Distributed Generation, Battery Storage, and Combined Heat and Power System Characteristics and Costs in the Buildings and Industrial Sectors

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Distributed Generation, Battery Storage, and Combined Heat and Power System Characteristics and Costs in the Buildings and Industrial Sectors

Distributed generation (DG) in the residential and commercial buildings sectors and in the industrial sector refers to onsite, behind-the-meter energy generation. DG often includes electricity from renewable energy systems such as solar photovoltaics (PV) and small wind turbines, as well as battery energy storage systems that enable delayed electricity use. DG can also include electricity and captured waste heat from combined heat and power (CHP) systems. Many factors influence the market for DG, including government policies at the local, state, and federal levels, and project costs, which vary significantly depending on location, size, and application.

Current and future DG equipment costs are subject to uncertainty. As part of our *Annual Energy Outlook* (AEO), we update projections to reflect the most current, publicly available historical cost data, and we use a number of third-party estimates of future costs in the near and long terms. DG system characteristics and performance data are likewise based on currently available technology and expert projections of future technologies.

Before the AEO2025 reporting cycle, we hired an external consultant to develop a cost and performance characterization report of PV, small wind, and CHP installations in residential and commercial buildings and the industrial sector.[1] The consultant provided cost and performance data for systems of various sizes in select historical years, 2012 through 2022.

From this report, we use national-level average annual costs for a typical system size in each sector. The consultant adapted the additional information in the report—including equipment degradation rate, system life, annual maintenance cost, inverter cost, and conversion efficiency—for the Distributed Generation Submodules of the Residential and Commercial Demand Modules of the National Energy Modeling System. Abbreviated tables of these system sizes and costs are available in the residential and commercial chapters of the *Assumptions to the AEO*.

As described in the assumptions reports and in our report on Modeling Distributed Generation in the Buildings Sectors, other information not included in the report—such as resource availability, avoided electricity cost, interconnection limitations, incentive amounts, installed capacity-based cost reductions, and other factors—ultimately affect the amount of DG and CHP capacity added within a given sector and year.

The report, *Analyze Distributed Generation, Battery Storage, and Combined Heat and Power Technology Data and Develop Performance and Cost Estimates and Analytic Assumptions for the National Energy Modeling System: Final Report*, is available in Appendix A. When referencing the report, cite it as a report by Z Federal and DNV, prepared for the U.S. Energy Information Administration.

[1] Distributed generation systems often cost more per unit of capacity than utility-scale systems. A separate analysis involves assumptions for electric power generation plant costs for various technologies, including utility-scale photovoltaics and both onshore and offshore wind turbines used in the Electricity Market Module.

APPENDIX A

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Distributed Generation, Battery, and Combined Heat and Power Research – Final Report

U.S. Department of Energy
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Acronyms and Abbreviations

AEO	*Annual Energy Outlook*
AC	Alternating current
AD/CVD	Anti-dumping and countervailing duties
AMO	DOE's Advanced Manufacturing Office
BESS	Battery energy storage system
BLS	U.S. Bureau of Labor Statistics
BNEF	Bloomberg New Energy Finance
BOP	Balance of plant
BOS	Balance of system
BTM	Behind-the-meter
Btu	British thermal units
CBECS	EIA's *Commercial Buildings Energy Consumption Survey*
CBP	U.S. Customs and Border Protection Agency
CEC	California Energy Commission
CHP	Combined heat and power
c-Si	Crystalline silicon
C&I	Commercial and industrial
DC	Direct current
DER	Distributed energy resources
DG	Distributed generation
DOC	U.S. Department of Commerce
DOE	U.S. Department of Energy
DRC	Democratic Republic of Congo
EBOS	Electrical balance of system
EIA	U.S. Energy Information Administration
EOL	End-of-life
EPA	U.S. Environmental Protection Agency
EPC	Engineering, procurement, and construction
ESG	Environmental, social, and governance
ESS	Energy storage system
EUL	Effective useful life
EV	Electric vehicle
EVA	Ethylene vinyl acetate
FCAB	Federal Consortium for Advanced Batteries
GHG	Greenhouse Gas
GWh	Gigawatthour
HFTO	DOE's Hydrogen and Fuel Cell Technologies Office
HHV	Higher heating value
H_2	Hydrogen
IEA	International Energy Agency
LFP	Lithium iron phosphate
ILR	Inverter loading ratio
IRA	Inflation Reduction Act
ITC	Investment tax credit
kW	Kilowatt
kW-AC	Kilowatt alternating current
kW-DC	Kilowatt direct current
ES	Kilowatthour
LAB	Lead acid battery
LBNL	Lawrence Berkeley National Laboratory

MACRS	Modified Accelerated Cost Recovery System
MCFC	Molten carbonate fuel cell
MECS	EIA's *Manufacturing Energy Consumption Survey*
MW-AC	Megawatt alternating current
MW-DC	Megawatt direct current
M2FCT	Million Mile Fuel Cell Truck Consortium
NAICS	North American Industry Classification System
NEMS	National Energy Modeling System
NMC	Nickel manganese cobalt
NREL	National Renewable Energy Laboratory
O&M	Operation and maintenance
OEA	EIA's Office of Energy Analysis
PACE	Property assessed clean energy
PAFC	Phosphoric acid fuel cell
PEM	Polymer electrolyte membrane
PEMFC	Polymer electrolyte membrane fuel cell
PERC	Passivated emitter and rear cell
PNNL	Pacific Northwest National Laboratory
PSPS	Public safety power shutoffs
PTC	Production tax credit
PV	Photovoltaic
R&D	Research and development
REAP	Rural Energy for America Program
RECS	EIA's *Residential Energy Consumption Survey*
SAM	NREL's System Advisor Model
SBOS	Structural balance of system
SECC	Smart Energy Consumer Collaborative
SGIP	California's Self-Generation Incentive Program
SOFC	Solid oxide fuel cell
TOPCon	Tunnel oxide passivated contract
TTS	Lawrence Berkeley National Laboratory's *Tracking the Sun*
TWh	Terawatthour
UFLPA	Uyghur Forced Labor Prevention Act
V	Volt
W	Watt
WETO	Wind Energy Technologies Office
WRO	Withhold Release Order

1 INTRODUCTION

This report presents the Z Federal and DNV analysis and data update for distributed generation (DG), battery storage, and combined-heat-and-power (CHP) technology and cost inputs into the U.S. Energy Information Administration's (EIA) *National Energy Modeling System* (NEMS). This document is accompanied by workbooks that map the detailed technology and cost data to inputs in NEMS. The workbooks include publicly available versions with summary information and versions for EIA's internal use only that contain proprietary data. EIA published a previous iteration of this effort in 2020.[1]

1.1 Background

EIA's Office of Energy Analysis (OEA) is responsible for the development, maintenance, and use of NEMS. NEMS is the primary analysis tool for the development of mid- and long-term projections of domestic energy markets published each year in the *Annual Energy Outlook* (AEO). Along with the annual projections of energy markets, OEA provides a wide array of analyses of current energy and environmental issues and their potential impacts on energy markets using NEMS.

DG in the residential, commercial, and industrial sectors (customer sectors) refers to on-site, behind-the-meter (BTM) generation of energy from distributed energy resources (DER), including solar photovoltaic (PV), small-scale wind, fuel cells, and combined-heat-and-power (CHP) systems. An emerging technology in the DG market is BTM battery energy storage paired with PV systems. Many factors influence the DG market, including resource and material availability, federal and state policies, technology research and development, costs, and DG technology interrelationships. This report presents the technology cost and performance assessment of DG technologies, BTM battery systems, and CHP systems for residential, commercial, and industrial applications. OEA specified the technologies selected for assessment in each sector based on the existing technologies represented in NEMS. The assessment for each technology includes:

- **Operational data for each technology aligned with customer sectors**, including expected kilowatthour (kWh) output by location as appropriate, usage characteristics by customer sector, performance characteristics such as efficiency and capacity factor, useful life expectations, incorporation of customer usage as appropriate, long-term degradation curves, and heat rates and thermal output.
- **Current system costs and system capacity configurations by customer sector**, including installation, operation and maintenance (O&M), permitting, and capital cost categories. The cost analysis includes the following for all technologies and associated configurations:
  - Installed cost and O&M costs on a dollar per kilowatt ($/kW) and dollar per kilowatthour ($/kWh) basis.
  - Expected end-use customer-sited installed costs (including dealer and installer mark-up/margin) over time.
  - Buying options (direct purchase, loans, leases, property assessed clean energy [PACE], etc.).
  - Customer sector composite financial analysis/cash flow, levelized cost-of-energy for purchase, and lease options.

[1] EIA, *Distributed Generation, Battery Storage, and Combined Heat and Power System Characteristics and Costs in the Buildings and Industrial Sectors*, May 2020.

The assessment for each of the technologies considered includes the following:

- The reference residential technologies information for 2015–2022. The reference industrial technologies information for 2015 and 2018–2022. The commercial technologies information for 2012–2022.
- The reference equipment tables provided in this report present cost and performance assumptions for new equipment installation, allowing for a direct comparison of new equipment across the projection period. Differences in costs and performance by year can occur due to functional efficiency improvements and equipment and installation cost escalation.
- The cost estimates include site preparation, structures, equipment, electrical, distribution cost, engineering and design, subcontractor fee and budget contingency, and owner's costs (specific to commercial and industrial sectors). All costs are based on 2022 prices and wages for a U.S. average with no location impacts (for example, urban construction constraints) or infrastructure needs (for example, a project-dedicated interconnection upgrade cost). Performance parameters include the electric heat rate based on the higher heating value (HHV) of the fuel, electric generating efficiency, total CHP efficiency, and fuel input rate.
- Other reported design and financial parameters include overnight construction costs, first year of residential/commercial/industrial application, typical unit size, contingencies, and fixed and variable operating costs.

1.2 Overview of reviewed technologies

This study evaluated the most common DER technologies adopted by residential, commercial, and industrial end users in the United States.

Solar photovoltaic systems

Solar PV systems convert sunlight into electrical energy. DNV determined the average system capacity for standalone solar PV systems using a variety of DNV proprietary and public data sources. Annual hourly generation was modeled for each representative system using DNV's SolarFarmer modeling software and National Renewable Energy Laboratory's (NREL's) System Advisor Model (SAM).

Solar photovoltaic + battery energy storage systems

The solar PV technology in the PV + battery energy storage system (BESS) was modeled using the same specifications as the standalone PV technology, with the exception of nameplate capacity. DNV determined that average system capacity for PV + BESS configurations are on average larger than standalone PV systems. DNV further segmented the PV + BESS technology by new PV + BESS installed where the PV and battery were installed and became operational together, and it added a Battery Retrofit case where a battery is added to an existing residential solar PV system.

Standalone battery energy storage systems

This report also assessed standalone battery storage systems. DNV assumed a fully integrated BESS for the residential and commercial sectors, which includes a battery pack, a bidirectional inverter, wiring, disconnect, and casing based on residential and commercial battery energy storage manufacturers such as Enphase, Sonnen, and Tesla.

Wind energy systems

Distributed wind technology is a relatively mature DER. Wind turbines generate electricity by converting kinetic energy in the wind into rotating shaft power that spins an alternating current (AC) generator. BTM small-scale wind systems typically serve rural homes, farms, and manufacturing facilities due to their size and land requirements. Wind resources, high retail electricity prices, and favorable policies are the key contributing factors to BTM wind system economics.

Fuel cells

Like BESS, fuel cells are a scalable technology that may contain a few to hundreds of individual fuel cells stacked together. An individual fuel cell consists of an electrolyte sandwiched between two electrodes. On either side of the cell, bipolar plates are located to help distribute gases and serve as current collectors. DNV assumed a combination of polymer electrolyte membrane (PEM) CHP configurations and solid oxide fuel cells (SOFC) CHP configurations for the residential fuel cell application and a combination of molten carbonate fuel cell (MCFC) and phosphoric acid fuel cell (PAFC) CHP configurations for the commercial fuel cell application.

Combined heat and power

CHP, or cogeneration, is a mature technology that has been used in the power sector and as a private generation resource for decades. The two most common CHP technologies for commercial and small-to-medium industrial applications are reciprocating engines and microturbines. Distributed CHP systems are installed at individual customer sites and are typically sized to provide most of the site's thermal energy (heating and/or cooling). CHP systems can offset a portion of site electricity, as well as inject power back into the grid when applicable.

