrystalline module pricing; this assumption is based on prices after the recent trade case ruling that applied tariffs to Chinese and Taiwanese solar modules.[8] The cost for modules for the larger utility-scale systems is assumed lower than distributed systems because of larger volume purchases.

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[6] "Draft 2015 Annual Budget & 2015-2016 Action Plan –Revisions," Renewable Energy Advisory Council, November 21, 2014 (http://energytrust.org/library/meetings/rac/RAC_meeting_packet_141121.pdf).
[7] "Photovoltaic System Pricing Trends," DOE/LBNL, 2014 (http://emp.lbl.gov/sites/all/files/presentation_0.pdf).
[8] "US slaps trade duties up to 165% on Chinese solar firms," PV Tech, December 19, 2014 (http://www.pv-tech.org/news/us_department_of_commerce_makes_final_ruling_in_china_solar_trade_case).

Cost estimates were generated for 7, 28, and 140 MWdc systems (5, 20, and 100 MWac). These are typical sizes for small and large projects. Typical conceptual designs were used, including a dc capacity to ac capacity ratio of 1:4 meant to optimize performance.

Assumptions for indirect costs were based on Black & Veatch experience and industry-accepted assumptions. Indirect costs considered included EPC profit and contingency as well as owner's project development fees, permitting costs, financing costs, and others. Interconnection and gen-tie costs are not included in these estimates but were separately estimated as discussed later in this section.

The results of the bottom-up cost estimate for utility scale solar is shown in Table 3-2. Additional estimates for single-axis tracking systems are provided in Appendix A.

**Table 3-2 Utility-Scale, Fixed-Tilt, Solar PV Cost Estimate Breakdown for Installation in 2015 (2014$)**

| PARAMETER | 5 $MW_{AC}$ (7 $MW_{DC}$) | | 20 MWAC (28 $MW_{DC}$) | | 100 $MW_{AC}$ (140 $MW_{DC}$) | |
|---|---|---|---|---|---|---|
| | $ | $/$W_{DC}$ | $ | $/$W_{DC}$ | $ | $/$W_{DC}$ |
| Modules | 5,040,000 | 0.72 | 20,160,000 | 0.72 | 100,800,000 | 0.72 |
| Inverters | 750,000 | 0.11 | 3,000,000 | 0.11 | 15,000,000 | 0.11 |
| Racking and Foundations | 1,144,000 | 0.16 | 4,576,000 | 0.16 | 22,882,000 | 0.16 |
| Balance of System | 939,000 | 0.13 | 2,354,000 | 0.08 | 9,954,000 | 0.07 |
| Installation | 1,364,000 | 0.19 | 4,225,000 | 0.15 | 19,059,000 | 0.14 |
| Total Direct Cost | 9,237,000 | 1.32 | 34,316,000 | 1.23 | 167,694,000 | 1.20 |
| EPC Indirects | 2,688,000 | 0.38 | 8,865,000 | 0.32 | 38,404,000 | 0.27 |
| **Total EPC Cost** | 11,925,000 | 1.70 | 43,180,000 | 1.54 | 206,098,000 | 1.47 |
| Owner's Costs (15%) | 1,789,000 | 0.26 | 6,477,000 | 0.23 | 30,915,000 | 0.22 |
| **Total Cost** | 13,714,000 | **1.96** | 49,657,000 | **1.77** | 237,012,000 | **1.69** |

## 3.4.2 Projected Utility-Scale Solar PV Costs

Black & Veatch developed a forecast of future PV system costs for utility-scale systems. Cost projections are based on Black & Veatch expectations and established industry roadmaps. PV solar costs have dropped dramatically over the last 10 years, surpassing the expectations of even the most optimistic analysts. Costs are expected to continue to fall, but market pressures are changing, and the cost reduction potential may be reaching theoretical limits.

The projections incorporated Black & Veatch's understanding of the technical limitations on cost reduction, the examples of more mature solar markets such as those that exist in Germany, and credible studies of cost reduction potential such as those performed for the DOE's SunShot Initiative.

Figure 3-9 shows the Black & Veatch forecast for typical utility-scale PV systems through 2035. By the end of the forecast period, Black & Veatch forecasts costs will have dropped to less than $1/Wdc for larger fixed-tilt systems. It is important to note that this figure is shown in 2014 dollars, and inflation will increase these costs in nominal dollar terms. In nominal terms, costs plateau around 2025, with the small continued improvements offset by inflationary increases. A table of the annual projection of costs for both tracking and fixed-tilt systems is provided in Appendix A.

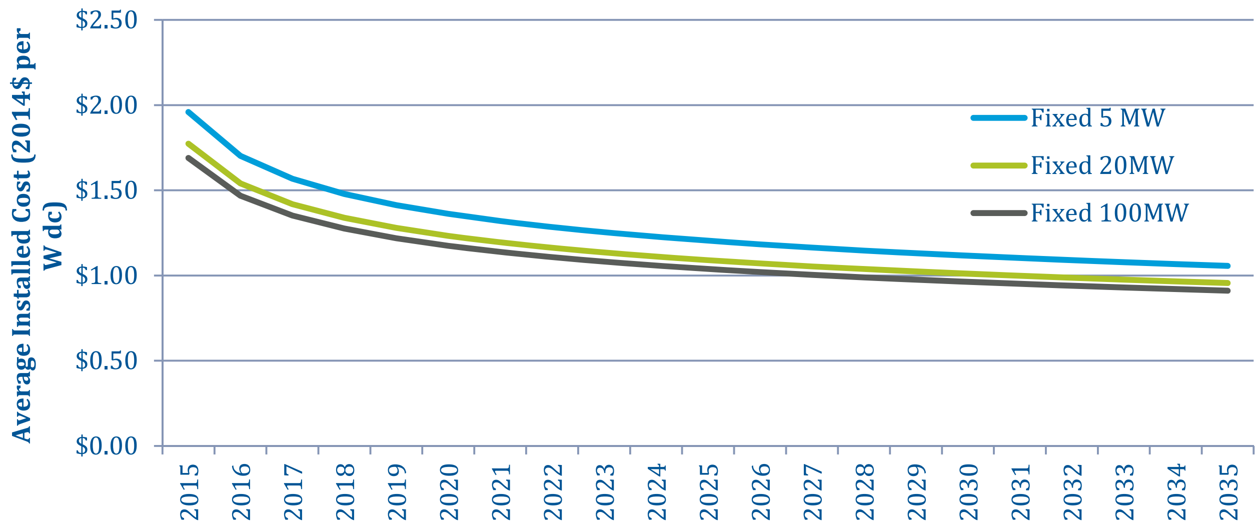



**Figure 3-9 Utility-Scale, Fixed-Tilt Solar PV Cost Projections from 2015 to 2035**

### 3.4.3 Transmission Cost Assumptions

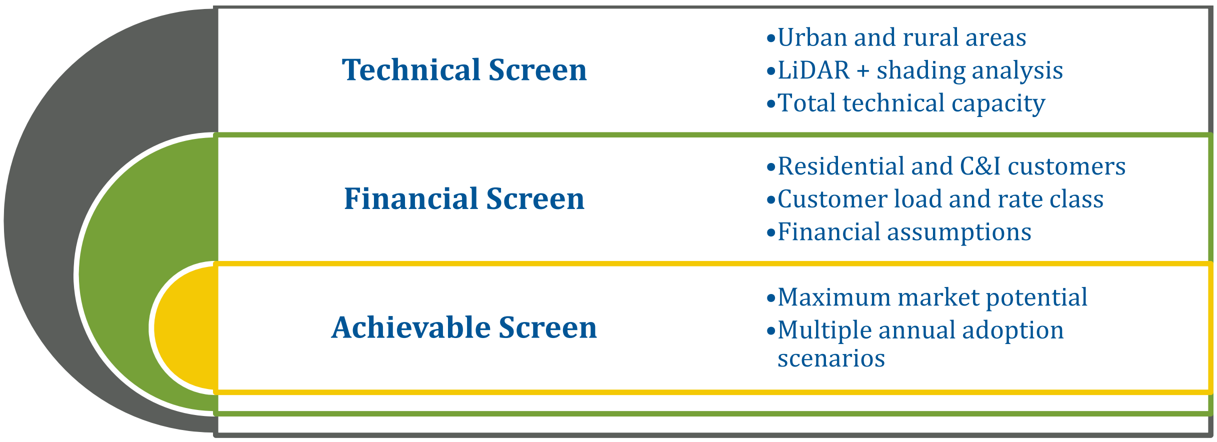
Larger utility-scale PV systems will likely connect to the transmission system and will incur costs for interconnection, including substation and generation tie-line costs. These costs are in addition to the PV plant costs discussed in the previous section. Black & Veatch recently provided updated transmission cost estimates and a transmission project cost estimation tool to the Western Electricity Coordinating Council (WECC) as part of its long-term planning process. These data were updated to be Oregon-specific and used for this financial screen. For utility-scale solar PV systems, Black & Veatch assumed that either an onsite substation would need to be built, or upgrades to a nearby utility substation would be required. Therefore, substation costs were applied to each project site, based on the size and voltage of the transmission line or substation. Generation tie-line (gen-tie) costs were also applied to each project based on its proximity to a transmission line or utility substation, the closer of the two.

**Table 3-3 Substation and Gen-Tie Line Cost Estimate Breakdown (2014$)**

| PARAMETER | < 100 KV (5 TO 50 MW) | 115 KV (5 TO100 MW) | 230 KV (20 TO 250 MW) | 500 KV (100 TO 250 MW) |
|---|---|---|---|---|
| Substation ($million)* | $3.18 | $3.38 | $10.0 | $19.5 |
| Generation Tie-Line ($million/mile) | $1.5 | $1.5 | $2.0 | $3.5 |
| *Primary components in substation cost include a transformer and circuit breakers. | | | | |

# 4.0 Distributed Solar PV Potential Assessment

Black & Veatch assessed the potential for distributed solar PV installed on customer rooftops within PGE's service territory. Black & Veatch utilized multiple innovative tools and processes to identify the solar PV distributed generation potential. The technical, financial, and achievable screens can be summarized as follows:




1. **Technical Screen:** The technical screen quantifies the amount of useable rooftop space on individual buildings across the urbanized areas of PGE's service territory. Technical potential is constrained to those roof areas that receive adequate solar resource as defined by Oregon's eligibility requirements for tax credits and incentives. The rooftop space is then translated to total capacity (MWdc). Black & Veatch then extrapolated the analysis outside the urban areas to estimate the total technical potential in PGE's service territory.
2. **Financial Screen:** For the financial screen, site-specific characteristics were developed to calculate the expected payback of individual buildings, accounting for solar profile, project size, and customer type. The financial screen limits sites to paybacks of 20 years or fewer for both residential and commercial customers. Detailed financial analysis was performed for hundreds of thousands of sites in the years 2016 and 2035, under two rate increase scenarios.
3. **Achievable Screen:** Black & Veatch developed estimates of achievable potential on the basis of the financial screen results and a range of market adoption scenarios. Forecasts were developed on an annual basis from the year 2016 through 2035. Black & Veatch sought to identify the higher and lower bounds of solar adoption potential over time using two approaches: bottom-up and top-down.

## 4.1 TECHNICAL SCREEN

The technical screen attempts to capture the amount of useable rooftop space on individual buildings across the PGE service territory that receives an adequate level of solar resource for development. Adequate resource is defined as areas that receive sufficient solar resource to meet eligibility requirements for ETO incentives and state tax credits, which require systems to have a Total Solar Resource Fraction (TSRF) of 75 percent or higher. This essentially means that a system placed at that site must perform 75 percent or better than a system ideally oriented, without shading, at the same site. Drivers that impact the solar resource on the plane of a surface include tilt of the roof, azimuth (i.e., compass heading), and surrounding obstructions (i.e., trees and buildings) that can cause shading at the site.

### 4.1.1 Approach

Black & Veatch developed a detailed and novel approach to evaluate technical potential for solar down to the individual customer level. The first step in the process was to use geospatial data (data gathered with remote sensing instruments) and proprietary analysis methods. Black & Veatch used the rich LiDAR data available for PGE's service territory. Black & Veatch focused on urban areas, as these are generally land-constrained and more amenable to rooftop installations. There were a few areas where LiDAR data are not available and, therefore, Black & Veatch was not able to assess solar PV potential using the LiDAR approach. The urban areas shown in green on Figure 4-1 were included in the LiDAR assessment. While the green areas cover less than 50 percent of the PGE territory, due to the much higher population density in these areas, about two-thirds of the estimated technical potential is within the green areas. For other areas, technical potential estimates were developed by extrapolating the results from similar parcels from the LiDAR study.

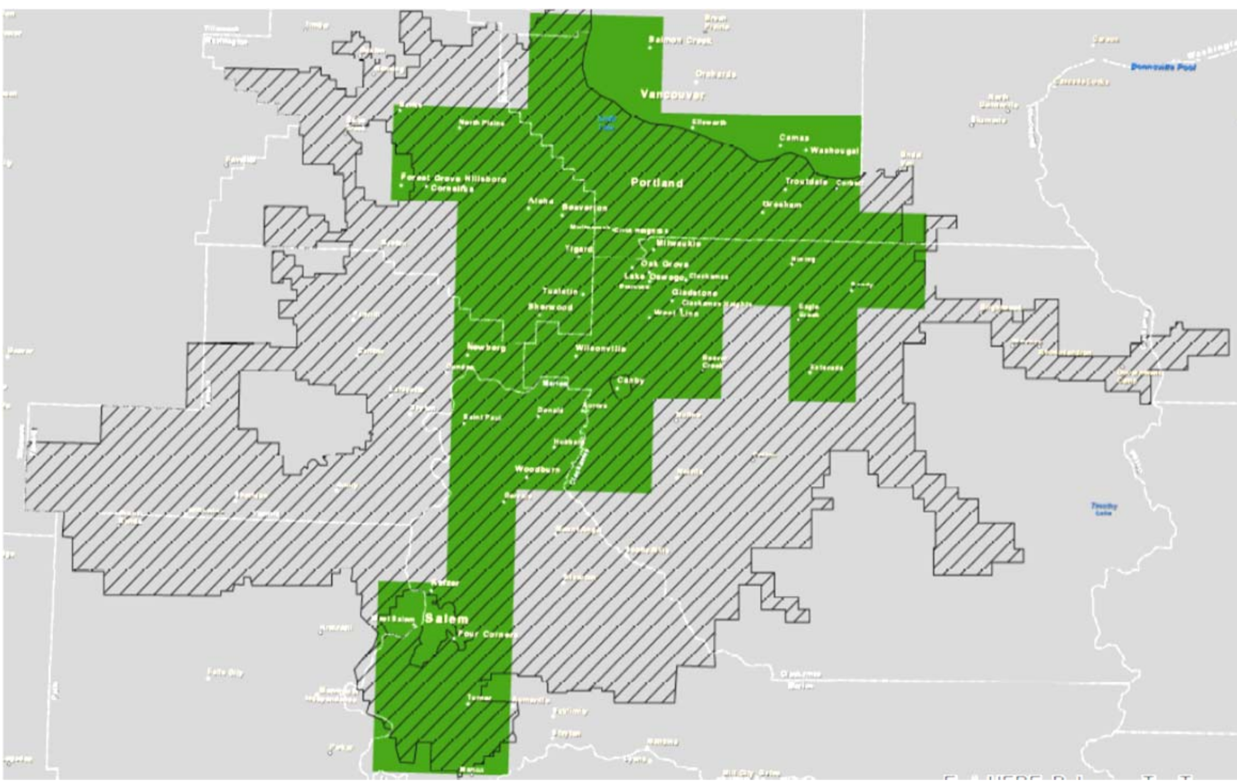



**Figure 4-1 Available LiDAR and Building Footprint Data for PGE Service Territory**

The tools and processes used in this analysis are extremely powerful, as they are used to evaluate individual rooftops for available roof area and appropriateness for solar development as well as the respective tilt and azimuth of each roof plane. The tool also accounts for the impact of shading from surrounding trees and buildings as it assesses the solar resource at each square foot on a roof each hour over a year. The analysis was able to identify the effective solar resource (irradiance) that reaches the plane of a roof, so any areas that did not meet the TSRF requirement were excluded.

Rooftops smaller than 400 square feet were removed to avoid detached garages, sheds, and other structures that are likely not structurally sound or connected to load. Using parcel data, Black & Veatch was able to differentiate between residential and commercial buildings.

Figure 4-2 illustrates this process. The image on the left shows several residential roofs and their associated orientations (tilt and azimuth) as well as shading sources (namely, trees and buildings). The image on the right shows the solar resource incident on these roofs, accounting for their orientation (i.e., south facing roofs have higher resource compared to north facing roofs). This image also clearly shows the effect of shading from trees. Red indicates good resource, while blue indicates poor resource. The mostly blue building in the center right is shaded by trees on the southern building perimeter.

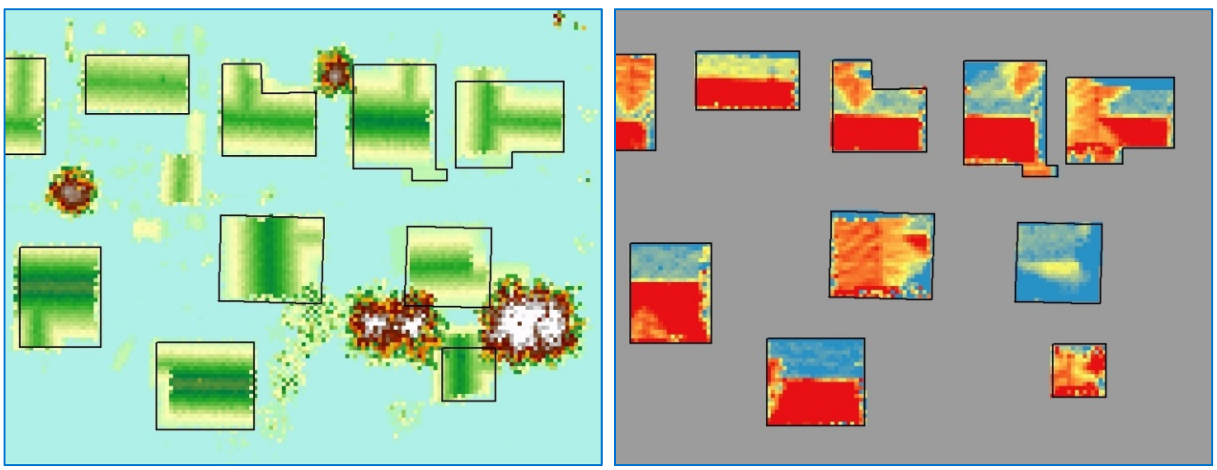


**Figure 4-2 Sample Rooftop GIS Analysis, Residential Area**

The process works similarly in residential or commercial areas. In contrast to the residential area shown on Figure 4-3, Figure 4-4 show the process applied in central Portland near the Pioneer Courthouse. The numbers represent average building height. Most of the shading in this area is from adjacent tall buildings or obstructions on the roof.

**Figure 4-3 Sample Rooftop GIS Analysis, Central Portland**

Following these initial processes, Black & Veatch programmed the ArcGIS tool to step through a series of criteria to select roof areas that would be considered technically feasible. These are described below and shown on Figure 4-4:

1. Isolate buildings from building footprint data. Identify roof planes and tilt and azimuth of each roof plane and account for appropriate setbacks.[9]
2. Filter roof areas that did not meet the TSRF metric of 75 percent or better. Areas in black in Figure 4-4 passed the TSRF metric. As would be expected from the TSRF requirement, most of the selected roofs were oriented southward or were flat roofs with minimal shading.
3. Seek a minimum contiguous area of 100 square feet on each roof plane to accommodate a reasonably sized solar PV system.
4. Apply a geometric constraint that at least one edge of the contiguous area must have a 4 foot length to fit a solar panel.

Once the technically feasible roof area was calculated, Black & Veatch converted the area to equivalent solar dc capacity. The conversion factors accounted for typical module dimensions, ratings, and orientations applicable in rooftop systems. For tilted roofs, Black & Veatch used a conversion factor of 10 Wdc per square foot (sq ft) because the roof systems can be flush-mounted. On flat roofs, systems are typically tilted slightly with spacing between rows to avoid shading. The conversion factor for flat roofs was assumed to be 5.8 Wdc per sq ft.

The LiDAR analysis focused on designated urban areas and was not performed for rural areas with low density of buildings. For these areas, parcel data were used to scale results from urban areas to the remainder of PGE’s service territory. The scaling factors were derived from counting the parcels in areas that were analyzed versus areas that were not analyzed. The scaling factors by property type are shown in Table 4-1

Additional details of the Black & Veatch approach, assumptions, and analysis can be found in Appendix B.

[9] Residential system setbacks – 2 feet from all edges.
Commercial system setbacks – 6 feet around the perimeter of the roof.


**Figure 4-4 Rooftop Assessment Criteria Filters**

### 4.1.2 Results

The analysis evaluated 1.2 billion square feet of rooftop space representing over 400,000 buildings. Of these buildings, single-family residential rooftops that passed the technical criteria totaled over 451 MWdc, and multi-family residential buildings represented another 125 MWdc. Commercial and industrial buildings represented over 1,162 MWdc, while public (government) roofs totaled 62 MWdc. The total technical potential of the areas assessed was 1,800 MWdc. After scaling up to cover the entire PGE service territory, the total technical potential amounted to 2,810 MWdc. Only about 30 percent of this amount is residential, the rest is composed of commercial, industrial, and public/semi-public properties. A summary of the technical screen results is provided in Table 4-1.

**Table 4-1 Identified Distributed Solar PV Technical Potential**

| PARAMETER | LIDAR-ASSESSED AREA TOTAL CAPACITY (MWDC) | SCALE-UP FACTOR | PGE SERVICE TERRITORY TOTAL CAPACITY (MWDC) |
|---|---|---|---|
| Single-Family Residential | 451 | 1.4 | 631 |
| Multi-Family Residential | 125 | 1.3 | 167 |
| Commercial | 586 | 1.5 | 874 |
| Industrial | 575 | 1.5 | 869 |
| Public/Semi-Public | 62 | 4.3 | 270 |
| **Total** | **1,800** | | **2,810** |

It is important to note that the technical potential estimate is based on assessment of the current building stock within PGE's territory. New construction could cause the technical potential to increase over time. A number of other factors could also influence this potential over time, including the following:

- Modifications to the existing building stock.
- Growth/removal of trees and other shading sources.
- Improvements in solar panel efficiency.
- Changes in permitting/zoning requirements and restrictions.
- Innovations in mounting structures, such as lower cost solar carports.

Black & Veatch recommends that PGE regularly update the technical potential estimate and consider these factors in future studies.

## 4.2 FINANCIAL SCREEN

The second step in the process was to apply a series of financially-related screens for estimating solar PV potential in the PGE service territory.

Black & Veatch performed financial calculations by customer site, using the technical assessment for each individual customer site. Site-specific satellite-based meteorological data[10] was used to generate hourly solar PV output profiles for each site. This solar profile then was compared to a customer's hourly load profile. Projects were resized to match designated load profiles, so systems would not over-generate under the net metering tariff. Corresponding utility rates and incentives were included in the calculation of the payback of solar PV for each customer site.

To perform all of these calculations, Black & Veatch developed a DG financial engine based on the National Renewable Energy Laboratory's (NREL) System Advisor Model (SAM). It comprises several modules, including the following:

1. PV System Performance -PVWatts.
2. Customer Rates and Load.
3. Financial Analysis.

Black & Veatch was able to develop an automated calculation approach using cloud computing to process hundreds of thousands of customer sites in a highly automated manner. Black & Veatch leveraged cloud computing to aid in reducing processing time for all production and financial modeling of individual buildings of PGE's service territory, which is an extremely data-intensive endeavor.

In addition to the financial analysis, multiple factors were considered in this screening step. Multi-family dwellings were excluded because there are fundamental challenges in installing systems for shared usage. Since installing solar PV on rooftops is a long-term commitment that both residential and commercial renters are unlikely to pursue, ownership factors were applied to the total estimated potential to represent the portion of the property type that were occupant-owned.

### 4.2.1 PV System Performance

Within SAM, Black & Veatch selected the PVWatts tool to model solar system output for a polycrystalline solar PV technology. It uses inputs that describe a system's dc capacity, array orientation, mounting type, and system losses. These input assumptions were extracted during the technical screen step. Along with PVWatts, Black & Veatch utilized Clean Power Research's hourly solar resource dataset, SolarAnywhere. These data are available for Oregon on a 10 kilometer (km) by 10 km grid, and each building was matched to the respective grid for the appropriate dataset. Black & Veatch developed system assumptions that are representative of typical system parameters or losses seen in the industry for input into SAM. These assumptions are summarized in Appendix B.

[10] These data were provided by Clean Power Research. The dataset is called SolarAnywhere.

### 4.2.2 Customer Load and Rates

To calculate the bill savings of solar to a customer, SAM is able to incorporate a customer's hourly load shape over a year as well as a particular utility rate structure as part of its utility rate and customer load modules. Based on the technical screen, buildings were segmented into residential and commercial customers. Without knowing what individual customer loads were, Black & Veatch utilized representative average load shapes, provided by PGE, for each customer rate class.[11] Residential and industrial customers were identified through their respective parcel classifications.

Building loads of commercial customers were not readily available, so building floor space was used, reported in tax parcel data, to classify commercial customers into appropriate rate classes. Black & Veatch developed representative ranges of building floor space using Commercial Building Energy Consumption Survey (CBECS) from the Energy Information Administration (EIA) specific to Oregon. Table 4-2 summarizes the rate classes, demand, and floor space equivalents assumed.

