

# Annual Technology Baseline 2017

## NATIONAL RENEWABLE ENERGY LABORATORY

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# Utility-Scale PV Power Plants

## Representative Technology

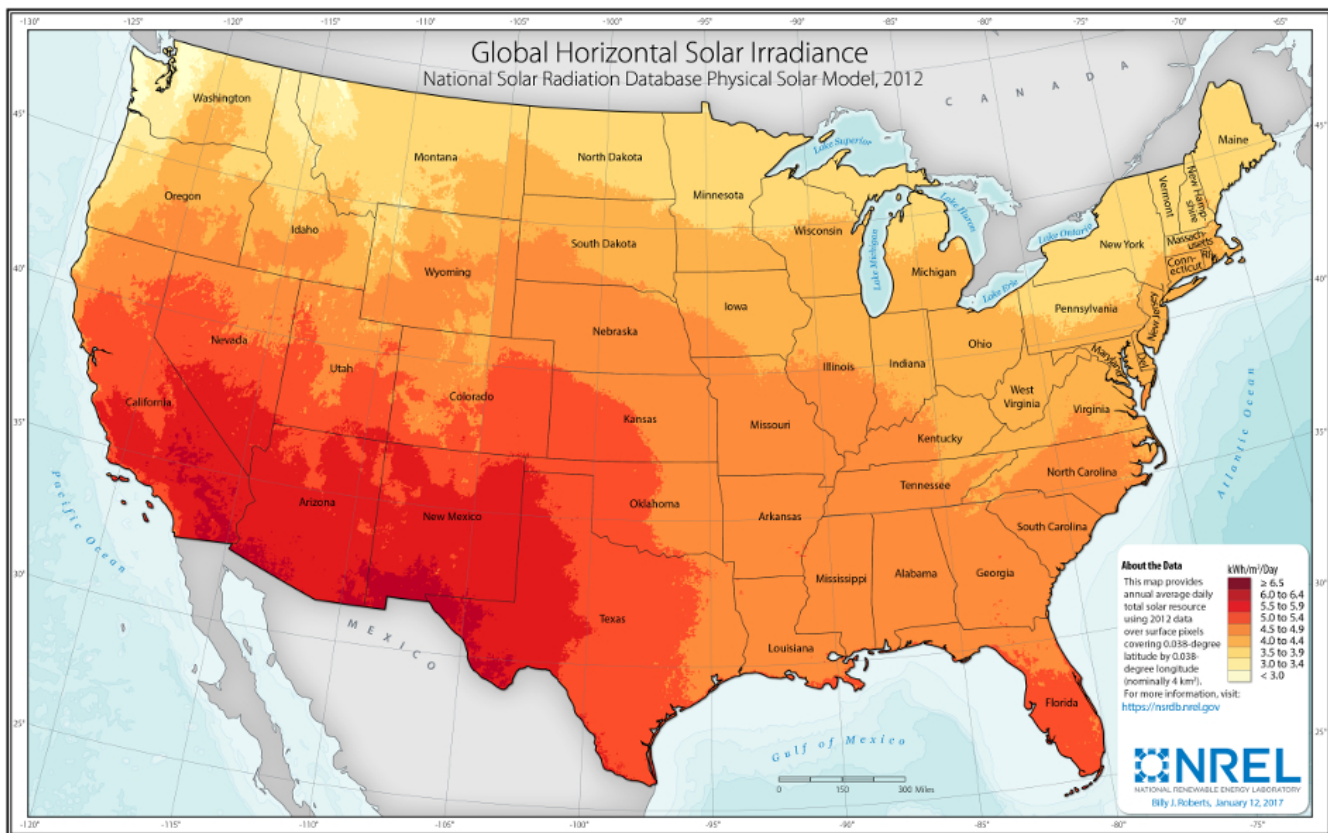
Utility-scale PV systems in the ATB are representative of one-axis tracking systems with performance characteristics in line with a 1.1 DC-to-AC ratio - or inverter loading ratio (ILR) - and pricing characteristics in line with a 1.2 DC-to-AC ratio (Fu et al. 2016). PV system performance characteristics were designed in the ReEDS model at a time when PV system ILRs were lower than they are in current system designs; pricing in the 2017 ATB incorporates more up-to-date system designs and therefore assumes a higher ILR.

## Resource Potential

Solar resources across the United States are mostly good to excellent at about 1,000-2,500 kWh/m<sup>2</sup>/year. The Southwest is at the top of this range, while Alaska and part of Washington are at the low end. The range for the contiguous United States is about 1,350-2,500 kWh/m<sup>2</sup>/year. Nationwide, solar resource levels vary by about a factor of two.

The total U.S. land area suitable for PV is significant and will not limit PV deployment. One estimate (Denholm and Margolis 2008) suggests the land area required to supply all end-use electricity in the United States using PV is about 5,500,000 hectares (ha) (13,600,000 acres),

which is equivalent to 0.6% of the country's land area or about 22% of the "urban area" footprint (this calculation is based on deployment/land in all 50 states).



*Map of mean solar resource available to PV systems in the United States*

Renewable energy technical potential, as defined by Lopez et al. (2012), represents the achievable energy generation of a particular technology given system performance, topographic limitations, and environmental and land-use constraints. The primary benefit of assessing technical potential is that it establishes an upper-boundary estimate of development potential. It is important to understand that there are multiple types of potential - resource, technical, economic, and market (Lopez et al. 2012; NREL, "Renewable Energy Technical Potential (<https://www.nrel.gov/gis/re-potential.html>)").

## Base Year and Future Year Projections Overview

The Base Year estimates rely on modeled CAPEX and O&M estimates benchmarked with industry and historical data. Capacity factor is estimated based on hours of sunlight at latitude for all geographic locations in the United States. The ATB presents capacity factor estimates that encompass a range associated with low, mid, and high levels across the United States.

Future year projections are derived from analysis of published projections of PV CAPEX and bottom-up engineering analysis of O&M costs. Three different projections were developed for

scenario modeling as bounding levels:

- **High cost:** no change in CAPEX, O&M, or capacity factor from 2016 to 2050; consistent across all renewable energy technologies in the ATB
- **Mid cost:** based on the median of literature projections of future CAPEX; O&M technology pathway analysis
- **Low Cost:** based on low bound of literature projections of future CAPEX; O&M technology pathway analysis.

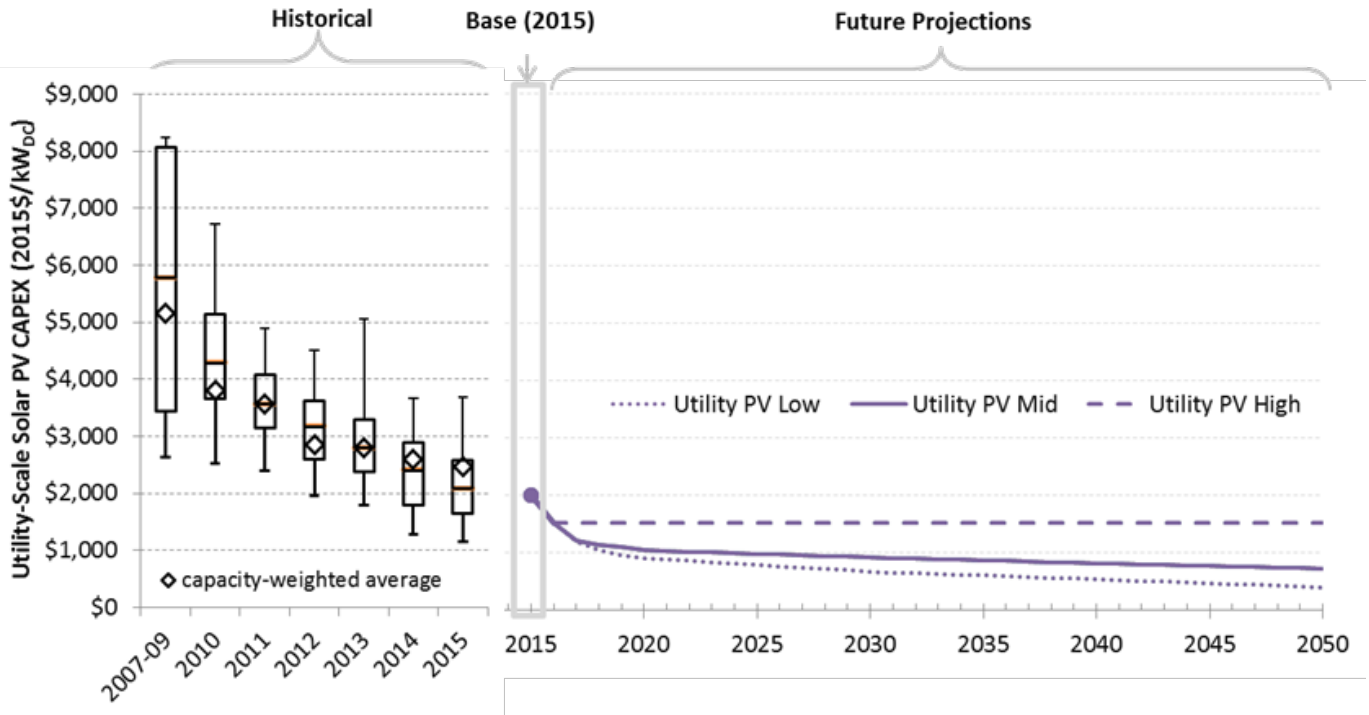
## CAPital EXpenditures (CAPEX): Historical Trends, Current Estimates, and Future Projections