Representative system sizes

Table 1-1 summarizes the representative system capacity for solar PV, solar + storage, and storage technologies used in the analysis for this study. Table 1-2 summarizes the representative capacities used for wind, fuel cell, and CHP systems.

Table 1-1. List of solar and storage technologies assessed and nominal capacity (2022)

Sector	Configuration	Technology	Technology Size Bin	Representative System Capacity
Residential	Solar PV (standalone)	Solar PV	Small	7.1 kW-DC
	Solar + Storage	Solar PV	Small	7.9 kW-DC
		Battery Storage (combined w/solar)	Small	5 kW-DC (12.5 kWh-DC)
		Battery Storage (retrofit)	Small	4.5 kW-DC (10 kWh-DC)
	Storage (standalone)	Battery Storage (standalone)	Small	6.9 kW-DC (13.5 kWh-DC)
Commercial	Solar PV (standalone)	Solar PV	Small 1	28.5 kW-DC
			Small 2	100 kW-DC
			Medium	250 kW-DC
			Large 1	500 kW-DC
			Large 2	1,000 kW-DC
	Solar + Storage	Solar PV	Small 1	28.5 kW-DC
			Small 2	100 kW-DC
			Medium	250 kW-DC
			Large 1	500 kW-DC
		Battery Storage (combined w/solar)	Small 1	20 kW-DC (40 kWh-DC)
			Small 2	60 kW-DC (120 kWh-DC)
			Medium	150 kW-DC (300 kWh-DC)
			Large 1	300 kW-DC (600 kWh-DC)

Sector	Configuration	Technology	Technology Size Bin	Representative System Capacity
	Storage (standalone)	Battery Storage (standalone)	Small	60 kW-DC (120 kWh-DC)
			Medium	150 kW-DC (300 kWh-DC)
			Large 1	300 kW-DC (600 kWh-DC)
Industrial	Storage (standalone)	Battery Storage (standalone)	Small	100 kW-DC (400 kWh-DC)
			Medium	500 kW-DC (2,000 kWh-DC)
			Large	1,000 kW-DC (4,000 kWh-DC)

Note: kW-DC=kilowatt direct current.

Table 1-2. List of wind, fuel cell, and CHP technologies assessed and nominal capacity (2022)

Sector	Configuration	Technology (includes fuel type if applicable)	Technology Size Bin	Representative System Capacity
Residential	Wind	Small Wind	Small	9.3 kW-AC
	CHP	Fuel Cell	Small	5.0 kW-AC
Commercial	Wind	Small Wind	Small	40 kW-AC
			Medium	300 kW-AC
			Large	2,000 kW-AC
	CHP	Fuel Cell	Medium	300 kW-AC
		Reciprocating Engine (Gas)	Small	300 kW-AC
		Reciprocating Engine (Oil)	Small	350 kW-AC
		Gas Turbine	Small	3,300 kW-AC
		Microturbine (Gas)	Medium	200 kW-AC
Industrial	CHP	Reciprocating Engine (Gas)	Medium	1,000 kW-AC
			Large	3,000 kW-AC
		Gas Turbine	Medium	5,000 kW-AC
			Large 1	10,000 kW-AC
			Large 2	25,000 kW-AC
			Large 3	40,000 kW-AC
		Combined Cycle	Small	100,000 kW-AC
			Large	375,000 kW-AC

Note: kW-AC=kilowatt alternating current.

1.3 Overview of cost estimation methodology

Capital costs and O&M costs were developed for each individual system detailed in the previous two tables, using the process defined in the following sections, with additional detail for individual systems provided in the respective technology sections. All cost values included throughout are reported on a 2022 constant (real) dollar basis.

1.3.1 Capital costs

Capital costs were developed to include all costs incurred to the point of system installation for each technology, identified capacity, and year within the analysis timeframe. All costs are in 2022 constant (real) dollars, and for a non-specific location in the United States. Additional capital costs were developed for each state for residential and commercial solar PV and battery storage technologies, and they are further described in Subsection 1.3.3. Given the variety in the level of detail of source data, capital cost estimates were derived from multiple unique categories for each individual technology, but they can be generally grouped into the following four categories:

- **Equipment costs** include hardware and equipment costs for the specific technology (for example, solar PV modules and inverter(s), battery pack(s) and inverter(s), engines, turbines).
- **Balance of plant (BOP) or balance of system (BOS) costs** include costs of associated structural and electrical components (for example, mounts, racking, wiring).
- **Installation soft costs** include items such as labor, project design and engineering, construction management, logistics and miscellaneous costs, and permitting and inspections.
- **Other soft costs** include items such as taxes, customer acquisition, overhead and margin, and general developer costs.

1.3.2 O&M costs

O&M costs refer to expenses required to ensure continuous operation of the technology within its specified capacity range and operating parameters after system installation and for the specified expected useful system life, considering planned system downtime. DNV developed both fixed and variable O&M costs. Fixed O&M costs are typically considered routine costs, which do not change based on system output. Fixed costs represent most O&M costs for all technologies. The analysis included the following six types of fixed O&M costs:

- System cleaning and vegetation management (if applicable)
- System inspection and monitoring
- Part/equipment replacement
- Land leases and property taxes (if applicable)
- Insurance, asset management, and security
- General administration

Annual fixed O&M costs ($/kW, -DC and -AC depending on the technology type) were developed in 2022 constant (real) dollars, for each technology, identified capacity, and year within the analysis timeframe. These costs were assumed to be an average annual cost experienced over the specified system life for each technology.

Variable O&M costs were developed only for fuel cell and CHP technologies. Variable costs vary based on system output and include items such as chemicals, catalysts, lubricants, and other engine-related components. Fuel costs were not included in this analysis, although they are considered a variable cost for system operation and calculated endogenously in NEMS. Variable O&M costs for fuel cell and CHP systems also include some of the fixed O&M cost categories stated above.

1.3.3 Cost factors and performance attributes

DNV developed state-level costs for residential and commercial solar PV and battery storage technologies using state-level labor costs, taxes, overhead and margin costs, and other installation costs where appropriate. State-level performance attributes for these systems were developed and accounted for local factors such as solar irradiation and average temperature based on a representative location. State-level representative system capacities were also developed for residential and commercial solar PV and battery storage technologies. These state-level cost and performance attributes were developed for use in NEMS modeling, but they are not publicly available.

U.S. average cost and performance attributes were developed for all technologies and sectors and are publicly available in the accompanying data files.

1.3.4 Technology performance specifications

Table 1-3. Technology performance specifications (2022)

Technology	Fuel	System Capacity	Heat Rate (HHV)	Capital Cost	Fixed O&M	Variable O&M
Residential Solar PV (Standalone)	Solar	7.1 kW-DC	N/A	$2,854/kW-DC	$31.13/kW-yr-DC	N/A
Residential Solar PV + Storage	Solar	7.9 kW-DC Solar 5.0 kW-DC Storage (12.5 kWh-DC)	N/A	$4,261/kW-DC (by PV capacity)	$115.20/kW-yr-DC	N/A
Residential Solar PV + Storage (Storage Retrofit)	Electric	6.9 kW-DC Solar 4.5 kW-DC Storage (10 kWh-DC)	N/A	$3,135/kW-DC (by storage capacity)	$87.19/kW-yr-DC	N/A
Residential Storage (Standalone)	Electric	6.9 kW-DC (13.5 kWh-DC)	N/A	$3,875/kW-DC	$96.88/kW-yr-DC	N/A
Residential Wind	Wind	9.3 kW-AC	N/A	$7,411/kW-AC	$38.04/kW-yr-DC	N/A
Residential Fuel Cell (Gas)	Natural Gas	5.0 kW-AC	7,638 Btu/kWh	$9,758/kW-AC	N/A	$0.036/kWh-AC
Commercial Solar PV (Standalone, Small 1)	Solar	28.5 kW-DC	N/A	$2,041/kW-DC	$19.06/kW-yr-DC	N/A
Commercial Solar PV (Standalone, Small 2)	Solar	100 kW-DC	N/A	$2,041/kW-DC	$19.06/kW-yr-DC	N/A
Commercial Solar PV (Standalone, Medium)	Solar	250 kW-DC	N/A	$1,903/kW-DC	$19.06/kW-yr-DC	N/A
Commercial Solar PV (Standalone, Large 1)	Solar	500 kW-DC	N/A	$1,786/kW-DC	$19.06/kW-yr-DC	N/A
Commercial Solar PV (Standalone, Large 2)	Solar	1,000 kW-DC	N/A	$1,340/kW-DC	$18.03/kW-yr-DC	N/A
Commercial Solar PV + Storage (Small 1)	Solar	28.5 kW-DC Solar 20 kW-DC Storage (40 kWh-DC)	N/A	$3,911/kW-DC (by PV capacity)	$75.94/kW-yr-DC	N/A
Commercial Solar PV + Storage (Small 2)	Solar	100 kW-DC Solar 60 kW-DC Storage (120 kWh-DC)	N/A	$3,358/kW-DC (by PV capacity)	$68.66/kW-yr-DC	N/A
Commercial Solar PV + Storage (Medium)	Solar	250 kW-DC 150 kW-DC Storage (300 kWh-DC)	N/A	$3,170/kW-DC (by PV capacity)	$66.80/kW-yr-DC	N/A
Commercial Solar PV + Storage (Large)	Solar	500 kW-DC 300 kW-DC Storage (600 kWh-DC)	N/A	$3,019/kW-DC (by PV capacity)	$65.52/kW-yr-DC	N/A
Commercial Storage (Standalone, Small)	Electric	60 kW-DC (120 kWh-DC)	N/A	$2,621/kW-DC	$65.53/kW-yr-DC	N/A
Commercial Storage (Standalone, Medium)	Electric	150 kW-DC (300 kWh-DC)	N/A	$2,492/kW-DC	$62.30/kW-yr-DC	N/A
Commercial Storage (Standalone, Large)	Electric	300 kW-DC (600 kWh-DC)	N/A	$2,406/kW-DC	$60.14/kW-yr-DC	N/A
Industrial Storage (Standalone)	Electric	100 kW-DC (400 kWh-DC)	N/A	$3,034/kW-DC	$75.86/kW-yr-DC	N/A
Industrial Storage (Standalone)	Electric	500 kW-DC (2,000 kWh-DC)	N/A	$2,638/kW-DC	$65.95/kW-yr-DC	N/A
Industrial Storage (Standalone)	Electric	1,000 kW-DC (4,000 kWh-DC)	N/A	$2,276/kW-DC	$56.91/kW-yr-DC	N/A
Commercial Wind (Small)	Wind	40 kW-AC	N/A	$6,231/kW-AC	$38.04/kW-yr-AC	N/A
Commercial Wind (Medium)	Wind	300 kW-AC	N/A	$4,057/kW-AC	$38.04/kW-yr-AC	N/A
Commercial Wind (Large)	Wind	2,000 kW-AC	N/A	$3,036/kW-AC	$38.04/kW-yr-AC	N/A
Commercial Fuel Cell (Gas)	Natural Gas	300 kW-AC	8,012 Btu/kWh	$7,150/kW-AC	N/A	$0.041/kWh-AC
Commercial Reciprocating Engine (Gas)	Natural Gas	300 kW-AC	10,431 Btu/kWh	$3,769/kW-AC	N/A	$0.020/kWh-AC
Commercial Reciprocating Engine (Oil)	Oil	350 kW-AC	10,139 Btu/kWh	$3,075/kW-AC	N/A	$0.019/kWh-AC
Commercial Gas Turbine	Natural Gas	3,300 kW-AC	13,801 Btu/kWh	$3,942/kW-AC	N/A	$0.015/kWh-AC

Technology	Fuel	System Capacity	Heat Rate (HHV)	Capital Cost	Fixed O&M	Variable O&M
Commercial Microturbine	Natural Gas	200 kW-AC	11,350 Btu/kWh	$3,134/kW-AC	N/A	$0.016/kWh -AC
Industrial Reciprocating Engine (Gas, Small)	Natural Gas	1,000 kW-AC	9,210 Btu/kWh	$3,125/kW-AC	N/A	$0.020/kWh -AC
Industrial Reciprocating Engine (Gas, Medium)	Natural Gas	3,000 kW-AC	8,417 Btu/kWh	$2,586/kW-AC	N/A	$0.016/kWh -AC
Industrial Gas Turbine (Gas, Medium)	Natural Gas	5,000 kW-AC	12,185 Btu/kWh	$2,628/kW-AC	N/A	$0.015/kWh -AC
Industrial Gas Turbine (Gas, Large 1)	Natural Gas	10,000 kW-AC	12,091 Btu/kWh	$2,020/kW-AC	N/A	$0.013/kWh -AC
Industrial Gas Turbine (Gas, Large 2)	Natural Gas	25,000 kW-AC	9,720 Btu/kWh	$1,697/kW-AC	N/A	$0.010/kWh -AC
Industrial Gas Turbine (Gas, Large 3)	Natural Gas	40,000 kW-AC	9,611 Btu/kWh	$1,448/kW-AC	N/A	$0.010/kWh -AC
Industrial Combined Cycle (Gas, Small)	Natural Gas	100,000 kW-AC	6,749 Btu/kWh	$1,632/kW-AC	N/A	$0.004/kWh -AC
Industrial Combined Cycle (Gas, Large)	Natural Gas	375,000 kW-AC	6,246 Btu/kWh	$1,383/kW-AC	N/A	$0.003/kWh -AC

Note: Btu=British thermal units; $/kW-yr=dollar per kilowatt per year.
Notes: All cost values are reported on a 2022 constant (real) dollar basis.