**Table 4-2 Customer Loads and Rate Classes**

| PGE RATE SCHEDULE | CUSTOMER CLASS | DEMAND RANGE (KW) | PARCEL CLASS | BUILDING FLOOR SPACE (SQ FT) |
|---|---|---|---|---|
| 7 | Residential | N/A | RES | N/A |
| 32 | Small Commercial | < 30 | COM | 0 to 6,000 |
| 83 | Medium Commercial | 31 - 200 | COM | 6,001 to 36,000 |
| 85 | Large Commercial | 201 - 4000 | COM | 36,001 to 728,000 |
| 89 | Industrial | > 4000 | IND | Over 728,000 |

Furthermore, given that Oregon's net metering rules do not compensate customers for annual energy production that exceeds annual consumption, PV systems were resized when they exceeded the respective building's annual load assumption.

### 4.2.3 Financial Analysis

NREL's SAM was used to analyze the financials for each customer site. SAM's financial model calculates a project's cash flow over an analysis period that a user specifies. The cash flow captures the electricity bill savings from a PV system and accounts for incentives, cost of installation, operation and maintenance, taxes, and financing assumptions. It is important to note that SAM calculates net energy savings differently for residential and commercial customers. For residential customers, the full energy savings annually is accounted for in the net cash flow calculation. However, for commercial customers, since electricity charges are an expense that is tax deductible as part of regular business operations, any reductions to their electricity bills (i.e., bill savings) will need to be adjusted by the commercial customer's effective federal plus state tax rate. In other words, the annual net bill savings is reduced by up to 40 percent for Oregon businesses. On the other hand, for public and non-profits that are tax-exempt, they are not able to take advantage of tax credits and accelerated depreciation treatment, so their upfront installed costs are higher.

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[11] The analysis could be improved in future work by using real customer load data for each site.

Black & Veatch chose to assess the identified systems using payback period as the financial metric because it is widely understood and is taken into account by customers considering a solar PV system on-site. Payback normalizes for system sizes since it compares total system cost to ongoing annual savings. Payback is also a common metric for adoption analysis, which is an input to the achievable screen.[12] Black & Veatch acknowledges that third-party leasing of systems, where customers do not have to pay an upfront cost, are becoming more prevalent in PGE's service territory, as evidenced by recent installations. However, given the observed pricing behavior of third-party participants, such as Solar City, resulting in negative earnings, it was not possible to model TPO financials in a reasonable manner,

For the purposes of calculating the payback period as the financial metric, Black & Veatch assumed a cash upfront purchase (no loans), 20 year project life, and an inflation rate of 2 percent, consistent with historical Consumer Price Index (CPI) changes. For ongoing operations and maintenance (O&M) costs, Black & Veatch assumed minimal maintenance costs on the part of the customer and no property taxes, as Oregon currently allows solar property to be exempt from property taxes. The primary component of the O&M cost is associated with inverter replacement some time during the life of the project. This cost was amortized over the life of the project. Refer to Table 4-3.

**Table 4-3 Distributed Financial Assumptions**

| INPUTS | ASSUMPTION | |
|---|---|---|
| | RESIDENTIAL | COMMERCIAL/INDUSTRIAL |
| Ownership Structure | Customer-owned | Customer-owned |
| Federal Income Tax Rate (%) | 25 | 35 |
| State Income Tax Rate (%) | 9 | 7.6 |
| Sales Tax | Exempt | |
| O&M Cost ($/kW-year) | 15 | 10 |

For distributed solar systems in Oregon, there are several federal and state solar PV incentives available to residential and commercial customers. Some of these incentives are due to expire in the near-term but there is a possibility of renewal, or renewal at a different amount. The ETO incentives are adjusted annually, both in total funding and incentive levels. Additional background information can be found in Appendix C.

In any case, there is significant uncertainty regarding the future availability of these incentives, both at the federal and state levels. Rather than testing various combinations of projected solar cost decline and incentive assumptions for 2016, Black & Veatch focused on the benefit/cost ratio to customers, similar to the Participant Test approach.[13] Since the ETO has the flexibility to adjust incentives according to market changes, whether it is system cost declines or changes to state tax

[12] The payback metric used in NREL's adoption surveys is a non-discounted payback, consistent with this report.
[13] The Participant Test derives from energy efficiency measures and is calculated as the net present value (NPV) of total benefits over the NPV of total costs. Benefits consist of bill savings, incentives, and other avoided fuel costs. Costs include customer outlays for initial capital costs and ongoing maintenance of the PV system.

incentives, the more critical component is the benefit/cost ratio to customers. Based on 2014 system costs and available incentives, the benefit/cost ratios for representative residential and commercial installations were calculated to be approximately 1.2 and 1.1, respectively. Refer to Table 4-4.

**Table 4-4 Benefit/Cost Ratio for Representative Systems in 2014**

| | CUSTOMER TYPE | |
|---|---|---|
| | RESIDENTIAL | COMMERCIAL/ INDUSTRIAL |
| Representative System Size (kWdc) | 4 | 100 |
| System Cost ($/Wdc) | 4.50 | 3.20 |
| Accelerated Depreciation | None | 5-years MACRS |
| Federal Incentives | 30% of total installed cost | |
| State Incentives | $1.90/W, 50% of installed cost or $6,000, whichever is less and rolled out over four years up to a max of $1,500 disbursed per year | None* |
| ETO Incentives ($/Wdc) | 0.95 | 1.08 |
| O&M ($/kW-year) | 15 | 10 |
| Calculated Benefit/Cost Ratio | 1.3 | 1.1 |
| Simple Payback (years) | 5 | 4 |

MACRS = Modified Accelerated Cost Recovery System.

Notes:
*Even though there is a state renewable energy grant for businesses, it is not possible to estimate the level of award since the grant program is competitively bid and is available to all renewable energy technologies, not just solar.

Based on the benefit/cost ratios calculated for 2014 systems, Black & Veatch estimated what the 2016 ETO incentive for residential and commercial customers would need to be, given the forecast of solar costs in 2016, to maintain a similar level of benefit/cost ratio. Since both the federal ITC and Oregon tax credits for residential customers will still be available in 2016 and Black & Veatch forecasted a steep drop in residential system costs, it was determined that no ETO incentives were needed to maintain the benefit/cost ratio for residential customers. Commercial customers, on the other hand, do not have the benefit of an Oregon tax credit. What is available is the Oregon business grant, but that is a competitive auction open to all renewable energy technologies, thus highly unpredictable as a source of funding. Therefore, while Black & Veatch forecasted a significant drop in commercial system costs by 2016, some level of incentives would still be needed in 2016 to maintain the benefit/cost ratio as experienced in 2014. Black & Veatch assumed a 50 percent reduction to 2014 incentives for commercial customers.

The incentive assumptions for 2016 are described in Table 4-5.

**Table 4-5 Distributed Generation Incentive Assumptions for 2016**

| INCENTIVE | CUSTOMER TYPE | |
|---|---|---|
| | RESIDENTIAL | COMMERCIAL/INDUSTRIAL |
| Accelerated Depreciation | None | 5 years MACRS* |
| Federal Incentives | Investment Tax Incentive (ITC): 30% of total installed cost | |
| State Incentives | $1.50/W, 50% of installed cost or $6,000, whichever is less and rolled out over 4 years up to a max of $1,500 disbursed per year | None |
| ETO Incentives** | No incentives necessary | (Half of 2014 Incentives)<br>0-25 kW: $0.65/W<br>26-250 kW: $0.65-$0.36/W<br>Max incentive per customer is $90,000 |

Notes:
*By law, the depreciation cost basis for MACRS is reduced by 50% of the ITC.
** The ETO incentives were estimated to maintain a benefit to cost ratio for sample residential and commercial projects under ETO's program in 2014.

For the 2035 test year, Black & Veatch assumed that no incentives would be available, except for the 5 year accelerated depreciation. By 2035, it is assumed that the market will be mature enough that incentives and subsidies are no longer necessary.

Incentives have long been an important part of the financials of PV, and Oregon has had some of the highest incentives for solar PV in the country. For example, the combined federal, state, and ETO incentives can reduce the installed cost of PV in Oregon by about 55 to 75 percent. This strongly influences the payback of systems in 2016. In contrast, the payback for systems in 2035 is tied to the more fundamental financials of the systems, including capacity factor, capital cost, and rate structure.

To illustrate the impact of incentives on net cost to customers, Figure 4-5 compares the modeled installed cost curves for 2016 and 2035 residential systems in real 2014$ by system size. Figure 4-6 shows similar information for commercial systems. The graphs also show the resulting net capital cost to residential and commercial customers after incentives. The combinations of applicable incentives (Federal ITC, MACRS, Oregon tax credit, and ETO incentives) in 2016 for residential and commercial customers tend to distort the net cost to customers, depending on the size of the system. For example, the 2016 residential net cost start at about $1,160/kW for a 1 kW system dips down to $830/kW for a 4 kW system, and then rises to $1,600/kW for a 12 kW system. The shape of the 2016 curve is due to the incentive limitations defined by the Oregon tax incentive program. Costs in 2035 are generally higher than the 2016 net cost after incentives. For example, while the net cost for a 4 kW system in 2016 is $830/kW, the same system in 2035 is $1,350/kW – about 60 percent higher.

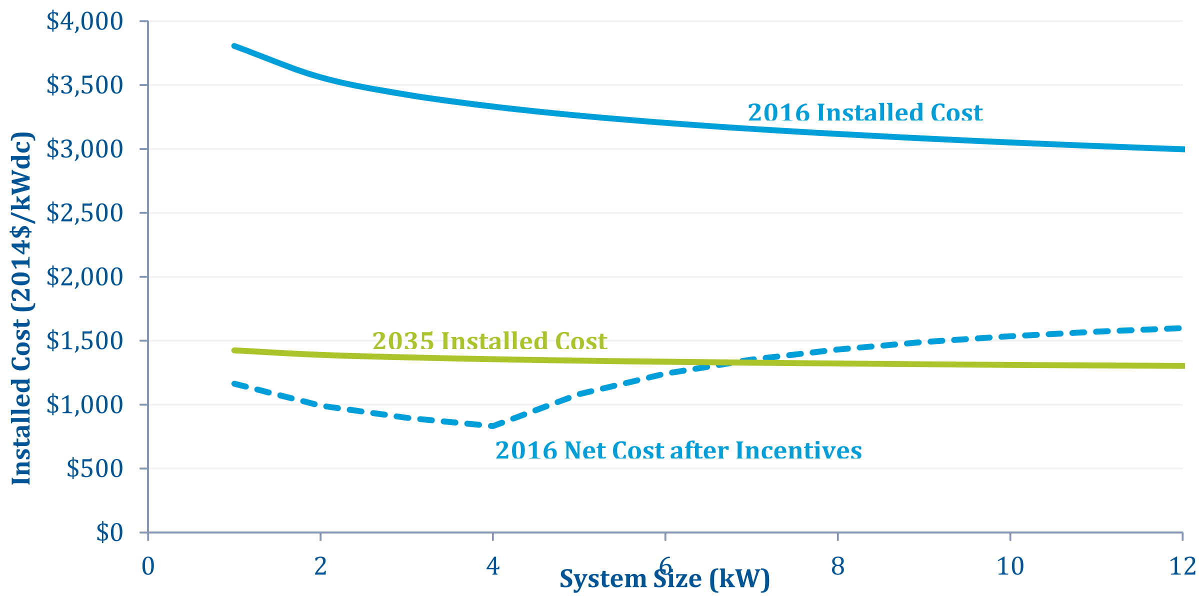



**Figure 4-5** **Comparison of Installed Residential PV Costs by System Size in 2016 and 2035**

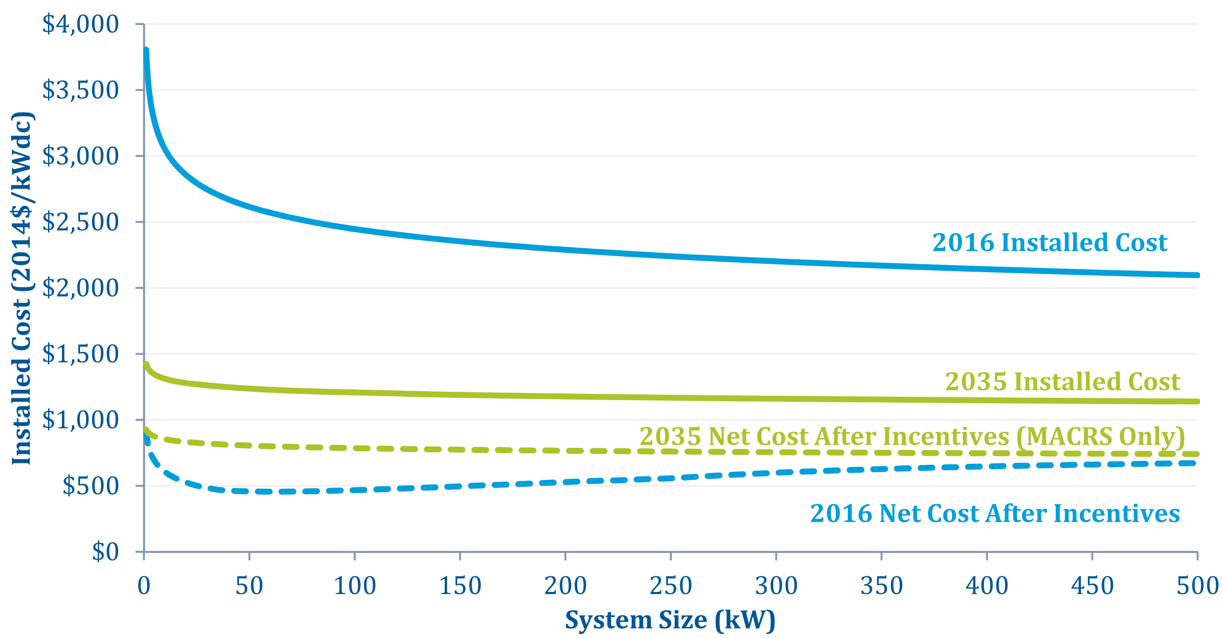



**Figure 4-6** **Comparison of Installed Commercial PV Costs by System Size in 2016 and 2035**

As shown on the commercial graph, the 2016 net cost declines to as low as $455/kW for a 60 kW commercial system and then rises to $670/kW for a 500 kW system. For commercial customers, the net capital cost in 2035 (after accounting for MACRS only) is significantly higher than the 2016 net cost for most systems. For both residential and commercial systems, costs for most systems installed in 2035 are assumed to be higher than the net costs of systems installed in 2016 with incentives. While system costs are projected to decline 50 to 65 percent over this period, the loss of the lucrative incentives is too much. These distortions caused by incentives will appear in the payback calculations in the financial analysis.

### 4.2.4 Financial Screen Cases

To model the financially viable potential over the study period (2016 to 2035), Black & Veatch first calculated the payback for sites at the beginning and end points of the period. For the 2016 cases, this case included all incentives that are available to solar by customer type including federal investment tax credit (ITC@30%) and accelerated depreciation, Oregon state tax credit for residential customers, and ETO funding. The 2016 case used the forecasted installed cost in 2016. The 2035 cases assumed no incentives would be available except for accelerated depreciation and included the 2035 forecasted installed cost. These two cost years were tested under utility rate increase conditions of CPI and CPI+1.

**Table 4-6 Financial Cases for Solar Distributed Generation**

| CASES | CPI | CPI+1 |
|---|---|---|
| 2016 | All incentives are available. 2016 cost assumptions. Utility rate escalates at CPI. | All incentives are available. 2016 cost assumptions. Utility rate escalates at CPI+1 percent. |
| 2035 | No incentives are available, except accelerated depreciation. 2035 cost assumptions. Utility rate escalates at CPI | No incentives are available, except accelerated depreciation, 2035 cost assumptions. Utility rate escalates at CPI+1 percent |

Financially viable potential is defined as systems with paybacks of less than 20 years, or the life of the project, for both residential and commercial customers. In all cases, almost all of the systems identified in the technical screen were also financially viable, in that they had paybacks of less than 20 years.[14]

As mentioned earlier, additional criteria were used to screen the potential in PGE's service territory, including exclusion of multi-family dwellings and residential and commercial renters Table 4-7 shows the assumed percent of owner-occupied buildings by sector.[15]

**Table 4-7 Assumed Owner-Occupied Portion of Buildings by Sector**

| RESIDENTIAL | COMMERCIAL | INDUSTRIAL | PUBLIC/ SEMI-PUBLIC |
|---|---|---|---|
| 72% | 48% | 48% | 100% |

[14] While it may seem surprising that nearly all the systems modelled are deemed financially viable, it is due to a few factors: (1) the technical potential estimate excluded lower quality systems with less than 75 percent TSRF, (2) incentives are often set to ensure systems can be financially viable, and (3) Black & Veatch is assuming cost reductions over time.

[15] The residential ownership data were provided by PGE, while the commercial ownership data were derived from EIA's 2003 Commercial Building Energy Consumption Survey (CBECS) for the Pacific region. The CBECS survey data represent a sampling of 580,000 buildings across California, Oregon, and Washington. No Oregon-specific data for commercial ownership were available.

For both 2016 and 2035 cases, under both utility rate increase scenarios, all systems analyzed demonstrated paybacks of fewer than 20 years across the scenarios. After applying the exclusions described above, the total remaining capacity represented is about 1,410 MWdc. Table 4-8 shows the breakdown between remaining residential and commercial customers classes for all scenarios.

**Table 4-8 Potential Capacity Remaining After Financial Screens**

| CUSTOMER CLASS | ALL SCENARIOS (MWDC) |
|---|---|
| Residential | 415 |
| Commercial (including industrial and public / semi-public) | 995 |
| **Total MWdc** | 1,410 |

### 4.2.5 Payback Distribution Discussion

For the various scenarios, however, the distributions of payback periods are different by customer type, year of analysis, and utility rate assumptions. The payback distribution for residential customers in 2016 and 2035 under CPI and CPI+1 percent are shown on Figure 4-7 and Figure 4-8. These graphs show the total MWdc of rooftop solar for each payback period (segmented by 0.1 years). The results show that while the cost of solar is assumed to decline significantly by 2035, the modest rise in utility rates in both cases is not sufficient to offset the lack of incentives. Therefore, the payback periods increase significantly in 2035. The residential paybacks appear to follow a log normal distribution with a wide range of payback periods due to site-specific solar resources (capacity factor) and system size (capital cost). In the 2035 CPI+1 percent scenario, the payback periods are improved compared to 2035 CPI scenarios, since the utility rate is higher by 2035.

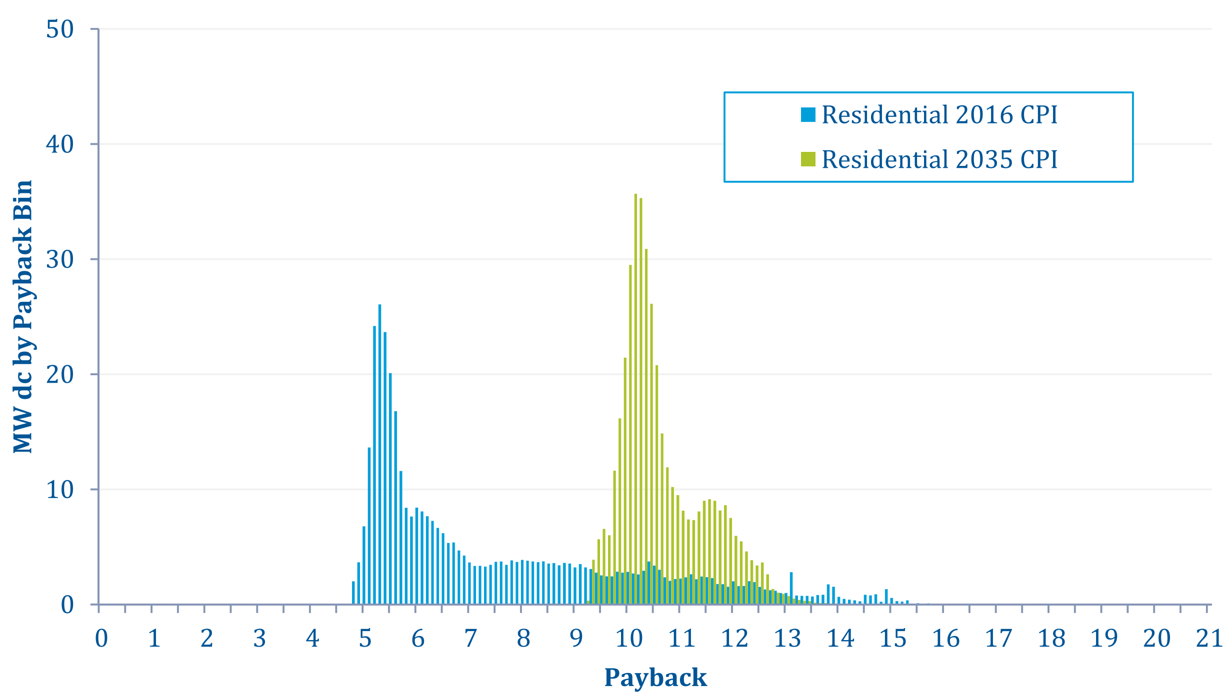


**Figure 4-7 Residential Systems by Payback Periods (CPI Scenario)**

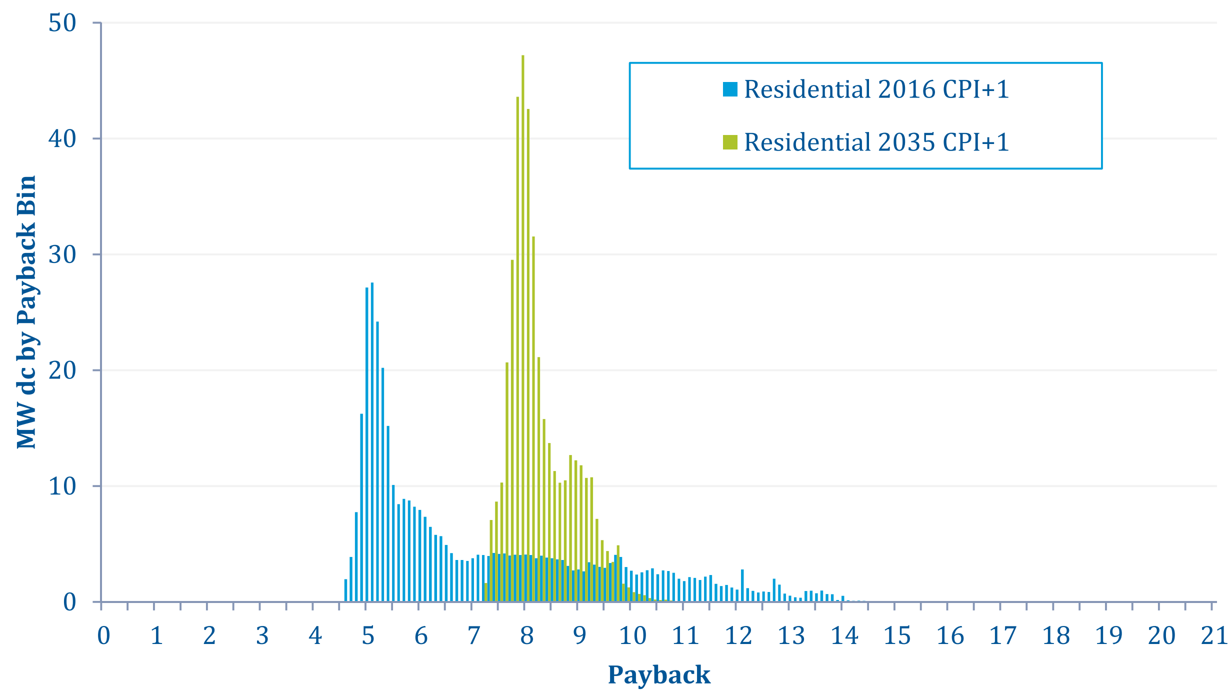



**Figure 4-8 Residential Systems by Payback Periods (CPI+1 Scenario)**

For commercial customers, the effect of the ETO incentive curve assumption in 2016 results in a bimodal distribution (i.e., two groups) of payback periods, as the ETO incentive does not reduce system costs uniformly across system sizes (refer to Figure 4-9 for the CPI scenario and Figure 4-10 for the CPI+1 scenario).