Capital expenditures (CAPEX) are expenditures required to achieve commercial operation in a given year. These expenditures include the hardware, the balance of system (e.g., site preparation, installation, and electrical infrastructure), and financial costs (e.g., development costs, onsite electrical equipment, and interest during construction) and are detailed in CAPEX Definition (</electricity/2017/index.html?t=su&s=cx>). In the ATB, CAPEX reflects typical plants and does not include differences in regional costs associated with labor or materials. The range of CAPEX demonstrates variation with resource in the contiguous United States.

The following figures show the Base Year estimate and future year projections for CAPEX costs in terms of  $$/kW_{DC}$  or  $$/kW_{AC}$ . Three cost reduction scenarios are represented: High, Mid, and Low. Historical data from utility-scale PV plants installed in the United States are shown for comparison to the ATB Base Year estimates. The estimate for a given year represents CAPEX of a new plant that reaches commercial operation in that year.

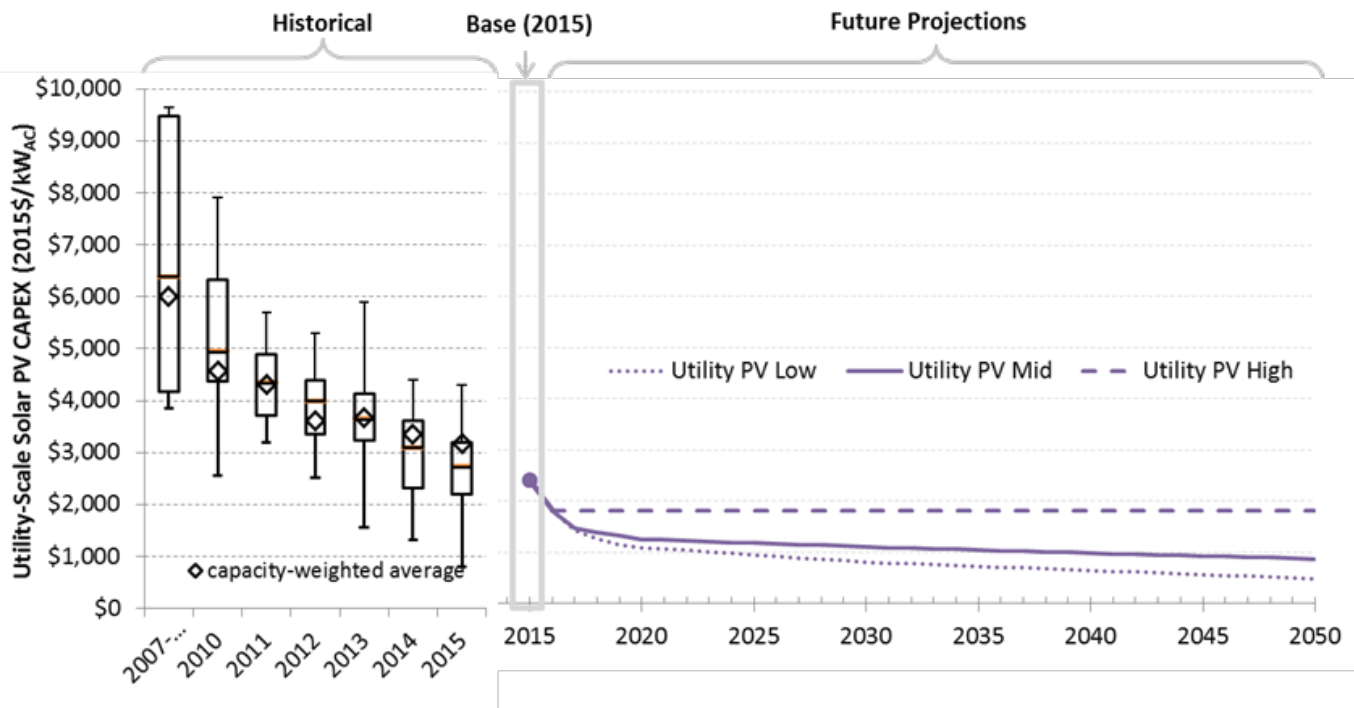
The PV industry typically refers to PV CAPEX in terms of  $$/kW_{DC}$  based on the aggregated module capacity. The electric utility industry typically refers to PV CAPEX in terms of  $$/kW_{AC}$  based on the aggregated inverter capacity. See Solar PV AC-DC Translation (</electricity/2017/pv-ac-dc.html>) for details. The figures illustrate the CAPEX historical trends, current estimates, and future projections in terms of  $$/kW_{DC}$  or  $$/kW_{AC}$  assuming an inverter loading ratio of 1.2.

DC



**CAPEX (CAPital EXpenditures) historical trends, current estimates, and future projection for utility PV (DC)**  
 Source: National Renewable Energy Laboratory Annual Technology Baseline (2017), <http://atb.nrel.gov>

AC



### CAPEX (CAPital EXPenditures) historical trends, current estimates, and future projection for utility PV (AC)

Source: National Renewable Energy Laboratory Annual Technology Baseline (2017), <http://atb.nrel.gov>

*Historical data shown in box-and-whiskers format where a bar represents the median, a box represents the 20th and 80th percentiles, and whiskers represent the minimum and maximum.*

*Year represents Commercial Online Date for a past or future plant.*

*CAPEX is shown as a single value because it does not vary with solar resource.*

## Recent Trends

Reported historical utility-scale PV plant CAPEX (Bolinger and Seel 2016) is shown in box-and-whiskers format for comparison to the ATB current CAPEX estimates and future projections. Bolinger and Seel (2016) provide statistical representation of CAPEX for 89% of all utility-scale PV capacity.

PV pricing and capacities are quoted in  $\text{kW}_{\text{DC}}$  (i.e., module rated capacity) unlike other generation technologies, which are quoted in  $\text{kW}_{\text{AC}}$ . For PV, this would correspond to the combined rated capacity of all inverters. This is done because  $\text{kW}_{\text{DC}}$  is the unit that the majority of the PV industry uses. Although costs are reported in  $\text{kW}_{\text{DC}}$ , the total CAPEX includes the cost of the inverter, which has a capacity measured in  $\text{kW}_{\text{AC}}$ .

CAPEX estimates for 2015 reflect continued rapid decline supported by analysis of recent power purchase agreement pricing (Bolinger and Seel 2016) for projects that will become operational in 2015 and beyond.

## Base Year Estimates

For illustration in the ATB, a representative utility-scale PV plant is shown. Although the PV technologies vary, typical plant costs are represented with a single estimate because the CAPEX does not vary with solar resource.

Although the technology market share may shift over time with new developments, the typical plant cost is represented with the projections above.

