The Levelized Cost of Energy for Distributed PV: A Parametric Study

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ABSTRACT

The maturation of distributed solar PV as an energy source requires that the technology no longer compete on module efficiency and manufacturing cost ($/Wp) alone. Solar PV must yield sufficient energy (kWh) at a competitive cost (¢/kWh) to justify its system investment and ongoing maintenance costs. These metrics vary as a function of system design and interactions between parameters, such as efficiency and area-related installation costs. The calculation of levelized cost of energy includes energy production and costs throughout the life of the system. The life of the system and its components, the rate at which performance degrades, and operation and maintenance requirements all affect the cost of energy. Cost of energy is also affected by project financing and incentives. In this paper, the impact of changes in parameters such as efficiency and in assumptions about operating and maintenance costs, degradation rate and system life, system design, and financing will be examined in the context of levelized cost of energy.

INTRODUCTION

Over the years, the cost of energy produced using rooftop mounted photovoltaic systems has decreased significantly, principally due to improved performance (efficiency), reliability (serviceable system life) and reduced initial investment requirements. Despite a much reduced upfront investment, solar PV systems still require a significant first cost that is often financed. Often, systems will be owned by a third party who will then sell the energy to the host site. Financial arrangements vary, as do the availability of incentives, and the ability of a system owner to monetize certain tax breaks. Regardless of the financing scheme, the initial upfront investment must be amortized over the system lifetime and discounted appropriately.

Although system ratings provide an indication of how much power is available from a system, the energy delivery over time is a function of the available solar resource, soiling, shading, the rate at which performance degrades, and the ultimate lifetime of the system. In order to accurately quantify the true cost of solar energy produced using a PV system it is therefore necessary to calculate the Levelized Cost of Energy (LCOE) using equation (1).

The numerator of the LCOE equation includes the full spectrum of first and operating costs over the life of the system by year (C_n), such as the installed cost, financing costs, credits for incentives, operating and maintenance costs, taxes, insurance, etc. In the denominator, Q_n is the energy output of the system by year. Future costs and energy production benefits are discounted by "d", the discount rate due to the time value of money.

$$LCOE = \frac{\sum_{n=1}^{N} \frac{C_n}{(1+d)^n}}{\sum_{n=1}^{n=N} \frac{Q_n}{(1+d)^n}} \qquad (1)$$

It is beyond the scope of this paper to provide definitive cost and performance data. Rather, we will use typical cost and performance data to illustrate how various parameters affect LCOE.

REFERENCE SYSTEMS

For the purposes of the illustrative analysis in this paper, the reference system designs shown in Table 1 were assumed.

The baseline residential system is a 4.2 kW crystalline silicon system. A system based on a roof-integrated thin-film laminate of the same power level but lower efficiency (greater system area requirements) is also considered. Because it is a laminate, it has lower Balance of System (BOS) and installation labor costs, but the module costs are estimated to be slightly higher. In some cases, roof area may be limited, so we also considered a 2.1 kW thin-film laminate of the same area as the crystalline silicon system. For this lower power but equivalent area system, BOS components costs are slightly higher per Watt, while the per Watt BOS labor (e.g. wiring to the inverter and inverter installation) increase substantially. Other fixed costs, including design, permitting, interconnection, and marketing also rise on a per Watt basis due to the assumption that these parameters are largely independent of system size.

For commercial systems, roof area is often a constraint, since building demand will usually exceed the capacity of the rooftop system. Two rooftop configurations are considered: a 500 kW crystalline system and a 250 kW thin-film laminate of the same area. As in the fixed area (lower power) residential rooftop case described above, per Watt BOS and labor costs are estimated to be lower for the thin-film laminate, but module costs are higher. Fixed costs, which are largely independent of system size, also rise on a per Watt basis.

