Appendix A. Changes in Methodology Between Q1 2020 and Q1 2021 Reports

Since 2010, NREL has performed PV system benchmark calculations. Each year we endeavor to improve the modeling to better characterize the U.S. market and the costs associated with installing (and operating, in the case of LCOE) residential, commercial, and utility-scale stand-alone PV, stand-alone storage, and PV-plus-storage systems. This appendix summarizes the major changes we made in the models between the publication of the Q1 2020 and Q1 2021 reports.

Different Methodology for Calculating Commercial and Utility-Scale Transmission and Interconnection Costs

For this year's version of our benchmarking analysis, we updated interconnection and transmission costs from estimates using MW_{DC} to estimates based on the defined point of interconnection capacity and assumed it is equal to the total AC capacity of the plant (MW_{AC}).

Different Methodology for Calculating Li-Ion Battery Costs

In previous year's benchmarks, Li-ion battery costs only represented their nameplate capacity without any upfront augmentation. For this year's version of our benchmarking analysis, we assume a DC overbuild accounting for RTE loss (10%) and state of charge limitations (20%); we assume the battery is shipped as a cabinet enclosure with all battery components preassembled; finally, we recategorize the container, racks, HVAC, thermal management system and battery management system previously included as a part of SBOS cost category into the cost of the Li-ion battery.

Changed Standard Size of Residential Li-ion Battery Capacity

In previous year's benchmarks, we calculated residential PV-plus-storage systems assuming a battery capacity of either 3 kW/6 kWh or 5 kW/20 KWh. For this year's version of our benchmarking analysis, we assume a battery size of 5 kW/12.5 kWh. The adjustment was made to conform with typical battery size currently available in marketplace (Barbose et al. 2021).

Changed Assumptions for Calculating Capacity Factor

The medium solar resource values were changed to better correspond with U.S. national averages. Low and high resource locations were made to show a wider range in solar resources available in the United States. We also adjusted PV system loss assumptions to better correspond with default assumptions in other NREL modeling applications. Finally, we adjusted tilt and azimuth assumptions for residential and commercial rooftop systems to better correspond to national averages (Barbose et al. 2020).

Table A-1 summarizes the current and previous methods.

Table A-1. Changes in Capacity Factor Methodology Between Q1 2020 and Q1 2021 Reports

Cost Category (All Sectors)	Q1 2020 Model: Summary of Method (Value)	Q1 2021 Model: Summary of Method (Value)
Capacity Factor	Low solar resource: New York City, New York Medium solar resource: Kansas City, Missouri High Solar resource: Phoenix, Arizona Tilt/azimuth: 25/180 (residential), 10/180 (commercial rooftop), and tracking/180 (utility-scale). Preinverter derate: 90.5% Inverter Efficiency: 98%	Low solar resource: Seattle, Washington Medium solar resource: Fredonia, Kansas (near the geographic center of the 48 conterminous states and corresponds with the area-weighted capacity factor of the 48 conterminous states as outlined in the 2021 Annual Technology Baseline) High Solar resource: Daggett, California Tilt/azimuth of 20/214 (residential) (Barbose et al. 2020), 10/190 (commercial rooftop) (Barbose et al. 2020), and tracking/180 (utility-scale). Preinverter derate: 85.9% Inverter Efficiency: 96%

Changed Assumptions for Calculating Residential Financial Costs, Lifetime, and Degradation

The percentage of host-owned PV systems has increased substantially over the past 5 years (63% of residential PV systems in 2019), and most of these owners finance the cost through the use of a personal loan. Though mortgages are not currently the most prevalent source of funding, they represent a major opportunity for cost reductions for PV system costs, and therefore we view this as reasonable long-term steady-state financing assumption. Because of host-ownership, we assume the homeowner does not spend as much time and effort on maintaining the PV system as a third-party and therefore O&M cost are reduced, while degradation rate increases, and system lifetime decreases.

Table A-2 summarizes the current and previous methods.

Table A-2. Changes in Residential PV LCOE Methodology Between Q1 2020 and Q1 2021 Reports

Cost Category (All Sectors)	Q1 2020 Model: Summary of Method (Value)	Q1 2021 Model: Summary of Method (Value)
Residential Financial Model Assumptions	Third-party ownership of residential PV system: • Equity discount rate (real): 6.1% • Debt interest rate: 5.0% • Debt fraction: 71.8% • Debt term: 18 years	Homeowner owns residential PV system and finances cost through their mortgage: • Equity discount rate (real): 10.2% • Debt interest rate: 4.5% • Debt fraction: 100.0% • Debt term: 25 years

Cost Category (All Sectors)	Q1 2020 Model: Summary of Method (Value)	Q1 2021 Model: Summary of Method (Value)
	• Entity: corporation • Analysis period: 30 years • Annual degradation: 0.7%/yr	• Entity: homeowner • Analysis period: 25 years • Annual degradation: 1.0%/yr

Changed Labor Wage Assumptions

In previous year's benchmarks, we used the average U.S. Bureau of Labor Statistics (BLS) labor wages by occupation across all states in United States. For this year's version of our benchmarking analysis, we use U.S. labor wage by occupation from BLS; instead of calculating average labor rate of all states, we use BLS reported value for the United States.