A system price of \$2.01/W<sub>DC</sub> in 2015 represents the median price of a utility-scale PV system installed in 2015 as reported in Bolinger and Seel (2016) and adjusted to remove regional cost multipliers based on geographic location of projects installed in 2015. The \$1.51/W<sub>DC</sub> price in 2016 is based on modeled pricing for one-axis tracking systems quoted in Q1 2016 as reported in Fu et al. (2016) and adjusted for inflation. These figures are in line with other estimated system prices reported in Feldman et al. (2016).

The Base Year CAPEX estimates should tend toward the low end of reported pricing because no regional impacts, time-lagged system prices, or spur line costs are included. These effects are represented in the historical market data.

For example, in 2014, the reported capacity-weighted average system price was higher than 80% of system prices in 2014 due to very large systems, with multi-year construction schedules, installed in that year. Developers of these large systems negotiated contracts and installed portions of their systems when module and other costs were higher.

## Future Year Projections

Projections of future utility-scale PV plant CAPEX are based on 14 system price projections from 8 separate institutions with short-term projections made in the past six months and long-term projections made in the last three years. We adjusted the "min," "median," and "max" analyst forecasts in a few different ways. All 2015 pricing is based on the median utility-scale system price as reported in Utility-Scale Solar 2015 (Bolinger and Seel 2016) and adjusted by the ReEDS state-level capital cost multipliers to remove geographic price distortions from 2015 reported pricing. All 2016 pricing is based on the bottom-up benchmark analysis reported in U.S. Solar Photovoltaic System Cost Benchmark Q1 2016 (adjusted for inflation) (Fu et al. 2016). These figures are in line with other estimated system prices reported in Feldman et al. (2016).

We adjusted the Mid and Low projections for 2017-2050 to remove distortions caused by the combination of forecasts with different time horizons and based on internal judgment of price trends. The High projection case is kept constant at the 2016 CAPEX value, assuming no improvements beyond 2016.

The largest annual reductions in CAPEX for the Mid and Low projections occur from 2015 to 2017, dropping 25% from 2015 to 2016 and another 19%-22% from 2016 to 2017. While reported CAPEX values have not been collected for all systems built in 2016 and 2017, CAPEX information collected from Annual Reports of Major Electric Utilities from the Federal Regulatory Commission (FERC Form 1) from nine major utilities found a 22% reduction in CAPEX from 2015 to 2016, falling to \$1.32/W, which is well below reported CAPEX in the ATB. (FERC Form 1 collected from the FERC Online elibrary (<https://elibrary.ferc.gov/IDMWS/search/fercgensearch.asp>) for the following utilities: Arizona Public Service, Florida Power & Light, Duke Energy Progressive, Georgia Power, Indiana Michigan Power Company, Kentucky Utilities, Pacific Gas & Electric, Public Service of New Mexico, and Southern California Edison.) The ATB values in 2017 are based on analysts' forecasts. Additionally, initially reported pricing for utility-scale power purchase agreements (PPAs) for utility-scale systems placed in service in that year fell 33% from 2015 to 2016; the ATB LCOE reduction over the same period is 23%. Detailed description of the methodology for developing Future Year Projections is found in Projections Methodology (</electricity/2017/index.html?t=su&s=md>).

Technology innovations that could impact future CAPEX costs are summarized in LCOE Projections (</electricity/2017/index.html?t=su&s=pr>).

## CAPEX Definition

Capital expenditures (CAPEX) are expenditures required to achieve commercial operation in a given year.

For the ATB—and based on EIA (2016a) and the NREL Solar PV Cost Model (Fu et al. 2016) - the utility-scale solar PV plant envelope is defined to include:

- Hardware
  - Module supply
  - Power electronics, including inverters
  - Racking
  - Foundation
  - AC and DC wiring materials and installation
  - Electrical infrastructure, such as transformers, switchgear, and electrical system connecting modules to each other and to the control center
- Balance of system
  - Land acquisition, site preparation, installation of underground utilities, access roads, fencing, and buildings for operations and maintenance
  - Project indirect costs, including costs related to engineering, distributable labor and

materials, construction management start up and commissioning, and contractor overhead costs, fees, and profit.

- Financial Costs
  - Owner's costs, such as development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, and property taxes during construction.
  - Electrical interconnection, including onsite electrical equipment (e.g., switchyard), a nominal-distance spur line (<1 mile), and necessary upgrades at a transmission substation; distance-based spur line cost (GCC) not included in the ATB
  - Interest during construction estimated based on six-month duration accumulated 100% at half-year intervals and an 8% interest rate (ConFinFactor).

CAPEX can be determined for a plant in a specific geographic location as follows:

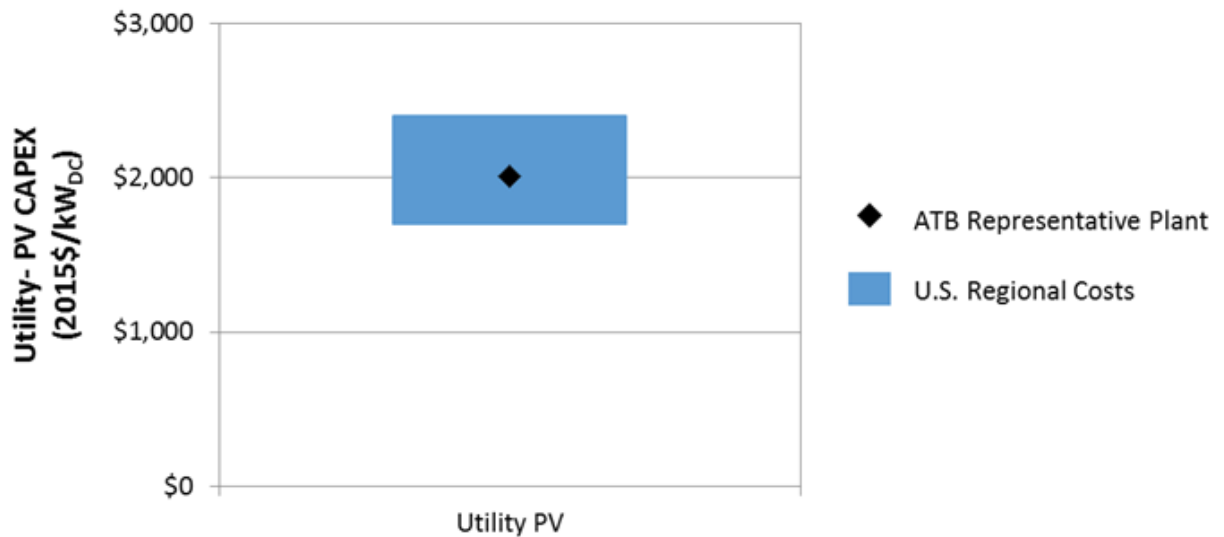
$$\text{CAPEX} = \text{ConFinFactor} * (\text{OCC} * \text{CapRegMult} + \text{GCC}).$$

(See the Financial Definitions tab in the ATB data spreadsheet (</electricity/data.html>).

Regional cost variations and geographically specific grid connection costs are not included in the ATB (CapRegMult = 1; GCC = 0). In the ATB, the input value is overnight capital cost (OCC) and details to calculate interest during construction (ConFinFactor).

In the ATB, CAPEX represents a typical one-axis utility-scale PV plant and does not vary with resource. The difference in cost between tracking and non-tracking systems has been reduced greatly in the United States. Regional cost effects associated with labor rates, material costs, and other regional effects as defined by EIA (2016a) expand the range of CAPEX. Unique land-based spur line costs based on distance and transmission line costs for potential utility-PV plant locations expand the range of CAPEX even further. The following figure illustrates the ATB representative plant relative to the range of CAPEX including regional costs (</electricity/2017/regional-capex.html>) across the contiguous United States. The ATB representative plants are associated with a regional multiplier of 1.0.





### CAPEX range for ATB representative plant and regional costs across U.S. for utility-PV plants

Source: National Renewable Energy Laboratory Annual Technology Baseline (2017), <http://atb.nrel.gov>

## Standard Scenarios Model Results

ATB CAPEX, O&M, and capacity factor assumptions for Base Year and future projections through 2050 for High, Mid, and Low projections are used to develop the NREL Standard Scenarios using the ReEDS model (<https://www.nrel.gov/analysis/reeds/>). See ATB and ATB and Standard Scenarios (</electricity/2017/scenarios.html>).