Reference Systems	Residential			Commercial		Sources for Cost Data
Tilt (°)	20			0		
Array (kW_{dc})	4.1	4.1	2.1	500	250	
Area (m^2)	30	60	30	3700		
STC Efficiency (%)	13.5	6.7	6.7	13.5	6.7	cSi: Photon International Module Price Survey Q1, 2010 with 30% margin added for residential case. Thin-Film: 2010 retail quote less 30% margin for commercial case.
Module Cost ($/Wdc)	2.84	3.43	3.43	1.99	2.40	
P_{mp} Temp. Coeff. (%/°C)	-0.5	-0.5	-0.3	-0.5	-0.3	
Inverter (kW_{ac})	4.0	4.0	2.0	400	250	Solarbuzz May 2010 Inverter Prices Survey less 30% margin for commercial case.
Inverter Cost ($/$W_{ac}$)	0.75			0.53		
CEC Inverter Efficiency (%)	95			95		
Balance of System ($/Wdc)	0.91	0.64	0.68	0.90	0.69	NREL internal estimate, based on installer survey and US national labor rates, RS Means, 2010.
Installation Labor ($/Wdc)	1.36	0.88	1.66	0.60	0.31	
Derate Factor (%)	90			90		NREL internal estimate: Residential: $500 permit, $900 interconnect, $1000 engineering, Commercial: $50k permit, $2200 interconnect, $10000 engineering.
Fixed Costs ($)	2,400			62,200		
System Degradation (%/yr)	0.5		1	0.5	1	
System Installed Cost ($/Wdc)	6.43	6.28	7.69	4.04	4.17	
Inverter Life (Yrs)	10			10		NREL internal estimate, based on installer survey.
Inv Repair (% 1st cost)	100			50		NREL internal estimate, based on installer survey.
Inverter Price Decline (%/Yr)	3%			3%		NREL internal estimate, based on installer survey.
Inv Repair Labor	4 hrs, $300			80 hrs, $6260		NREL internal estimate, based on installer survey.
Other O&M ($/kW-yr)	25			15		NREL internal estimate, based on installer survey.

Table 1. Reference System Designs and Cost

REFERENCE SYSTEM PERFORMANCE

PV modules are characterized at Standard Test Conditions (STC), which specify a cell operating temperature of 25°C and an irradiance condition of 1000 W/m^2. This rating is then used in describing the $/$W_{dc}$ cost of modules and systems.

Actual module performance is a function of both the incident irradiance and the operating temperature, which has a critical effect on system performance. In operation, the actual temperature of PV cells will often exceed 25°C. Cell performance generally decreases as cell temperature increases, though the sensitivity is specific to the cell technology. Cell temperature is a function of incident radiation, ambient air temperature and wind speed, and will vary for different mounting configurations and module designs. Module manufacturers generally provide a maximum power (P_{mp}) temperature coefficient. For a typical crystalline silicon module, the coefficient is -0.5%/°C, which indicates that module performance decreases 0.5% for each degree the cell temperature is above the STC rating condition of 25°C. Other rating conditions such as PVUSA test condition (850 W/m^2, 20°C ambient temperature, and 1m/s wind speed), are often used as a better indication of system performance, but this rating reflects operation of the PV modules in a rack-mount configuration, with air flowing freely around the module. However, when installed on a pitched residential roof, modules are usually installed close to the roof with limited air flow beneath them, or are integrated to the roof with no air flow beneath them.

Figure 1 presents the impact of the P_{mp} temperature coefficient for the two module technologies analyzed in this paper, and for three mounting configurations. Two climates with similar annual irradiance are considered: Phoenix, AZ (hot) and Alamosa, CO (cold). The data in Figure 1 is normalized to the energy expected from the STC rating, meaning the annual output has been divided by the available solar irradiance times the module STC rating.