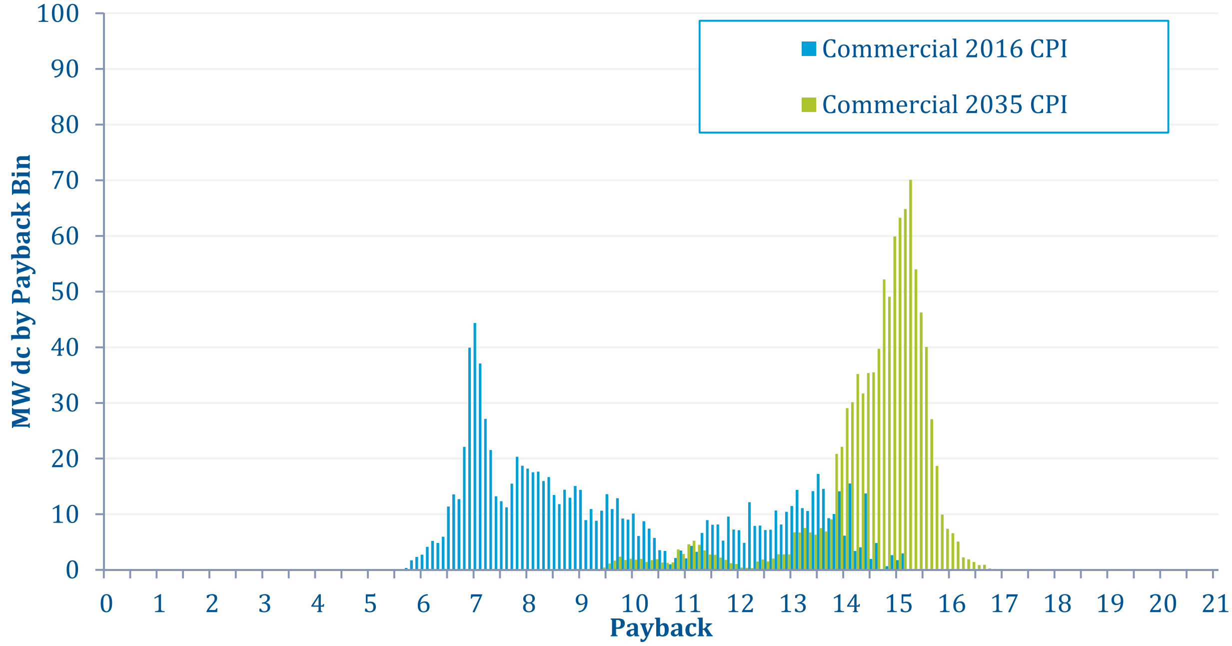



**Figure 4-9** Commercial Systems by Payback Period (CPI Scenario)

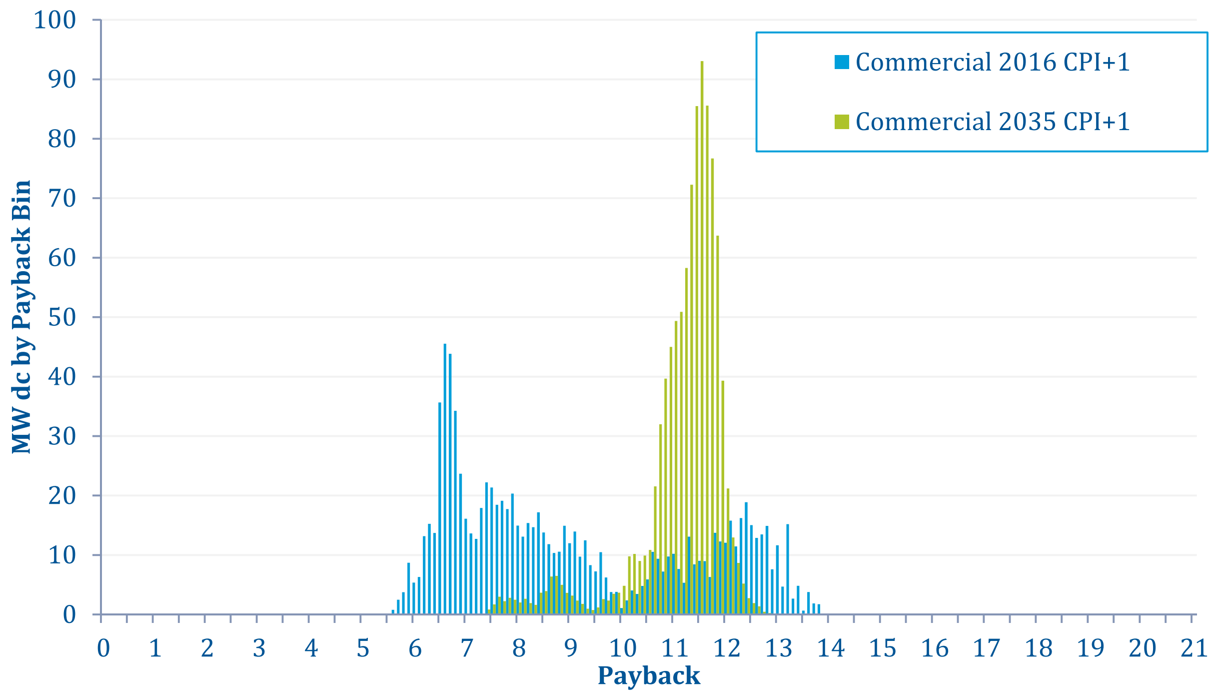



**Figure 4-10** Commercial Systems by Payback Period (CPI+1 Scenario)

There is more complexity displayed in the distribution of commercial paybacks than in the residential sector distribution. This is due to the much wider range of system sizes available and the multiple rate schedules modeled. That said, the overriding trends in the commercial sector payback periods are similar to the residential sector. Payback periods are longer for systems in the 2035 case, and higher rate increase cases significantly lower paybacks. The commercial sector payback periods are more sensitive to rate increase assumptions because of the way bill savings are reduced by the effective tax rate in the cash flow calculation.

While the financial calculations show paybacks of less than 20 years for all systems, this does not necessarily translate to adoption by customers. There are other numerous factors that influence a customer's decision to adopt a technology that may not be directly tied to financials. In the next section, market penetration constraints are applied to the payback distribution to estimate achievable potential.

## 4.3 ACHIEVABLE SCREEN

In order to determine achievable potential within the study period, Black & Veatch used survey-based data to translate the previous payback distributions to maximum market potential and then forecasted the adoption of solar over the study period under two different approaches.

Black & Veatch took two approaches to capture the range of adoption of solar over time: bottom-up (technology adoption limited) and top-down (ETO constrained).

1. **Technology Adoption Limited:** The first approach is a bottom-up approach maximum achievable market potential and applying a technology adoption curve to simulate annual adoption going forward.
2. **ETO Funding Constrained**: For the top-down approach, Black & Veatch opted to test alternative scenarios where the payback, thus maximum market potential, over time is maintained at the same level as in 2016 by assuming thatETO incentives continue to be available during the study period.

The annual adoption scenarios tested are shown in Table 4-9.

**Table 4-9 Scenarios for Annual DG Solar Adoption**

| | CPI | CPI+1 |
|---|---|---|
| **Technology Adoption Limited (Bottom-Up)** | Market matures from incentives available in 2016 to no incentives available by 2035 | Market matures from incentives available in 2016 to no incentives available by 2035 |
| **ETO Funding Limited* (Top-Down)** | **With Tax Credits:** Federal (10% ITC) and state tax credits (residential only)** available throughout study period | **With Tax Credits:** Federal (10% ITC) and state tax credits (residential only)** available throughout study period |
| | **No Tax Credits:** Only ETO incentives are available | **No Tax Credits:** Only ETO incentives are available |

* Total annual ETO funding is capped for residential ($3 million) and commercial ($2.6 million) customers, based on 2015 ETO incentives allocated to PGE's service territory.
** Oregon residential tax credit is stepped down by $0.20/W per year.

### 4.3.1 Maximum Market Potential

While the financial calculations show paybacks of less than 20 years for all systems, an individual's willingness to adopt the technology will depend on whether the payback period is attractive to the individual. Using the results of surveys of residential and commercial customers' preferences for adopting solar and distributed generation, NREL (residential) R.W. Beck (commercial), and Navigant (commercial) developed maximum market penetration curves that indicate the likelihood of market penetration given a certain amount of payback for that customer class. In other words, the survey data specifies what portion of a group of customers given a certain payback outlook, would actually adopt the technology--the shorter the payback period, the more likelihood of adoption. The penetration curve was then applied to the payback distribution for each of the financial cases to determine the total achievable potential. The two step process is described below:

1. **Maximum Market Penetration Curves:** Maximum market penetration curves represent the potential adoption of a technology based on an expected payback period (Figure 4-11). For example, for sites that can achieve a 5 year payback, the uptake by residential customers is about 64 percent, while commercial customers would be 22 percent. This is due, in large part, to commercial customers requiring much quicker paybacks on investments. These surveys account for the decision-making process across a broad demographic of customers.

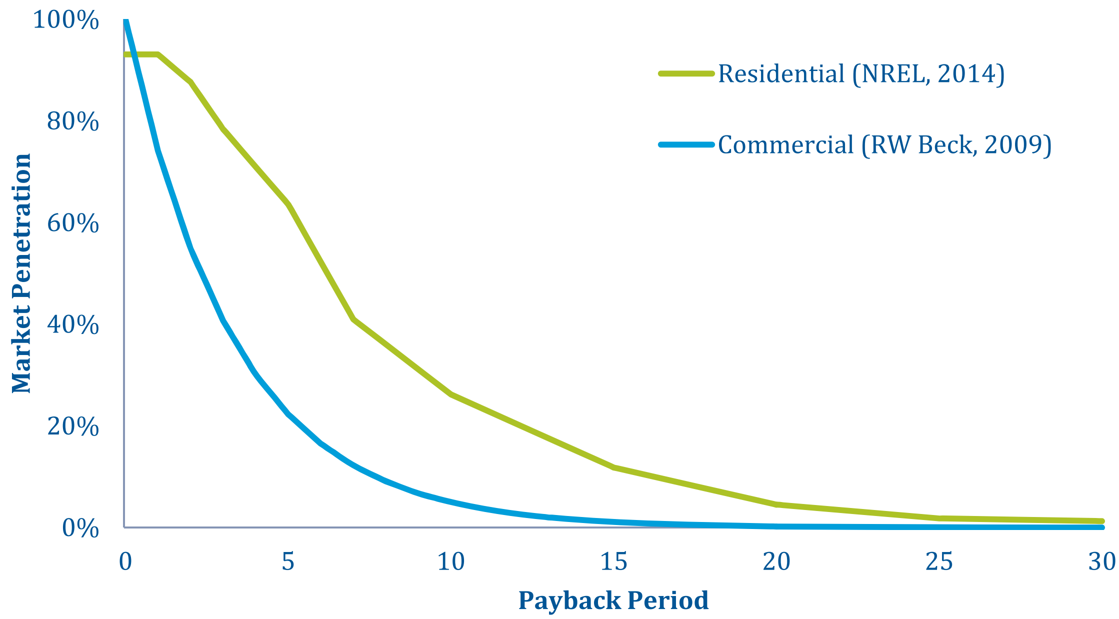



**Figure 4-11 Maximum Market Penetration Curve for DG Solar (source: NREL and R.W. Beck)**

2. **Resulting Maximum Market Potential:** By multiplying the payback distributions for each of the four financial cases and customer type (Figure 4-7 through Figure 4-10) and the max market penetration level for each payback period (Figure 4-11), it is then possible to derive the cumulative total maximum market potential for the customer class. Figure 4-12 and Figure 4-13 show the result for the CPI + 1 cases for residential and commercial customers. Note the application of the maximum market penetration curve greatly reduces the market potential when paybacks are 5 to 15 years, as they are in each of the cases in this study. It is also important to understand the powerful effect of the commercial market penetration curve on the commercial sector, as the potential is reduced from 995 MW of potential to just over 80 MW of maximum market potential in 2016 CPI+1 case. The maximum market potential is even lower in the other commercial customer cases. Furthermore, the maximum market potential in 2035 actually is lower than in 2016 because the net capital cost to customers increases in real dollars after expiration of incentives.

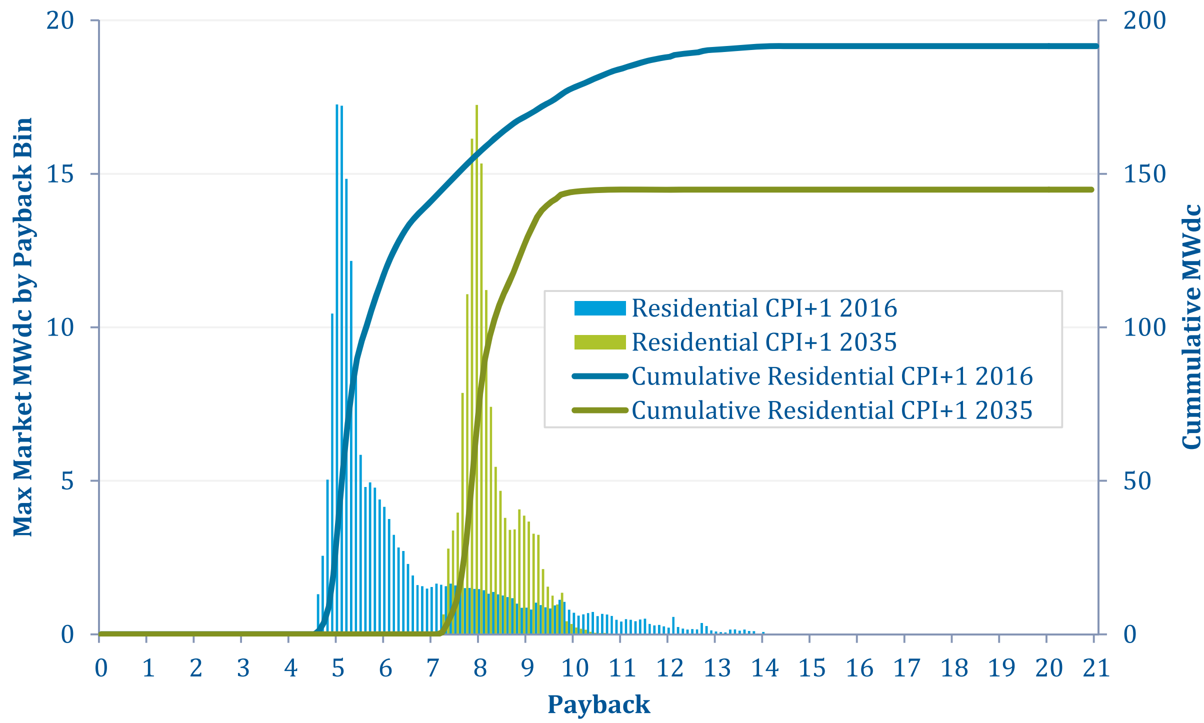



**Figure 4-12** **Maximum Market Potential Example (Residential CPI+1)**

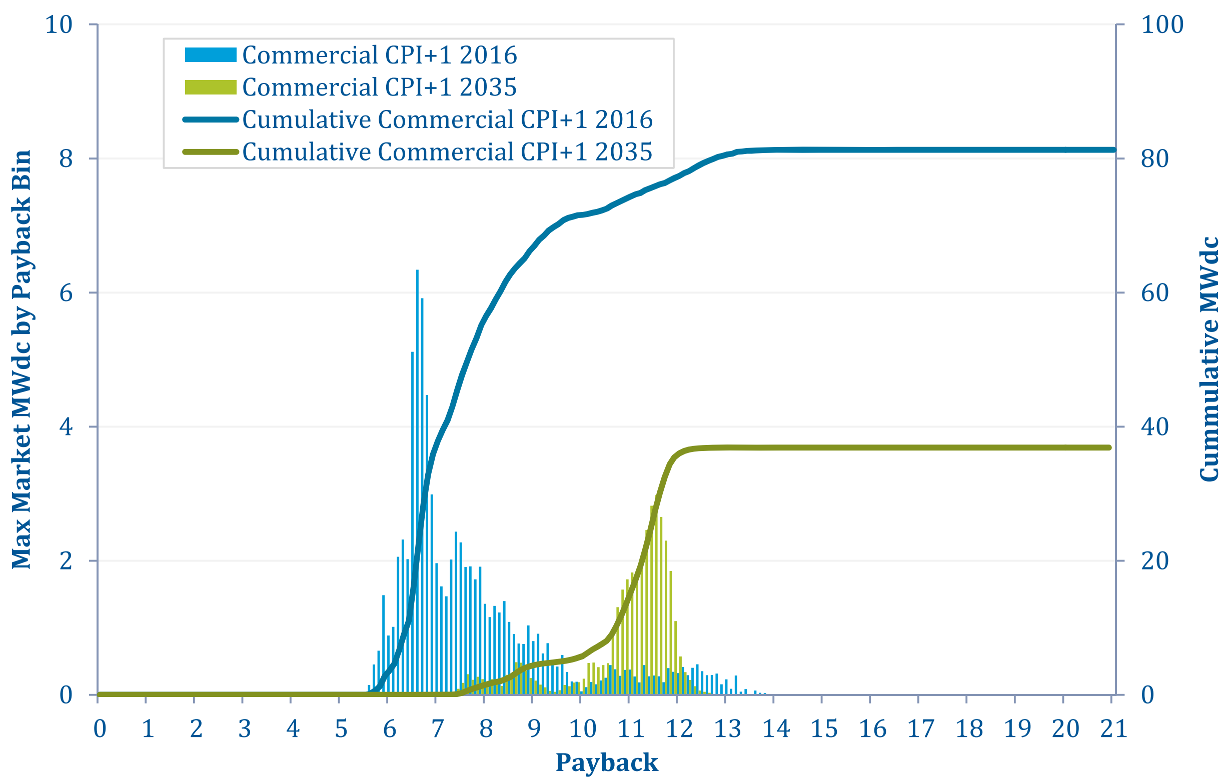



**Figure 4-13** **Maximum Market Potential Example (Commercial CPI+1)**

The resulting cumulative maximum market potential for each of the cases tested is shown in Table 4-10. These represent the maximum market potential under each of the financial cases and include already installed systems in PGE service territory. The remaining market potential is also shown.

**Table 4-10 Summary of Maximum Market Potential (MWdc)**

| | CPI | | CPI+1 | |
|---|---|---|---|---|
| | 2016 | 2035 | 2016 | 2035 |
| Residential | 180 | 102 | 192 | 145 |
| Commercial | 70 | 14 | 81 | 37 |
| **Total** | **250** | **116** | **273** | **182** |
| **Remaining Potential (Less Current and 2015 Installations)** | **202** | **68** | **225** | **134** |

### 4.3.2 Annual Adoption Forecast

Taking the maximum market potential, Black & Veatch then developed estimates of annual adoption based on a range of adoption scenarios. Forecasts were developed on an annual basis from the year 2016 through 2035. Black & Veatch took two approaches to capture the range of forecasted adoption of solar over time: bottom-up (technology adoption limited) and top-down (ETO constrained), which are discussed in greater detail in the following sections.

#### 4.3.2.1 Technology Adoption Limited

Once the maximum market potential under each of the four cases was determined, Black & Veatch implemented a standard analytical approach using a technology adoption curve approach to determine annual adoption over time. Black & Veatch relied on representative S-curve adoption curves to forecast adoption over time in this approach. Typically the adoption curve is applied to the maximum market potential to derive the annual adoption each year, but for the 2016 and 2035 cases tested, the maximum market penetration level is lower in 2035 cases than 2016 cases due to different cost and incentive assumptions, Therefore, the overall maximum market potential is assumed to decline linearly overtime between 2016 and 2035.

The steps below describe the process.

1. **Linear Decline of Maximum Market Potential**: Taking the 2016 and 2035 financial cases of maximum market potential as bookends, the maximum market potential was linearly interpolated across time to represent a decline in overall market potential. The decline in market size over time assumes that various state and federal incentives are being reduced over time as the market transitions to a self-sustaining, mature market. The lack of incentives by 2035 results in a smaller maximum market potential as PV paybacks are higher than in the 2016 cases when incentives are readily available. This implies that, given forecasted capital costs, the market potential by 2035 will continue to require incentives or alternative financing, at some level to support continued growth.

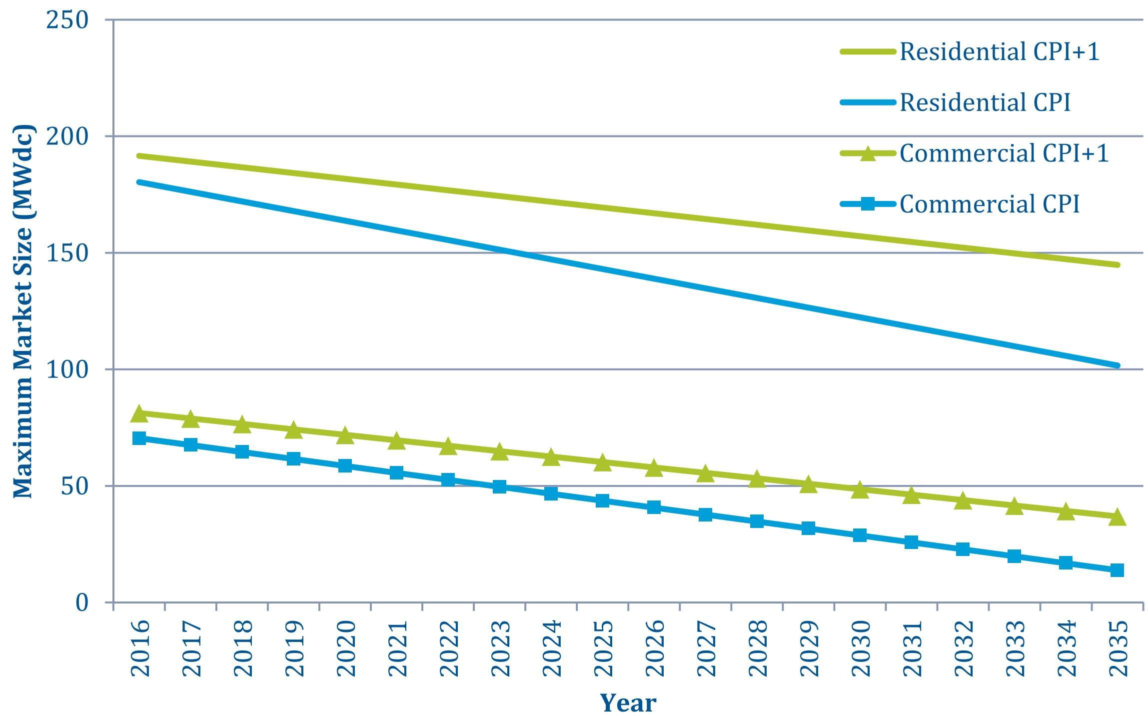



**Figure 4-14 Technology Adoption Limited Maximum Market Size Over Time**

2. **Adoption Curve:** Once the maximum market potential is established, the annual uptake of the technology each year is then determined using a technology adoption curve approach. The rate of PV adoption (S-Curve) is calculated using the bass-diffusion model where time ($T$), the "coefficient of innovation" characterizing early adopters of a technology ($p$), and the "coefficient of imitation" characterizing late adopters of a technology ($q$) define the rate of adoption. Because paybacks of up to 20 years are included, the maximum market potential was further divided into those with paybacks equal to or less than 10 years and those greater than 10 years, as these two different segments would have different adoption rates.[16] The bass-diffusion model $p$ and $q$ values came from NREL's SolarDS work. NREL uses a $p$ value of 0.0015, and a $q$ value that varies with the financial attractiveness. For paybacks of 3 to 10 years, $q$ = 0.4, and for payback greater than 10 years, $q$ = 0.3. Because the solar market is relatively nascent and dynamic, there is not a strong empirical rationale for these exact values, but the values are based on NREL's literature review in 2009, which indicated these as suitable values for technologies similar to distributed PV.[17] Figure 4-15 shows the two adoption curves. Notably, it takes about 22 years to reach 95 percent market adoption for paybacks less than 10 years, and 28 years for paybacks greater than 10 years.

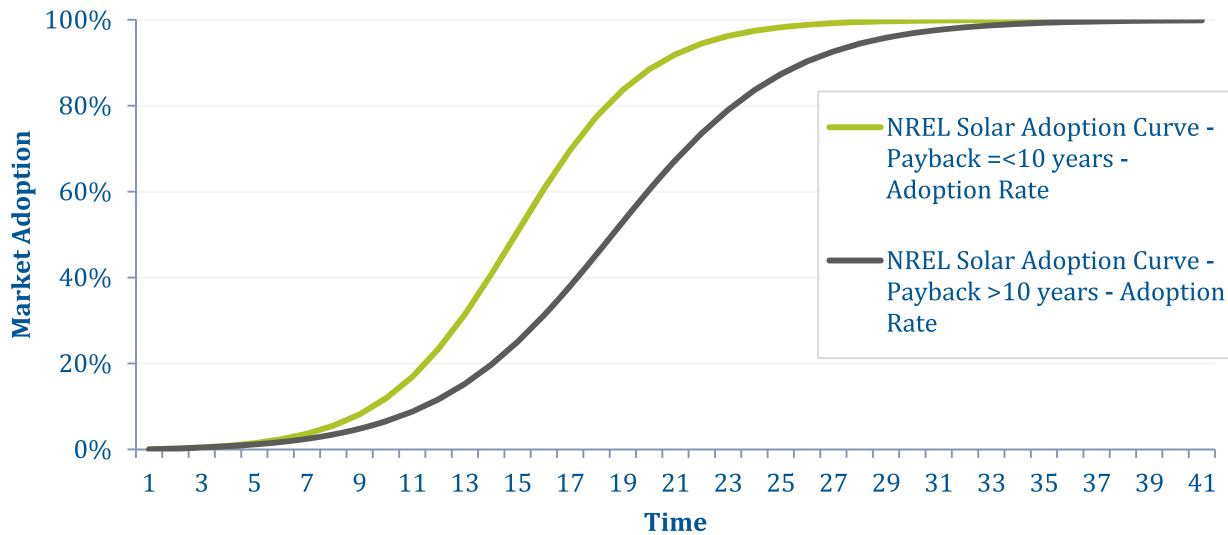



**Figure 4-15 Assumed Solar Adoption S-Curves for Two Payback Ranges (adapted from NREL)**

[16] "Advanced Modeling of Renewable Energy Market Dynamics," May 2006, NREL. http://www.nrel.gov/docs/fy07osti/41896.pdf.

[17] Mahajan, Vijay; Muller, Eitan and Bass, Frank (1995). "Diffusion of new products: Empirical generalizations and managerial uses." Marketing Science 14 (3): G79-G88. doi:10.1287/mksc.14.3.G79.

3. **Current Penetration Level:** To determine the starting point on the adoption curve, Black & Veatch included the total installations in PGE's service territory through 2015 and divided this number by the maximum market potential found for 2016. The initial penetration level includes currently installed net metered and solar feed-in-tariff systems within PGE's service territory, less large ground-mount systems, and additional estimated installations in 2015 based on ETO's planned solar incentives in PGE's service territory. The total MWdc of installed capacity used for determining initial penetration year for residential and commercial customers respectively, were 27.8 and 20.1 MW, respectively. These correspond to the 9th and 11th year along the adoption curves for residential and commercial customers. This matches well with the fact that the ETO has been promoting solar through incentive programs for about 10 years. Refer to Table 4-11.