CAPEX in the ATB does not represent regional variants (CapRegMult) associated with labor rates, material costs, etc., but the ReEDS model does include 134 regional multipliers (EIA 2016a).

CAPEX in the ATB does not include a geographically determined spur line (GCC) from plant to transmission grid, but the ReEDS (<https://www.nrel.gov/analysis/reeds/>) model calculates a unique value for each potential PV plant.

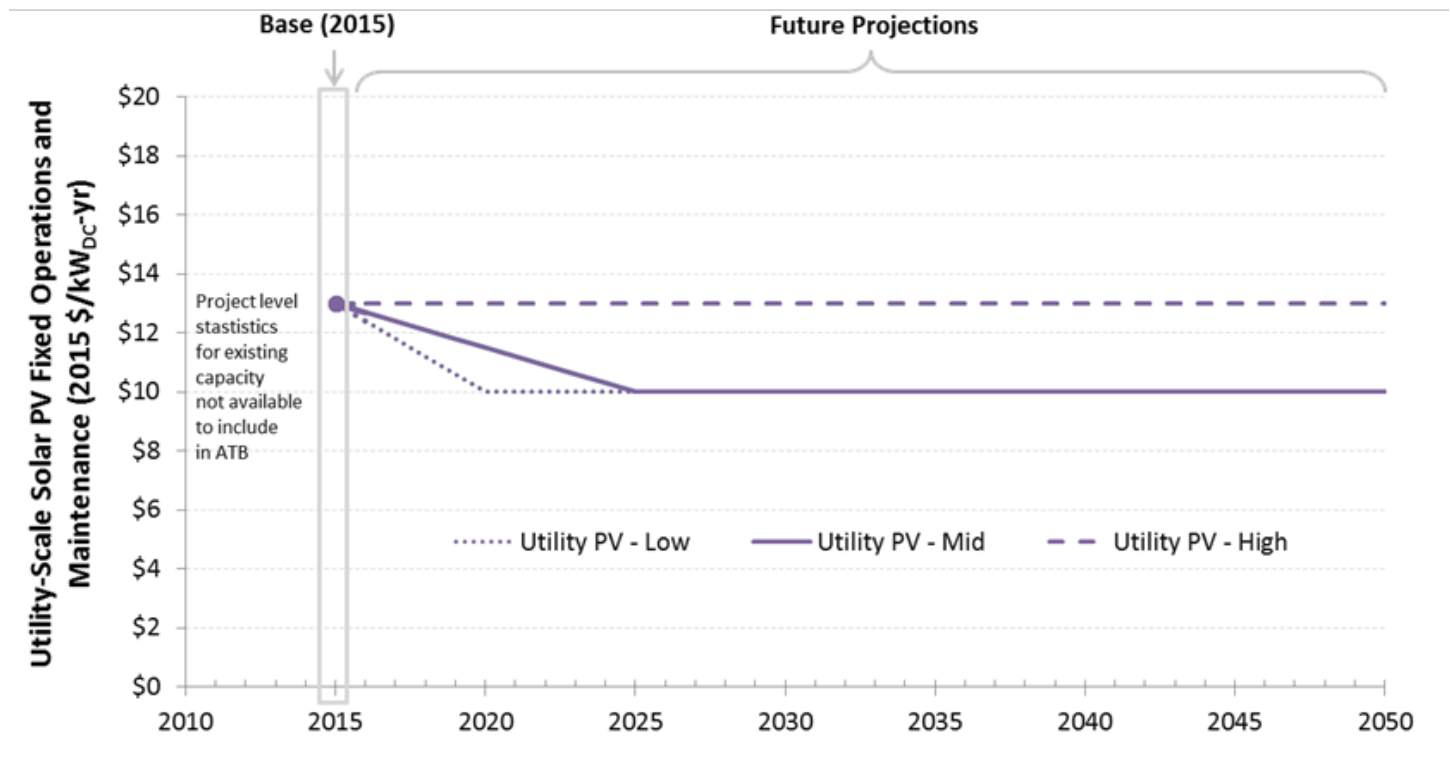
## Operation and Maintenance (O&M) Costs

Operations and maintenance (O&M) costs represent the annual fixed expenditures required to operate and maintain a solar PV plant over its technical lifetime of 30 years (the distinction between economic life and technical life is described here (</electricity/2017/finance-impact.html>)), including:

- Insurance, property taxes, site security, legal and administrative fees, and other fixed costs
- Present value, annualized large component replacement costs over technical life (e.g., inverters at 15 years)

- Scheduled and unscheduled maintenance of solar PV plants, transformers, etc. over the technical lifetime of the plant (e.g., general maintenance, including cleaning and vegetation removal)

The following figure shows the Base Year estimate and future year projections for fixed O&M (FOM) costs. Three cost reduction scenarios are represented. The estimate for a given year represents annual average FOM costs expected over the technical lifetime of a new plant that reaches commercial operation in that year.



Utility PV plant O&M projections

Source: National Renewable Energy Laboratory Annual Technology Baseline (2017), <http://atb.nrel.gov>

## Base Year Estimates

FOM of \$13/kW<sub>DC</sub>-yr is based on Bolinger and Seel (2016), who state that "average O&M costs for the cumulative set of PV plants within this sample have steadily declined from about \$31/kW<sub>AC</sub>-yr (or \$19/MWh) in 2011 to about \$16/kW<sub>AC</sub>-yr (\$7/MWh) in 2015." AC was converted into DC by dividing by 1.2. A wide range in reported prices exists in the market, in part depending on the maintenance practices that exist for a particular system. These cost categories include asset management (including compliance and reporting for incentive payments), different insurance products, site security, cleaning, vegetation removal, and failure of components. Not all these practices are performed for each system; additionally, some factors are dependent on the quality of the parts and construction. NREL analysts estimate O&M costs can range between \$0 and \$40/kW<sub>DC</sub>-yr.

## Future Year Projections

Future FOM is assumed to decline to \$10/kW<sub>DC</sub>-yr by 2020 in the Low cost case and by 2025 in the Mid cost case through improvements in system operation and more durable, better performing capital equipment, as per Woodhouse et al. 2016.

A detailed description of the methodology for developing future year projections is found in Projections Methodology (</electricity/2017/index.html?t=su&s=md>).

Technology innovations that could impact future O&M costs are summarized in LCOE Projections (</electricity/2017/index.html?t=su&s=pr>).

## Capacity Factor: Expected Annual Average Energy Production Over Lifetime

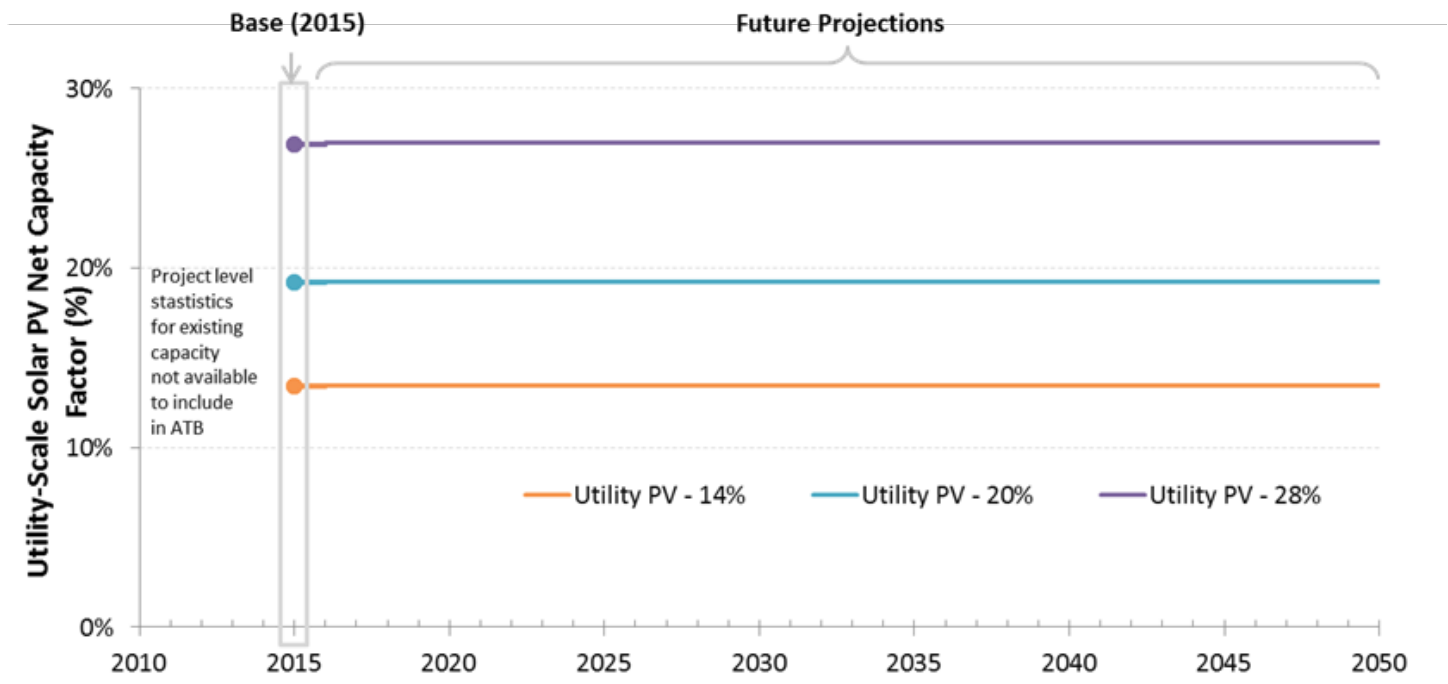
The capacity factor represents the expected annual average energy production divided by the annual energy production, assuming the plant operates at rated capacity for every hour of the year. It is intended to represent a long-term average over the technical lifetime of the plant (the distinction between economic life and technical life is described here (</electricity/2017/finance-impact.html>)). It does not represent interannual variation in energy production. Future year estimates represent the estimated annual average capacity factor over the technical lifetime of a new plant installed in a given year.