Changed Assumptions for Calculating O&M

For this year's version of our benchmarking analysis, we revised certain line items and costs. Specifically, we adjusted: the analysis period, labor rates, module and inverter replacement costs, discount rate, inflation rate, capital expenditures, module power and efficiency, degradation rates, warranty period, cost of aerial inspection, and property insurance premium. Additionally, based on high-level market research, some of the original 133 line item measures were deleted because they were either dated or not applicable to certain type of systems – especially for residential and utility systems (one-axis tracking).

Changes to the Cost Categorization in PV Plus Storage Cost Models

To match the calculation methodology of PV bottom-up cost models: Site Staging and DC to DC converter cost is included under EBOS cost category, EPC overhead markup on module, inverter and battery cost is excluded from EPC overhead calculation, EPC overhead and profit markup on labor cost are excluded from EPC overhead and profit margin calculation.

The changes summarized in this appendix result in Q1 2020 and Q1 2021 benchmarks with different results than would have been calculated using the previous edition's models and assumptions, particularly for commercial and utility-scale PV-plus-storage systems. To better distinguish the historical cost trends from the changes to our cost models, we also calculate Q1 2020 PV-plus-storage system cost benchmarks for commercial and utility-scale PV-plus-storage systems using the previous and current model versions.

Table A-3 summarizes the impacts these changes have on each cost category in the commercial and utility-scale PV plus Storage benchmarks for Q1 2020.

Table A-3. Comparison of Q1 2020 Benchmark Costs, per Category, of Commercial and Utility PV Plus Storage Systems Calculated Using Previous Report's Model (Q1 2020) and the Current Model (Q1 2021) in 2020 USD

	Commercial DC Coupled ($/$W_{DC}$ Q1 2020)			Commercial AC Coupled (($/$W_{DC}$ Q1 2020)			Utility DC Coupled (($/$W_{DC}$ Q1 2020)			Utility AC Coupled (($/$W_{DC}$ Q1 2020)		
	Q1 2020 Model	**Q1 2021 Model**	**% Change**	**Q1 2020 Model**	**Q1 2021 Model**	**% Change**	**Q1 2020 Model**	**Q1 2021 Model**	**% Change**	**Q1 2020 Model**	**Q1 2021 Model**	**% Change**
PV Module	0.411	0.410	0%	0.411	0.410	0%	0.411	0.410	0%	0.411	0.410	0%
Li-Ion Battery/Cabinets	0.467	0.642	38%	0.467	0.642	38%	0.467	0.631	35%	0.467	0.631	35%
Solar Inverter	0.000	0.000	0%	0.072	0.072	0%	0.000	0.000	0%	0.052	0.050	0%
Bidirectional Inverter	0.036	0.036	0%	0.036	0.036	0%	0.036	0.036	0%	0.036	0.036	0%
Structural BOS	0.182	0.124	-32%	0.175	0.138	-21%	0.161	0.132	-18%	0.155	0.127	-18%
Electrical BOS	0.228	0.318	40%	0.192	0.301	56%	0.136	0.172	27%	0.105	0.168	61%
Installation labor	0.274	0.240	-13%	0.100	0.080	-20%	0.157	0.144	-9%	0.136	0.113	-16%
EPC Overhead	0.163	0.089	-46%	0.131	0.068	-48%	0.080	0.058	-27%	0.069	0.053	-23%
Sales Tax	0.084	0.092	10%	0.086	0.097	13%	0.077	0.083	8%	0.078	0.085	9%
Permitting Fee	0.008	0.009	14%	0.008	0.009	14%	0.002	0.002	-8%	0.002	0.002	-6%
Interconnection Fee	0.028	0.017	-40%	0.029	0.017	-40%	0.028	0.025	-11%	0.028	0.026	-10%
Transmission Line	0.000	0.000	0%	0.000	0.000	0%	0.017	0.020	18%	0.017	0.020	18%
Contingency	0.056	0.047	-17%	0.055	0.049	-10%	0.047	0.043	-9%	0.047	0.044	-5%
Developer Overhead	0.056	0.094	66%	0.055	0.098	79%	0.047	0.058	22%	0.047	0.059	26%
EPC/Developer Profit	0.150	0.137	-9%	0.155	0.143	-8%	0.083	0.077	-8%	0.082	0.079	-5%
Total price	2.154	2.265	5%	2.092	2.171	4%	1.750	1.901	9%	1.732	1.904	10%