1.4 Report organization

This report contains separate chapters for each examined technology:

- Solar PV
- Battery storage
- Wind energy
- Fuel cells
- CHP

Each chapter contains two subsections. The first subsection in each chapter details the technology and cost data to input into NEMS and the methodology used to determine those inputs. The second subsection in each chapter discusses topics such as resource and material availability trends, government policies and market incentives, research and development rates, relationships to other technologies, and trends in disposal, recycling, or repurposing. Section 6, CHP, does not include a discussion subsection. Instead, the CHP discussion is grouped with Section 7, industrial DER market discussion, which leverages in-depth interviews with eight installers of CHP systems and six end users of CHP systems.

As mentioned above, this report is accompanied by workbooks of technology and cost data inputs for NEMS. The accompanying workbooks contain relevant data used to inform assumptions contained within the report. The data are used in final cost and performance data calculations. The workbooks include "Summary" data tables for each representative technology referenced throughout the report. Three workbooks are publicly available:

- "Res_Tech&Cost_Data.xlsx" and "Com_Tech&Cost_Data.xlsx" contain detailed technology attributes and cost data for distributed representative residential and commercial systems. Summary tabs provide all relevant performance attributes, capital cost, and O&M cost data for each sector and system capacity within each representative technology. These tabs contain relevant mapping variables and data units for each performance and cost metric used in NEMS, such as equipment type, fuel type, NEMS file, and historical year, depending on the sector.

- "Ind_Tech&Cost_Data.xlsx" contains all relevant technology attributes and cost data for representative industrial CHP and battery storage systems. The "Summary_Tables" tab provides a single table with all performance attributes, capital cost, and O&M cost data for each representative system, system capacity, and year for use in NEMS.

2 SOLAR PHOTOVOLTAIC SYSTEMS

2.1 Solar PV systems technology attributes and cost data

The following subsections provide an overview of solar PV performance attributes and cost data for representative residential and commercial systems, and highlight key factors influencing future pricing, adoption, and technology deployment trends.

2.1.1 Technology attributes and cost estimation methodology

DNV developed detailed distributed generation technology cost and performance data for use in NEMS. Technology attributes and cost data for BTM solar PV technologies were developed and aligned with relevant residential and commercial customer sectors. Attributes and cost data for standalone solar PV systems were developed in addition to solar + storage configurations, which are detailed in subsequent report sections. State and U.S. representative system capacities for residential and commercial solar PV systems were developed using a variety of DNV proprietary and public data sources. Annual hourly generation profiles were modeled for each standalone solar PV configuration to gather detailed operational data, and additional relevant performance data was assembled for all system configurations. The final step was to develop 2022 constant (real) dollar estimates from publicly available data and align associated cost estimates and attributes with previous years of EIA sector-level surveys: *Residential Energy Consumption Survey* (RECS), *Commercial Buildings Energy Consumption Survey* (CBECS), and *Manufacturing Energy Consumption Survey* (MECS).

2.1.2 System configurations

DNV first collected recent BTM solar PV installation data from Lawrence Berkeley National Laboratory's (LBNL) *Tracking the Sun* (TTS) database through 2022 and segmented the data to identify statistically significant representative residential and commercial system sizes for each relevant year in the analysis timeframe (2015–2022 for residential and 2012–2022 for commercial) for each state contained in the database. DNV used proprietary project trackers and databases for smaller distributed systems to confirm sizes and extrapolate to similar states based on relevant technical factors and subject matter expertise. DNV also cross-referenced this data with EIA's Form EIA-861 data that contains data on distributed solar PV capacity in specific utility territories. This process allowed DNV to identify residential representative system capacities for each state, with an average U.S. system capacity of 7.1-kilowatt direct current (kW-DC) for year 2022. Similarly, the representative commercial system capacity was 28.5 kW-DC across all commercial installations. The state-level representative system capacity and performance attribute data for residential solar PV systems is available in the accompanying data files. Although state-level cost data was gathered and used in NEMS modeling, this data is proprietary and not available for public dissemination.

Due to the range of capacities of commercial solar PV installations, DNV also identified four additional commercial solar PV capacities to capture this variation across the United States. These capacities are also aligned with Wood Mackenzie's *U.S. Solar PV System Pricing* report, which was an important component of the capital cost data used in this assessment.[2] These capacities were compared with LBNL's TTS installation data and DNV proprietary project libraries to confirm that they represent the range in the current commercial installation market and the potential future growth opportunities as larger commercial sites take advantage of decreasing system costs and state and federal incentives.

[2] Wood Mackenzie, *US Solar PV system pricing: H2 2022*, November 21, 2022.

As discussed further in Subsection 0, DNV used a blended approach to develop cost data for each representative system based on typical inverter types present in recent year installations and trends in previous years. Table 2-1 shows which approach was selected for each market segment and size. Table 2-1 also highlights the standalone solar PV system configuration capacities, along with solar + storage technology. Solar + storage configurations are further discussed in Section 3, but they are presented here for comparison and consistency.

Two different technology configurations for solar PV are modeled: Solar PV (standalone) and Solar PV and storage (solar + storage). Solar + storage systems' PV components were modeled using the same specifications as the standalone PV configuration, except for PV nameplate capacity. The residential solar + storage technology configuration is further segmented by new solar + storage systems that were installed and became operational together and a retrofit case where a battery is added to an existing PV system. Residential and commercial battery energy storage systems can be installed as a standalone system, added to an existing PV system, or installed with a new PV system. DNV assumed all representative battery installations that are co-located with a PV system have an AC-coupled configuration and that all standalone battery storage systems would be installed in a DC-coupled configuration.

PV system racking is the equipment that affixes solar panels to surfaces, such as roofs, carports, or the ground. Racking equipment is typically made from metal, such as aluminum and steel, and sets the orientation and tilt of the solar array. In terms of system costs, racking is commonly defined as the structural BOS. Racking and mounting systems are site-dependent, and although a wide variety of options exist, residential pitched-roof, commercial flat-roof (ballasted), and commercial fixed-tilt ground mounted systems represent most customer-sited PV racking systems. Commercial flat-roof ballasted racking systems require less material, equipment, and labor than the ground-mounted racking system. However, installed extra-large commercial ground-mounted systems (1 megawatt [MW] or more) provide economies of scale, thereby reducing BOS costs.[3]

Solar PV system inverters are power electronics devices that convert DC to AC. PV panels produce DC power that must be converted to AC power if the system is grid-connected. Single-phase string inverters are the oldest and most common type of PV system inverter used today. They are centralized systems that connect multiple strings of solar panels to transform the DC power produced by the panels into usable AC power for the site. An alternative approach to the single inverter system involves each PV module having its own microinverter mounted directly onto the backside of each panel. The advantage to this system lies in its increased flexibility; having an inverter installed on each module avoids the risk of shade or a poorly performing module bringing down an entire string or an inverter malfunction taking down the entire array. Individual microinverters also facilitate granular remote monitoring, which can help identify and isolate performance issues at the module level. The advantages of microinverters come at a cost—a single-phase string inverter is cheaper on a dollar-per-watt ($/W) basis, especially for larger arrays. DC power optimizer systems are a middle ground between a single-phase string and microinverters. These systems include power optimizers installed on each module that connect to a single-phase string inverter for power conversion. Similar to microinverters, DC optimizer systems reduce the impact of single-panel malfunction on system performance and offer module-level performance monitoring.

[3] Ramasamy, Vignesh and Jarett Zuboy, *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2022*, National Renewable Energy Laboratory (September 2022).

The representative module type modeled for all sectors was the mono passivated emitter rear cell (PERC) type, which is made from p-type monocrystalline silicon cells with PERC cell architecture. Monocrystalline and multicrystalline (also known as polycrystalline) silicon PERC cells have comprised the majority of global market share over the last decade, as they have had the best combination of efficiency and production costs. Since 2015, material use has trended toward monocrystalline silicon because it yields higher cell efficiencies due to having fewer material defects and chemical impurities than multicrystalline silicon. Although multicrystalline panels are less expensive than monocrystalline panels, the improved performance in higher temperatures, higher overall efficiencies, and improving panel costs in recent years have made monocrystalline panels more attractive to installers. PERC cell architecture has also grown in popularity since 2015. Its market share grew from 10% in 2015 to over 80% by 2020 because it improves standard cell efficiencies. As of 2020, the global market share of mono PERC-type modules was 64%.[4]

Table 2-1. Technology attributes for solar PV configurations and representative systems

Market Sector	Configuration	Representative System Capacity	Racking Solution	Inverter Type	Module Type
Residential (Small)	Solar PV (standalone)	7.1 kW-DC	Pitched roof (roof-mount)	Blended based on segment market share: string inverter, microinverter, DC optimizer	Mono PERC module (blended based on market share of standard and high-efficiency models)
	Solar + storage	7.9 kW-DC PV (5 kW-DC, 12.5 kWh Battery Storage)			
	Solar + storage (retrofit)	6.9 kW-DC PV (6.9 kW-DC, 14.5 kWh-DC Battery Storage)			
Commercial (Small 1)	Solar PV (standalone)	28.5 kW-DC	Flat roof (roof-mount)	Blended based on segment market share: string inverter, microinverter, DC optimizer	Mono PERC module (blended based on market share of standard and high-efficiency models)
	Solar + storage	28.5 kW-DC PV (20 kW-DC, 40 kWh-AC Battery Storage)			
Commercial (Small 2)	Solar PV (standalone)	100 kW-DC	Flat roof (roof-mount)	Blended based on segment market share: string inverter, microinverter, DC optimizer	Mono PERC module (blended based on market share of standard and high-efficiency models)
	Solar + storage	100 kW-DC PV (60 kW-DC, 120 kWh-DC Battery Storage)			
Commercial (Medium)	Solar PV (standalone)	250 kW-DC	Flat roof (roof-mount)	Blended based on segment market share: string inverter, microinverter, DC optimizer	Mono PERC module (blended based on market share of standard and high-efficiency models)
	Solar + storage	250 kW-DC PV (150 kW-DC, 300 kWh-DC Battery Storage)			
Commercial (Large 1)	Solar PV (standalone)	500 kW-DC	Flat roof (roof-mount)	Blended based on segment market share: string inverter, microinverter, DC optimizer	Mono PERC module (blended based on market share of standard and high-efficiency models)
	Solar + storage	500 kW-DC PV (300 kW-DC, 600 kWh-DC Battery Storage)			
Commercial (Large 2)	Solar PV (standalone)	1,000 kW-DC	Commercial fixed-tilt (ground-mount)	String inverter	Mono PERC module (blended based on market share of standard and high-efficiency models)

Note: kW/yr=kilowatt per year.