Other technologies' capacity factors are represented in exclusively AC units; however, because PV pricing in this ATB documentation is represented in \$/kW<sub>DC</sub>, PV system capacity is a DC rating. The PV capacity factor is the ratio of annual average energy production (kWh<sub>AC</sub>) to annual energy production assuming the plant operates at rated DC capacity for every hour of the year. For more information, see Solar PV AC-DC Translation (</electricity/2017/pv-ac-dc.html>).

The capacity factor is influenced by the hourly solar profile, technology (e.g., thin-film versus crystalline silicon), axis type (e.g., none, one, or two), expected downtime, and inverter losses to transform from DC to AC power. The DC-AC ratio is a design choice that influences the capacity factor. PV plant capacity factor incorporates an assumed degradation rate of 0.5%/year (Jordan and Kurtz 2013) in the annual average calculation.

The following figure shows a range of capacity factors based on variation in solar resource in the contiguous United States. The range of the Base Year estimates illustrate the effect of locating a utility-scale PV plant in places with lower or higher solar irradiance. These values are the maximum, median, and minimum values for all geographic locations in the United States as implemented in the ReEDS model (Eurek et al. 2017 ). Future projections for High,

Mid, and Low cost scenarios are unchanged from the Base Year. Technology improvements are focused on CAPEX and O&M cost elements.



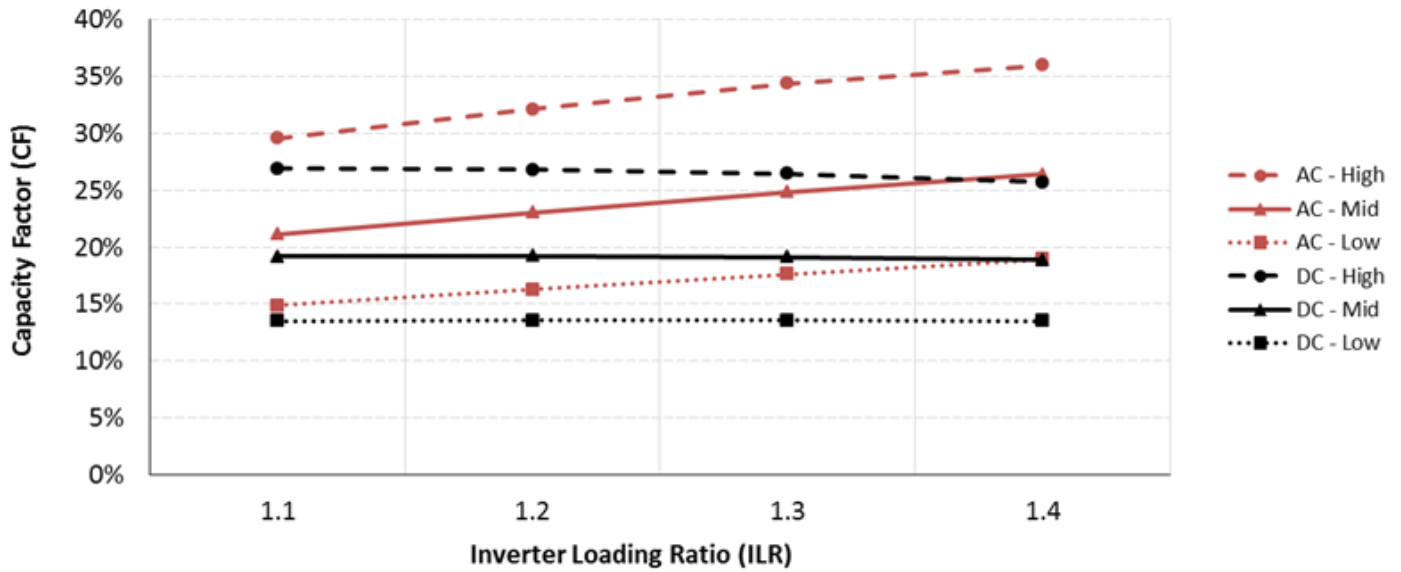
#### Utility PV net capacity factor

Source: National Renewable Energy Laboratory Annual Technology Baseline (2017), <http://atb.nrel.gov>

*The legend labels refer to the first-year operation capacity factors. The data illustrated modifies the first-year capacity factor by including estimated degradation over the economic life of a PV plant.*

PV system inverters, which convert DC energy/power to AC energy/power, have AC capacity ratings; therefore, the capacity of a PV system is rated in  $MW_{AC}$ , or the aggregation of all inverters' rated capacities, or  $MW_{DC}$ , or the aggregation of all modules' rated capacities. The capacity factor calculation uses a system's rated capacity, and therefore, capacity factor can be represented using exclusively AC units or using AC units for electricity (the numerator) and DC units for capacity (the denominator). Both capacity factors will result in the same LCOE as long as the other variables use the same capacity rating (e.g., CAPEX in terms of  $$/kW_{DC}$ ). PV systems' DC ratings are typically higher than their AC ratings; therefore, the capacity factor calculated using a DC capacity rating has a higher denominator. In the ATB, we use capacity factors of 14%, 20%, and 28% for the first year of a PV project and adjust the values to reflect an average capacity factor for the lifetime of a project, calculated with  $MW_{DC}$ , assuming 0.5% module capacity degradation per year. The adjusted average capacity factor values used in the ATB are 13.5%, 19.2%, and 26.9%. These numbers would change to approximately 14.8%, 21.2%, and 29.6% if the ATB used  $MW_{AC}$ . The following figure illustrates capacity factor - both DC and AC - for a range of inverter loading ratios. The ATB capacity factor assumptions are

based on ILR = 1.1.