**Table 4-11 Current 2014 and Estimated 2015 Installed Base of DG Solar in PGE Service Territory**

| CUSTOMER CLASS | 2014 INSTALLED CAPACITY (MWDC)* | ESTIMATED ETO FUNDED INSTALLATIONS IN 2015 (MWDC)** | CUMULATIVE INSTALLATIONS THROUGH 2015 (MWDC) | ESTIMATED ADOPTION YEAR |
|---|---|---|---|---|
| Residential | 23.5 | 4.3 | 27.8 | 9 |
| Commercial | 17.0 | 3.0 | 20.1 | 11 |

* Total installed capacity includes Net Metered and Solar Payment Option projects (level 1 interconnection only) in PGE service territory.

**Based on published ETO funding for 2015 for PGE customers. http://energytrust.org/library/forms/Solar_Status_Report.pdf (Accessed January 15, 2015).

4. **Annual Adoption:** Once a starting point for adoption year was established, Black & Veatch was then able to model the annual adoption of solar PV for the 20 year study period by multiplying the level of adoption for a given year (Figure 4-15) by the corresponding maximum market potential for that year (Figure 4-14) . The resulting annual adoption levels over time for the two utility rate scenarios are shown on Figure 4-16 and Table 4-12. Since solar adoption in PGE's territory was already 9 to11 years along the adoption curves, the adoption rate in the next decade will see an acceleration in adoption until the adoption rate slows down and cumulative market adoption, including the installed base, reaches the maximum market potential, consistent with the adoption curves in Figure 4-15.

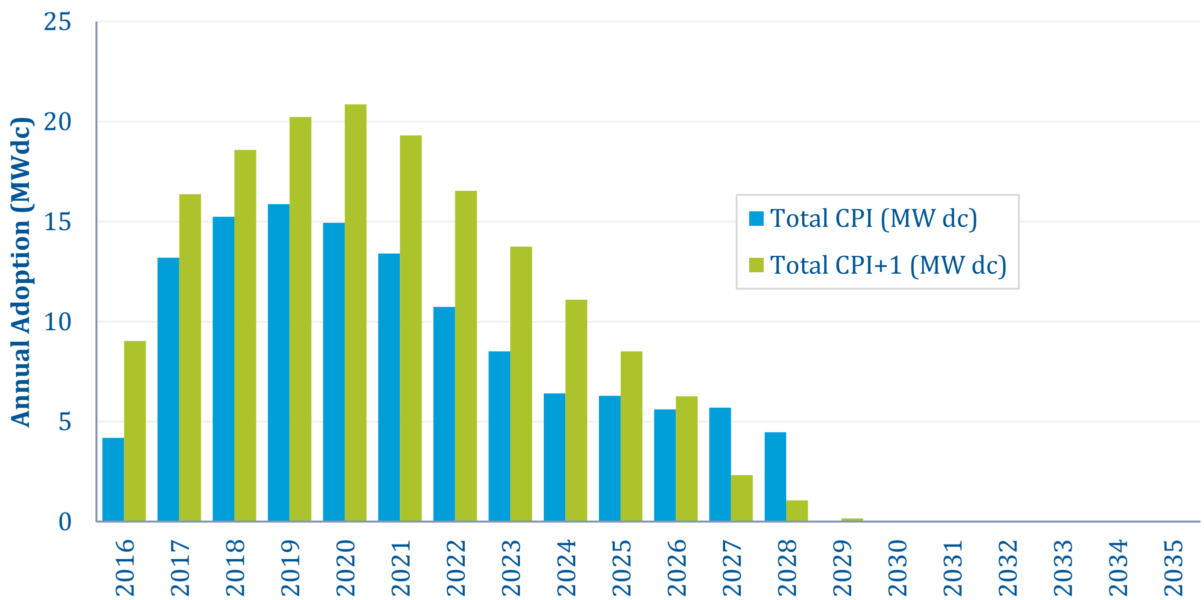



**Figure 4-16 Technology Adoption Limited Annual Solar Distributed Generation Adoption (2016-2035)**

The total cumulative solar installations between 2016 and 2035 equal 124.2 MWdc (CPI) and 164.2 MWdc (CPI+1).

**Table 4-12 Technology Adoption Limited Annual Solar Distributed Generation Adoption (MWdc)**

| YEAR | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|
| CPI | 4.2 | 13.2 | 15.2 | 15.9 | 14.9 | 13.4 | 10.7 | 8.5 | 6.4 | 6.3 |
| CPI+1 | 9.0 | 16.4 | 18.6 | 20.2 | 20.9 | 19.3 | 16.5 | 13.8 | 11.1 | 8.5 |
| **YEAR** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** |
| CPI | 5.6 | 5.7 | 4.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CPI+1 | 6.3 | 2.3 | 1.1 | 0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

While these scenarios reflect a bottom-up approach to capturing market dynamics of technology adoption over time, they do rely on the assumption that sufficient incentives are available to achieve the maximum market potential as forecasted in the intermediate years between 2016 and 2035. These results also reflect a declining market potential because of the inherent assumption that no incentives are available by 2035. By about 2028, the maximum market potential is reached and no additional solar PV is adopted thereafter. In other words, all the customers who would install PV systems have already installed those systems by about 2028-29. Refer to Figure 4-17.

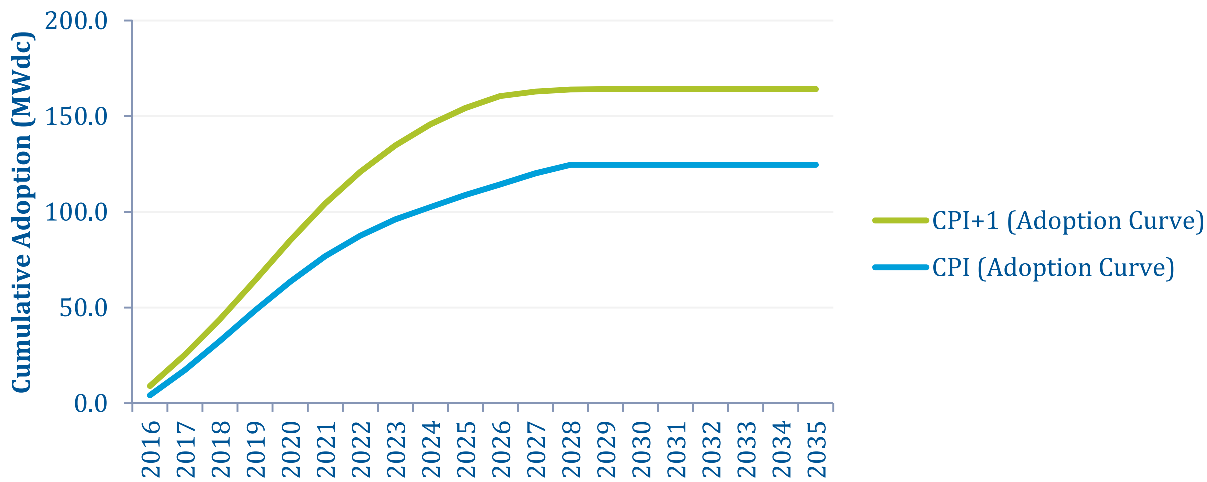



**Figure 4-17 Technology Adoption Limited Cumulative DG Solar Adoption**

In the next section, the impact of incentive funding on adoption is examined.

#### 4.3.2.2 ETO Funding Achievable Potential

In the previous analysis, it was assumed that incentives would not be available by 2035, which resulted in higher paybacks and declining maximum market potential over time. For this analysis, it is assumed that the payback levels, thus maximum market potential established in 2016 would be maintained by adjusting the level of ETO incentives each year going forward. Thus, the maximum market potential remains the same over the study period at 250 MW (CPI) and 273 MW (CPI+1) for the entire study period (see Table 4-10). The remaining potential after netting existing and 2015 installations is also shown.

**Table 4-13 Maximum Market Potential for DG Solar Under 2016 Case**

| | CPI (2016) | CPI+1 (2016) |
|---|---|---|
| Residential | 180 | 192 |
| Commercial | 70 | 81 |
| **Total** | **250** | **273** |
| **Remaining Potential (Less Current and 2015 Installations)** | **202** | **225** |

The assumed objective for these scenarios is that the ETO would provide enough incentives ($/W) to maintain similar payback levels as modeled for the 2016 cases for residential and commercial customers. The ETO $ per W incentive levels are adjusted under different tax incentives conditions and rate increases (CPI and CPI+1 percent). The one limitation is that the absolute annual ETO funding is capped at the announced 2015 levels-- residential ($3 million) and commercial ($2.6

million)--thus limiting the annual MW of projects that the annual budget can support. Black & Veatch assumed this cap increases with the corresponding inflation assumption.

Figure 4-18 and Figure 4-19 show the annual adoption under each of the scenarios. For the cases with tax incentives, greater adoption is seen in the early years because residential customers are assumed to continue to receive the Oregon tax credit, stepped down by $0.20 per W per year, so fewer ETO incentives are needed. Lower ETO incentives mean more capacity can be funded given the fixed amount of funding available. Furthermore, since the maximum market potential for commercial customers is fairly low, the commercial market is saturated by the middle of the study period. Additional breakdown of adoption between commercial and residential customers is provided in 5.3Appendix D.

The highest total cumulative adoption cases by the end of the study period are the two cases that assume a continuation of Oregon tax credits and availability of a 10 percent ITC for the entire study period (Figure 4-20). The detailed annual adoption levels are provided in 5.3Appendix D. In all cases, some ETO incentives are needed throughout the entire study period to maintain the original payback level.

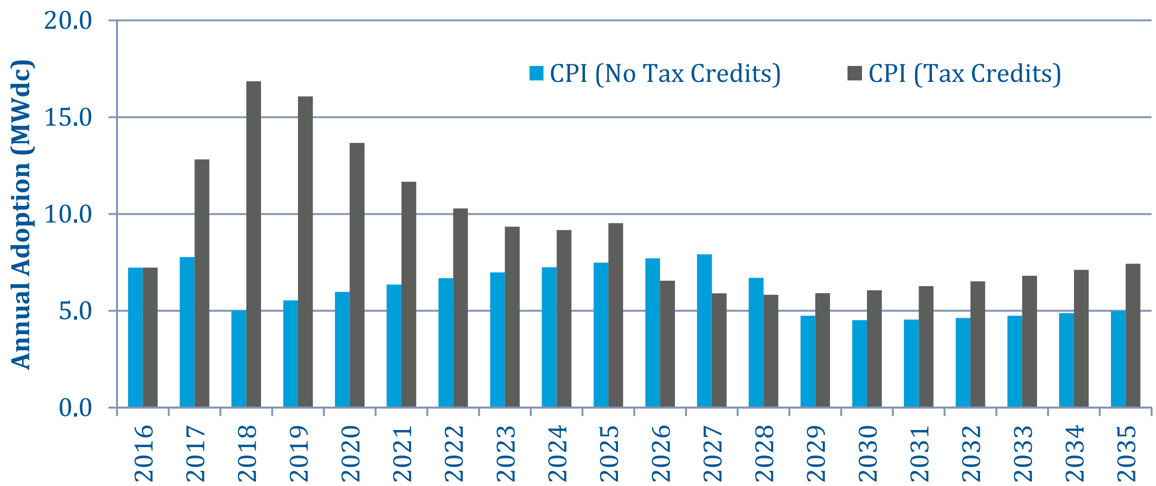



**Figure 4-18 ETO Funding Limited Total Annual DG Solar Adoption (CPI)**

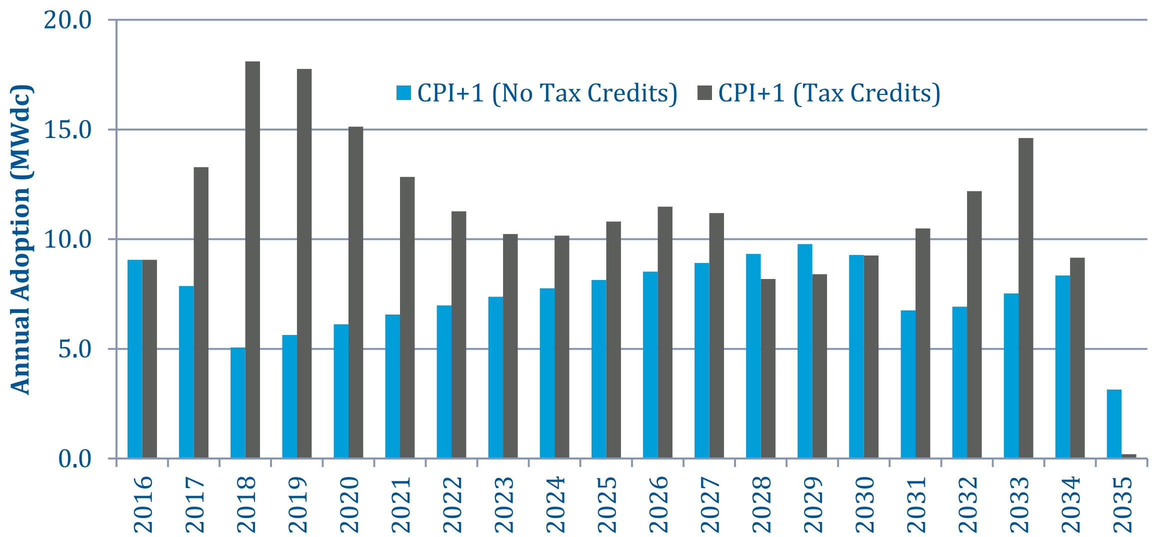



**Figure 4-19 ETO Funding Limited Total Annual DG Solar Adoption (CPI+1)**

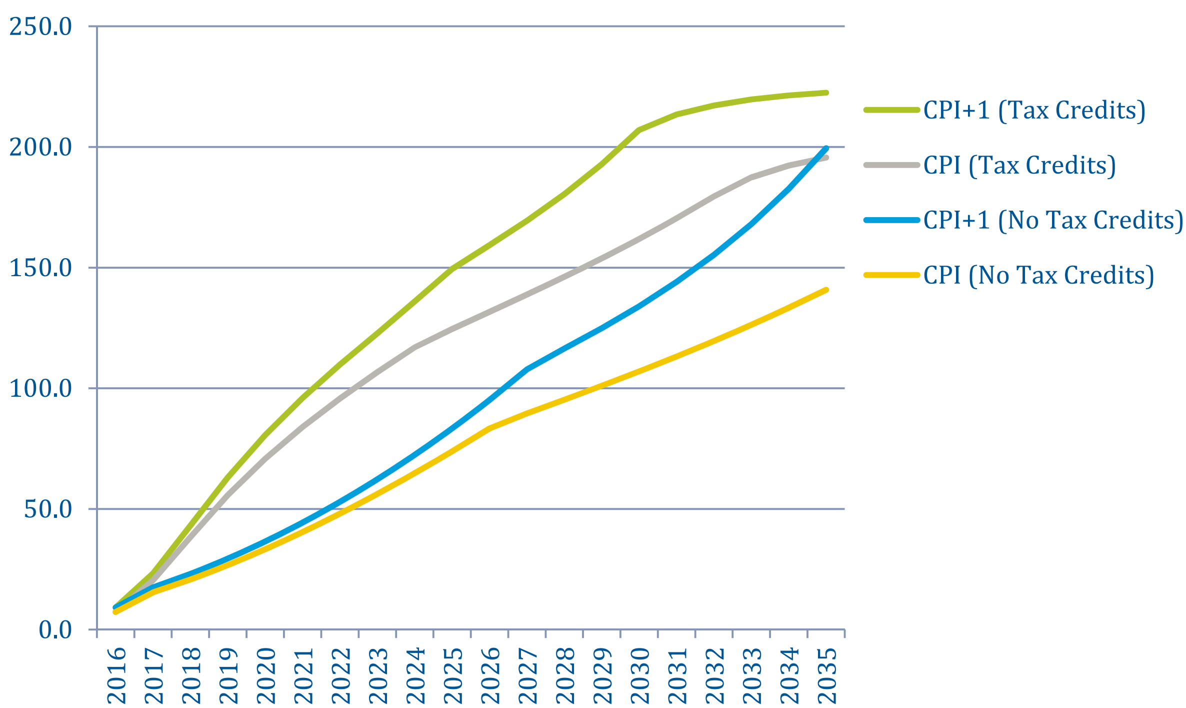



**Figure 4-20 ETO Funding Limited Cumulative DG Solar Adoption (2016-2035)**

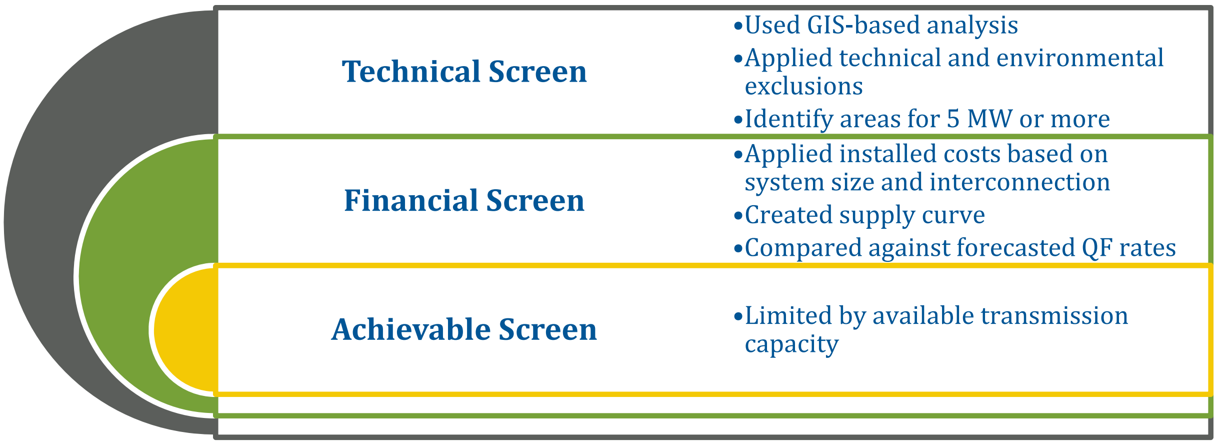
The total cumulative solar installation between 2016 and 2035 without tax credits equals 140.8MWdc (CPI) and 199.5MWdc (CPI+1), and with tax credits equals 195.6 MWdc (CPI) and 222.5 MWdc (CPI+1).

**Table 4-14 ETO Funding Limited Annual Solar Distributed Generation Adoption (MWdc)**

| | CPI (ETO FUNDING -NO TAX CREDITS) | | | CPI+1 (ETO FUNDING - NO TAX CREDITS) | | | CPI (ETO FUNDING – WITH TAX CREDITS) | | | CPI+1 (ETO FUDNING – WITH TAX CREDITS) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | RES | COM | TOTAL | RES | COM | TOTAL | RES | COM | TOTAL | RES | COM | TOTAL |
| 2016 | 2.4 | 4.9 | 7.3 | 4.2 | 5.0 | 9.2 | 2.4 | 4.9 | 7.3 | 4.2 | 5.0 | 9.2 |
| 2017 | 5.2 | 2.9 | 8.1 | 5.4 | 3.0 | 8.3 | 9.9 | 3.2 | 13.1 | 10.4 | 3.7 | 14.1 |
| 2018 | 2.0 | 3.3 | 5.3 | 2.1 | 3.4 | 5.5 | 13.8 | 4.1 | 17.9 | 15.5 | 4.3 | 19.8 |
| 2019 | 2.3 | 3.7 | 6.0 | 2.5 | 3.9 | 6.3 | 12.8 | 4.6 | 17.4 | 15.1 | 4.9 | 20.0 |
| 2020 | 2.6 | 3.9 | 6.6 | 2.9 | 4.2 | 7.1 | 10.1 | 5.0 | 15.1 | 12.2 | 5.4 | 17.5 |
| 2021 | 2.9 | 4.2 | 7.1 | 3.3 | 4.6 | 7.8 | 7.8 | 5.3 | 13.1 | 9.5 | 5.9 | 15.3 |
| 2022 | 3.2 | 4.4 | 7.6 | 3.7 | 4.9 | 8.6 | 6.2 | 5.6 | 11.8 | 7.5 | 6.3 | 13.9 |
| 2023 | 3.5 | 4.6 | 8.1 | 4.1 | 5.2 | 9.3 | 5.1 | 5.9 | 10.9 | 6.2 | 6.8 | 13.0 |
| 2024 | 3.8 | 4.8 | 8.6 | 4.6 | 5.5 | 10.1 | 4.9 | 5.4 | 10.3 | 6.1 | 7.2 | 13.3 |
| 2025 | 4.1 | 5.0 | 9.1 | 5.1 | 5.8 | 10.9 | 5.3 | 2.3 | 7.6 | 6.9 | 6.5 | 13.4 |
| 2026 | 4.4 | 5.1 | 9.5 | 5.7 | 6.1 | 11.8 | 5.8 | 1.4 | 7.1 | 7.8 | 2.0 | 9.9 |
| 2027 | 4.7 | 1.5 | 6.2 | 6.3 | 6.4 | 12.7 | 6.2 | 0.9 | 7.1 | 9.0 | 1.1 | 10.1 |
| 2028 | 5.0 | 0.7 | 5.7 | 7.0 | 1.5 | 8.6 | 6.7 | 0.6 | 7.3 | 10.3 | 0.7 | 11.0 |
| 2029 | 5.3 | 0.4 | 5.8 | 7.8 | 0.6 | 8.4 | 7.2 | 0.4 | 7.7 | 11.9 | 0.5 | 12.4 |
| 2030 | 5.6 | 0.3 | 5.9 | 8.8 | 0.3 | 9.1 | 7.8 | 0.3 | 8.1 | 13.9 | 0.3 | 14.2 |
| 2031 | 6.0 | 0.2 | 6.2 | 9.8 | 0.2 | 10.1 | 8.3 | 0.2 | 8.5 | 6.2 | 0.2 | 6.4 |
| 2032 | 6.3 | 0.1 | 6.4 | 11.1 | 0.1 | 11.3 | 8.9 | 0.1 | 9.1 | 3.6 | 0.1 | 3.7 |
| 2033 | 6.7 | 0.1 | 6.7 | 12.6 | 0.1 | 12.7 | 7.8 | 0.1 | 7.9 | 2.4 | 0.1 | 2.5 |
| 2034 | 7.0 | 0.1 | 7.1 | 14.5 | 0.1 | 14.6 | 4.8 | 0.1 | 4.9 | 1.6 | 0.1 | 1.7 |
| 2035 | 7.4 | 0.0 | 7.4 | 16.9 | 0.0 | 16.9 | 3.3 | 0.0 | 3.3 | 1.1 | 0.0 | 1.1 |
| **Total** | **90.5** | **50.3** | **140.8** | **138.5** | **61.0** | **199.5** | **145.4** | **50.3** | **195.6** | **161.5** | **61.0** | **222.5** |

# 5.0 Utility-Scale Solar PV Potential Assessment

Applying lessons learned from the California Renewable Energy Transmission Initiative (RETI) and Western Renewable Energy Zones (WREZ) planning work, Black & Veatch estimated utility-scale solar PV potential across Oregon using the screens described below. Since utility-scale projects are developed at a much larger scale and have greater environmental sensitivities than distributed generation, a different approach was taken to evaluate the potential for Oregon.




The utility-scale solar potential assessment focused on areas across Oregon for projects ranging from 5 to 250 MWac. Black & Veatch first identified potential sites by excluding land areas based on certain environmental considerations, proximity to existing transmission, technical limitations, and other parameters. Next, a financial screen was applied to these sites by comparing each site's levelized cost of energy (LCOE) to PGE's long-term qualified facility (QF) rates, without considering transmission capacity availability. To arrive at an achievable potential, an additional screen was applied to these sites, assuming firm transmission availability constraints on existing transmission lines would limit delivery to PGE's service territory and size of projects that can interconnect. This assumes no new transmission is built in Oregon.

## 5.1 THE SECTIONS BELOW FURTHER DESCRIBE THIS ANALYSIS AND THE RESULTS. TECHNICAL SCREEN

Using publicly available geographic information system (GIS) layers, Black & Veatch excluded areas that would pose challenges for solar PV development on the basis of land use and environmental constraints (e.g., environmentally sensitive lands, sage grouse habitat, public ownership and parklands, waterways, forested land, cropland, and wetlands). Also excluded were areas too far from current transmission infrastructure and land with significant slope. A summary of the excluded areas is provided in Table 5-1. Additional maps showing each of these exclusion areas can be found in Appendix E.

The exclusions have simply been applied for the purposes of estimating technical potential. It is important to emphasize that the purpose of these exclusions is for conceptual planning and not to recommend specific project siting and land use decisions. Development may be possible within some of the lands that have been excluded. Conversely, candidate lands shown as "open" for development should not necessarily be assumed to be appropriate for siting plants either. Any project will still need to proceed through all local, state, and federal permitting processes.

**Table 5-1 Area Exclusions for Utility-Scale Solar PV Development**

| MAP LAYERS | EXCLUSIONS | DATA SOURCE |
|---|---|---|
| WECC Environmental Data Task Force (EDTF) | Categories 3 (high risk) and 4 (precluded by law) | WECC Geospatial Data Viewer |
| Sage Grouse | Sage grouse habitat | http://184.169.179.203/flexviewers/WECC3/index.html |
| Public Ownership and Parkland | Bureau of Land Management, Department of Defense, Forest Service and Fish & Wildlife land | https://nrimp.dfw.state.or.us/DataClearinghouse/default.aspx?p=202&XMLname=944.xml |
| Land Use | Water, forests (all types), cultivated crops, wetlands (all types), developed (low, medium, high intensity), perennial snow/ice | ESRI detailed parks dataset 2013 |
| Transmission System | Greater than 5 miles from transmission lines | http://www.oregon.gov/odf/pages/gis/gisdata.aspx “Public Ownership” |
| Topography | Slope greater than 5 percent | National Land Cover Database 2011 |

In order to accommodate a minimum of 3.6 MWac, the GIS analysis then identified contiguous areas remaining that were greater than 25 acres. Each site area was then divided by a factor of 3.6 acres per MWac (equivalent to 5 acres per MWdc) to determine the technical potential per site. The dark orange and red colors on Figure 5-1 show the identified utility-scale potential sites.