[4] Woodhouse, Michael and David Feldman, *Research and Development Priorities to Advance Solar Photovoltaic Lifecycle Costs and Performance*, National Renewable Energy Laboratory (October 2021).

2.1.3 Generation shapes and technology attributes

After developing technology system configurations and representative capacities, DNV modeled each representative system using DNV's SolarFarmer modeling software and the NREL's System Advisor Model (SAM) to collect hourly generation shapes and associated performance metrics. Figure 2-1 shows the performance metrics that were collected for each representative system in each state using a representative location in each year within the analysis timeframe. As mentioned previously, state-level representative system capacities and performance attributes are available in the accompanying data files.

Figure 2-1. Performance metrics for PV systems

- Hourly System Generation (kWh-h)
- PV System Equipment Effective Useful Life (EUL)
- Inverter Effective Useful Life (EUL)
- PV Module Efficiency (%)
- Inverter Efficiency (%)
- PV Module Efficiency (%)
- Inverter Loading Ratio (ILR)
- Capacity Factor (%)
- Annual System Degradation (%)
- Average Annual System Losses (%)

2.1.4 System performance attributes

Table 2-2 through a b Degradation values represent the year one or annual degradation percentage compared to the rated system capacity at 100% in the identified year.

Table 2-7 details performance attributes for representative U.S. average residential and commercial solar PV systems summarized from the data developed in the previous subsections. The data are presented to align with previous years of EIA sector-level surveys for each customer segment (RECS, CBECS, and MECS) starting with the residential sector from 2015 to 2022. Although single-family residential solar PV installations are typically smaller than most commercial installations, roof-mounted systems in both sectors have many performance and operational similarities.

Table 2-2. Residential solar PV system performance attributes

Year	Rep. System Capacity	Module Efficiency	Inverter Efficiency	Capacity Factor	Year One Degradation [a]	Average Annual Degradation [b]	Average Annual System Losses
2015	6.5 kW-DC	19.0%	98.0%	17.3%	97.10%	99.10%	14.0%
2016	6.7 kW-DC	19.0%	98.0%	17.4%	97.10%	99.10%	14.0%
2017	6.8 kW-DC	19.0%	98.0%	17.4%	97.10%	99.10%	14.0%
2018	6.9 kW-DC	19.0%	98.0%	17.5%	97.10%	99.10%	14.0%
2019	7.0 kW-DC	19.5%	98.0%	17.5%	97.10%	99.10%	14.0%
2020	7.0 kW-DC	20.4%	98.0%	17.5%	97.10%	99.10%	14.1%
2021	7.1 kW-DC	20.4%	98.0%	17.5%	97.10%	99.10%	14.1%
2022	7.1 kW-DC	20.4%	98.0%	17.6%	97.10%	99.10%	14.1%

[a] [b] Degradation values represent the year one or annual degradation percentage compared to the rated system capacity at 100% in the identified year.

The average U.S. residential solar PV system capacity increased steadily from 2015 to 2022 due to many factors such as home size, available rooftop space, increased home energy use, and electrification of end uses. Performance characteristics have improved over the same period largely due to increased component efficiencies. Commercial solar PV installations and system performance follow similar trends.

As mentioned above, cost and performance data were developed for multiple commercial solar PV representative system capacities in addition to the representative system capacity developed from LBNL's TTS and other data sources. Unlike residential single-family buildings, which are relatively similar in size, in rooftop configuration and area, and in their requirements for solar PV installations, commercial systems are installed in facilities with varying rooftop sizes, space considerations, and energy end uses. The following tables detail U.S. average performance attributes for commercial solar PV systems. Table 2-3 highlights the representative median size developed from LBNL's TTS data, and the subsequent tables summarize performance attributes for the remaining commercial sizes.

Table 2-3. Commercial solar PV system performance attributes for median representative system capacity

Year	Rep. System Capacity	Module Efficiency	Inverter Efficiency	Capacity Factor	Year One Degradation [a]	Average Annual Degradation [b]	Average Annual System Losses
2012	28.3 kW-DC	19.8%	95.9%	17.5%	97.02%	99.15%	14.0%
2013	30.6 kW-DC	19.8%	96.8%	17.5%	97.20%	99.20%	14.0%
2014	29.9 kW-DC	19.8%	97.5%	17.5%	97.37%	99.25%	14.0%
2015	27.2 kW-DC	20.0%	98.0%	17.5%	97.72%	99.35%	14.0%
2016	29.3 kW-DC	20.0%	98.0%	17.6%	97.72%	99.35%	14.0%
2017	32.7 kW-DC	20.2%	98.0%	17.6%	97.72%	99.35%	14.0%
2018	33.4 kW-DC	20.2%	98.0%	17.6%	97.72%	99.35%	14.1%
2019	30.2 kW-DC	20.8%	98.0%	17.6%	97.72%	99.35%	14.1%
2020	29.3 kW-DC	20.8%	98.0%	17.7%	97.72%	99.35%	14.1%
2021	26.8 kW-DC	21.0%	98.0%	17.7%	97.72%	99.35%	14.1%
2022	28.5 kW-DC	21.0%	98.0%	17.7%	97.72%	99.35%	14.1%

[a b] Degradation values represent the year one or annual degradation percentage compared to the rated system capacity at 100% in the identified year.

Median capacities for representative commercial solar PV systems have fluctuated over the last 10 years due to a variety of factors. The large sample size and variety of installation types throughout the United States contribute significantly to this variability. However, performance attributes generally do not change when moving from the smallest representative capacity to the 100 kW-DC system or even to the larger roof-mounted systems. The capacity factor rises slightly when the system size increases.

Table 2-4. Commercial solar PV system (100 kW-DC) performance attributes

Year	Rep. System Capacity	Module Efficiency	Inverter Efficiency	Capacity Factor	Year One Degradation [a]	Average Annual Degradation [b]	Average Annual System Losses
2012	100 kW-DC	19.8%	95.9%	17.5%	97.02%	99.15%	14.0%
2013	100 kW-DC	19.8%	96.8%	17.5%	97.20%	99.20%	14.0%

Year	Rep. System Capacity	Module Efficiency	Inverter Efficiency	Capacity Factor	Year One Degradation [a]	Average Annual Degradation [b]	Average Annual System Losses
2014	100 kW-DC	19.8%	97.5%	17.5%	97.37%	99.25%	14.0%
2015	100 kW-DC	20.0%	98.0%	17.5%	97.72%	99.35%	14.0%
2016	100 kW-DC	20.0%	98.0%	17.6%	97.72%	99.35%	14.0%
2017	100 kW-DC	20.2%	98.0%	17.6%	97.72%	99.35%	14.0%
2018	100 kW-DC	20.2%	98.0%	17.6%	97.72%	99.35%	14.1%
2019	100 kW-DC	20.8%	98.0%	17.6%	97.72%	99.35%	14.1%
2020	100 kW-DC	20.8%	98.0%	17.7%	97.72%	99.35%	14.1%
2021	100 kW-DC	21.0%	98.0%	17.7%	97.72%	99.35%	14.1%
2022	100 kW-DC	21.0%	98.0%	17.7%	97.72%	99.35%	14.1%

[a] [b] Degradation values represent the year one or annual degradation percentage compared to the rated system capacity at 100% in the identified year.

Table 2-5. Commercial solar PV system (250 kW-DC) performance attributes

Year	Rep. System Capacity	Module Efficiency	Inverter Efficiency	Capacity Factor	Year One Degradation [a]	Average Annual Degradation [b]	Average Annual System Losses
2012	250 kW-DC	19.8%	95.9%	17.6%	97.02%	99.15%	14.0%
2013	250 kW-DC	19.8%	96.8%	17.6%	97.20%	99.20%	14.0%
2014	250 kW-DC	19.8%	97.5%	17.6%	97.37%	99.25%	14.0%
2015	250 kW-DC	20.0%	98.0%	17.7%	97.72%	99.35%	14.0%
2016	250 kW-DC	20.0%	98.0%	17.7%	97.72%	99.35%	14.0%
2017	250 kW-DC	20.2%	98.0%	17.7%	97.72%	99.35%	14.0%
2018	250 kW-DC	20.2%	98.0%	17.8%	97.72%	99.35%	14.1%
2019	250 kW-DC	20.8%	98.0%	17.8%	97.72%	99.35%	14.1%
2020	250 kW-DC	20.8%	98.0%	17.8%	97.72%	99.35%	14.1%
2021	250 kW-DC	21.0%	98.0%	17.8%	97.72%	99.35%	14.1%
2022	250 kW-DC	21.0%	98.0%	17.8%	97.72%	99.35%	14.1%

[a] [b] Degradation values represent the year one or annual degradation percentage compared to the rated system capacity at 100% in the identified year.

Table 2-6. Commercial solar PV system (500 kW-DC) performance attributes

Year	Rep. System Capacity	Module Efficiency	Inverter Efficiency	Capacity Factor	Year One Degradation [a]	Average Annual Degradation [b]	Average Annual System Losses
2012	500 kW-DC	19.8%	95.9%	17.7%	97.02%	99.15%	14.0%
2013	500 kW-DC	19.8%	96.8%	17.7%	97.20%	99.20%	14.0%
2014	500 kW-DC	19.8%	97.5%	17.7%	97.37%	99.25%	14.0%
2015	500 kW-DC	20.0%	98.0%	17.7%	97.72%	99.35%	14.0%
2016	500 kW-DC	20.0%	98.0%	17.7%	97.72%	99.35%	14.0%

Year	Rep. System Capacity	Module Efficiency	Inverter Efficiency	Capacity Factor	Year One Degradation [a]	Average Annual Degradation [b]	Average Annual System Losses
2017	500 kW-DC	20.2%	98.0%	17.8%	97.72%	99.35%	14.0%
2018	500 kW-DC	20.2%	98.0%	17.8%	97.72%	99.35%	14.1%
2019	500 kW-DC	20.8%	98.0%	17.8%	97.72%	99.35%	14.1%
2020	500 kW-DC	20.8%	98.0%	17.9%	97.72%	99.35%	14.1%
2021	500 kW-DC	21.0%	98.0%	17.9%	97.72%	99.35%	14.1%
2022	500 kW-DC	21.0%	98.0%	17.9%	97.72%	99.35%	14.1%

[a b] Degradation values represent the year one or annual degradation percentage compared to the rated system capacity at 100% in the identified year.

Table 2-7. Commercial solar PV system (1,000 kW-DC) performance attributes

Year	Rep. System Capacity	Module Efficiency	Inverter Efficiency	Capacity Factor	Year One Degradation [a]	Average Annual Degradation [b]	Average Annual System Losses
2012	1,000 kW-DC	19.8%	95.9%	17.7%	97.02%	99.15%	14.0%
2013	1,000 kW-DC	19.8%	96.8%	17.8%	97.20%	99.20%	14.0%
2014	1,000 kW-DC	19.8%	97.5%	17.8%	97.37%	99.25%	14.0%
2015	1,000 kW-DC	20.0%	98.0%	17.8%	97.72%	99.35%	14.0%
2016	1,000 kW-DC	20.0%	98.0%	17.8%	97.72%	99.35%	14.0%
2017	1,000 kW-DC	20.2%	98.0%	17.9%	97.72%	99.35%	14.0%
2018	1,000 kW-DC	20.2%	98.0%	17.9%	97.72%	99.35%	14.1%
2019	1,000 kW-DC	20.8%	98.0%	17.9%	97.72%	99.35%	14.1%
2020	1,000 kW-DC	20.8%	98.0%	18.0%	97.72%	99.35%	14.1%
2021	1,000 kW-DC	21.0%	98.0%	18.0%	97.72%	99.35%	14.1%
2022	1,000 kW-DC	21.0%	98.0%	18.0%	97.72%	99.35%	14.1%

[a b] Degradation values represent the year one or annual degradation percentage compared to the rated system capacity at 100% in the identified year.