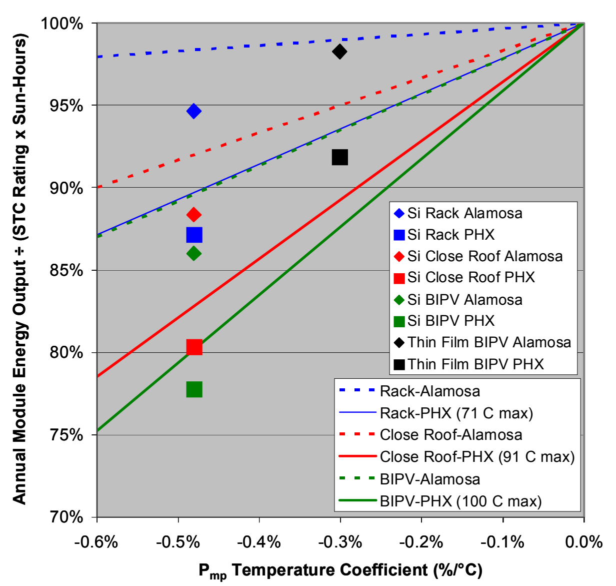

Figure 1. Impact of P_{mp} Temperature Coefficient and Mounting Configuration on Annual Energy Output

The lines in the figure were obtained by applying the P_{mp} temperature coefficient to the module rating with cell temperature determined using equations from King et al.

[1] that relate cell temperature to incident irradiance, air temperature, and wind speed. As shown in the figure, even a rack-mounted module will operate substantially above the rated condition of 25ºC, and as a result of the relationship between operating temperature and series resistance, the annual energy output of a typical crystalline silicon module in Phoenix is decreased approximately 10% relative to its nameplate rating. The loss in annual yield is even greater for modules mounted close to the roof (minimal back-surface air flow) or for Building-Integrated PV (BIPV). The impact on modules with smaller temperature coefficients is proportionately less, as is the impact in a significantly cooler, but still sunny climate, like Alamosa, CO.

The individual data points show the expected performance of a crystalline silicon module and of a thin-film laminate, based on detailed on-sun characterization of modules at Sandia National Laboratories. The module performance coefficients generated from this testing were used with the Sandia PV Array Performance Model [1] to generate these data points. The Sandia model uses separate temperature coefficients for maximum-power voltage (V_{mp}) and maximum-power current (I_{mp}), unlike most manufacturer data, which usually includes only a single efficiency for maximum power (P_{mp}).

For the crystalline silicon module, the effect of operating temperature on annual yield when estimated using the Sandia model is seen to be somewhat greater than calculated using just the P_{mp} temperature coefficient. The P_{mp} temperature coefficient measured at Sandia for the crystalline silicon modules was -0.5%/°C, while the coefficient measure for the thin-film laminate was -0.3%/°C. The estimated annual energy yield for this module is higher than would be expected for a silicon module with the same temperature coefficient. This likely reflects both the higher performance at low light-levels than at STC and the improved heat transfer through the laminate's thin polymer top layer relative to a typical glass module.

FINANCIAL PARAMETERS

When calculating LCOE, financial parameters such as the interest rate on borrowed money, the term of the loan, the inflation rate, tax rates, and incentives have significant impact. Residential systems are most often financed, for example through a tax-deductible homeowner's line-of-credit. Roof-mounted commercial systems may be purchased and financed, but, often, large systems are installed by third-parties who operate as an Independent Power Producer (IPP) and sell the power to the building occupant. Table 2 shows the values of financial parameters used in this analysis.

BASELINE ANALYSIS

Tables 3 and 4 contain the Levelized Cost of Energy calculated for the reference system designs. The analysis that follows was performed with the Sandia PV Array Performance Model in the Solar Advisor Model using module performance coefficients derived from measurements conducted at Sandia. The Solar Advisor Model was developed by the National Renewable Energy Laboratory and Sandia National Laboratories [2].

Tables 3 and 4 illustrate that installed cost alone is not a good indicator of cost of energy. The first three columns of Table 3 illustrate the impact the mounting configuration on system performance, as indicated by the system performance factor, and the resulting impact on LCOE in the hot Phoenix climate. The PV System Performance Factor is a unitless quantity defined as $kWh_{ac} \div (kW_{dc} * \text{POA peak sun hours})$, where kWh_{ac} is the measured ac energy output over a year, kW_{dc} is the nameplate rating of the PV array at Standard Test Conditions and POA peak sun hours is the equivalent number of hours in a year that the plane of the array is receiving 1,000 W/m^2.