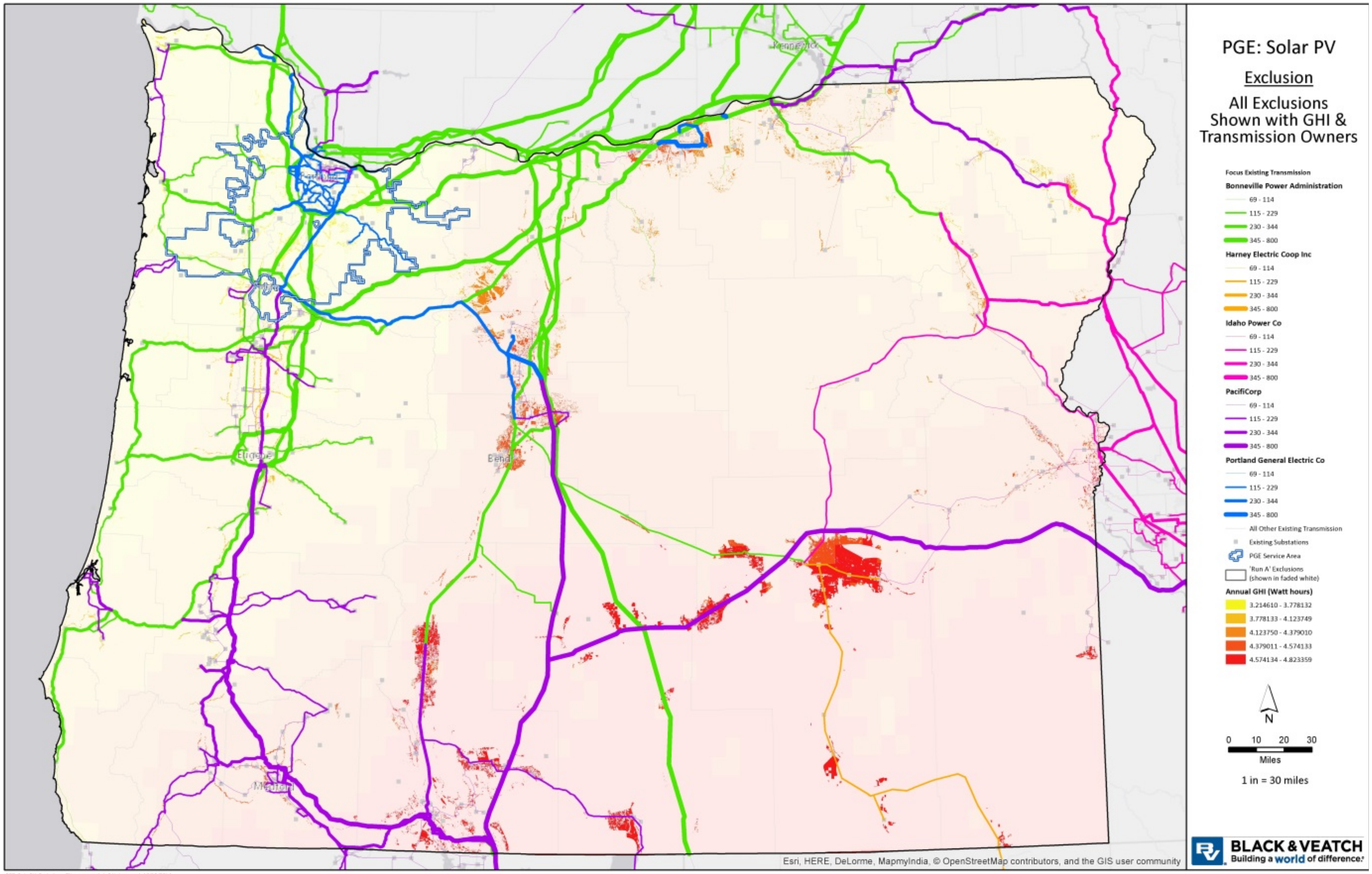



**Figure 5-1 Identified Utility-Scale Solar PV Technical Potential**

The maximum system size for a particular site was then constrained based on the voltage of the transmission line or substation that the site would need to interconnect with. In addition to limitations related to line or substation capacity, Black & Veatch made several assumptions regarding interconnection:

- No new transmission is built.
- Each contiguous area identified in the technical screen is considered a "site" and has only one solar PV project associated with the "site."
- The solar PV system size per site is capped at what the closest transmission line or substation voltage can accept. The maximum assumed system size in MWac for the respective transmission/substation voltages are shown in Table 5-2.

**Table 5-2 Assumed Maximum Utility-Scale Project Size by Interconnection Voltage**

| TRANSMISSION/SUBSTATION VOLTAGE | MAXIMUM PROJECT SIZE (MWAC) |
|---|---|
| <100 kV | 50 |
| 115 kV | 100 |
| 230 kV | 250 |
| 500 kV | 250 |

Based on this screen, Black & Veatch identified approximately 3,500 potential sites in Oregon (Table 5-3). The total technical potential across Oregon is estimated to be over 56 gigawatts (GW), assuming a capacity density of 3.6 acres per MWac.

**Table 5-3 Identified Utility-Scale Solar PV Technical Potential (MWac)**

| MW BIN | NUMBER OF PROJECTS PER BIN | TOTAL TECHNICAL POTENTIAL (MWAC) |
|---|---|---|
| <20 | 2,834 | 22,104 |
| 20-50 | 514 | 17,226 |
| 50-100 | 99 | 8,005 |
| 100-250 | 44 | 8,812 |
| **Total** | **3,491** | **56,147** |

## 5.2 FINANCIAL SCREEN

Black & Veatch then developed LCOE supply curves for each year in the study period, both with and without tax credit incentives. Using the technical screen results, the SolarAnywhere solar resource data, and the previously projected costs of utility-scale solar and transmission interconnection, Black & Veatch calculated the LCOE of individual sites identified previously. As with the distributed generation potential, Black & Veatch utilized SAM to perform the energy production analysis for the utility-scale systems. The LCOE of each project site was calculated using Black & Veatch's proprietary tools and supply curves were developed for each financial case. Next, a financial screen was applied to these sites by comparing each site's levelized cost of energy (LCOE) to PGE's long-term qualified facility (QF) rates, without considering transmission capacity availability.

### 5.2.1 Cost Assumptions

The capital cost assumptions for each site are based on system size, gen-tie cost, and substation cost. The solar PV plant costs were forecasted to decline over time using the cost curves developed in Section 3.0. Gen-tie costs from Table 3-3 were applied based on the distance to the nearest substation or transmission line, which was calculated using GIS analysis. All projects were assumed to require a new substation or upgrades to an existing substation at costs for each respective voltage level summarized in Table 3-3.

For ongoing costs, both O&M, property taxes, wheeling charges and real power losses were included, where applicable. The O&M costs include typical costs associated with an O&M contract as well as inverter replacement fund, insurance, and land leases. The fixed O&M costs range from $32 to $36 per kWac-year (in 2014$), depending on the size of the system. Annual property taxes was assumed to be 0.5% of the installed cost of the system, though actual property taxes for projects will differ by county and alternative payment mechanisms may be negotiated with local government. Additional wheeling charges/transmission tariffs for sites connecting to transmission lines not owned by PGE were also applied to deliver the energy to PGE's service territory. Energy losses (real power losses) to wheel power were also included. Wheeling and real power losses are shown in Table 5-4. In some cases, wheeling and real power losses through multiple transmission providers needed to be applied to reach PGE territory.

**Table 5-4 Transmission Tariffs by Owner (2014)**

| TRANSMISSION OWNER | TOTAL TRANSMISSION TARIFF/WHEELING CHARGE ($/KWAC-YR) | REAL POWER LOSSES |
|---|---|---|
| Bonneville Power Administration | $20.8 | 1.9% |
| PacifiCorp | $31.6 | 4.6% |
| Idaho Power | $22.7 | 3.6% |
| Harney Elec. Cooperative (see notes) | $13.2 | 0% |

Sources:
Transmission tariff includes Point-to-Point Annual Firm Transmission,
BPA – 2014-2015 Tariffs for Generators
http://www.bpa.gov/Finance/RateInformation/RatesInfoTransmission/2014%20Rate%20Schedule%20Summary_10-01-13.pdf and
http://www.bpa.gov/transmission/Doing%20Business/Tariff/Documents/bpa_oatt.pdf
PacifiCorp – http://www.oatioasis.com/PPW/PPWdocs/Rate_Table_20140601.pdf and
http://www.oasis.oati.com/PPW/PPWdocs/Rate_Update_FAQ_20140601.pdfIdaho Power
http://www.oatioasis.com/IPCO/IPCOdocs/IPC_OATT_Issued_2015-01-13.pdf and
http://www.oatioasis.com/IPCO/IPCOdocs/IPCO_Current_Transmission_Rates_08-28-14.pdf
Harney Elec. Cooperative does not have published wheeling costs for generation on its system and has indicated that rates would be established as needed. Therefore, Black & Veatch used another Oregon cooperative, Central Electric Coop, as a proxy for wheeling cost. –http://www.cec.coop/wp-content/uploads/sch_w.pdf. Neither cooperative published losses, so assumed 0% losses.

### 5.2.2 Production and Financial Modeling

To estimate the energy production of each facility, Black & Veatch developed system assumptions that are representative of typical system parameters or losses seen in the industry for inputs into SAM. These assumptions are summarized in Appendix E, Table E-2. Energy production for each individual site was modeled using SAM and solar resource data from SolarAnywhere.

Financial assumptions used for modeling utility-scale solar PV assumed a typical independent power producer (IPP) ownership structure. These are summarized in Table 5-5.

**Table 5-5 Utility-Scale Financial Assumptions**

| INPUTS | ASSUMPTION |
|---|---|
| Debt/Equity Assumption | All Equity |
| Equity Return Requirement (%) | 6.5 |
| Analysis Period (years) | 20 |
| Inflation Rate (%/year) | 2 |
| O&M Escalation (%/year) | 1 |
| Discount Rate (%) | 6.5 |
| Federal Income Tax Rate (%) | 35 |
| State Income Tax Rate (%) | 7.6 |
| Sales Tax | Exempt |

### 5.2.3 LCOE Analysis Results

Rather than performing payback analysis, Black & Veatch chose to calculate LCOE for the identified utility-scale systems. The LCOE metric is more applicable to utility-scale systems because the energy is sold at the wholesale level and can be compared to a utility's cost of energy.

Black & Veatch calculated two cost scenarios: with and without ITC, with the exception that the ITC of 30 percent is available in 2016 in both cost scenarios. For the ITC scenario, it was assumed that the ITC drops to 10 percent after 2016. Cost curves were developed for all years from 2016 to 2035. Sample years of resulting supply curves for the ITC case are shown on Figures 5-2 and 5-3.

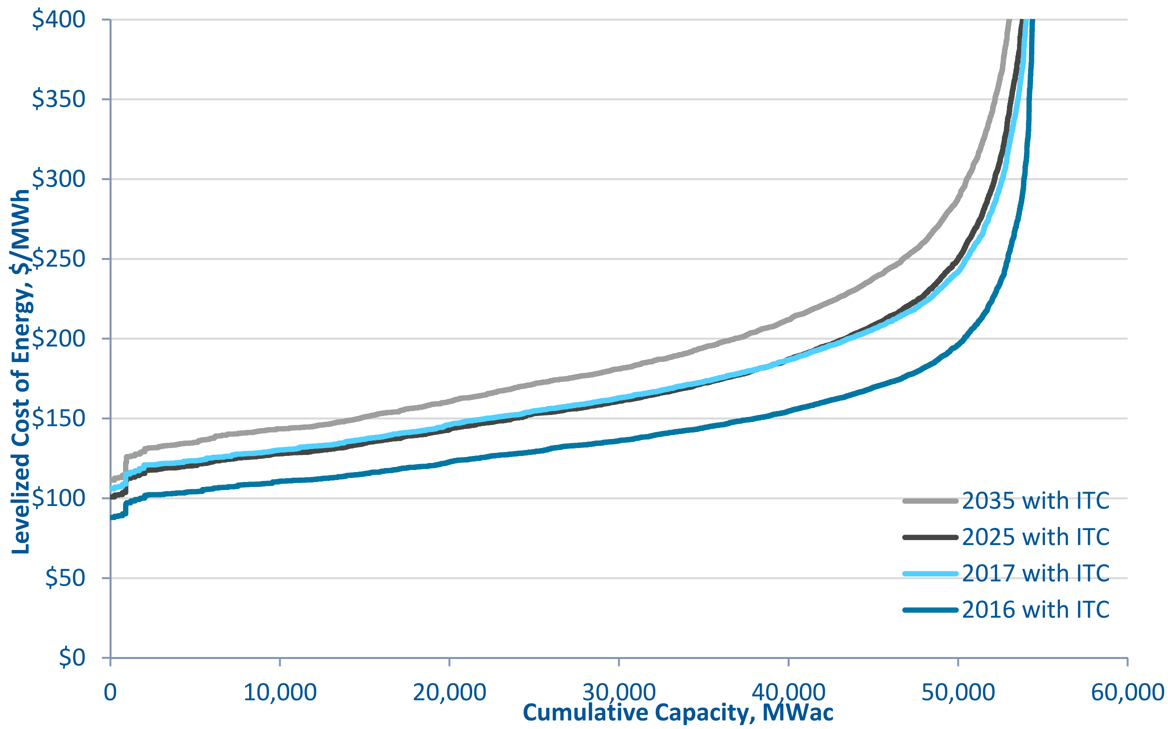



**Figure 5-2 Utility Solar Supply Curve With ITC (10% after 2016)**

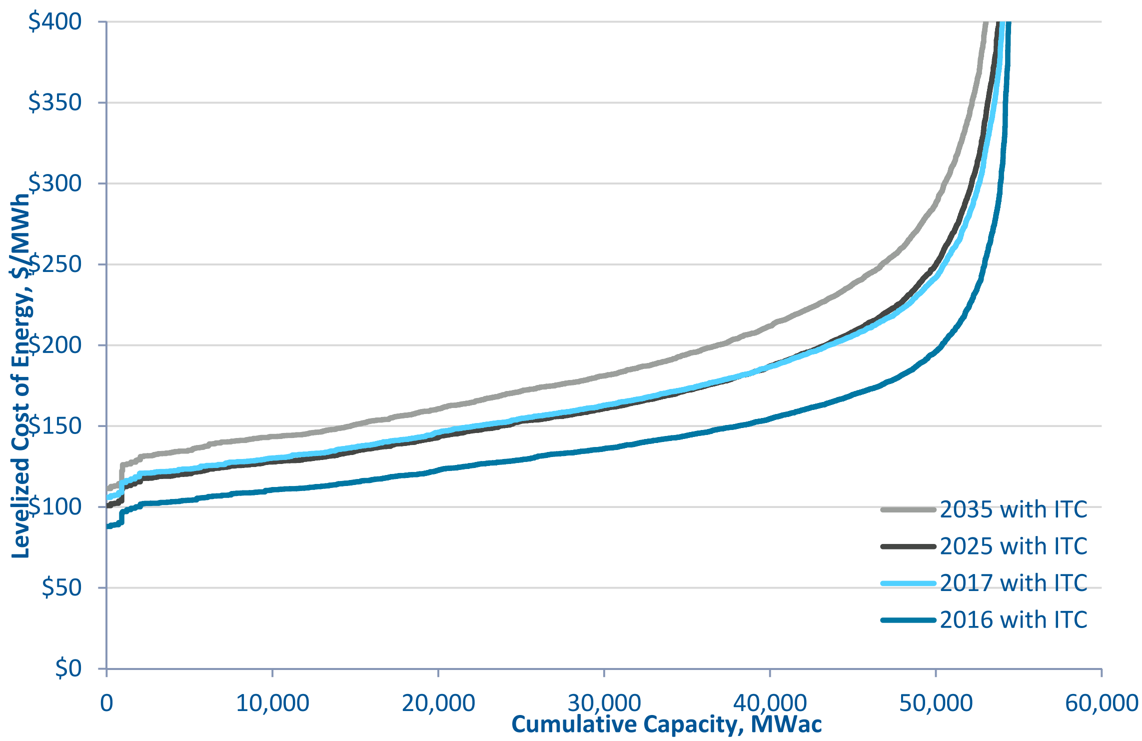



**Figure 5-3 Utility Solar Supply Curve Without ITC**

### 5.2.4 Avoided Cost Screen

Utility-scale solar PV will offset power purchases, power generation, or new power plant construction that PGE might otherwise make. Black & Veatch calculated the levelized cost of PGE's long-term QF tariff for variable solar to compare against the LCOEs previously calculated. The QF values used are shown in Table 5-6.

Comparing solar LCOE to QF rates is a simplified screening approach. Other approaches in examining solar PV financials may be considered in future studies.

**Table 5-6 PGE QF Tariffs ($/MWh) for Variable Solar (Nominal)**

| YEAR | SOLAR PRODUCTION WEIGHTED AVERAGE PRICE | LEVELIZED COST (20 YEARS) | YEAR | SOLAR PRODUCTION WEIGHTED AVERAGE PRICE | LEVELIZED COST (20 YEARS) |
|---|---|---|---|---|---|
| 2016 | $40 | $89 | 2026 | $109 | $127 |
| 2017 | $42 | $94 | 2027 | $111 | $130 |
| 2018 | $45 | $100 | 2028 | $113 | $132 |
| 2019 | $47 | $106 | 2029 | $116 | $135 |
| 2020 | $96 | $112 | 2030 | $118 | $138 |
| 2021 | $98 | $115 | 2031 | $121 | $140 |
| 2022 | $100 | $117 | 2032 | $123 | $143 |
| 2023 | $102 | $119 | 2033 | $125 | $146 |
| 2024 | $104 | $122 | 2034 | $128 | $149 |
| 2025 | $106 | $124 | 2035 | $130 | $152 |
| Note: Levelized cost assumes 2035 costs continue to escalate at inflation. Costs were levelized assuming a 6.5 percent discount rate. | | | | | |

### 5.2.5 Utility Scale Financial Screening Results

The annual LCOE supply curves were compared to the levelized annual QF prices with and without ITC in order to determine the amount of capacity with LCOE lower than levelized QF rates each year as shown on Figure 5-4. In 2016, the total potential capacity in the supply curve that can produce energy lower than $89/MWh on a levelized basis is approximately 0.5 GW. This represents only a handful of sites with large capacity. By 2017 and 2018, as the 30 percent ITC is no longer available, there is no capacity with costs lower than the levelized QF rates in either case (No ITC and ITC of 10 percent). Beyond that, the amount of capacity increases as solar PV costs are forecasted to decline, along with increasing levelized cost of QF contracts. By 2035, 7.5 GW (no ITC) and 15.5 GW (ITC) of capacity have LCOE lower than forecasted QF rates.

However, the financial screen does not consider transmission constraints to deliver the power to PGE's service territory. These constraints will be applied in the achievable screen section, discussed next.

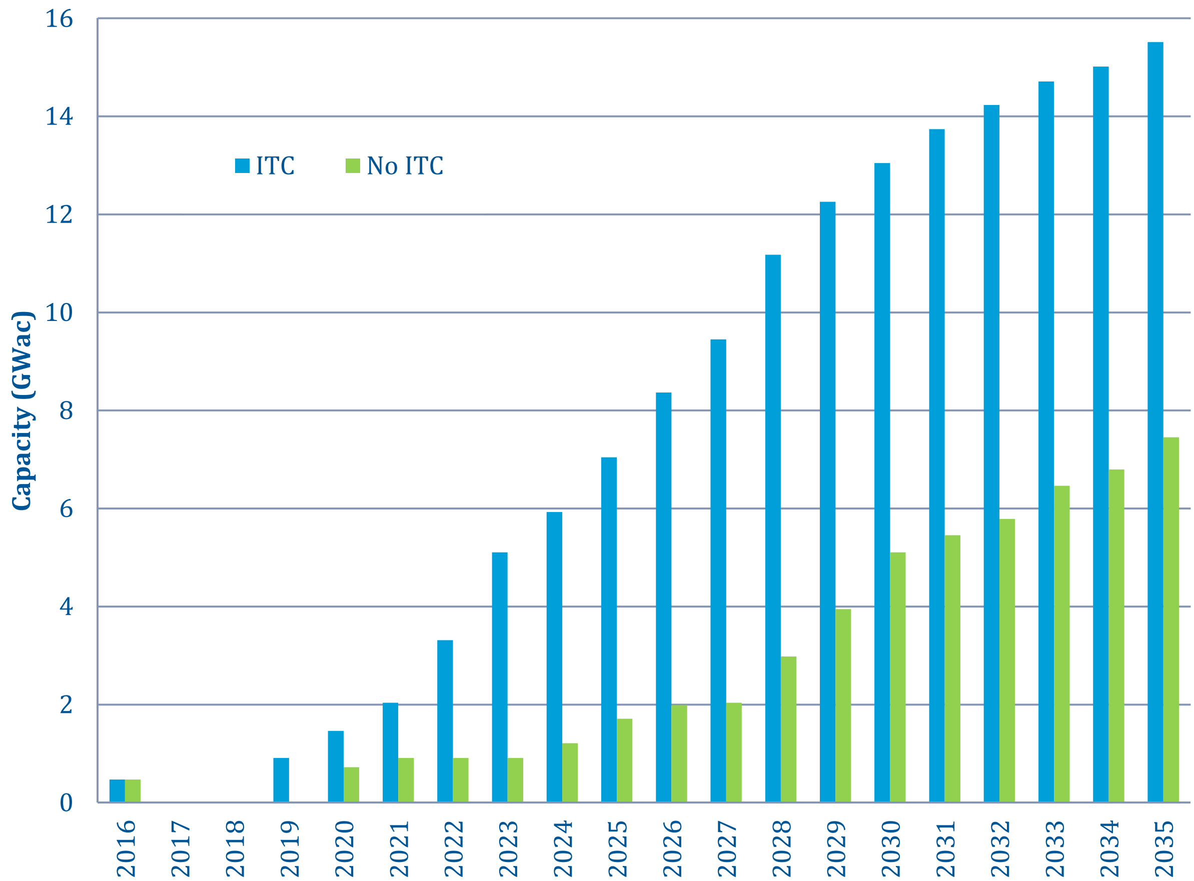



**Figure 5-4 Annual Maximum Utility-Scale Potential after Financial Screen**

## 5.3 ACHIEVABLE SCREEN

To estimate achievable potential for utility-scale solar, Black &Veatch assumed that the primary constraint is transmission availability. While transmission could be upgraded to deliver solar PV, such upgrades would be relatively expensive given the low utilization rate of solar. With input from PGE, several transmission zones were established for areas where PGE's staff estimated available firm transmission capacity may be available for delivery to PGE's service territory. These zones are denoted on Figure 5-5.

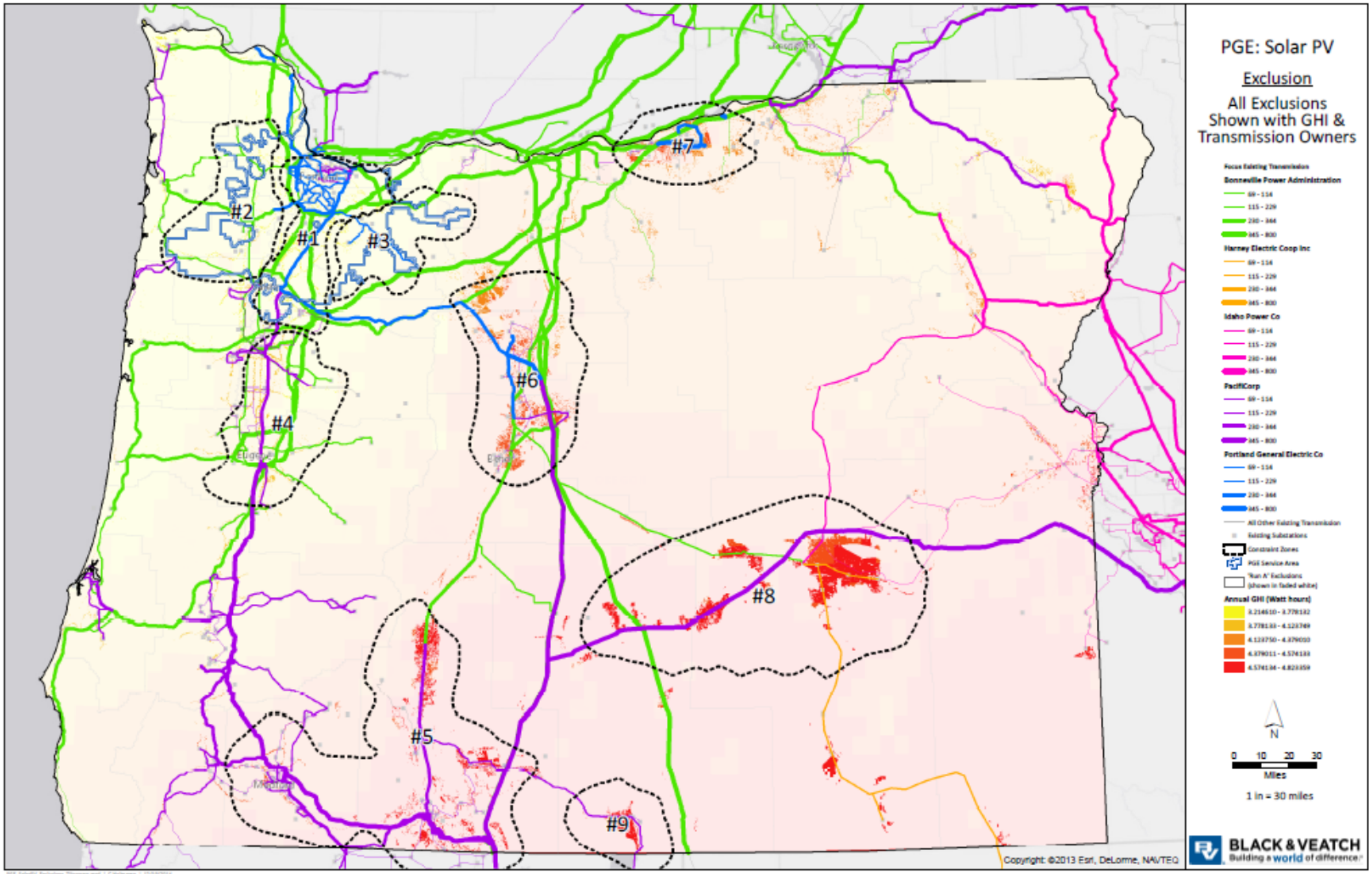



**Figure 5-5** **Utility-Scale Solar by Transmission Zone**

Black & Veatch understands that transmission for sending energy from the Pacific Northwest to California is largely allocated, but there is some availability to deliver energy from the south to the north part of Oregon. PGE staff provided estimated maximum incremental transmission capacity that may be available for solar for delivery to PGE by zone and provided guidance on practical system sizes for interconnection by transmission voltage class, as shown in Table 5-7.