2.1.5 2022 cost data

Capital cost data were collected for each system configuration within each state for years 2020–2022 using Wood Mackenzie's *U.S. Solar PV System Pricing* reports for the respective years.[5] These data were used as a component of building the final costs datasets, consisting of additional scaling and market adjustment factors.[6] DNV used a blended approach to develop capital cost data based on inverter type for the representative systems. Inverter type is based on installation data and aligned with NREL's approach to developing national cost estimates in its annual cost benchmark reports.[7] For example, the majority of residential installations use DC optimizers with

[5] Wood Mackenzie, *US Solar PV system pricing: H2 2022*, November 21, 2022.
[6] State-level capital cost data by individual category for distributed solar PV systems is proprietary and not contained within the public data files or used directly in this report.
[7] Ramasamy, Vignesh and Jarett Zuboy, *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2022*, National Renewable Energy Laboratory (September 2022).

string inverters and microinverters, which together comprised over 80% of the 2022 installed market, whereas in recent years, most commercial installations, comprising over 70% market share, use string inverters. Specific market share percentages used in the capital cost modeling are shown in Table 2-8.

Table 2-8. Solar PV inverter market share (percentage) by customer sector and year

Year	Customer Sector	String Inverter	Optimizer Solution	Microinverter
2020	Residential	14.6%	49.8%	35.6%
	Commercial	55.2%	39.2%	5.6%
2021	Residential	14.8%	50.5%	34.7%
	Commercial	74.8%	20.0%	5.3%
2022	Residential	16.4%	44.5%	39.1%
	Commercial	74.5%	19.1%	6.4%

DNV combined this data with DNV proprietary project installation data obtained from developers and direct project experience to provide scaling criteria for specific cost categories based on market factors present within the last three years for installed residential and commercial distributed solar PV systems. Market factors found included decreasing PV module and inverter costs, based on proprietary DNV data, as well as increasing labor costs since 2020. DNV gathered cost data for each state and system configuration in years 2020–2022 using the above approach, and then it compiled the data into 13 summary capital cost categories to align with historical capital cost data. The detailed cost categories and associated assumptions are described further in Table 2-9.

Table 2-9. Cost categories and associated assumptions

Cost Category	Residential	Commercial (Roof-mounted)	Commercial (Ground-mounted)
Module	▪ PERC P-type Mono c-Si [a]		
Inverter	▪ String: 600V 3-phase inverter ▪ DC Optimizer: 1-unit/module ▪ Microinverter: 1-microinverter/module	▪ String: 1,000V 3-phase inverter ▪ DC Optimizer: 1-unit/module	▪ String: 1,500V 3-phase inverter
Electrical balance of system (EBOS)	▪ Includes wiring, conduit, and module connectors, rapid shutdown, pass-through box, junction box, surge protection, combiner box and AC subpanel (if applicable), monitoring		▪ Includes wiring, conduit, and module connectors, pass-through box, junction box, surge protection, combiner box and AC subpanel (if applicable), monitoring
Structural balance of system (SBOS)	▪ Includes mounting, module clamps and wire management, MLPE mount, inverter rack and accessories	▪ Includes mounting, ballast blocks, module clamps and wire management, MLPE mount, inverter rack and accessories	▪ Includes mounting, module clamps and wire management, foundation, inverter rack and accessories
Labor [a]	▪ Includes AC/DC electrical (AC only for microinverter systems), module and racking installs ▪ Based on wages from BLS	▪ Includes AC/DC electrical, module and racking installs ▪ Based on wages from BLS	▪ Includes AC/DC electrical, module and racking installs, foundation install ▪ Based on wages from BLS
Design and engineering	▪ Includes site design and layout, and residential permits	▪ Includes site design and layout, structural and electrical engineering	▪ Includes site design and layout, civil, structural and electrical engineering
Permitting and Inspection	▪ Solar and building permit inspection, and interconnection		
Supply chain, logistics, and miscellaneous	▪ Includes mobilization, travel/shipping to site ▪ Assumes oversea freight costs included in component cost (oversea freight for inverters included) ▪ 10% distribution markup for modules, 5% for inverters included		▪ Includes mobilization, travel, and shipping to site ▪ Assumes oversea freight costs included in component cost (oversea freight for inverters included)
Civil engineering	▪ N/A		▪ General site preparation work
Taxes	▪ Blended sales tax for U.S. average, individual state sales tax		
Customer acquisition and origination	▪ General customer acquisition and origination		
Overhead and margin	▪ Site assessment, general project and contract management, EPC margin		▪ Site assessment, general project and contract management, EPC margin, contingency
EPC costs	▪ Assumes single EPC company, no developer costs	▪ Turnkey EPC	▪ Turnkey EPC
Developer cost	▪ N/A	▪ Interconnection, origination, environmental and other permitting, due diligence, other general management	▪ Interconnection, origination, environmental and other permitting, due diligence, other general management, land acquisition

[a] Wages are represented in 2022 constant (real) dollars.
Note: BLS=U.S. Bureau of Labor Statistics[8].
Note: c-Si=Crystalline silicon; V=volt; EPC=Engineering, Procurement and Construction.

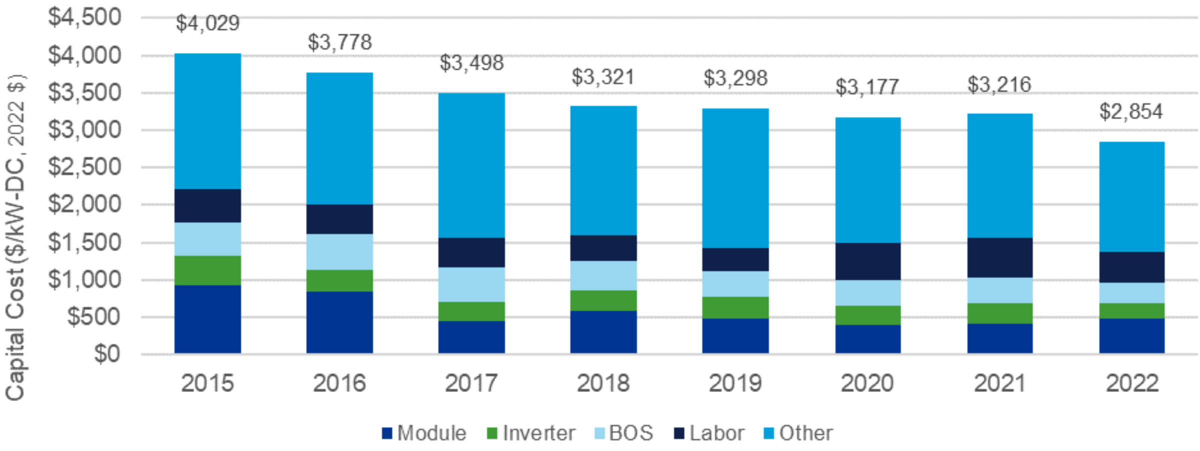
[8] U.S. Bureau of Labor Statistics, Occupational Employment and Wage Statistics, Tables Created by BLS, May 2022

2.1.6 Historical cost data

Baseline historical capital cost data were collected from NREL annual cost benchmark reports and data files at the national level and then disaggregated using a variety of factors to produce state-level cost data for each year in the analysis timeframe.[9] DNV used labor costs, sales tax, and components of supplemental Wood Mackenzie PV system pricing data to disaggregate historical PV system configurations into state-level cost data for five individual capital cost categories.[10] These data are combined with current cost data detailed in the previous subsection and summarized for the residential customer sector. Figure 2-2 shows the U.S. average residential solar PV system capital costs in 2022 constant (real) dollars.

Residential solar PV system capital costs have decreased over the past eight years due to declines in module prices from technology advancements and increased module power density. Supply chain challenges and labor shortages have increased some specific cost categories in recent years, but decreases in soft costs such as margin, overhead, and customer acquisition helped to lower total capital costs for residential solar PV systems in 2022.

Figure 2-2. U.S. average residential solar PV system capital costs (kW-DC, 2022 $)

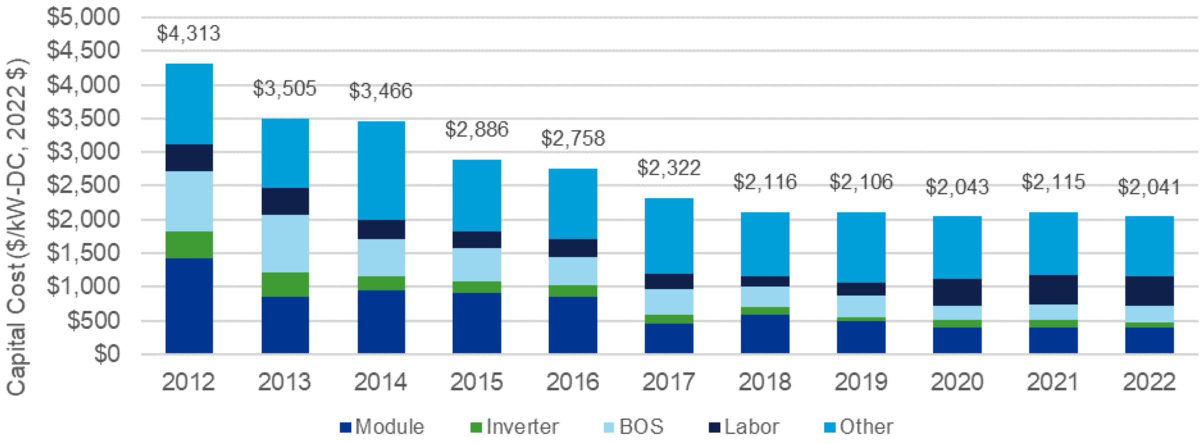


U.S. average cost data for commercial solar PV systems were also computed. Figure 2-3 shows capital costs for a 100-kW-DC system (that is, string inverter and DC optimizer) used for the inverter category in the smallest commercial size range based on the blended cost approach. Figure 2-4 shows historical capital cost data for a 250 kW-DC roof-mounted system with string inverters. Lastly, Figure 2-5 shows capital costs for a 1,000 kW-DC ground-mounted system.

[9] Ramasamy, Vignesh and Jarett Zuboy, *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2022*, National Renewable Energy Laboratory (September 2022).

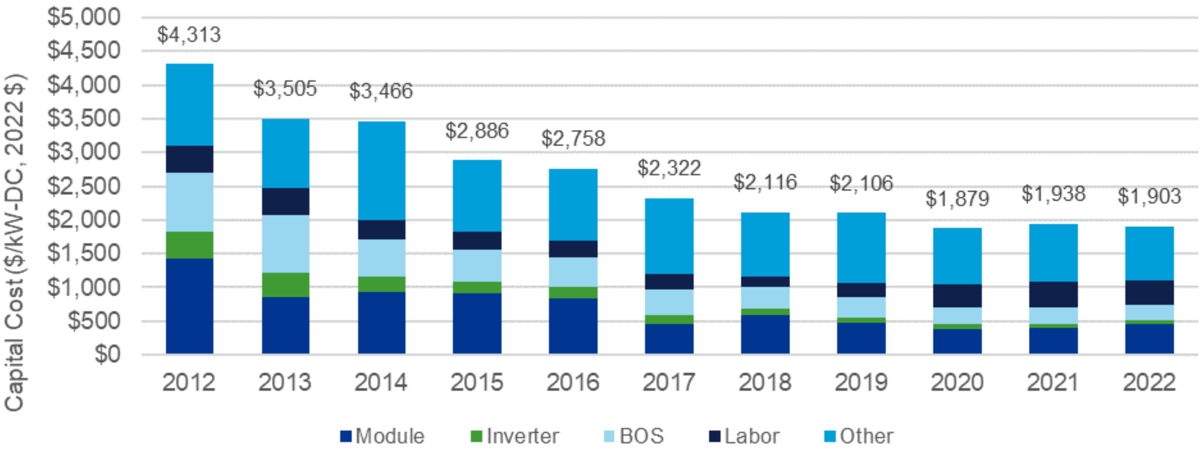
[10] Wood Mackenzie, *US Solar PV system pricing: H2 2022*, November 21, 2022.