Type of Financing	**Residential Home Equity**	**Commercial Loan**	**Independent Power Producer**
Inflation Rate (%)	2.5	2.5	2.5
Analysis Period (yrs)	30	30	30
Cost of Equity (%)	8.5	15	15
Real Discount Rate (%)	5.2	8.2	8.7
Loan Term (yrs)	15	15	20
Loan Rate (%)	7.75	6	7.5
Loan Fraction (%)	100	60	60
Federal Tax (%)	28	35	35
State Tax (%)	7	7	8
Property tax (%)	0	0	0
Insurance (%)	0	0	0
Fed. Depreciation Type	n/a	MACRS Mid -Q	
State Depreciation Type	n/a		
Federal Tax Credit (%)	30	30	30

Table 2. Financial Parameters

For the 4.1 kW thin-film laminate system, LCOE is significantly less even though the module cost is higher and the installed cost is similar. As described above and as shown in the higher system performance factor, this reflects the lower temperature coefficient, the improved heat transfer through the polymer front layer, and the response of the module to low light levels.

Technology	**Crystalline Silicon**			**Thin-Film**	
Array (kWdc)	4.1	4.1	4.1	4.1	2.0
Area (m^2)	30	30	30	60	60
Mounting	Rack	Close	BIPV	BIPV	BIPV
$/Wdc Installed	6.45	6.45	6.45	6.30	7.72
Sys. Perf. Factor	0.75	0.69	0.66	0.79	0.79
LCOE – Total	**17.5**	**19.0**	**19.6**	**17.1**	**20.5**
First Cost	**14.4**	**15.6**	**16.2**	**14.1**	**17.2**
Total O&M	**3.1**	**3.3**	**3.4**	**3.1**	**3.3**
Routine O&M	1.5	1.6	1.6	1.5	1.5
Inverter O&M	1.6	1.7	1.8	1.6	1.8

Table 3. LCOE for Residential Reference Systems in Phoenix, Arizona

The impact of an area-constrained system on installed cost and LCOE is shown in the last column of Table 3.

The effect the constrained area is smaller for the large commercial systems, shown in Table 4, than for the residential systems because fixed costs are a smaller fraction of installed system cost. The impact of the higher system cost on LCOE is more than offset by the performance of the thin-film system compared to the crystalline silicon system in a hot climate like Phoenix.

Also illustrated in the first two columns of Table 4 is the cost impact of third-party financing. Third-party financing is popular because the recipient of the power does not have to make a large upfront investment, but it does not necessarily result in the lowest cost of energy.

Technology	**Crystalline Silicon**		**Thin-Film**
Financing	IPP	Loan	Loan
Array (kWdc)	500	500	250
Area (m^2)	3700	3700	3700
Mounting	Close	Close	BIPV
$/Wdc Installed	$4.04	$4.04	$4.17
Sys. Perf. Factor	0.69	0.69	0.80
LCOE – Total	**11.2**	**7.2**	**6.8**
First Cost	**9.7**	**6.2**	**5.8**
Total O&M	**1.5**	**0.9**	**0.9**
Routine O&M	1.0	0.6	0.6
Inverter O&M	0.5	0.3	0.4

Table 4. LCOE for Commercial Reference Systems in Phoenix, AZ

PARAMETRIC ANALYSIS

In the analyses that follow, we examine the effect of various system parameters on LCOE for the crystalline silicon, loan-financed, close-roof configurations from Tables 1 and 2. In each case, one parameter is changed while the others are held constant. The enlarged data points in each figure represent the close-roof mount, silicon systems in Tables 3 and 4 above.

Operations and Maintenance

System Lifetime. Since LCOE is calculated over time, the lifetime of the system and its components are important. We have used an analysis period of 30 years with routine maintenance and inverter service or replacement, but no module replacements. Currently, modules are warranted up to 25 years. As shown in Figure 2, while system lifetimes shorter than 25-30 years lead to higher LCOE, extending (warranting) system life beyond 30 years has minimal impact on LCOE.