**Table 5-7 PGE Estimated Available Transmission Capacity by Zone**

| ZONE | NUMBER OF SYSTEMS CONNECTING AT TRANSMISSION VOLTAGE (PROJECT MAX MW) | | | ESTIMATED MAX EXPORT CAPACITY BY ZONE | WHEELING REQUIREMENT |
|---|---|---|---|---|---|
| | 57/69 (10 MW) | 115/138 (20 MW) | 230 (50 MW) | | |
| No. 1 | 3-7 | 6-10 | 2-4 | 400 – 500 MW | No wheeling costs applied on PGE line |
| No. 2 | 3-5 | 3-5 | | 200 MW | No wheeling costs applied on PGE line |
| No. 3 | 3-4 | 1-2 | | 100 MW | No wheeling costs applied on PGE line |
| No. 4 | 4-5 | 4-5 | 2-4 | 150 MW | Require third party wheeling to PGE |
| No. 5 | 5-6 | 4-5 | 2-4 | 200 MW | Require third party wheeling to PGE |
| No. 6 | 3-4 | 4-5 | 2-3 | 200 MW | Require third party wheeling to PGE (PGE lines in this zone do not have capacity) |
| No. 7 | 2-3 | 2-4 | 1-2 | 200 MW | Require third party wheeling to PGE. (PGE lines in this zone do not have capacity) |
| No. 8 | 4-5 | 2-3 | | 60 MW | Require third party wheeling to PGE |
| No. 9 | 2-4 | | | 40 MW | Require third party wheeling to PGE |

Based on the revised size limitations for individual projects connected at the various voltage classes, the system size at each site and capital cost assumptions were adjusted to accommodate the smaller system size limitation. After applying the size revisions and quantifying only the sites that that fall within each zone in the map, the table below sums up the total remaining potential.

**Table 5-8 Utility Solar PV Potential within Zone**

| ZONE | REVISED POTENTIAL (MWAC) |
|---|---|
| No. 1 | 2,223 |
| No. 2 | 753 |
| No. 3 | 187 |
| No. 4 | 3,510 |
| No. 5 | 4,963 |

| | |
|---|---|
| No. 6 | 3,380 |
| No. 7 | 325 |
| No. 8 | 497 |
| No. 9 | 5 |
| **Total** | **15,632** |

Sites were then identified that met the transmission constraints in Table 5-7 and Table 5-8 and had LCOE that were less than the levelized QF price for that year. Once the estimated maximum export capacity for a zone was met, no additional projects were allowed to be built in the zone. The resulting build-out over time for the ITC and no ITC scenarios are shown on Figure 5-6. The total cumulative adoption of the ITC and no ITC scenarios are 369 MWac and 100 MWac, respectively (Figure 5-7).

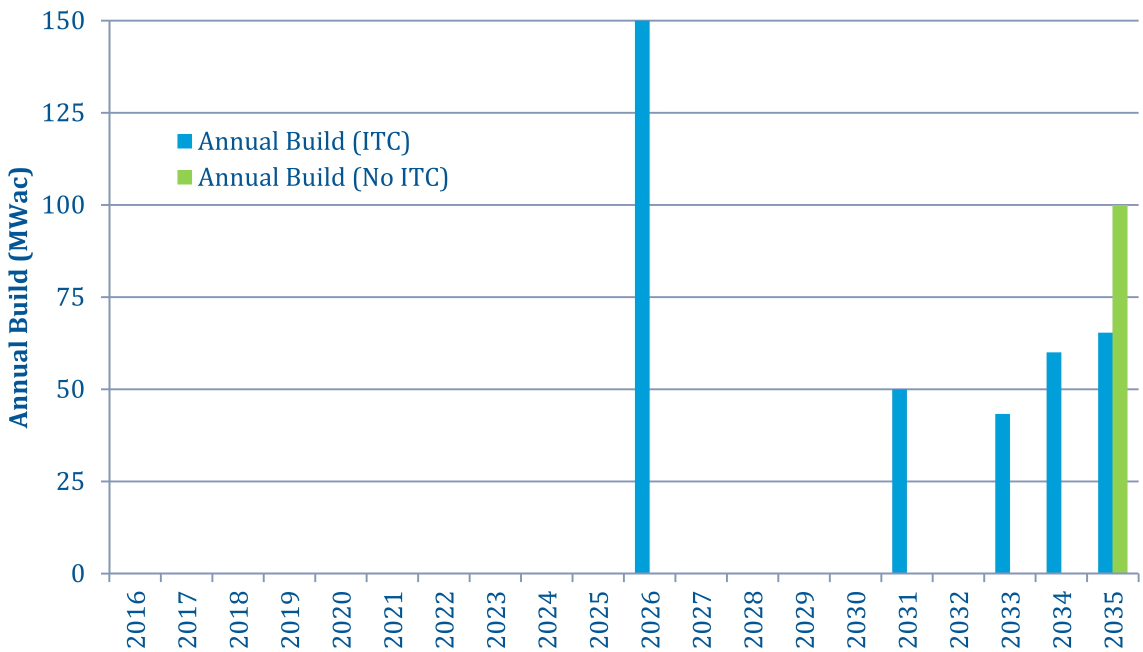



**Figure 5-6 Annual Constrained Build-out of Utility-Scale Solar PV (2016-2035)**

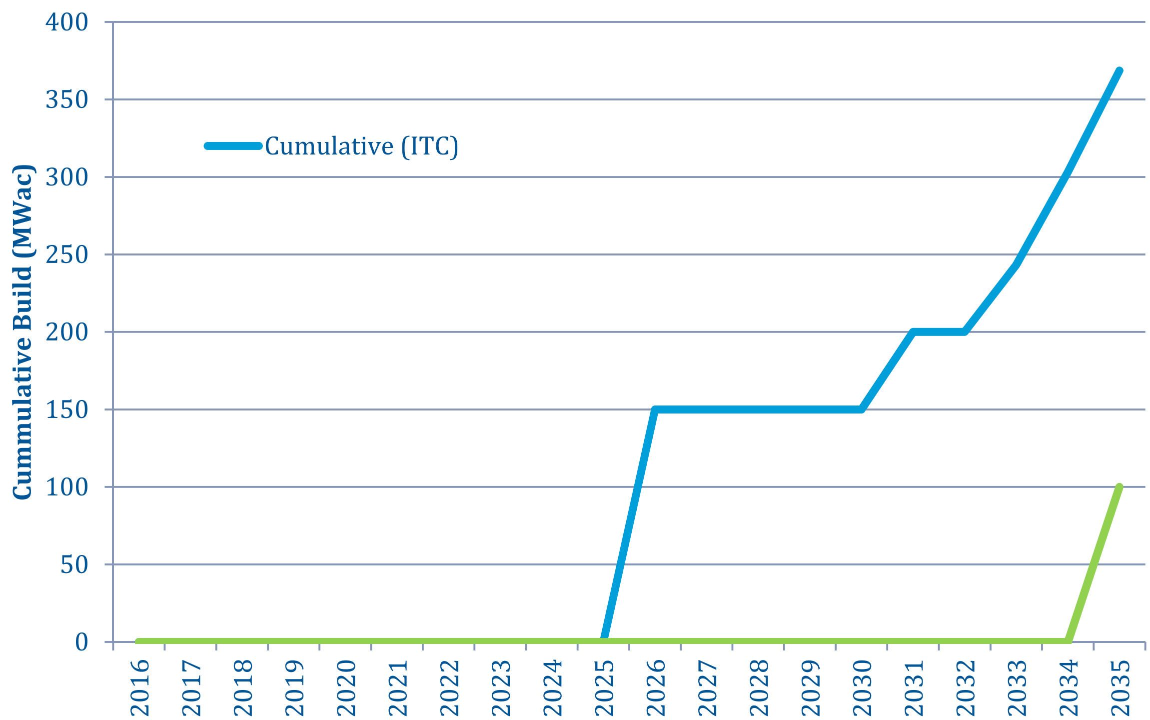



**Figure 5-7 Cumulative Utility-Scale Achievable Solar Penetration**

A detailed breakdown of where systems were deployed is provided in Table 5-9. The most cost-effective zones are 5, 6, and 8, where solar resources are good and systems sizes can be maximized. These are preferred to projects located in Zones 1 to 4, where solar resources are not ideal. The years without any builds indicate that the next lowest cost sites are not yet cost-effective relative to that year's levelized QF prices. The added screen of transmission constraints results in much lower achievable potential due to the combination of smaller systems sizes, thus higher installed cost, and limited capacity on PGE lines, so projects outside of Zones 1, 2, and 3 must incur wheeling costs and losses. .

**Table 5-9 Annual Constrained Build-Out of Solar PV by Zone**

| YEAR | PROJECT ZONE | ANNUAL BUILD (ITC) MWAC | PROJECT ZONE | ANNUAL BUILD (NO ITC) MWAC |
|---|---|---|---|---|
| 2016 | | | | |
| 2017 | | | | |
| 2018 | | | | |
| 2019 | | | | |
| 2020 | | | | |
| 2021 | | | | |
| 2022 | | | | |
| 2023 | | | | |
| 2024 | | | | |
| 2025 | | | | |
| 2026 | #No. 6 | 150 | | |
| 2027 | | | | |
| 2028 | | | | |
| 2029 | | | | |
| 2030 | | | | |
| 2031 | #No. 5 | 50 | | |
| 2032 | | | | |
| 2033 | #No. 5 | 43 | | |
| 2034 | #No. 6 & #No. 8 | 60 | | |
| 2035 | #No. 5 & #No. 8 | 65 | #No. 6 | 100 |

# Appendix A. Solar PV Cost Forecasts

**Table A-1 Rooftop Solar Price Projections (2014$/Wdc)**

| | RESIDENTIAL | COMMERCIAL | |
|---|---|---|---|
| YEAR | 4 KWDC | 50 KWDC | 250 KWDC |
| 2015 | $3.74 | $2.62 | $2.50 |
| 2016 | $3.37 | $2.36 | $2.25 |
| 2017 | $2.71 | $2.01 | $1.93 |
| 2018 | $2.38 | $1.83 | $1.77 |
| 2019 | $2.18 | $1.71 | $1.66 |
| 2020 | $2.03 | $1.63 | $1.58 |
| 2021 | $1.91 | $1.56 | $1.52 |
| 2022 | $1.82 | $1.50 | $1.47 |
| 2023 | $1.75 | $1.46 | $1.43 |
| 2024 | $1.68 | $1.42 | $1.39 |
| 2025 | $1.63 | $1.38 | $1.36 |
| 2026 | $1.58 | $1.35 | $1.33 |
| 2027 | $1.54 | $1.33 | $1.31 |
| 2028 | $1.50 | $1.30 | $1.29 |
| 2029 | $1.47 | $1.28 | $1.27 |
| 2030 | $1.43 | $1.26 | $1.25 |
| 2031 | $1.41 | $1.24 | $1.23 |
| 2032 | $1.38 | $1.22 | $1.21 |
| 2033 | $1.35 | $1.21 | $1.20 |
| 2034 | $1.33 | $1.19 | $1.18 |
| 2035 | $1.31 | $1.18 | $1.17 |

**Table A-2 Utility-Scale Solar Price Projections (2014$/Wdc) (source: Black & Veatch analysis)**

| YEAR | FIXED 5 MWAC | FIXED 20 MWAC | FIXED 100 MWAC | TRACKING 5 MWAC | TRACKING 20 MWAC | TRACKING 100 MWAC |
|---|---|---|---|---|---|---|
| 2015 | $1.96 | $1.77 | $1.69 | $2.17 | $1.97 | $1.88 |
| 2016 | $1.70 | $1.54 | $1.47 | $1.88 | $1.70 | $1.63 |
| 2017 | $1.57 | $1.42 | $1.35 | $1.73 | $1.56 | $1.49 |
| 2018 | $1.48 | $1.34 | $1.28 | $1.62 | $1.47 | $1.41 |
| 2019 | $1.41 | $1.28 | $1.22 | $1.55 | $1.40 | $1.34 |
| 2020 | $1.36 | $1.23 | $1.17 | $1.49 | $1.35 | $1.29 |
| 2021 | $1.32 | $1.19 | $1.14 | $1.44 | $1.31 | $1.25 |
| 2022 | $1.28 | $1.16 | $1.11 | $1.40 | $1.27 | $1.21 |
| 2023 | $1.25 | $1.14 | $1.08 | $1.37 | $1.24 | $1.19 |
| 2024 | $1.23 | $1.11 | $1.06 | $1.34 | $1.21 | $1.16 |
| 2025 | $1.20 | $1.09 | $1.04 | $1.31 | $1.19 | $1.14 |
| 2026 | $1.18 | $1.07 | $1.02 | $1.29 | $1.17 | $1.12 |
| 2027 | $1.16 | $1.05 | $1.00 | $1.27 | $1.15 | $1.10 |
| 2028 | $1.15 | $1.04 | $0.99 | $1.25 | $1.13 | $1.08 |
| 2029 | $1.13 | $1.02 | $0.98 | $1.23 | $1.12 | $1.06 |
| 2030 | $1.12 | $1.01 | $0.96 | $1.21 | $1.10 | $1.05 |
| 2031 | $1.10 | $1.00 | $0.95 | $1.20 | $1.09 | $1.04 |
| 2032 | $1.09 | $0.99 | $0.94 | $1.18 | $1.07 | $1.02 |
| 2033 | $1.08 | $0.98 | $0.93 | $1.17 | $1.06 | $1.01 |
| 2034 | $1.07 | $0.97 | $0.92 | $1.16 | $1.05 | $1.00 |
| 2035 | $1.06 | $0.96 | $0.91 | $1.15 | $1.04 | $0.99 |

# Appendix B. Distributed Solar Technical Potential Assessment Methodology

## TECHNICAL SCREEN

Black & Veatch's methodology for identifying distributed solar PV technical potential throughout PGE's service territory is described in this appendix.

Black & Veatch used publically available LiDAR data and GIS software to identify the amount of technical potential for rooftop solar PV installations available in the PGE service territory.

### LIDAR Data and GIS Software Methodology

All GIS analyses were performed using Esri ArcGIS for Desktop Advanced, Version 10.2 plus the Spatial Analyst and 3D Analyst extensions. All-Returns LiDAR data were utilized in this methodology to generate 3D Digital Surface Model (DSM) files for the study area. DSM files were generated at 2 foot resolution. The LiDAR data were collected from several online sources to obtain the best coverage possible for the PGE service territory. Coverage for the greater Portland Metro Area consists of four distinct LiDAR series shown in the Oregon Department of Geology and Mineral Industries (DOGAMI) online map titled "DOGAMI LiDAR Data, Quadrangle (LDQ) Series, Portland Metro Area." The "Portland Pilot" and "Lower Columbia" LiDAR projects were produced in 2004 and 2005, respectively, and those data were retrieved from the Puget Sound LiDAR Consortium (PSLC) website (pugetsoundlidar.ess.washington.edu). The "Oregon City" data, produced in 2004, and the "Portland Metro" data, produced in 2007, were downloaded from the OpenTopography website (www.opentopography.org).

Pre-processing of the All-Returns LiDAR data varied between the LiDAR projects described above. Data downloaded from PSLC are compressed text files (.txt) that were converted first to LASer (LAS) files using LAStools inside ArcGIS v10.2 and then converted to raster format. Data collected from OpenTopography (provided by DOGAMI) was downloaded as compressed LAS files (LAZ) and converted to raster format in ArcGIS. Once decompressed, all of the LiDAR data for this analysis required nearly a terabyte of disk space; however, after converting to raster format, the required disk space was reduced to approximately 200 GB.

Building footprint data were also critical to the GIS methods. Building footprint data for the greater Portland Metro Area were retrieved from the CivicApps for Greater Portland website (www.civicapps.org). Additional building footprint data were collected by contacting city government GIS professionals. Building footprint data were not available for all areas in the PGE service areas, and those areas were excluded from the analysis. Additional data utilized in the analysis included parcel/tax lot data, city boundaries, PGE service territory boundary, United States Geological Survey (USGS) 1:24,000 topo index, USGS 1:12,000 topo index; and other ancillary data.

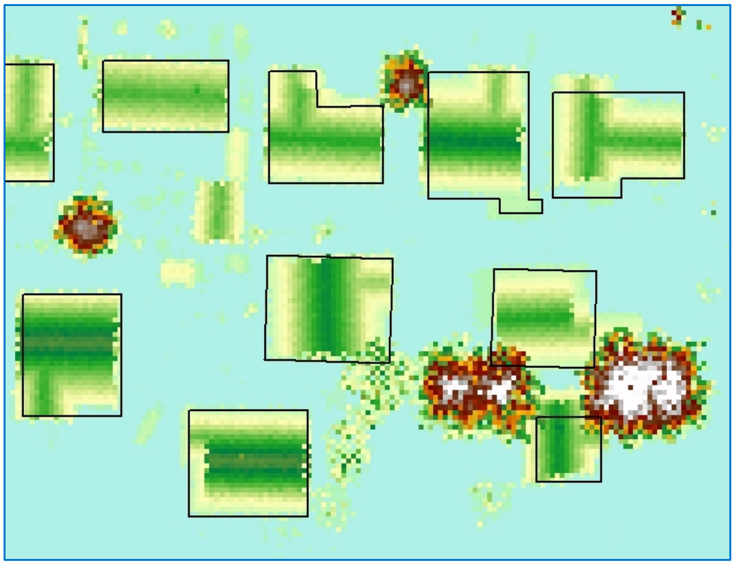


**Figure B-1 All-Returns LiDAR-Derived Digital Surface Model (DSM)**

The process for distilling All-Returns LiDAR and building footprints data into suitable PV mounting planes is fairly complex. For purposes of description, it is best to break the process into three main components:

1. Run the Point Solar Radiation tool in ArcGIS to calculate monthly/annual watt-hour per square meter (Wh/m$^2$).
2. Extract mounting planes.
3. Calculate monthly shading factors for each extracted mounting plane.

These steps are described in the following sections.

### Point Solar Radiation

The ArcGIS for Desktop Advanced tool called Point Solar Radiation was run for all pixels within the building footprints (2 foot resolution). The settings used allowed values of direct radiation to be compared and the shading effects from obstacles such as trees, chimneys, HVAC equipment, nearby structures, and topography within 400 feet of the building edges to be measured. Before choosing a 400 foot "sky size," Black & Veatch evaluated the effects of shading from obstacles farther away, particularly major topographic features, and their effect on rooftop solar radiation is very low compared to obstacles within 400 feet of the building edges. Refer to Figure B-2 for an example of Point Solar Radiation results.

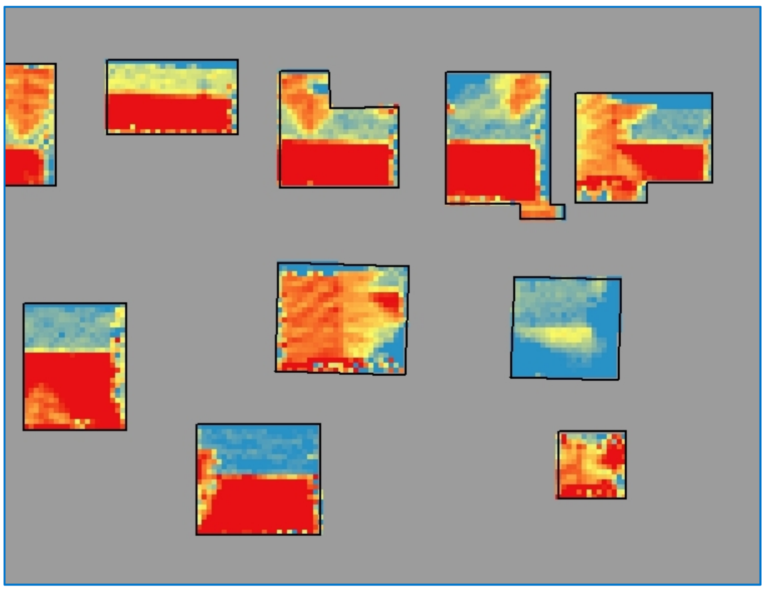


**Figure B-2 Example of Point Solar Radiation Results (cool colors – lower insolation)**

In the figure above, cool colors indicate relatively lower insolation. Effects of azimuth, tilt and shading are clearly shown.

### Extracting Mounting Planes

Black & Veatch has developed a complex geoprocessing algorithm to extract rooftops areas that are likely suitable for rooftop PV. There are many inputs for this geoprocessing model: DSM generated from All-Returns LiDAR data; building footprints; Point Solar Radiation results; tax lots; tilt/slope (generated from DSM during processing); and azimuth/aspect (generated from DSM during processing). The geoprocessing model includes logic to process roof planes differently according to their attributes; for example, the process distinguishes between flat roof areas and tilted roof areas and applies logic accordingly. Additionally, incorporating land use data allows the model to process single-family residential (SFR) buildings differently than commercial buildings, including calculating larger setbacks from the roof plane edges. Refer to Figures B-3, B-4, and B-5.

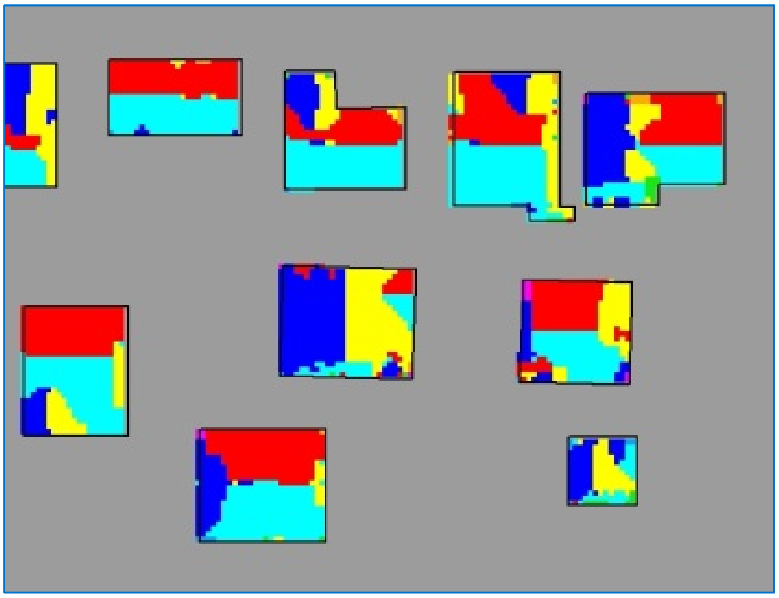


**Figure B-3 Example Azimuth Values (colors indicate different azimuths)**

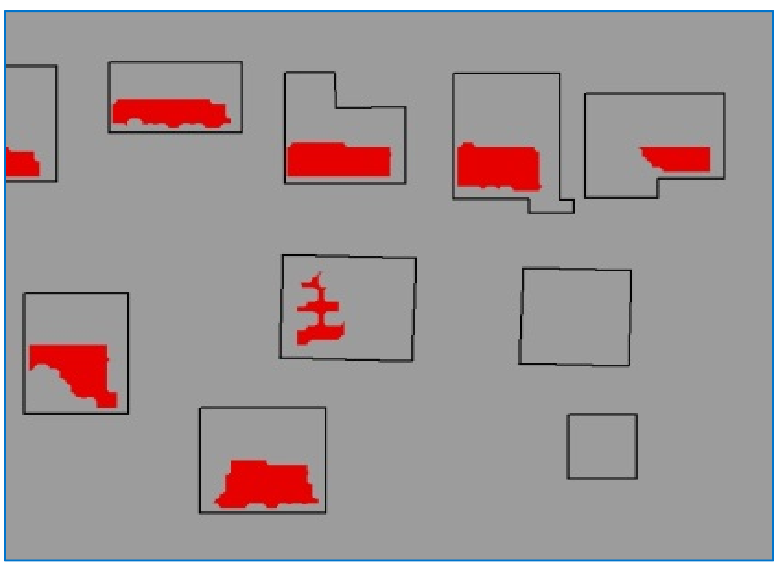


**Figure B-4 Tilted Roof Planes Meeting Solar Cutoff and Setback Requirements (red areas indicate areas meeting cutoff and setback requirements)**

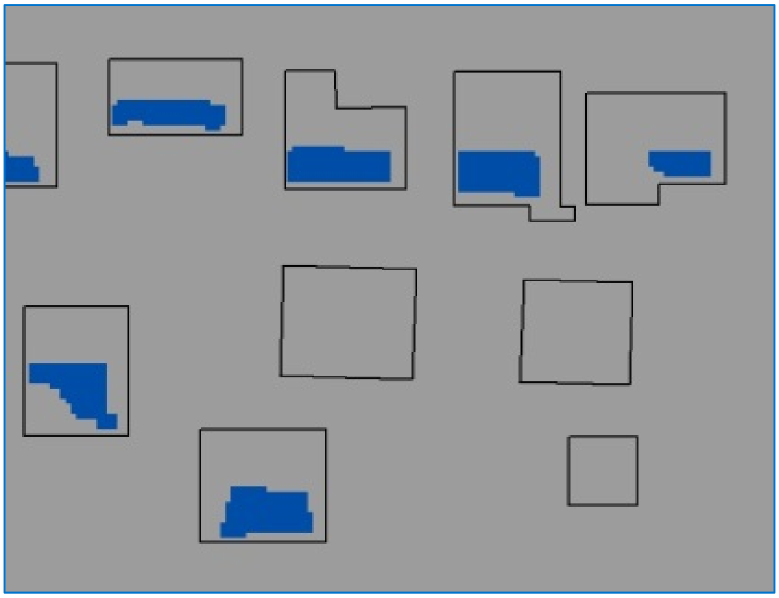


**Figure B-5 Tilted Roof Planes After Filtering for Geometric Requirements (blue areas indicate areas meeting geometric requirements)**

### Calculate monthly shading factors

Each mounting plane identified through the process above then goes through a process to have monthly shading factors calculated. Conceptually, the process is to find all of the points output from the Point Solar Radiation tool that overlap the extracted mounting plane. The mean values of the monthly solar radiation values are then used to determine monthly shading factors to be input into SAM. Black & Veatch has developed custom procedures in GIS to iteratively handle these calculations, as it involves billions of points of information and is extremely processing-intensive.