Figure 2-3. U.S. average commercial solar PV system (100 kW-DC) capital costs ($/kW-DC, 2022 $)



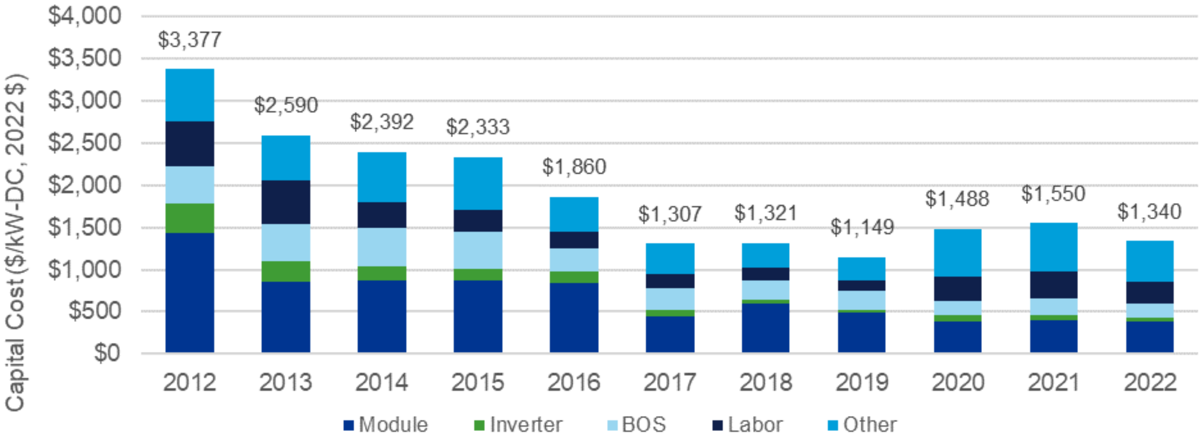
Historical capital cost data for a commercial 100 kW-DC system follows a similar declining trend as residential solar PV systems over the same time period. Although historically cost savings were achieved through module, inverter, and BOS cost reductions, more recently these costs have remained relatively consistent due to supply chain issues in recent years.

Figure 2-4. U.S. average commercial solar PV system (250 kW-DC) capital costs ($/kW-DC, 2022 $)



Medium and large roof-mounted commercial solar PV installations also showed similar cost improvements over the same period to the smaller commercial systems but were slightly more affected in recent years by supply chain and labor cost increases. More significant cost reductions were achieved in margin and customer acquisition costs due to developers pursuing a portfolio sales approach that can optimize on economies of scale. This approach has helped to level total system costs for recent years (2020–2022). Note, although costs have decreased since 2020, 1,000 kW-DC systems are the only capacity group to have an increase in capital costs from 2019 to 2020 and that has 2022 costs higher than 2019.

Figure 2-5. U.S. average commercial solar PV system (1,000 kW-DC) capital costs ($/kW-DC, 2022 $)



Larger capacity ground-mounted systems experienced cost fluctuations in recent years as the supply chain and labor cost effects directly affected these larger systems, more similar to utility-scale installations than the smaller commercial systems. Of the representative commercial solar PV systems, the 1,000 kW-DC system was the only one to experience an increase in average capital costs since 2019.

2.1.7 O&M cost data

DNV used a similar approach to compile O&M cost data for 2022 and historical years within the analysis timeframe. O&M cost data in 2022 constant (real) $/kW-yr-DC for nine separate categories was collected from NREL annual PV cost benchmarks and confirmed by internal DNV installation data and reported individual project experience for 2022. DNV then created scalars for individual states to normalize individual cost categories based on relevant property taxes in individual states and align O&M labor costs for individual categories. DNV used historic wage data to scale O&M cost categories to each year in the analysis timeframe. The O&M cost categories included in this assessment are shown in Table 2-10, including the percentage breakdown for specific categories relative to the respective customer segment and solar PV configuration.

Table 2-10 shows the mix of O&M costs for each customer sector and system configuration. Overall, differences exist in the distribution of O&M costs between each customer sector due to the physical and site-specific factors affecting the need for various types of maintenance. Annual historical O&M costs for each customer sector and configuration are shown in Table 2-10.

Table 2-10. O&M cost categories for solar PV systems by customer sector and configuration

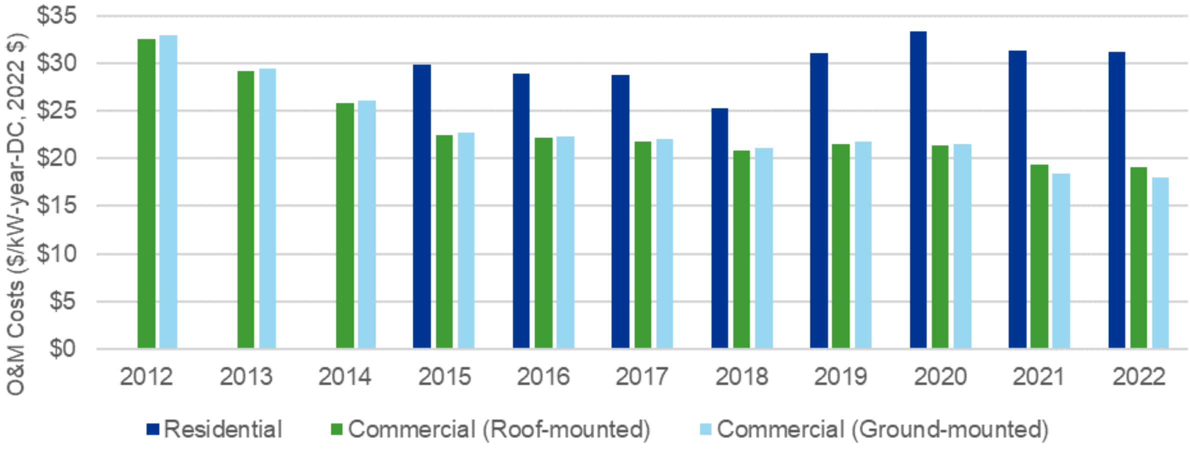
O&M Cost Category	Residential	Commercial (Roof-mounted)	Commercial (Ground-mounted)
Module cleaning & vegetation management	5%	16%	21%
System inspection & monitoring	13%	22%	12%
Component parts replacement	31%	8%	4%
Module replacement	6%	9%	8%
Inverter replacement	24%	13%	13%
Land lease	0%	0%	13%
Property tax	7%	10%	10%

O&M Cost Category	Residential	Commercial (Roof-mounted)	Commercial (Ground-mounted)
Insurance, asset management, and security	3%	15%	14%
Operations administration	12%	8%	4%

Note: Column percentages may not add up to 100% due to rounding.

As shown in Figure 2-6, residential O&M costs for solar PV systems are higher than commercial system costs due to higher insurance and component replacement costs. O&M costs for solar PV system typically range between 0.5% and 0.75% per year of total system cost, but given labor shortages, property insurance premium increases, and other market factors affecting smaller systems, O&M costs in recent years for residential systems have increased to over $30/kW-yr-DC.

Figure 2-6. U.S. average solar PV historical O&M cost data ($/kW-year-DC, 2022 $) by customer sector and system configuration



Note: Residential data for 2012—2014 is not included due to data being gathered in alignment with previous years of EIA sector-level surveys for each customer segment (RECS, CBECS, and MECS). The last year of alignment for residential data was 2015.

2.2 Solar PV market discussion

The following subsections provide an overview of factors affecting solar PV system pricing and overall market adoption of systems. Although individual component (for example, module, inverter) costs and related supply chain considerations play an important role in overall capital costs, several other factors can affect future system pricing and shift overall market dynamics. The availability of raw materials will continue to play an increasing role in determining component prices, and research and development efforts can focus on cost-effective products and approaches. Finally, the emergence of new federal and evolving state incentives affects adoption across various markets, customer sectors, and system technologies.

2.2.1 Solar PV component trends

The domestic content requirements under the Inflation Reduction Act (IRA) aim to support and strengthen U.S.-based production industries by incentivizing the use of domestically sourced materials and components in renewable energy products. To qualify for the domestic content bonus, all structural steel or iron products used in the project must be produced in the United States and a required percentage of the total costs of manufactured products (including components) of the system need to be mined, produced, or manufactured in the United States. Executive Order 14017 America's Supply Chains directed the Secretary of Energy to submit a report on supply chains for the energy sector industrial base. In response, the U.S. Department of Energy (DOE) prepared and issued a series of assessments of supply chains for 11 different technology sectors, including solar PV. These assessments illustrate the limited domestic production capacity available for many renewable technologies, including raw material, feedstock processing, and finished product manufacturing and assembly. Manufacturing capacity of components for solar PV is expected to expand in the United States, as companies secure funding through the production tax credit (PTC) system that is part of the IRA.

2.2.2 Resource and material availability trends

The global solar market has been affected by a wide array of supply chain issues, as well as macroeconomic and geopolitical factors. Manufacturing lines and product availability are at risk due to the impacts of the COVID-19 pandemic and elevated raw material prices. Increased raw material costs such as for polysilicon, PV glass, ethylene vinyl acetate (EVA), and aluminum, along with increased freight costs, contributed to higher module prices beginning in 2021 and 2022. Polysilicon prices initially increased due to limited production availability because of the COVID-19 pandemic, followed by high demand. The price of polysilicon increased over 200% between 2021 and 2022, but prices have since declined by 35%, as of June 2023. A large amount of new manufacturing capacity is slated to come on line in the next five years, and global production is expected to double by 2025. This increase in module supply and decrease in polysilicon price is expected to lead to decreasing module costs. Electrical and structural balance of system component costs are expected to continue rising as raw materials such as copper, aluminum, and steel remain high due to supply chain issues hampering availability.[11]

The COVID-19 pandemic also spurred an increase in global freight costs as a result of high demand, labor shortages, and a shortage of shipping containers. These factors caused shipping port congestion and shipment delays across the solar industry beginning in 2020 and continued to have lasting impacts on elevated freight prices through 2023.[12] PV module prices in the United States are particularly exposed to international freight cost fluctuations because most product is imported from countries in Southeast Asia such as Vietnam, Thailand, and Malaysia. Further, although steel foundations are likely to be procured domestically, other racking equipment is typically imported, and thereby exposed to high international freight costs and delays. Demand for U.S.-produced steel is expected to increase as developers try to meet the domestic content requirement to qualify for the 10% bonus investment tax credit (ITC) from the IRA for large, 1-MW-AC-plus systems. Although electrical and structural balance of system component costs are expected to continue increasing, the effect on total system cost will be offset by decreasing module costs.

2.2.3 Technology research and development trends

Successful R&D investments in the PV market have resulted in increased performance and lower manufacturing costs for PV systems over the last decade. Impactful production technology advancements to date for crystalline silicon (c-Si) cells include larger ingot and wafer sizes, the switch to PERC production, and improved cell metallization and cell interconnection approaches that reduce the derate factor in efficiency from cells to modules. Tunnel oxide passivated contract (TOPCon) cell architecture is the newest PV cell type to appear in commercial production. At the cell-level, TOPCon cells currently have a 0.5%–1.0% absolute efficiency gain over PERC cells and

[11] Wood Mackenzie, *US solar PV system pricing: H1 2023*, June 19, 2023.

[12] Lerh, Jeslyn, "Global port congestion, high shipping rates to last into 2023 - execs," Reuters (June 15, 2022).

use many of the same manufacturing steps and equipment.[13] Industry trends indicate most new commercial-scale systems will migrate to n-type TOPCon modules by the mid- to late 2020s as p--type PERC technology gets phased out.[14] Improving module efficiency remains a prominent route for reducing system capital costs and therefore remains a primary focus for R&D efforts.

Another route for achieving system cost reductions has historically been through improvements to system power electronics, such as increasing inverter efficiency. Continuing advancements in inverter efficiency improvements is seen as a key area to reduce systems costs in the future.[15]

2.2.4 Disposal and recycling costs

Expanded solar PV adoption in the United States has spurred environmental and resource concerns, including raw material requirements and plans for managing system components that reach end of life. To date, PV module recycling is the current focus of most research, investment, and policy related to end-of-life (EOL) management for photovoltaics.[16] Historically, recycling R&D has focused less on recovery of trace materials and more on recovery of bulk materials such as glass, aluminum, and silicon at EOL. With the rising cost of raw trace materials such as copper, better trace material recycling processes in c-Si PV recycling are increasingly needed. A circular economy approach to EOL PV management goes farther than recycling-only to retain the value of materials and products for as long as possible by recirculating recovered materials at all stages of the PV life cycle (that is, manufacturing, operation, and EOL).[17] Strategies beyond recycling, such as reducing material demands through dematerialized designs or recovery and reuse of manufacturing scrap materials, have been shown to retain a greater portion of the value of the original products and provide greater environmental and economic benefits.