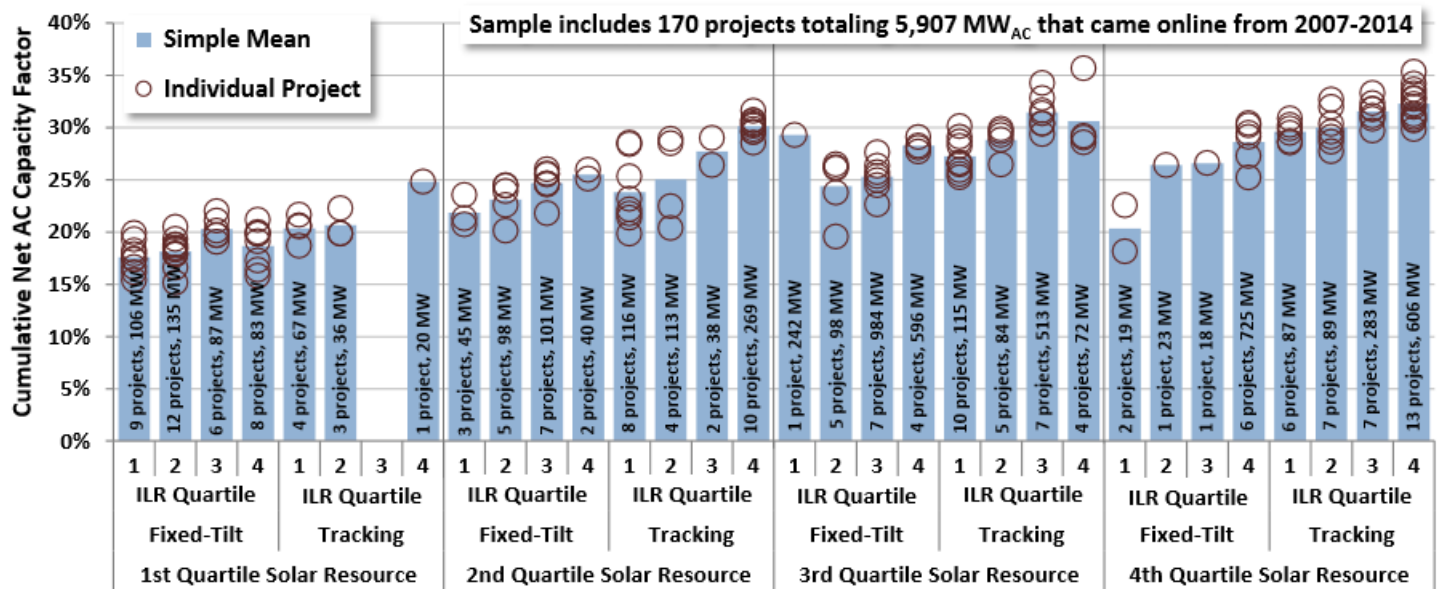


Utility-scale PV capacity factor by inverter loading ratio

Source: National Renewable Energy Laboratory Annual Technology Baseline (2017), <http://atb.nrel.gov>

## Recent Trends

At the end of 2015, the capacity-weighted average AC capacity factor for all U.S. projects installed at the time was 27.6% (including fixed-tilt systems), but individual project-level capacity factors exhibited a wide range (15.1%–35.7%).



Cumulative capacity factor by resource strength, fixed-tilt vs. tracking, and inverter loading ratio

Source: Bolinger and Seel 2016

The capacity-weighted average capacity factor was more closely in line with the higher end of the range because 88% of the installed capacity was in the southwestern United States or

California, where the average capacity factor was 30.2% for one-axis systems and 25.6% for fixed-tilt systems (Bolinger and Seel 2016). The upper and lower capacity factor values in the ATB are conservative due to the lower DC-to-AC ratio.

## Base Year Estimates

For illustration in the ATB, a range of capacity factors associated with the range of latitude in the contiguous United States is shown.

Over time, PV plant output is reduced. This degradation (at 0.5%) is accounted for in ATB estimates of capacity factor. The ATB capacity factor estimates represent estimated annual average energy production over the 20-year economic life of the plant (the distinction between economic life and technical life is described here (</electricity/2017/finance-impact.html>)).

Given the historical reported capacity factors by systems installed in the United States and the potential for technological improvements that can improve the solar PV plant capacity factors (e.g., less reflectivity and improved low-light performance), these values likely represent a conservative estimate of system production. Part of this is due to differences in inverter loading ratios (also called DC-to-AC ratio), which can increase production but also increases cost ( $\$/W_{DC}$ ). In 2015, the cumulative PV capacity factors for low-, mid-, and high-insolation regions, for tracking systems with a mid-level inverter loading ratio (1.19:1.25) were 20.7%, 26.7%, and 30.0% respectively (in  $W_{AC}$ ) (Bolinger and Seel 2016), which is comparable to or significantly higher than the 14.8%, 21.2%, and 29.6% (in  $W_{AC}$ ) used in the ATB (13.5%, 19.2%, and 26.9% in  $W_{DC}$ ). Currently reported capacity factors for deployed systems are, on average, reflective of capacity factors for relatively new plants.

These capacity factors are for a one-axis tracking system with a DC-to-AC ratio of 1.1.

## Future Year Projections

Projections of capacity factors for plants installed in future years are unchanged from the Base Year. Solar PV plants have very little downtime, inverter efficiency is already optimized, and tracking is already assumed. That said, there is potential for future increases in capacity factors through technological improvements such as less panel reflectivity, lower degradation rates, and improved performance in low-light conditions.

## Standard Scenarios Model Results

ATB CAPEX, O&M, and capacity factor assumptions for the Base Year and future projections through 2050 for High, Mid, and Low projections are used to develop the NREL Standard Scenarios using the ReEDS model. See ATB and Standard Scenarios (</electricity>

/2017/scenarios.html).

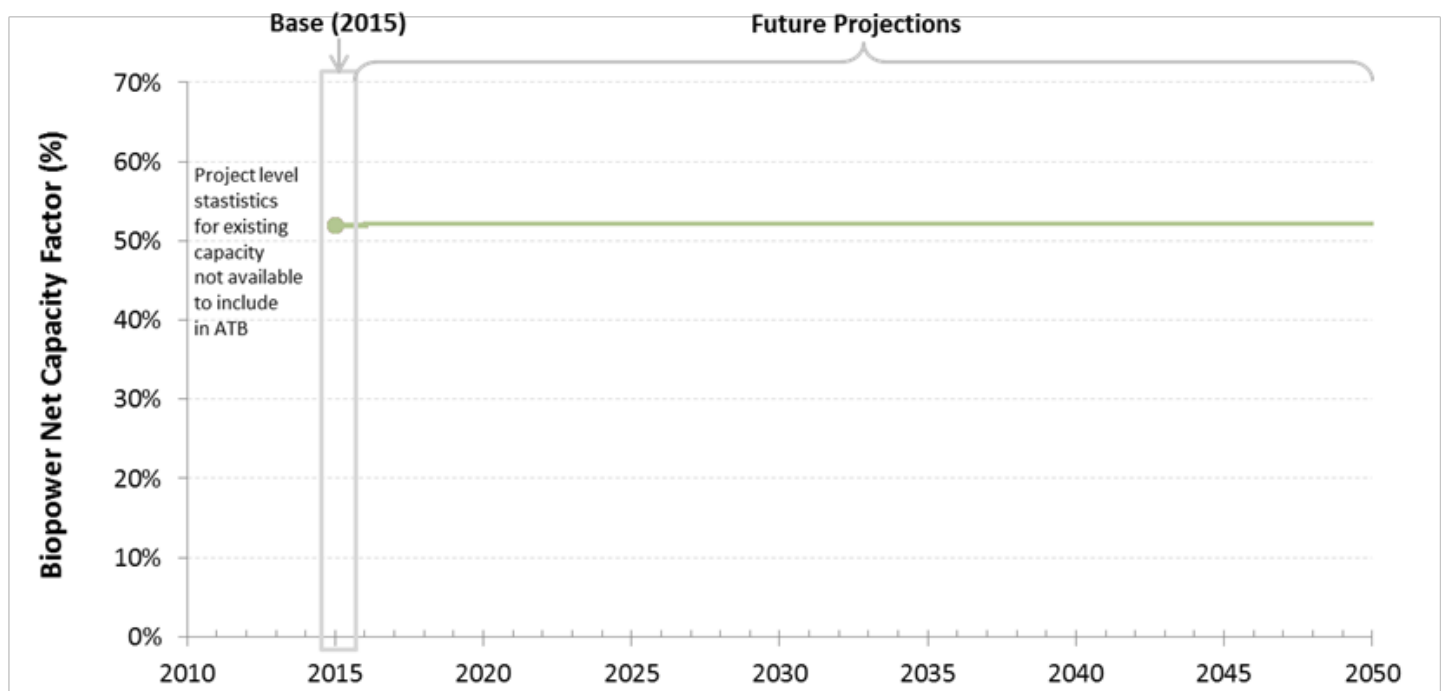
The ReEDS model output capacity factors for wind and solar PV can be lower than input capacity factors due to endogenously estimated curtailments determined by system operation.