Inverter Lifetime. The lifetime of current inverters is estimated to be 10 years or more. The impact of inverter lifetime on system LCOE is a function of the cost of refurbishment or replacement. In the analysis of the residential system, it is assumed that the inverter has a lifetime of 10 years, that inverters are declining in price in real dollars by 3%/yr and that the labor-hours required for replacement is 4 hours. In the analysis of the commercial system, it is again assumed that the inverter has a lifetime of 10 years and that inverters are declining in price in real dollars by 3%/yr. However, it is assumed that larger commercial inverters can be refurbished at 50% of the cost of a new inverter. Time to perform the refurbishment of a large three-phase inverter is estimated at 80 person-hours.

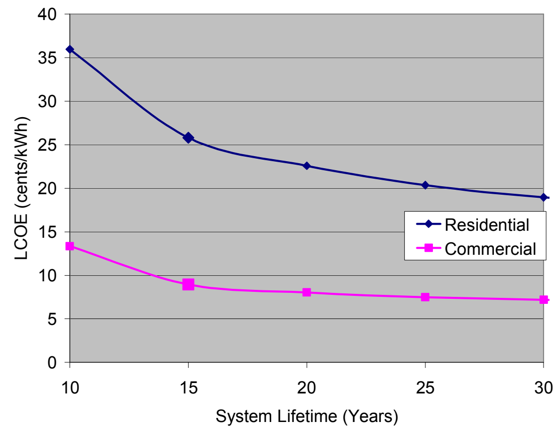

Figure 2. Effect of System Lifetime on LCOE

As shown in Figure 3, the impact of inverter lifetime on residential LCOE is significant. The 75¢/W initial cost, which is >10% of the installed system cost, contributes 1.9¢/kWh to LCOE while the replacement at years 10 and 20 adds another 1.8¢/kWh. The impact on LCOE for the commercial system is lower because it is assumed that large inverters can be refurbished. However, in either case, it may be that, after 20 years, replacement parts or identical units will not be available. Installation of a new inverter could be more costly because new conduit, etc. may be required, and the system may require substantial updates to meet new code requirements.

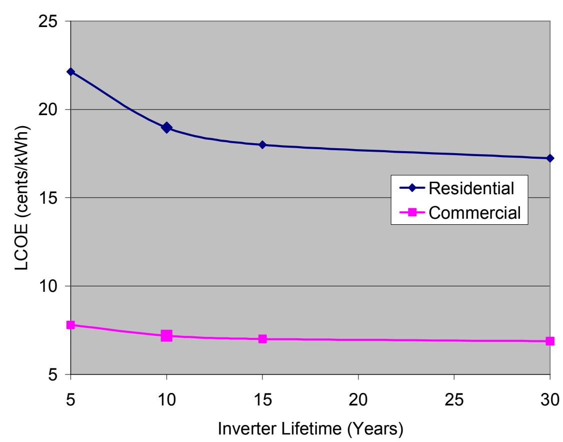

Figure 3. Impact of Inverter Lifetime on LCOE

Routine O&M. For fixed-tilt PV systems, a common expectation is that there will be minimal maintenance required, beyond occasional cleaning, since the systems have no moving parts. Larger systems, especially third-party-owned systems, will likely include performance monitoring to detect performance problems that may impact revenue. Because most systems include electrical components operating at up to 600 V_{dc}, periodic inspection may also be performed to minimize shock and fire hazards. Also, roof replacement may be required during the life of a PV system, leading to removal and reinstallation of the system. In this analysis, routine O&M is taken to include everything except inverter replacement, such as cleaning, inspection, system monitoring, and minor repairs. Annual inverter inspection and maintenance, recommended by some inverter manufacturers, is also considered part of routine O&M. Two papers by Moore et al., estimate O&M for residential systems at 1.1% of installed cost, including annual inspections, and 0.33% of installed cost for a group of 150 kW systems at a utility site [3, 4]. In our baseline analysis, we assumed a cost of $25/kW-yr for the residential system and $15/kW-yr for the commercial systems, or approximately 0.4% of installed system cost for both. As shown in Figure 4, higher O&M costs can significantly increase LCOE. Note, as shown in the upper scale, the 0.4% figure for residential systems is $100/yr, or equivalent to the labor for one service call. The cost of a service call is likely independent of system size, so the impact of routine maintenance on LCOE for smaller systems would likely be higher.