According to NREL, recycling a solar panel in the United States can cost $15–$45, while disposing of a panel at the landfill costs only $1–$5. Based on NREL estimates, about 10% of solar PV panels are recycled in the United States, and very few have 100% of their material recovered. For context, driven by national policies that mandate PV module recycling, recycling costs in Europe are estimated to be as low as $0.70 per module, and recycling rates are as high as 95%.[18]

No federal law, regulation, or standardized testing process currently exists regarding solar panel reuse or disposal management in the United States. However, numerous states are discussing public policy to recycle and repurpose retired solar panels. As of 2022, California, Illinois, Maryland, New Jersey, North Carolina, and Washington State have either created commissions or implemented rules for the reuse and recycling of PV modules. In March 2022, DOE released a five-

[13] Woodhouse, Michael and David Feldman, *Research and Development Priorities to Advance Solar Photovoltaic Lifecycle Costs and Performance*, National Renewable Energy Laboratory (October 2021).
[14] Fischer, Anne, "Falling costs, 15 GW of US solar module production, TOPCon trends," *pv magazine* (January 26, 2023).
[15] Ibid
[16] Heath, Garvin and Dwarakanath Ravikumar, *Environmental and Circular Economy Implications of Solar Energy in a Decarbonized U.S. Grid*, National Renewable Energy Laboratory (February 2022).
[17] Heath, Garvi and Dwarak Ravikumar, *A Critical Review of the Circular Economy for Lithium-Ion Batteries and Photovoltaic Modules: Status, Challenges, and Opportunities*, National Renewable Energy Laboratory (June 30, 2022).
[18] Curtis, Taylor L. and Heather Buchanan, *A Circular Economy for Solar Photovoltaic System Materials: Drivers, Barriers, Enablers, and U.S. Policy Considerations*, National Renewable Energy Laboratory, revised April 2021.

year action plan to enable safe and cost-effective recycling of PV EOL materials and reduce the environmental impact of solar energy modules.[19]

2.2.5 Federal policies and market incentives

PV module supply issues in the United States are further compounded by policy uncertainty. Tariff uncertainty remains as the market awaits further updates on Section 301 tariffs, which affect PV modules and inverters imported from China.[20] Additionally, Section 201 tariffs have been extended through to February 2026, with a bifacial module exemption, which affects PV modules imported from China and Southeast Asia. In June 2021, the U.S. Customs and Border Protection agency (CBP) placed a Withhold Release Order (WRO) on imported items containing metallurgical-grade silicon from Hoshine Silicon Industry (Shanshan) Co., the world's largest manufacturer of metallurgical-grade silicon, which is based in the Xinjiang region of China. According to the CBP, this WRO was issued based on concerns of the use of forced labor in the manufacturing process for certain silica-based components.[21]

At the end of 2021, the Uyghur Forced Labor Prevention Act (UFLPA) was signed into law.[22] The purpose of the UFLPA is to prevent goods that were made with forced labor from entering the United States; any product made in the Xinjiang Uyghur Autonomous Region in China will be presumed to have been made with forced labor, and importers must provide proof to contrary to ensure release of goods. PV module shipments were being detained as a result of the multiple policies' enforcement. In addition to Sections 201 and 301 tariffs and supply chain complexities related to the UFLPA, the anti-dumping and countervailing duties (AD/CVD) currently in place for solar cells imported from China were proposed to be expanded to other countries in Southeast Asia.[23]

In late March 2022, the U.S. Department of Commerce (DOC) initiated an anti-circumvention investigation into Chinese solar cell and module companies in Malaysia, Vietnam, Thailand, and Cambodia. The DOC released its preliminary determination on the investigation in December 2022 and found four of the eight manufacturers investigated to be circumventing restrictions.[24] The potential tariff rate on these manufacturers may be as high as 255%, which is the current Chinese country-wide tariff.[25] The preliminary ruling provided some clarity on which manufacturers are deemed safe, which has helped alleviate some industry uncertainty that developers and their procurement teams were facing.

While imported PV modules are facing challenges, recent policy developments support an increase in domestic PV production across the supply chain. The IRA, which was signed into law in August 2022, includes tax credit incentives for the domestic manufacturing of PV system components.

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[19] U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, DOE Releases Action Plan For Photovoltaic Systems End-Of-Life Management, March 18, 2022.

[20] U.S. Trade Representative, Issue Areas, Section 301 Investigations, Section 301-China Technology Transfer, China Section 301-Tariff Actions and Exclusion Process, accessed January 24, 2024.

[21] U.S. Customs and Border Protection, Newsroom, National Media Release, "The Department of Homeland Security Issues Withhold Release Order on Silica-Based Products Made by Forced Labor in Xinjiang," Press Release (June 24, 2021).

[22] U.S. Customs and Border Protection, Trade, Forced Labor Uyghur Forced Labor Prevention Act, updated January 26, 2024.

[23] Sylvia, Tim, "US government to move forward with PV anti-circumvention investigation," *pv magazine* (March 29, 2022).

[24] U.S. Department of Commerce, News, Press Release, "Department of Commerce Issues Preliminary Determination of Circumvention Inquiries of Solar Cells and Modules Produced in China," Press Release (December 27, 2022).

[25] Wood Mackenzie, *US solar PV system pricing: H1 2023*, June 19, 2023.

Since the passing of the IRA, the federal ITC has been extended 10 years past its original expiration date. For systems beginning construction before January 1, 2025, the Bill sets the ITC for up to 30% of the cost of installed equipment for 10 years and then steps the credit down to 26% in 2033 and 22% in 2034. For projects beginning construction after 2019 that were placed in service before January 1, 2022, the ITC was set at 26%. In addition to the new federal ITC schedule for generating facilities (that is, systems), the updated ITC includes credits for standalone energy storage with a capacity of at least 3 kWh for residential customers and 5 kWh for non-residential customers. The bill also includes a five-year Modified Accelerated Cost Recovery System (MACRS) depreciation schedule for non-residential energy storage.

Balance of system, engineering, and labor costs continue to rise as inflation increases wages and the cost of production. The IRA also has prevailing wage and apprenticeship requirements that could further push costs upwards.

Incentives for solar PV include, but are not limited to:

- Federal and state tax incentives
- State and/or utility rebates
- Avoided cost of kWh not purchased from utility
- kWh sold back to the grid (net metering or net billing export credits)

Residential solar PV has the highest level of awareness among customers among all DER offerings (for example, demand response programs, electric vehicles, customer-sited generation, and battery storage) and is consistently high among all demographics. Early adopters of solar PV were motivated primarily by the desire to support clean energy technology applications. With solar PV costs declining and state, local, and/or utility incentives continuing, customers were motivated not only by supporting clean energy but also by a favorable economic environment to purchase solar. In a recent survey of homeowners with solar PV systems, more than 80% received an incentive (that is, rebate and/or net metering export credits) for their solar project.[26] With traditional net metering DER compensation schemes, utility customers receive export credits for excess generation at the same dollar-per-kWh rate that they would have otherwise paid to purchase electricity from the grid.

Retail tariff structures such as time-of-use, tiered tariffs, and rates that include high demand charges generally increase the value of solar + storage configurations compared with PV-Only configurations, while other factors such as load profiles and DER compensation mechanisms can minimize the impact of such tariffs on the customer economics of solar + storage systems. The following attributes for load profiles can have a favorable effect on customer economics for solar + storage systems:

- Coincident peak demand with high solar irradiation
- Short duration peak demand that is not coincident with solar
- The ability to maintain a firm power supply throughout a 24-hour period

Net billing is a second-generation DER compensation mechanism that incentivizes solar + storage co-adoption, as customers can lower their electricity bills by charging their batteries with excess PV generation and dispatching their batteries to meet on-site load during times of day when retail energy prices are high. From the sole perspective of utility bill savings, solar + storage systems may not be a cost-effective option for many customers. Customers who seek the resiliency and reliability of

[26] Smart Energy Consumer Collaborative, *Distributed Energy Resources: Meeting Consumer Needs*, December 11, 2019.

backup power show more of a willingness to pay for this product, especially if they reside in areas that are prone to outages and severe weather events.

2.2.6 Relationship to other DG technologies

Although solar PV benefits from being a familiar option to customers as a method of procuring clean energy under favorable economic conditions, customers don't necessarily perceive the same degree of benefits to battery storage adoption. Adoption of battery storage systems by customers is largely dependent on the value the customer places on accessing reliable backup power. So, battery storage adoption is more closely linked to the customer's perception and quantification of resiliency needs, and solar is more closely linked to a customer's desire to achieve energy savings or access clean energy.

Storage adoption can be motivated by severe weather events leading to outages or other dangerous scenarios. Natural disasters such as hurricanes, floods, wildfires, and other events can leave marked impressions on the customer's psyche and will influence how the customer prioritizes resilience and backup power for everyday needs or medical needs.[27,28,29] The ability of a battery storage system to provide backup power in the event of an outage or other emergency is an important attribute that sets these systems apart from the broad category of DERs. Most utilities adhere to safety and interconnection rules that prevent customers with solar-only (that is, not solar + storage) from using solar PV electricity during an outage event. Incorporating battery storage along with solar PV enables customers to use their electricity generated in response to different events such as weather or billing tariffs. Solar + storage is unique in that it empowers customers to bolster their resiliency at their home or business while also reducing greenhouse gas emissions by generating and storing clean power.

The potential value of a battery storage system that a customer can obtain is dependent on available programs and pricing structures. Peak shaving and dispatching a battery storage system in response to pricing or outage events on the grid will be influenced by the dispatching incentives, peak pricing, and other factors determined by the grid energy provider.[30]

The Smart Energy Consumer Collaborative (SECC) survey found that among residential utility customers with solar PV systems, adoption of plug-in electric vehicles, home energy management systems, battery storage, and small wind turbines is more common.[31]

2.3 Solar PV summary and conclusions

Overall, solar PV throughout the residential and commercial sectors has experienced growth in recent years as customers continue to adopt the technology due to lower system costs, energy bill savings, environmental benefits, and resilience or reliability especially when combined with energy storage. Although system costs have been decreasing due to improved module efficiencies and other component improvement factors, recent supply chain issues, labor shortages, and other tariff

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[27] Stevens, Pippa, "Extreme weather events are pushing consumers to solar and residential storage," CNBC (August 25, 2021).

[28] Swim, Janet and Susan Clayton, *Psychology and Global Climate Change: Addressing a Multi-faceted Phenomenon and Set of Challenges*, American Psychological Association, accessed November 14, 2023.

[29] Chavez, Maria, "Energy Storage Can Help People With Disabilities Through Extreme Weather Events," *Clean Technica*, accessed April 12, 2023.

[30] Prasanna, Ashreeta and Kevin McCabe, *Storage Futures Study: Distributed Solar and Storage Outlook: Methodology and Scenarios*, National Renewable Energy Laboratory, 2021.

[31] Smart Energy Consumer Collaborative, *2023 State of the Consumer Report and Webinar*, March 22, 2023.

and geopolitical factors have limited overall cost reductions for both the residential and commercial sectors. Cost reductions are expected to continue in the coming years as component markets stabilize, component efficiencies continue to improve, customers and developers take advantage of federal and state incentives, and developers achieve economies of scale through alternative sales strategies. Additionally, capacities of both residential and commercial systems are expected to increase similar to recent years to amortize costs more efficiently and to take advantage of evolving site space and energy end-use factors.

3 BATTERY STORAGE

3.1 Battery storage technology attributes and cost data

3.1.1 Overview

Battery systems typically consist of a number of batteries wired in series and parallel combinations to achieve the desired ampere-hour capacity and voltage rating. When paired with a solar PV system, battery systems store any excess power produced from the array during the day. The stored energy can later be used to meet evening demand. In addition to storing energy, batteries provide several other important energy services for solar PV systems, including the ability to provide surges of current that are much higher than the instantaneous current available from the array.