## Plant Cost and Performance Projections Methodology

The capacity factor represents the assumed annual energy production divided by the total possible annual energy production, assuming the plant operates at rated capacity for every hour of the year. For biopower plants, the capacity factors are typically lower than their availability factors. Biopower plant availability factors have a wide range depending on system design, fuel type and availability, and maintenance schedules.

Biopower plants are typically baseload plants with steady capacity factors. For the ATB, the biopower capacity factor is taken as the average capacity factor for biomass plants for 2015, as reported by EIA.

Biopower capacity factors are influenced by technology and feedstock supply, expected downtime, and energy losses.



### Biopower net capacity factor (dedicated and cofire)

Source: National Renewable Energy Laboratory Annual Technology Baseline (2017), <http://atb.nrel.gov>

*Current estimates and future projections calculated from EIA (2017) and modified.*

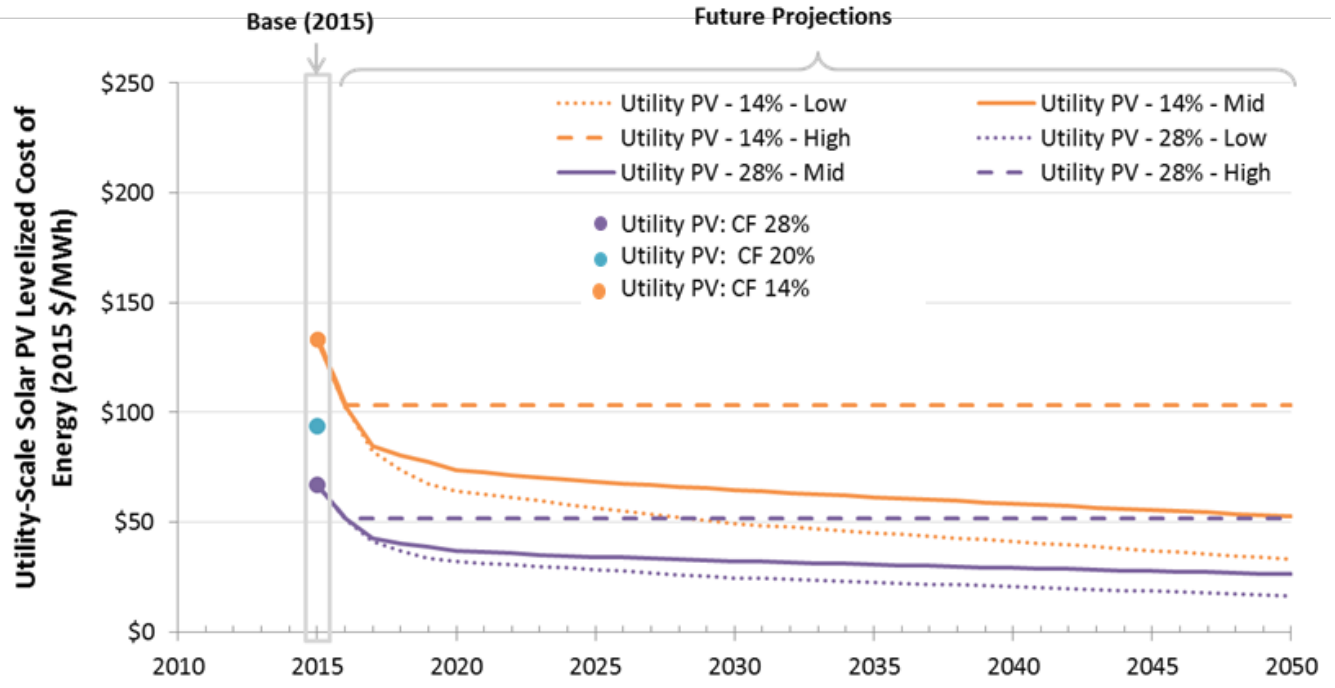
# Levelized Cost of Energy (LCOE) Projections

Levelized cost of energy (LCOE) is a simple metric that combines the primary technology cost and performance parameters, CAPEX, O&M, and capacity factor. It is included in the ATB for illustrative purposes. The focus of the ATB is to define the primary cost and performance parameters for use in electric sector modeling or other analysis where more sophisticated comparisons among technologies are made. LCOE captures the energy component of electric system planning and operation, but the electric system also requires capacity and flexibility services to operate reliably. Electricity generation technologies have different capabilities to provide such services. For example, wind and PV are primarily energy service providers, while the other electricity generation technologies provide capacity and flexibility services in addition to energy. These capacity and flexibility services are difficult to value and depend strongly on the system in which a new generation plant is introduced. These services are represented in electric sector models such as the ReEDS (<http://www.nrel.gov/analysis/reeds/>) model and corresponding analysis results such as the Standard Scenarios (</electricity/2017/scenarios.html>).

The following three figures illustrate the combined impact of CAPEX, O&M, and capacity factor projections across the range of resources present in the contiguous United States. The Current Market Conditions LCOE demonstrates the range of LCOE based on macroeconomic conditions similar to the present. The Historical Market Conditions LCOE presents the range of LCOE based on macroeconomic conditions consistent with prior ATB editions and Standard Scenarios model results. The Normalized LCOE (all LCOE estimates are normalized with the lowest Base Year LCOE value) emphasizes the effect of resource quality and the relative differences in the three future pathways independent of project finance assumptions. The ATB representative plant characteristics that best align with recently installed or anticipated near-term utility-scale PV plants are associated with Utility PV: CF 20%. Data for all the resource categories can be found in the ATB data spreadsheet (</electricity/data.html>).