## Development of Filters and Exclusions

Black & Veatch eliminated rooftops according to several filters and exclusions. The filters and exclusions are intended to discount the identified roof area for various accessibility requirements, identify practical roofs, and eliminate areas that have attributes that negatively impact the energy production capability of a site. These filters and exclusions are described in the sections below.

### Minimum Roof Size

Black & Veatch filtered roofs to exclude roofs with an area below 400 square feet. This was done to eliminate structures such as separate garages that likely do not have a large load or a separate meter and are less likely to have a solar PV system installed than larger structures such as houses.

### Setbacks

Black & Veatch applied setbacks to identified rooftops. These setbacks, summarized below, are intended to account for possible fire code and other access requirements for each site. These requirements are largely based on the California Department of Forestry and Fire Protection requirements for solar PV systems, and Black & Veatch finds that some utilities and jurisdictions require at least partial compliance with this code. In discussions with PGE, it was learned that PGE may consider requiring these setbacks for self-owned systems:

- Residential Systems
  - 2 foot setbacks from all edges of the roof[18]
- Commercial Systems
  - 6 foot setbacks around perimeter of roof[19]

### Contiguous Area

In order to identify efficient and practical roofs for solar PV development, Black & Veatch identified a minimum contiguous area. This allows the elimination of roofs that may pass other filters and exclusions but are otherwise impractical because they are overall small for a cost-effective installation, or have a section too small for a solar PV module.

To identify the minimum contiguous area, Black & Veatch estimated that a typical 60 cell solar PV module has approximate dimensions of 4 feet by 6 feet. A typical capacity for a 60 cell module is roughly 250 W. With these metrics, a 1.0 kW system (4 - 250 W modules) has an area of approximately 100 square feet. Therefore, the minimum contiguous area was set to 100 square feet, which is effectively a minimum system size of 1.0 kW.

Similarly, a minimum length was set for each side of the contiguous area to be equal to the shortest side of a typical panel, 4 feet, to avoid unrealistically slim areas where a panel may not fit.

### Available Solar Resource

Roofs that do not receive adequate solar resource were eliminated from the analysis. Solar resource access on roofs may be limited by objects that cause shading such as trees and buildings or from poor roof orientation such as tilt and azimuth.

[18] Black & Veatch notes that the California Department of Forestry and Fire Protection requires a 3 foot setback from edges and eaves of roofs, and no setback from the roofs bottom edge. To efficiently capture this in GIS, Black & Veatch assumed a 2 foot setback from all edges of each roof.

[19] Other typical setback or access requirements, such as setbacks from skylights and other roof objects, and walkways are accounted for in Black & Veatch's conversion from area to kW capacity, and in the approach to incorporate TSRF.

The ETO has a shading and orientation requirement for systems that wish to receive their solar incentive. This factor, called the Total Solar Resource Fraction (TSRF), must be 75 percent or above for each point in an array[20,21]. Black & Veatch incorporated this cutoff into the technical screen.

### Conversion to Technical Potential

Black & Veatch converted the available area identified with GIS to a kWdc capacity. For tilted rooftop systems, the conversion factor used was 10 W per square foot. For flat roofs, modules would be tilted at 10 degrees and require spacing between rows. Therefore, for flat roofs, Black & Veatch implemented a conversion factor of 5.8 W per square foot.

## FINANCIAL SCREEN

The following section discusses development of assigning rate classes and sites and energy modeling assumptions.

### Building Load Profiles

Load profiles for commercial and industrial customers (C&I) influence the financial results of the analysis since C&I customers are generally under rates with demand charges; whereas, residential customers are not. Load profiles for C&I customers were determined based on a statistical sampling of customers within the PGE service territory. The Commercial Building Energy Consumption Survey (CBECS) provides building characteristics for different regions throughout the US by the Energy Information Administration (EIA). Buildings are classified according to principal activity, which is the primary business, commerce, or function carried on within each building. The 2003 CBECS data were chosen since this is the most recent and complete survey available from EIA[22]. The EIA defines building types in the Pacific Northwest. A distribution of building types in the Pacific Northwest is shown on Figure B-6.

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[20] From ETO's Program Guide for Solar Electric Allies "The TSRF calculation must reflect the worst location on the array(s)—the location with the lowest TSRF value—and be 75% or greater in order to qualify for Program incentives."

[21] From ETO's Solar Electric Installation Requirements "Total Solar Resource Fraction ("TSRF") shall be 75% or greater at all points on the array for string inverters. Projects may include individual modules with a TSRF of less than 75% if the modules are electrically isolated from one another using microinverters; however, those modules that do not meet the 75% requirement will not be eligible for program incentives." Black & Veatch assumed most systems would not use microinverters and, therefore, assumed that all of the array must meet the 75% requirement.

[22] There is a 2012 survey, but that dataset will not be available in its entirety until late next year.

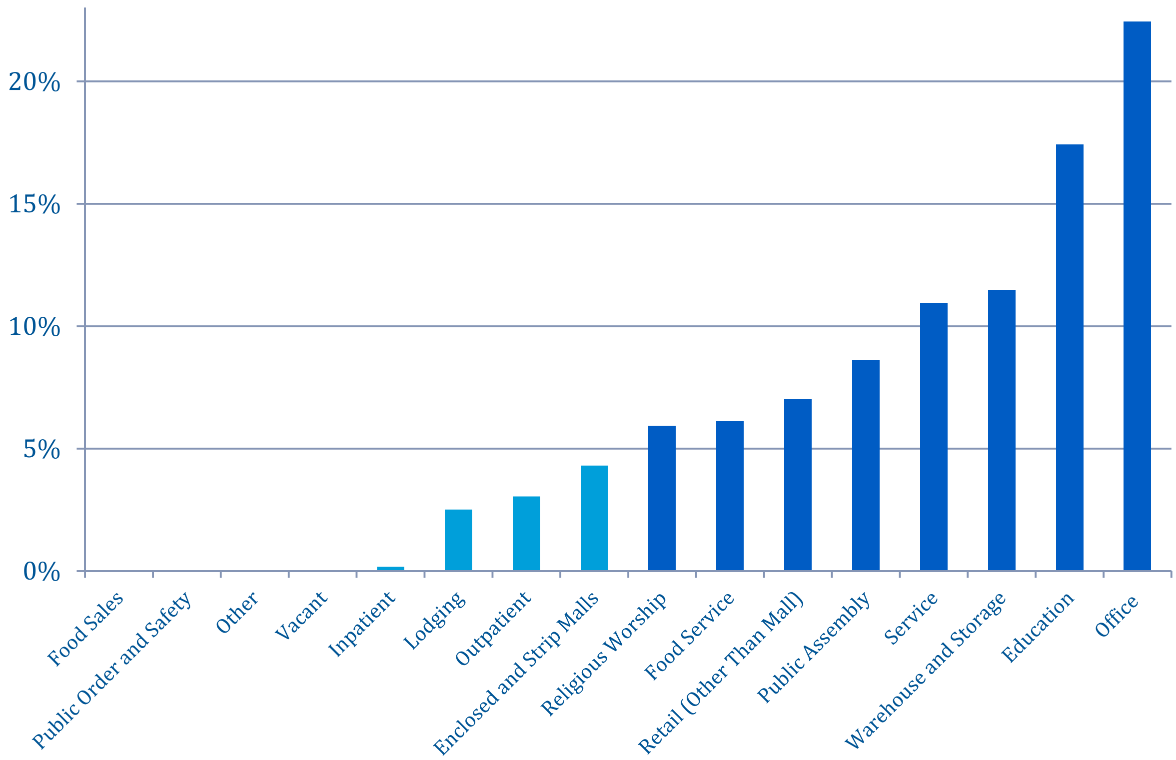


**Figure B-6 Distribution of Buildings for the Pacific Northwest (source: EIA)**

Black & Veatch used the top eight building types to model the hourly load profiles indicative of the PGE service territory utilizing the DOE's Energy Plus model. Energy Plus is a whole building energy simulation program that engineers, architects, and researchers use to model energy and water use in buildings. From the load profile outputs of Energy Plus, Black & Veatch determined the load factor for each building given, as follows:

$$Load\ Factor\ (\%) = \frac{Annual\ Average\ Load\ (kWh)}{Annual\ Peak\ Load\ (kWh)} * (100)$$

The average load factor weighted by number of buildings for the top 8 buildings compromising 90 percent of the building stock was then determined as shown in Table B-1.

**Table B-1 Load Factor by Building Type**

| BUILDING TYPE | LOAD FACTOR |
|---|---|
| Religious Worship | 22% |
| Retail (other than mall) | 37% |
| Public Assembly | 28% |
| Service | 49% |
| Food Service | 37% |
| Warehouse | 32% |
| Education | 31% |
| Office | 37% |
| **Weighted Average** | **35%** |

For the building analysis, Black & Veatch utilized the electricity consumption energy intensity within the CBECS dataset. This dataset provides different energy intensity metrics for different climate zones throughout the US.

The weighted average load factor given in Table B-1 was used to determine approximately what demand (kW) corresponds to a given amount of floor space as defined from the technical suitability portion of the analysis. Interpolating between high and low demand data points was done to back into the range of building square footage that would yield the appropriate applicability requirements for each rate class.

## Energy Production Model Assumptions

Table B-2 summaries system parameters and loss assumptions made for distributed generation systems in the energy production analysis. These assumptions are largely based on typical parameters seen in the industry.

### Table B-2 Distribution Scale Production Modeling Assumptions

| INPUTS | ASSUMPTION | REASONING |
| --- | --- | --- |
| System DC Size | Changes by customer | Technical output from GIS LiDAR analysis. |
| Module Type | Standard | Polycrystalline. |
| Inverter Loading Ratio | 1.1 | |
| Inverter Efficiency | 97% | |
| Array Type | Fixed roof mount | |
| Tilt | Varies by customer | Technical output from GIS LiDAR analysis. |
| Azimuth | Varies by customer | Technical output from GIS LiDAR analysis. |
| Ground Coverage Ratio | 56% | Only applies to flat roofs where modules are assumed to be tilted to 10 degrees. |
| Soiling | 1% | Black & Veatch ran its proprietary soiling model for a system west of the Cascade Mountains, where PGE's service territory primarily resides. The weather patterns west of the Cascades are fairly consistent and, therefore, Black & Veatch applied the same soiling loss to systems in PGE's service territory. |
| Shading | Changes by customer | For distributed generation systems, shading from nearby trees, buildings and terrain is accounted for on a monthly basis. |
| Snow | 0% | Accounted for in Black & Veatch's soiling loss parameter. |
| Mismatch | 1% | |
| Wiring | 1.5% | Black & Veatch estimates 2 percent for wiring and connection losses. This value is split between wiring and connection losses in SAM. |
| Connections | 0.5% | See above. |
| Light-Induced Degradation | 1.5% | Typical for polycrystalline. |
| Nameplate | 0.5% | |
| Age | 0.35% | Degradation seen during the first year. |
| Availability | 99% | |
| Degradation | 0.7%/year | |

# Appendix C. Federal and Oregon State Incentives

To help offset solar system installation costs and facilitate adoption of PV in the state, federal and state incentives are available to residential and business customers, although nearly all are set to expire or are subject to annual adjustments. Oregon also provides a property tax exemption for solar PV systems. Tables C-1 and C-2 summarize the incentives available to residential and commercial customers in 2014 and anticipated or proposed levels for 2015.

**Table C-1 Residential Customer Incentives**

| INCENTIVE | 2014 INCENTIVE/FUNDING | 2015 INCENTIVE/ FUNDING |
|---|---|---|
| Federal Residential Investment Tax Credit (ITC) | 30% of installed cost | 30% of installed cost |
| Oregon Residential Energy Tax Credit[23] | Lower of $1.90 per W/ $6,000/50% of installed cost (up to $1500 per year) | Lower of $1.70 per W/ $6,000/50% of installed cost (up to $1500 per year) |
| Energy Trust of Oregon (ETO) Residential Incentives | Stepped down from $1.00 per W to $0.90 per W (Maximum of $9,500 per customer) Total 2014 budget: $5,390,000[24] | Stepped down from $0.95 per W to $0.82 per W. Total 2015 Budget: $3.0 million[25] |

[23] Summary of HB 3672 (2011) Tax Credit Extension Bill http://www.oregon.gov/ENERGY/CONS/docs/HB3672summary.pdf.
[24] ETO Incentive Status Report for PGE (Dec. 15, 2014) http://energytrust.org/library/forms/Solar_Status_Report.pdf.
[25] Based on published ETO funding for 2015 for PGE customers. http://energytrust.org/library/forms/Solar_Status_Report.pdf (Accessed January 15, 2015).

**Table C-2 Business Customer Incentives**

| INCENTIVE | 2014 INCENTIVE/FUNDING | 2015 INCENTIVE/ FUNDING |
|---|---|---|
| Federal Business Investment Tax Credit (ITC) | 30% of installed cost | n/a |
| Modified Accelerated Depreciation (MACRS) | 5 years | n/a |
| Oregon Renewable Energy Development (RED) Grant26 | Competitive Bid for multiple RE technologies (max of $250,000 or 35% of project cost)<br>Total 2014 Funding: $1,500,000 | $1,500,000 |
| Energy Trust of Oregon (ETO) Business Incentives | $1.30 to $0.70 per W (size dependent) (max of $180,000)<br>Total 2014 Funding: $4,600,00027 | $1.30 to $0.70 per W (size dependent), step down $1.20 to $0.66 per W (size dependent)<br>Total 2015 Budget: $3.0 million 28 |

Figure C-1 shows the changes to these incentives over time, as the federal ITC is set to expire by the end of 2016, and the Oregon tax credits and grants are set to expire by the end of 2017. The ETO incentive programs are also adjusted annually to step down over time to account for declining cost of solar over time.

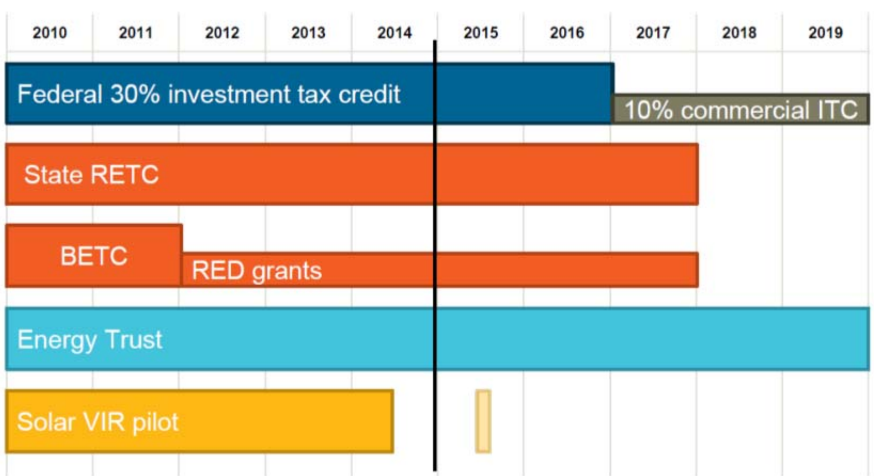


**Figure C-1 Incentives for Oregon Solar Projects (source: ETO)**

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[26] Summary of HB 3672 (2011) Tax Credit Extension Bill http://www.oregon.gov/ENERGY/CONS/docs/HB3672summary.pdf.

[27] ETO Incentive Status Report for PGE (Dec. 15, 2014) ETO Incentive Status Report for PGE (Dec. 15, 2014).

[28] [28] Based on published ETO funding for 2015 for PGE customers. http://energytrust.org/library/forms/Solar_Status_Report.pdf (Accessed January 15, 2015).

# Appendix D. Results

### Table D-1 Annual Solar Distributed Generation Adoption by Customer and Scenario (MWdc)

| RATE CASE | CPI | | | | | | CPI+1 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SCENARIO APPROACH | ADOPTION CURVE | | ETO FUNDING (NO TAX CREDITS) | | ETO FUNDING (WITH TAX CREDITS) | | ADOPTION CURVE | | ETO FUNDING (NO TAX CREDITS) | | ETO FUNDING (WITH TAX CREDITS) | |
| CUSTOMER CLASS | COM | RES | COM | RES | COM | RES | COM | RES | COM | RES | COM | RES |
| 2016 | 1.80 | 2.40 | 4.91 | 2.41 | 4.91 | 2.41 | 4.81 | 4.23 | 4.96 | 4.24 | 4.96 | 4.24 |
| 2017 | 4.37 | 8.83 | 2.89 | 5.19 | 3.20 | 9.93 | 5.23 | 11.15 | 2.96 | 5.38 | 3.65 | 10.44 |
| 2018 | 4.16 | 11.09 | 3.31 | 2.00 | 4.12 | 13.77 | 5.03 | 13.55 | 3.45 | 2.09 | 4.30 | 15.48 |
| 2019 | 3.49 | 12.39 | 3.65 | 2.33 | 4.57 | 12.83 | 4.48 | 15.75 | 3.86 | 2.48 | 4.86 | 15.13 |
| 2020 | 2.46 | 12.48 | 3.94 | 2.64 | 4.95 | 10.14 | 4.12 | 16.74 | 4.23 | 2.86 | 5.37 | 12.17 |
| 2021 | 1.86 | 11.54 | 4.19 | 2.94 | 5.29 | 7.85 | 3.02 | 16.29 | 4.58 | 3.26 | 5.86 | 9.48 |
| 2022 | 0.95 | 9.79 | 4.42 | 3.23 | 5.59 | 6.23 | 1.97 | 14.58 | 4.91 | 3.68 | 6.32 | 7.54 |
| 2023 | 0.88 | 7.64 | 4.62 | 3.52 | 5.85 | 5.10 | 1.74 | 12.02 | 5.22 | 4.12 | 6.77 | 6.20 |
| 2024 | 0.93 | 5.49 | 4.80 | 3.81 | 5.42 | 4.87 | 1.94 | 9.16 | 5.53 | 4.60 | 7.20 | 6.06 |
| 2025 | 0.94 | 5.35 | 4.96 | 4.10 | 2.25 | 5.31 | 2.08 | 6.44 | 5.82 | 5.12 | 6.52 | 6.89 |
| 2026 | 0.00 | 5.62 | 5.11 | 4.40 | 1.37 | 5.76 | 2.16 | 4.12 | 6.11 | 5.69 | 2.04 | 7.85 |
| 2027 | 0.00 | 5.71 | 1.53 | 4.70 | 0.92 | 6.23 | 0.00 | 2.34 | 6.39 | 6.32 | 1.11 | 8.96 |
| 2028 | 0.00 | 4.48 | 0.71 | 5.00 | 0.63 | 6.71 | 0.00 | 1.07 | 1.54 | 7.03 | 0.73 | 10.28 |
| 2029 | 0.00 | 0.00 | 0.44 | 5.31 | 0.43 | 7.23 | 0.00 | 0.17 | 0.59 | 7.84 | 0.49 | 11.89 |

| RATE CASE | CPI | | | | | | CPI+1 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SCENARIO APPROACH | ADOPTION CURVE | | ETO FUNDING (NO TAX CREDITS) | | ETO FUNDING (WITH TAX CREDITS) | | ADOPTION CURVE | | ETO FUNDING (NO TAX CREDITS) | | ETO FUNDING (WITH TAX CREDITS) | |
| CUSTOMER CLASS | COM | RES | COM | RES | COM | RES | COM | RES | COM | RES | COM | RES |
| 2030 | 0.00 | 0.00 | 0.29 | 5.63 | 0.29 | 7.77 | 0.00 | 0.00 | 0.34 | 8.77 | 0.33 | 13.90 |
| 2031 | 0.00 | 0.00 | 0.19 | 5.96 | 0.19 | 8.34 | 0.00 | 0.00 | 0.22 | 9.84 | 0.22 | 6.21 |
| 2032 | 0.00 | 0.00 | 0.13 | 6.30 | 0.13 | 8.95 | 0.00 | 0.00 | 0.15 | 11.11 | 0.15 | 3.57 |
| 2033 | 0.00 | 0.00 | 0.09 | 6.65 | 0.09 | 7.80 | 0.00 | 0.00 | 0.10 | 12.64 | 0.10 | 2.41 |
| 2034 | 0.00 | 0.00 | 0.06 | 7.02 | 0.06 | 4.84 | 0.00 | 0.00 | 0.07 | 14.51 | 0.07 | 1.65 |
| 2035 | 0.00 | 0.00 | 0.01 | 7.39 | 0.01 | 3.33 | 0.00 | 0.00 | 0.01 | 16.86 | 0.01 | 1.12 |
| ***Subtotal*** | ***21.83*** | ***102.80*** | ***50.26*** | ***90.54*** | ***50.26*** | ***145.38*** | ***36.57*** | ***127.60*** | ***61.04*** | ***138.45*** | ***61.04*** | ***161.47*** |
| **Total** | **124.63** | | **140.80** | | **195.64** | | **164.17** | | **199.50** | | **222.52** | |

# Appendix E. Utility-Scale Solar Potential Assessment Methodology

## TECHNICAL SCREEN

Black & Veatch identified areas appropriate for utility-scale solar PV development by excluding areas of the state based on several criteria. These criteria were intended to exclude areas that are less likely to be developed because of environmental concerns, terrain, proximity to transmission, and other factors. Because the potential for solar development is so large, the exclusions applied are relatively restrictive. Development of solar PV could be possible in areas shown as excluded on in these maps (such as farmland), but other areas may be preferred.

All exclusion areas were merged together and removed from the overall state boundary. The result of this was further filtered by contiguous acreage, removing any land with a contiguous acreage of less than 25 (approximately 5 MWdc).

The exclusions implemented by Black & Veatch are summarized in the following sections:

- Environmental Screens (EDTF Categories 3 and 4).
- Sage Grouse Habitat.
- Publicly Owned and Park Lands.
- Land Use.
- More than 5 Miles from Transmission Lines.
- Land with Slope Greater than 5 Percent.

### Environmental Screens

The WECC created the Environmental Data Task Force (EDTF) to map environmental sensitivities of lands across the west. The EDTF has created the most comprehensive, stakeholder-vetted dataset of environmental restrictions for energy development in the west. The EDTF maintains data to support the identification of land appropriate for transmission line development. While the initial purpose was for transmission siting, similar development constraints would apply to solar PV projects.

The EDTF data consists of four categories, summarized in Table E-1.

**Table E-1 EDTF Categories**

| CATEGORY | DESCRIPTION |
| --- | --- |
| Category 1 | Least Risk of Environmental or Cultural Resource Sensitivities and Constraints: Areas with minimal identified environmental or cultural resource constraints and/or with existing land uses or designations that are compatible with or encourage transmission development. These areas would present few or minimal environmental and cultural mitigation requirements and are least likely to result in project delays. |
| Category 2 | Low to Moderate Risk of Environmental or Cultural Resource Sensitivities and Constraints: Areas where development may encounter one or more environmental or cultural resource sensitivity or constraints that would require low to moderate permit complexity or mitigation costs. This category also includes areas in the Protected Areas Database of the United States (PAD-US) dataset that have an unknown land use designation or degree of restriction to transmission development. |
| Category 3 | High Risk of Environmental or Cultural Resource Sensitivities and Constraints: Transmission development is likely to encounter one or more environmental or cultural resource sensitivities or constraints that will substantially increase permitting complexity and which could result in project delays and high mitigation costs. This category also includes areas identified as avoidance areas (based on environmental and cultural sensitivities) in Canada from the Western Renewable Energy Zones (WREZ) Phase 1 Report. |
| Category 4 | Areas Presently Precluded by Law or Regulation: Areas where transmission development is presently precluded by federal, state, or provincial law, policy, or regulation, and areas identified as exclusion areas (based on environmental and cultural sensitivities) in Canada from the WREZ process. |
| Source: https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Environmental-and-Cultural-Considerations.aspx | |

Black & Veatch excluded Categories 3 and 4, as these represent precluded or high-risk areas for development. EDTF Categories 3 and 4 are shown on Figure E-1 in orange. Remaining uncolored areas are Categories 1 and 2.