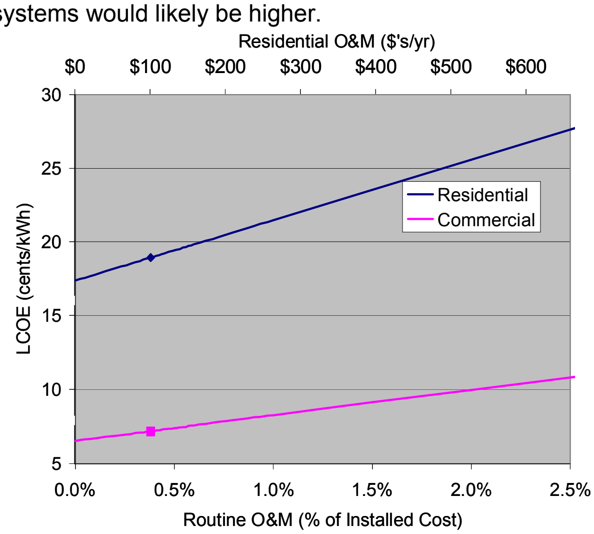

Figure 4. Impact of Routine O&M Cost on LCOE

Performance

PV modules typically carry a materials and workmanship guarantee of 5-10 years and a performance guarantee of 80% of initial minimum rating after 25 years. The minimum rating is the nominal STC rating minus the tolerance on that rating, which is typically ±5%. The 80% performance level can be met at 25 years if output degrades at an annually-compounded rate of ~1%. As shown in Figure 5, LCOE increases about 10% per 1% increase in system degradation rate, where system degradation includes not only the modules, but also performance losses in wiring, inverters, and other BOS components. Such rates are difficult to measure and require years of precise system characterization. Values of 0.5-1%/yr or less have been observed in crystalline-silicon arrays [5]. Minimal data have been published on degradation rates for thin-film systems. Two years of monitoring of inverters has not identified any detectable degradation in performance [6].

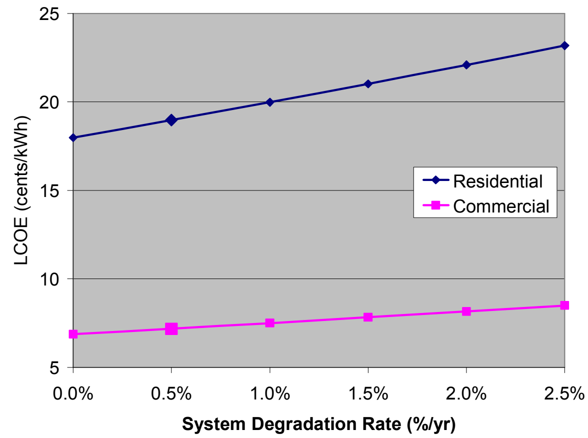

Figure 5. Impact of Degradation Rate on LCOE

In Figure 6, module efficiency is varied, while the area of the array is fixed, as would be the case where the roof area constrains the project size. In this case, lower efficiency means fewer kWh, while the area covered by the array and the associated BOS and installation costs are assumed to remain the same, except that the cost of the inverter and associated O&M was scaled with the array power. While other costs, such as project development costs, marketing, system design, permitting, etc. may be estimated as a percent of hardware costs, these costs may be per project costs that are relatively constant for systems of various sizes. In this scenario, systems with lower efficiency modules would have to have a proportionally lower total installed cost to have the same LCOE as more efficient modules.