Current Market Conditions

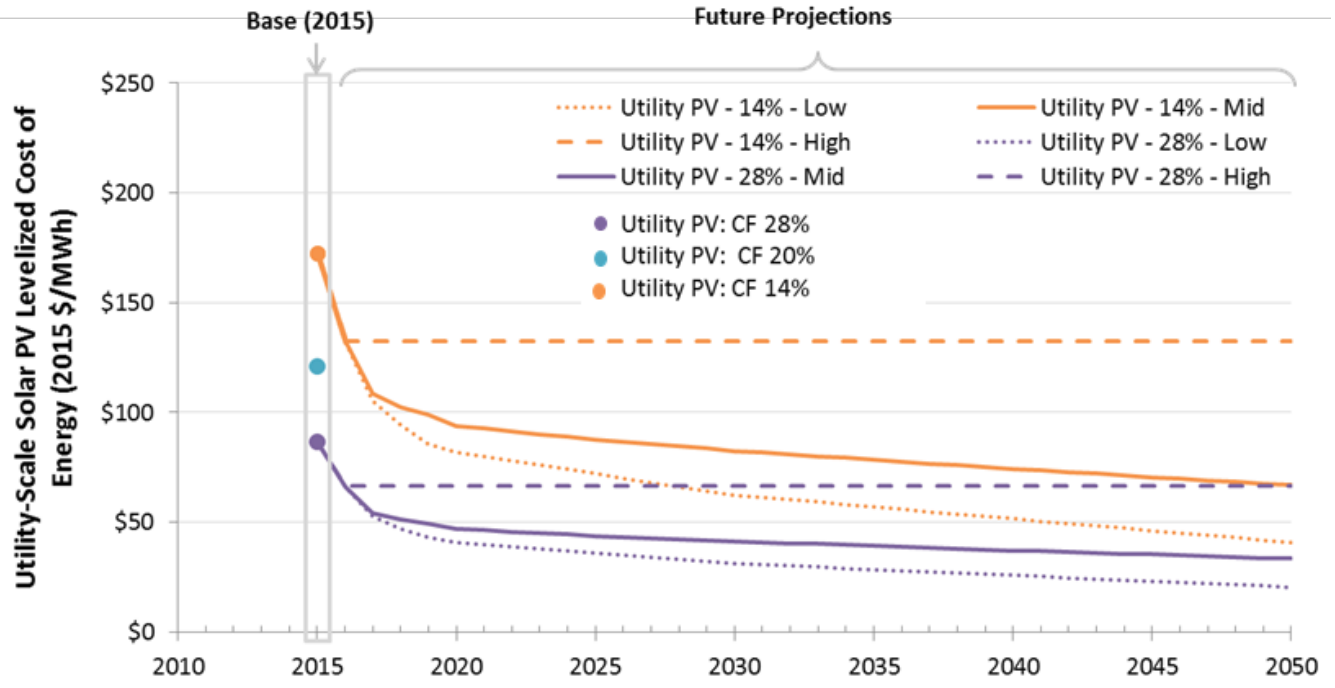




**Utility PV plant LCOE projections based on current market conditions**

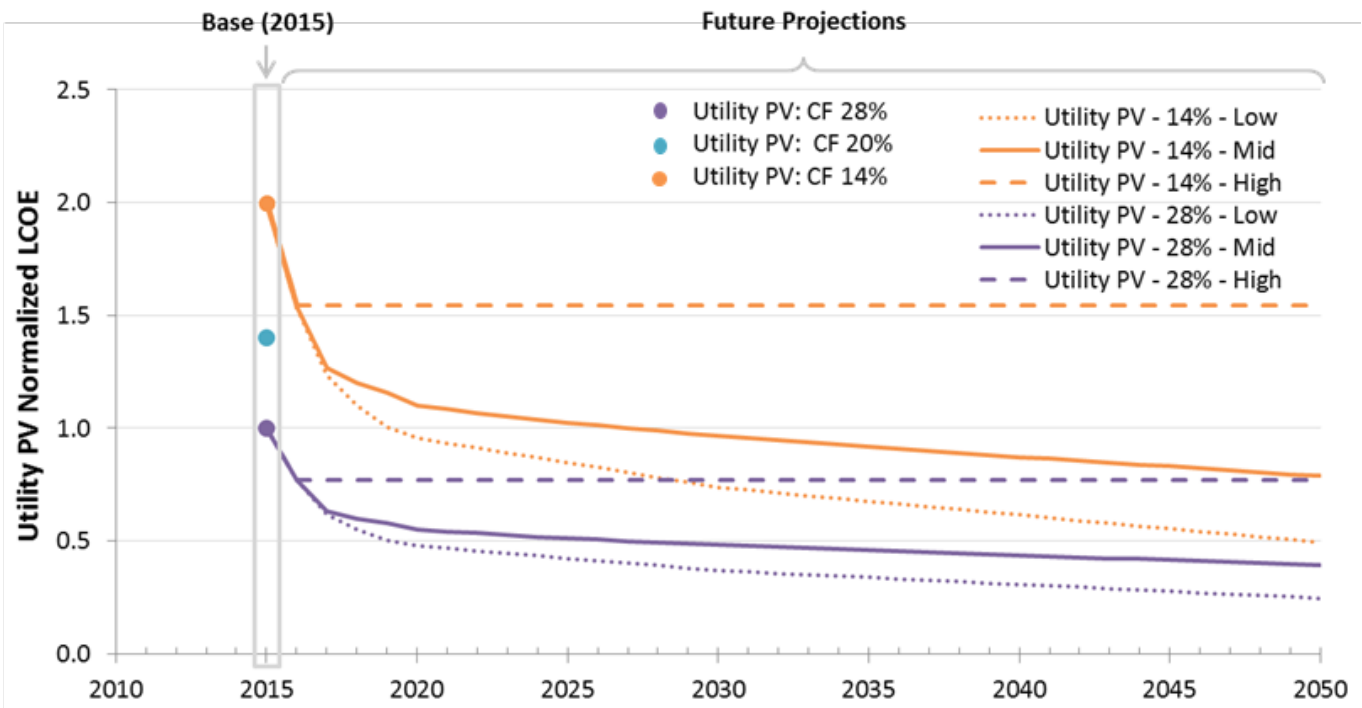
Source: National Renewable Energy Laboratory Annual Technology Baseline (2017), <http://atb.nrel.gov>

Historical Market Conditions



**Utility PV plant LCOE projections based on long-term historical market conditions**  
 Source: National Renewable Energy Laboratory Annual Technology Baseline (2017), <http://atb.nrel.gov>

Normalized



**Utility PV plant normalized levelized cost of energy (LCOE) projections**

Source: National Renewable Energy Laboratory Annual Technology Baseline (2017), <http://atb.nrel.gov>

*The ATB representative plant characteristics that best align with recently installed or anticipated near-term utility-scale PV plants are associated with Utility PV: CF 20%.*

The methodology for representing the CAPEX, O&M, and capacity factor assumptions behind each pathway is discussed in Projections Methodology (</electricity/2017/index.html?t=su&s=md>). The three pathways are generally defined as:

- **High** = Base Year (or near-term estimates of projects under construction) equivalent through 2050 maintains current relative technology cost differences
- **Mid** = technology advances through continued industry growth, public and private R&D investments, and market conditions relative to current levels that may be characterized as "likely" or "not surprising"
- **Low** = Technology advances that may occur with breakthroughs, increased public and private R&D investments, and/or other market conditions that lead to cost and performance levels that may be characterized as the "limit of surprise" but not necessarily the absolute low bound.

To estimate LCOE, assumptions about the cost of capital to finance electricity generation projects are required. For comparison in the ATB, two project finance structures are represented.

- **Current Market Conditions:** The values of the production tax credit (PTC) and investment tax credit (ITC) are ramping down by 2020, at which time wind and solar projects may be financed with debt fractions similar to other technologies. This scenario reflects debt interest (4.4% nominal, 1.9% real) and return on equity rates (9.5% nominal, 6.8% real) to represent 2017 market conditions (AEO 2017) and a debt fraction of 60% for all electricity generation technologies. An economic life, or period over which the initial capital investment is recovered, of 20 years is assumed for all technologies. These assumptions are one of the project finance options in the ATB spreadsheet.
- **Long-Term Historical Market Conditions:** Historically, debt interest and return on equity were represented with higher values. This scenario reflects debt interest (8% nominal, 5.4% real) and return on equity rates (13% nominal, 10.2% real) implemented in the ReEDS model and reflected in prior versions of the ATB and Standard Scenarios model results. A debt fraction of 60% for all electricity generation technologies is assumed. An economic life, or period over which the initial capital investment is recovered, of 20 years is assumed for all technologies. These assumptions are one of the project finance options in the ATB spreadsheet.

These parameters are held constant for estimates representing the Base Year through 2050. No incentives such as the PTC or ITC are included. The equations and variables used to estimate LCOE are defined on the equations and variables (</electricity/2017/equations-variables.html>) page. For illustration of the impact of changing financial structures such as WACC and economic life, see Project Finance Impact on LCOE (</electricity/2017/finance-impact.html>). For LCOE estimates for High, Mid, and Low scenarios for all technologies, see 2017 ATB Cost and Performance Summary (</electricity/2017/summary.html>).

In general, the degree of adoption of a range of technology innovations distinguishes the High, Mid and Low cost cases. These projections represent the following trends to reduce CAPEX and FOM.

- Modules
  - Increased module efficiencies and increased production-line throughput to decrease CAPEX; overhead costs on a per-kilowatt will go down if efficiency and throughput improvement are realized.
  - Reduced wafer thickness or the thickness of thin-film semiconductor layers
  - Development of new semiconductor materials
  - Development of larger manufacturing facilities in low-cost regions
- Balance of system (BOS)
  - Increased module efficiency, reducing the size of the installation
  - Development of racking systems that enhance energy production or require less

- robust engineering
- Integration of racking or mounting components in modules
- Reduction of supply chain complexity and cost
  - Creation of standard packages system design
  - Improvement supply chains for BOS components in modules
- Improved power electronics
  - Improvement of inverter prices and performance, possibly by integrating micro-inverters
- Decreased installation costs and margins
  - Reduction of supply chain margins (e.g., profit and overhead charged by suppliers, manufacturer, distributors, and retailers); this will likely occur naturally as the U.S. PV industry grows and matures.
  - Streamlining of installation practices through improved workforce development and training, and developing standardized PV hardware
  - Expansion of access to a range of innovative financing approaches and business models
  - Development of best practices for permitting interconnection, and PV installation such as subdivision regulations, new construction guidelines, and design requirements.

FOM cost reduction represents optimized O&M strategies, reduced component replacement costs, and lower frequency of component replacement.

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