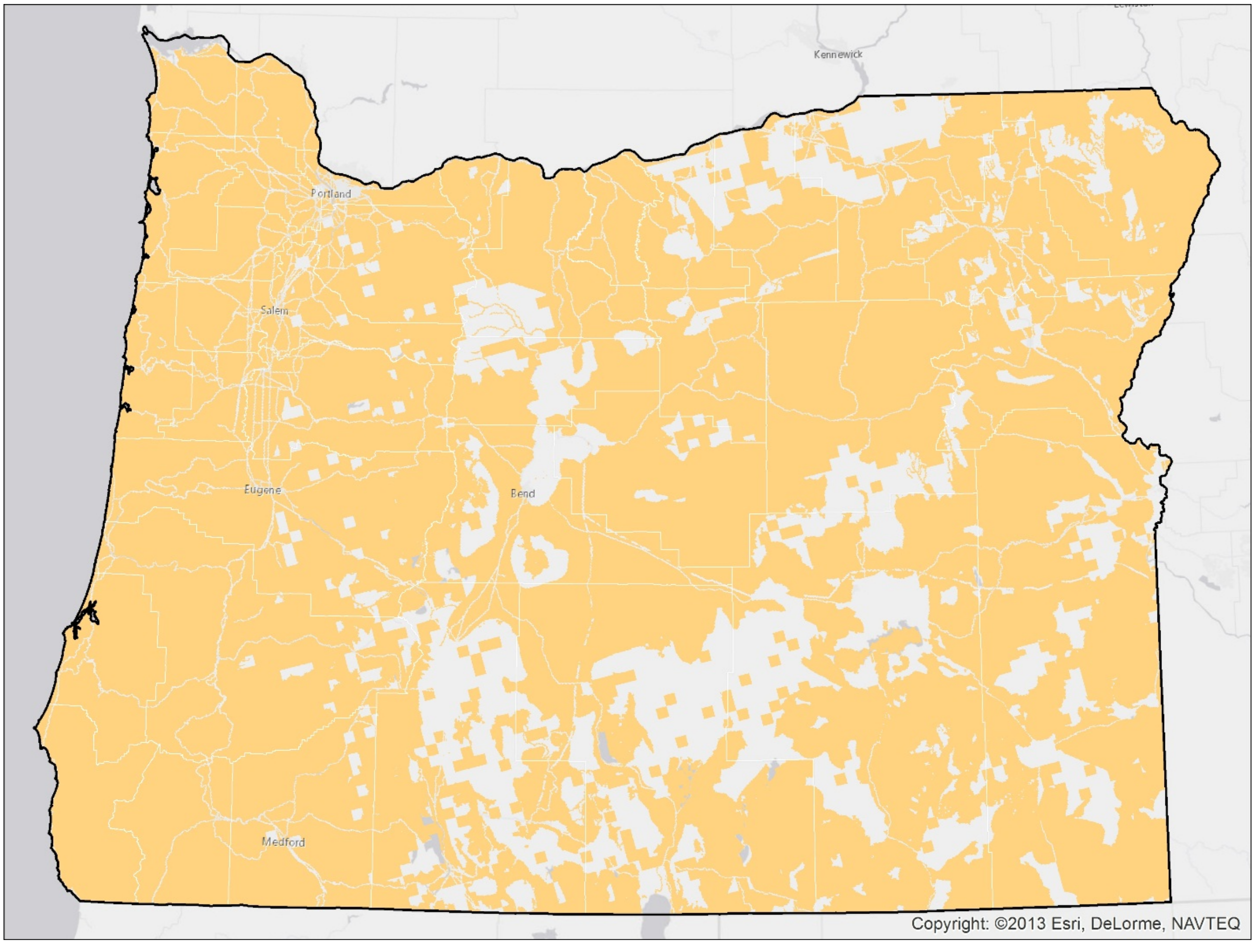


**Figure E-1 EDTF Categories 3 and 4**

## Sage Grouse

Sage grouse is a bird that dwells in sagebrush. The species is a candidate for listing under the Federal Endangered Species Act, and there are significant efforts to conserve sage grouse habitat. Therefore, sage grouse habitat areas were excluded from this analysis. Figure E-2 shows the sage grouse habitat in Oregon.

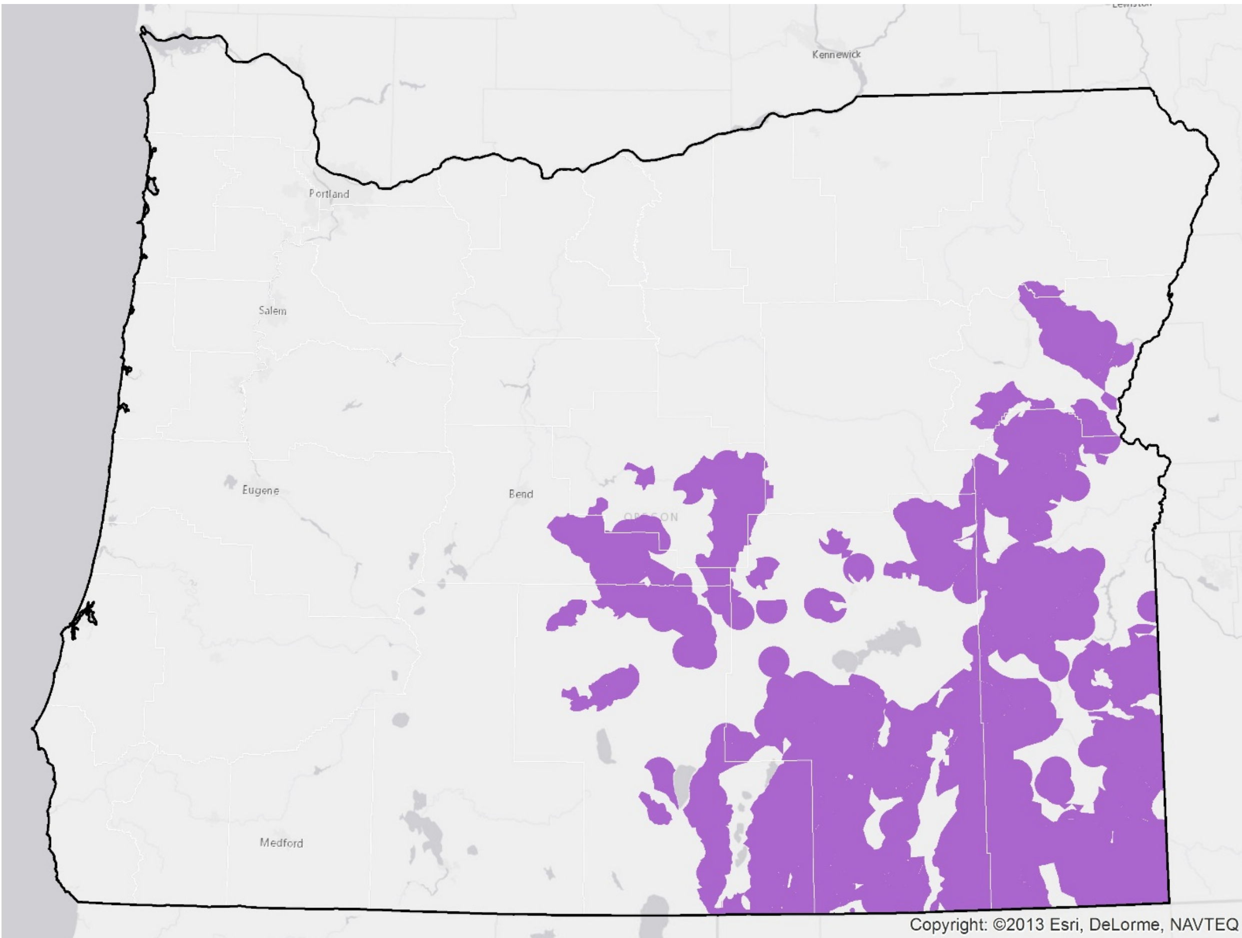


**Figure E-2 Sage Grouse Habitat**

## Public Ownership & Parkland

Black & Veatch also eliminated land owned by the Bureau of Land Management (BLM), Department of Defense (DOD), Forest Service, and Fish and Wildlife Service. These areas are identified on Figure E-3.

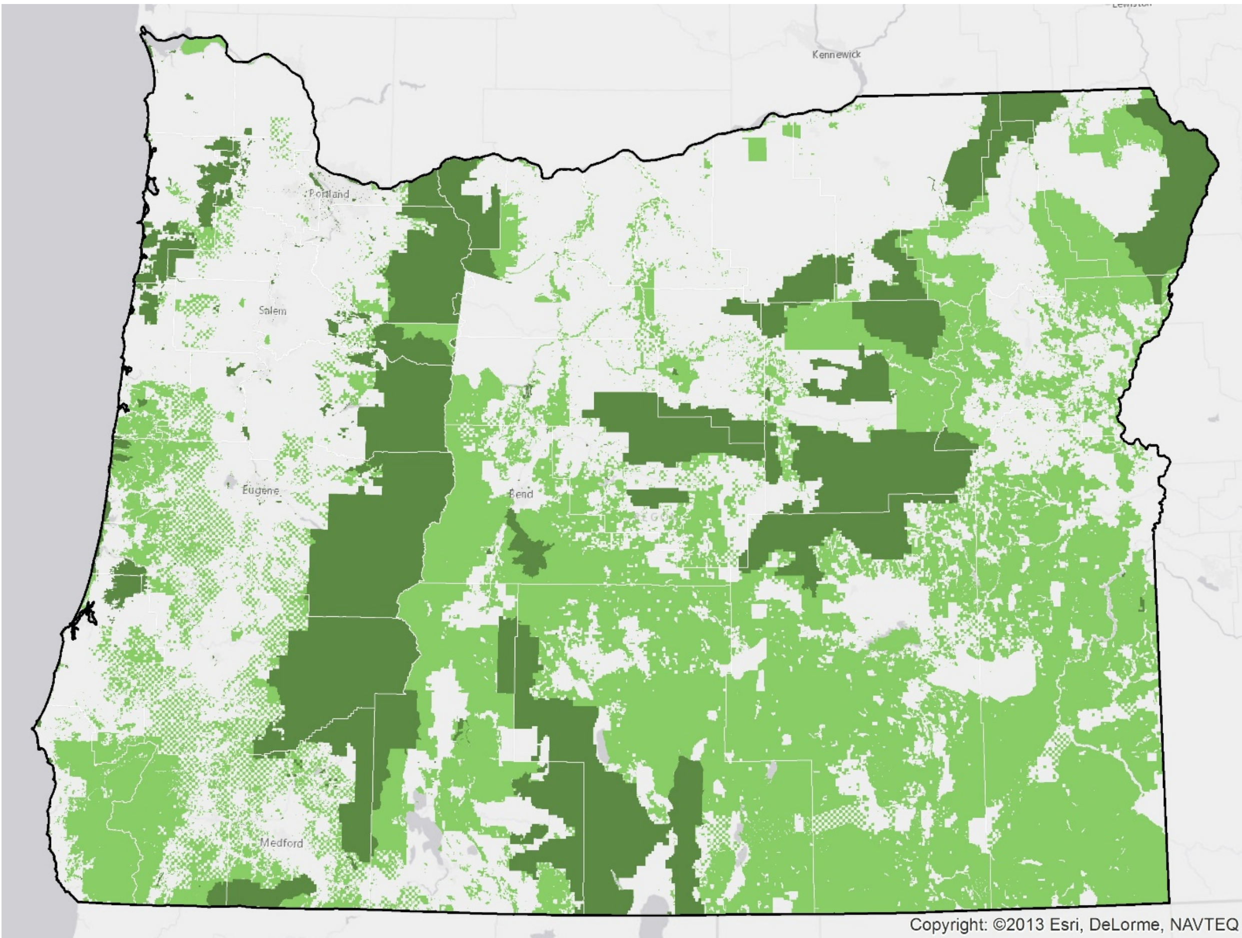


**Figure E-3 Public Ownership & Parkland**

## Land Use

Black & Veatch also eliminated lands based on their usage. Lands that are bodies of water, have low development, medium and high density (urban), forested, cropland, or wetlands were excluded from this analysis. Lands that fall into these land use categories are shown on Figure E-4.

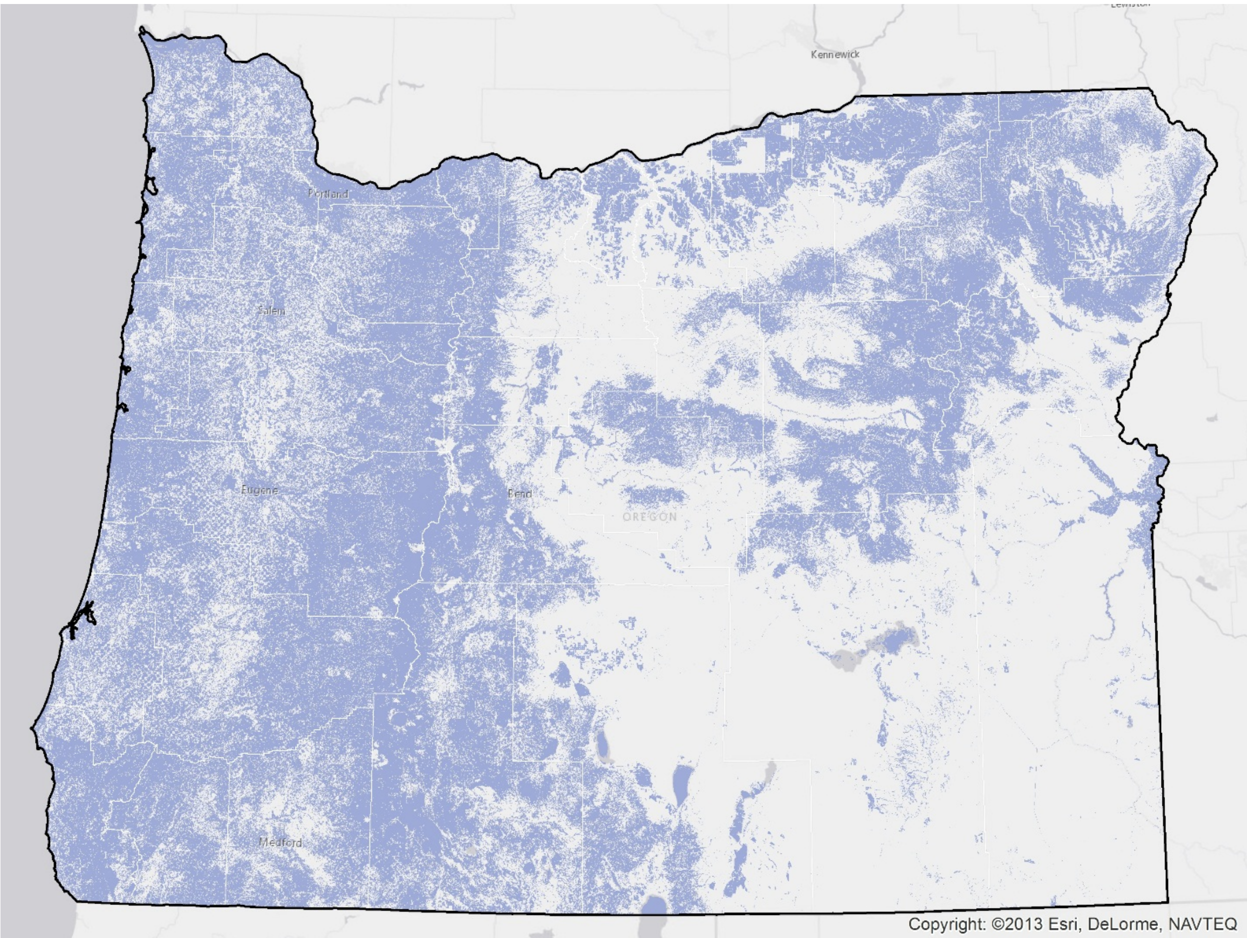


**Figure E-4 Water, Developed Low, Medium and High Density, Forests, Cropland, and Wetlands (Land Use)**

## Distance to Transmission

Black & Veatch focused on appropriate lands within 5 miles of existing electric transmission. Sites further than 5 miles are not expected to be financially viable because of the need to build long generation interconnection lines. An image illustrating areas outside of 5 miles from transmission lines is shown on Figure E-5.

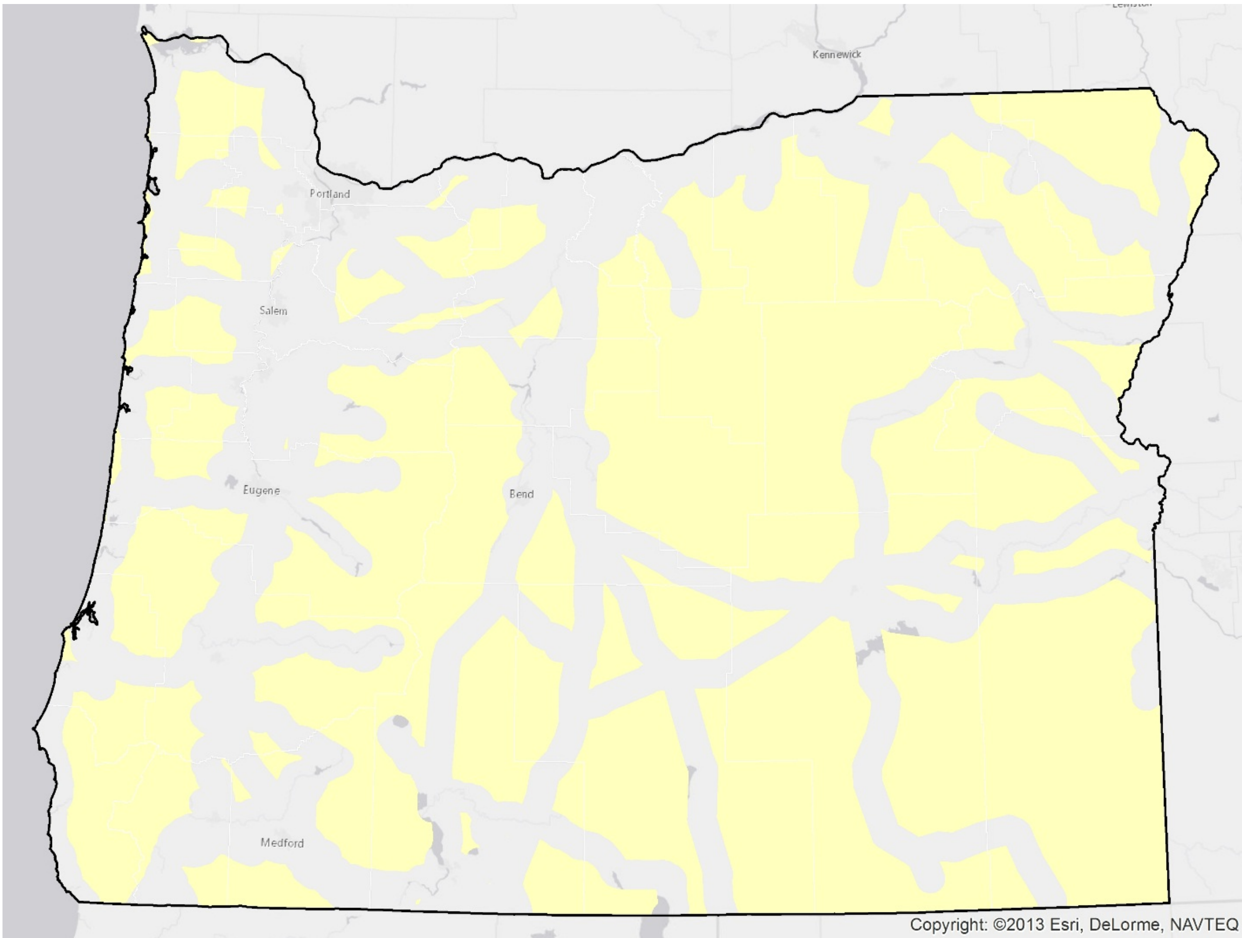


**Figure E-5 More than 5 Miles from Transmission Lines**

## Land Slope

Ground-mounted solar PV projects are generally installed on relatively flat land. This is because the mounting systems often cannot accommodate drastic slopes and because sloped land may negatively alter the orientation of the solar PV panels from the sun. Based on typical projects and typical tolerances of solar PV mounting systems, Black & Veatch eliminated lands with slopes greater than 5 percent. These lands are shown on Figure E-6.

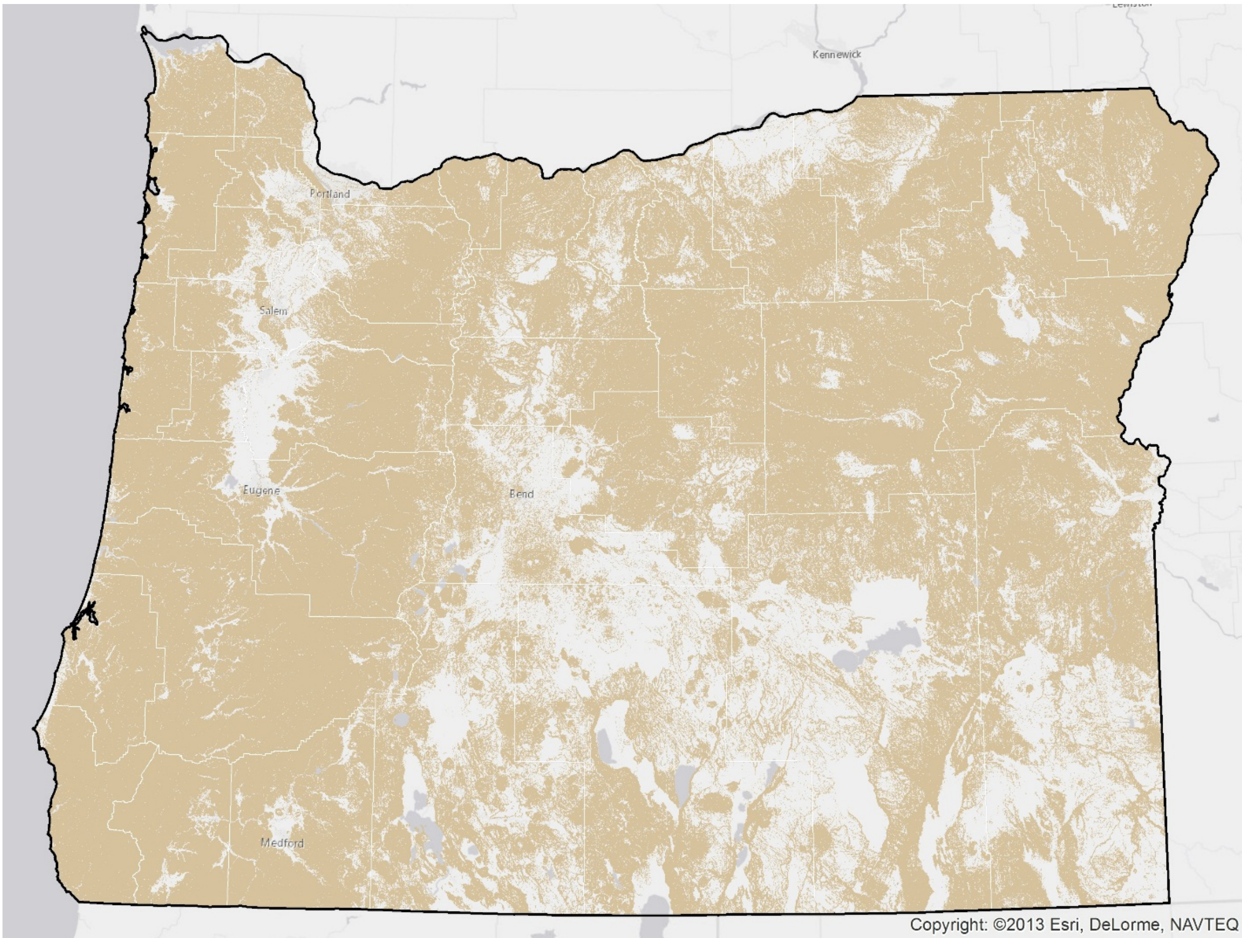


**Figure E-6 Land with Slope Greater than 5 Percent**

## FINANCIAL SCREEN

### Energy Production Model Assumptions

Table E-2 summarizes system parameters and loss assumptions made for utility-scale systems. These assumptions are largely based on typical parameters seen in the industry.

**Table E-2 Utility-Scale Production Modeling Assumptions**

| INPUTS | ASSUMPTION | REASONING |
|---|---|---|
| System DC Size | Changes by customer | Technical output from GIS LiDAR analysis. |
| Module Type | Standard | Polycrystalline. |
| Inverter Loading Ratio | 1.4 | |
| Inverter Efficiency | 97% | |
| Array Type | Fixed open rack | |
| Tilt | Varies by customer | Technical output from GIS LiDAR analysis. |
| Azimuth | Varies by customer | Technical output from GIS LiDAR analysis. |
| Ground Coverage Ratio | 40% | |
| Soiling | 1% for west of Cascade mountains;<br><br>5% for east of the Cascade Mountains (about 121.5 degree longitude line) | Black & Veatch ran its proprietary soiling model for a system west of the Cascade Mountains. The weather patterns west of the Cascades are fairly consistent, and therefore, Black & Veatch applied the same soiling loss to all systems west of the Cascades.<br><br>Areas east of the Cascade Mountains have different weather patterns, including snowfall. Black & Veatch ran its snow model for various sites throughout eastern Oregon. Although snowfall varies by location, the variation happens during a few months that have low solar resource. Therefore, the same soiling loss estimate is applied to all systems east of the Cascades. This estimate is 5 percent annually. |
| Shading | Changes by customer | Assumed that the shading sources are eliminated. |
| Snow | 0% | Accounted for in Black & Veatch's soiling loss parameter. |
| Mismatch | 1% | |
| Wiring | 1.5% | Black & Veatch estimates 2 percent for wiring and connection losses. This value is split between wiring and connection losses in SAM. |
| Connections | 0.5% | See above. |
| Light-Induced Degradation | 1.5% | Typical for polycrystalline. |
| Nameplate | 0.5% | |
| Age | 0.35% | Degradation seen during the first year. |
| Availability | 99% | |
| Degradation | 0.7%/year | |