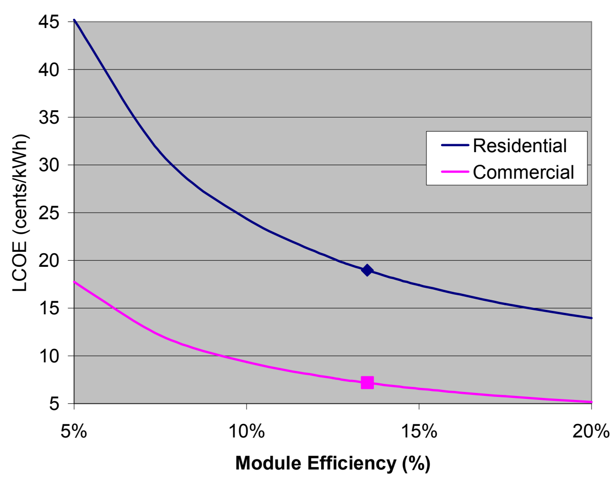

Figure 6. Impact of Module Efficiency on LCOE

SUMMARY

The purpose of this paper is to illustrate the importance of considering multiple system parameters when optimizing PV technology and system design. A common approach to valuing system options is to compare system installed cost, as shown in Figure 7 for the systems analyzed in this paper. However, this approach does not differentiate the performance of different technologies and installation options. Figure 8 shows the levelized cost of energy for the same systems when a full performance and financial analysis is performed.

As shown in the first three columns of Figure 8, the flat-plate cSi module response to temperature and mounting configuration is shown to have a significant impact on Levelized Cost of Energy. Further research to insure that temperature is being modeled correctly is warranted.

Little data have been published on system maintenance, which has the potential to have a significant impact on LCOE. The systems degradation rate, including modules and other system components, increases LCOE with a 1% system degradation rate increasing LCOE about 10%. Because the change in performance is small, years of data are required to verify these rates. Data for newer technologies is generally not available.

Inverter lifetime appears to have a minor effect on LCOE for large commercial systems, but can have a greater impact on small systems. Industry now offers extended warranties to mitigate risk. The largest risk may be that, over time, parts are not available and installing a different inverter may be significantly more costly.

Module cost and efficiency is important, but must be examined in the context of other costs, such as BOS and installation, as well as the details of module performance. Given the same module, BOS and installation costs, higher efficiency modules will tend to reduce LCOE, while lower efficiency modules in area-constrained systems may increase LCOE.

ACKNOWLEDGEMENT

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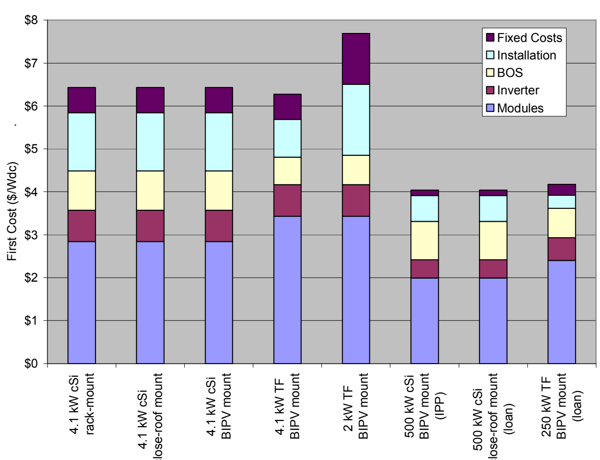

Figure 7. Installed Cost by System Type

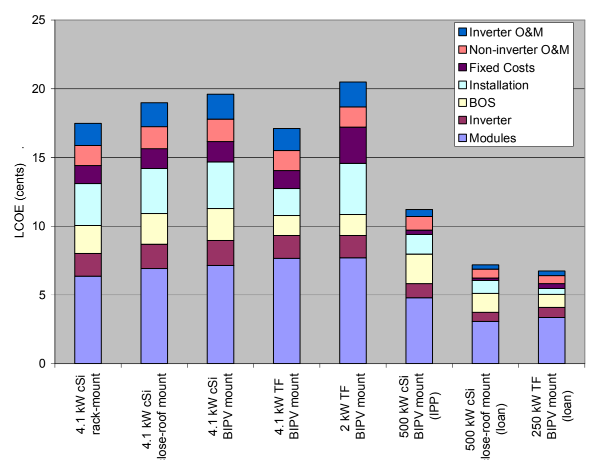

Figure 8. Levelized Cost of Energy by System Type (Module, Mounting Configuration, Application)