The following subsections provide an overview of battery storage performance attributes and cost data for representative residential and commercial systems, as well as highlight key factors influencing future pricing, adoption, and technology deployment trends. This section also highlights storage systems paired with solar PV in both the residential and commercial segments. Although the solar PV section identifies specific configurations, this section provides more detail on the configuration assumptions as well as detailed performance and cost data for solar + storage systems.

3.1.2 Technology attributes and cost estimation methodology: Battery storage

DNV developed technology attributes and cost data for BTM battery storage systems and battery storage systems combined with solar PV systems, aligned with relevant residential and commercial customer segments. These attributes and cost data are also aligned with solar PV system capacities determined in Section 2.1.2 based on representative installed systems. DNV first developed state and U.S. average representative system capacities for residential and commercial battery storage and solar + storage using a variety of internal and public data sources. DNV then modeled annual hourly generation profiles for each standalone battery storage system and solar + storage configuration to gather detailed operational data and assembled additional relevant performance data for all system configurations. The final step was to develop 2022 constant (real) dollar cost estimates from available data and align associated cost estimates and attributes with previous years of EIA sector-level surveys: RECS, CBECS, and MECS. The process is described in the following subsections.

3.1.3 System configurations

DNV first collected recent BTM battery storage and solar PV installation data from LBNL's TTS database through 2022 and segmented the data to identify statistically significant representative residential and commercial system sizes for each relevant year in the analysis period (2015–2022 for residential and 2012–2022 for commercial) for each state contained in the database. Although most of the priority states for solar + storage deployment are represented in this database, notable exceptions include Georgia, Kansas, Missouri, Montana, Oklahoma, and South Carolina. DNV identified representative sizes for all configurations including standalone solar PV, solar + storage (new), solar + storage (retrofit), and standalone battery storage. The solar + storage (new) configuration is used to represent new combined solar + storage installations, whereas the solar + storage (retrofit) configuration is used to represent storage systems installed on existing solar PV systems. Cost data for the solar + storage (retrofit) configuration is only provided for the storage component, as it is unknown what year the existing solar PV systems were installed in. Additionally, this retrofit configuration was only applied to residential systems.

DNV then used its project trackers and databases for smaller, distributed systems to confirm capacities and extrapolate to similar states based on relevant technical factors and its subject matter expertise. DNV also cross-referenced this data with EIA's Form EIA-861 data, which contains data on distributed storage and solar PV capacity in specific utility territories. These processes were also used to identify representative system capacities for states not contained within the TTS data. This process allowed DNV to identify residential representative system sizes for 2022 for each state, with an average U.S. system capacity of 6.9 kW-DC for standalone storage systems, 5 kW-DC for new storage systems paired with solar PV, and 4.5 kW-DC for retrofit storage systems. Similarly, the representative commercial system capacity was determined to be 50 kW-DC for standalone storage systems and 20 kW-DC for new solar + storage systems across all commercial installations.

DNV also developed representative battery storage system capacities aligned with each of the roof-mounted commercial solar PV capacities previously defined in the Solar PV section. These capacities were also used as the representative sizes for commercial standalone storage configurations. As discussed in the previous section, these capacities are aligned with system capacity bins in Wood Mackenzie's *U.S. Solar PV System Pricing* report.[32] These capacities were also compared with TTS installation data and DNV proprietary project databases to confirm that they represent the range in the current commercial installation market and potential future growth opportunities.

Table 3-1 highlights configurations and system capacities for solar + storage or standalone storage systems. Standalone solar PV configurations are also repeated for certain market segments for comparison purposes.

Table 3-1. Technology attributes for battery storage configurations and representative systems

Market Sector	Configuration	Representative Solar PV System Capacity	Representative Battery Storage System Capacity
Residential (Small)	Solar PV (standalone)	7.1 kW-DC	N/A
	Solar + storage (new)	7.9 kW-DC	5 kW-DC, 12.5 kWh-DC
	Solar + storage (retrofit)	6.9 kW-DC	4.5 kW-DC, 10 kWh-DC
	Storage (standalone)	N/A	6.9 kW-DC, 13.5 kWh-DC
Commercial (Small 1)	Solar PV (standalone)	28.5 kW-DC	N/A
	Solar + storage (new)	28.5 kW-DC	20 kW-DC, 40 kWh-DC
	Storage (standalone)	N/A	N/A
Commercial (Small 2)	Solar PV (standalone)	100 kW-DC	N/A
	Solar + storage (new)	100 kW-DC	60 kW-DC, 120 kWh-DC
	Storage (standalone)	N/A	60 kW-DC, 120 kWh-DC
Commercial (Medium)	Solar PV (standalone)	250 kW-DC	N/A
	Solar + storage (new)	250 kW-DC	150 kW-DC, 300 kWh-DC
	Storage (standalone)	N/A	150 kW-DC, 300 kWh-DC
Commercial	Solar PV (standalone)	500 kW-DC	N/A

[32] Wood Mackenzie, *US solar PV system pricing: H2 2022*, November 21, 2022.

Market Sector	Configuration	Representative Solar PV System Capacity	Representative Battery Storage System Capacity
(Large 1)	Solar + storage (new)	500 kW-DC	300 kW-DC, 600 kWh-DC
	Storage (standalone)	N/A	300 kW-DC, 600 kWh-DC

AC-coupled installations use both a grid-tied inverter for the solar PV system and an inverter for the battery, allowing both systems to be dispatched independently. Multi-inverter AC-coupled systems are commonly used for grid-connected installations and make it technically easier to add battery systems to existing solar PV systems (retrofit configuration). DC-coupled systems share an inverter and grid interconnection point, resulting in decreased installation costs and higher efficiency when compared with AC-coupled systems. However, AC-coupled systems are the most popular solar + storage configuration historically and currently for the representative systems in this analysis due to their flexibility and versatility of installation and their ability to provide enhanced resilience given the system redundancy.

3.1.4 Technology attributes and generation shapes

DNV assumed a fully integrated BESS product for the residential and commercial sectors, which includes a battery pack, a bidirectional inverter, wiring, disconnect, and casing provided by a residential and commercial battery energy storage manufacturer with high market penetration such as Enphase, Sonnen, or Tesla. DNV modeled the costs for each component separately, and performance attributes and cost data for these installed systems were then used as comparison metrics for fully integrated systems at both the national and state level.

Battery degradation was modeled using DNV’s Battery AI, a data-driven battery analytics tool that predicts short-term and long-term useable energy capacity degradation under different usage conditions. In this analysis, Battery AI modeled several current-generation, commercially available nickel manganese cobalt (NMC) cells to predict expected degradation performance of generic cells. Both cycling and calendar effects were considered in the degradation assessment. The analysis assumed the battery cell temperature will be controlled to be around 25°C for most of the time, using proper thermal management. DNV notes that temperature, both hot and cold, plays a key role in battery degradation. Continuous operation under extreme low or high temperatures will accelerate degradation in battery state of health.

DNV used its proprietary solar + storage operational modeling tool, Lightsaber, to model battery dispatch. Battery dispatch strategy dictates the flow of energy between the solar PV system, battery, and the grid. The dispatch model is capable of modeling dispatch strategies such as peak shaving, energy arbitrage, and manual dispatch. Self-consumption was modeled for all sectors’ BESS control strategy, which utilizes the battery by charging only from excess solar PV generation and discharging only if solar PV production falls below load. For the residential sector, the dispatch model used energy arbitrage to reduce time-of-use charges. For the commercial sector, the dispatch model used energy arbitrage to reduce demand charges and time-of-use charges, where applicable. This approach facilitated the development of hourly generation profiles for all storage configurations, which resulted in additional performance metrics. The following performance metrics were collected for each system in each state using a representative location in each year within the analysis timeframe.

3.1.5 System performance attributes

Table 3-2 details performance attributes for representative U.S. average residential storage and solar + storage systems summarized from the data developed in the previous subsections. The data are presented to align with previous years of EIA sector-level surveys for each customer sector starting with the residential sector from 2015 to 2022. Although single-family residential storage and solar + storage installations are typically smaller than most commercial installations, many performance and operational similarities exist between residential and smaller commercial systems.

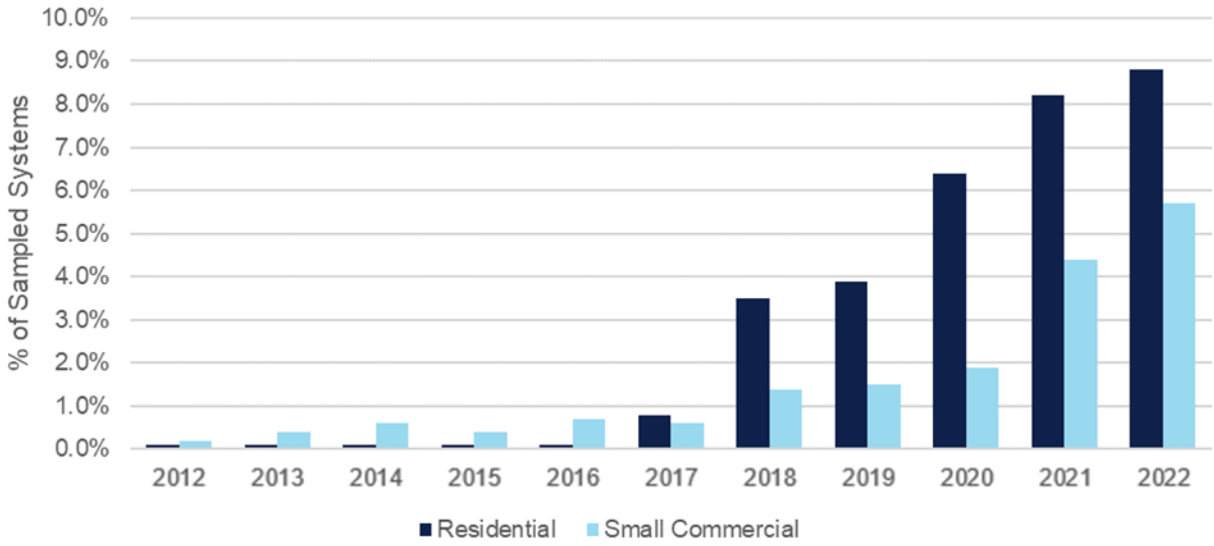
Table 3-2. Residential battery storage system performance attributes

Year	Standalone Storage Rep. System Capacity	Solar + storage Rep. System Capacity	Round-Trip Efficiency [a]	BESS Inverter Efficiency	AC Line Losses [b]	Cycles/ Year	EUL [c]
2015	5.9 kW-DC	4.6 kW-DC	86.0%	96.0%	0.5%	365	15 years
2016	6.0 kW-DC	4.7 kW-DC	86.0%	96.0%	0.5%	365	15 years
2017	6.2 kW-DC	4.7 kW-DC	86.0%	96.5%	0.5%	365	15 years
2018	6.4 kW-DC	4.9 kW-DC	87.0%	96.5%	0.5%	365	15 years
2019	6.4 kW-DC	4.9 kW-DC	87.0%	97.0%	0.5%	365	15 years
2020	6.7 kW-DC	4.9 kW-DC	87.0%	97.0%	0.5%	365	15 years
2021	6.8 kW-DC	5.0 kW-DC	88.0%	97.5%	0.5%	365	15 years
2022	6.9 kW-DC	5.0 kW-DC	88.0%	97.5%	0.5%	365	15 years

[a] Round-trip efficiency is the ratio of total energy input from the grid to total energy output by the system.
[b] AC line losses (percentage, %) are included to show the average losses from the delivery of grid power to the on-site storage system. Battery cycling assumes that the average residential system will cycle once per day to minimize grid power consumption or shift energy to lower cost time-of-use (TOU) periods.
[c] EUL=estimated useful life.

Although historical and 2022 storage system capacities are presented separately, performance attributes and costs detailed in the next subsections were modeled using similar system configurations. Overall, representative standalone storage system sizes have increased moderately over the last seven years, but standalone residential storage installations have had very little penetration throughout the United States. Solar + storage system installations in the United States have significantly increased in recent years for both residential and small commercial sectors. Although individual state differences are present, Figure 3-1 shows the increasing penetration of solar + storage systems at the national level within the last 10 years.

Figure 3-1. Percentage of solar PV systems with battery storage by segment (2012–2022)



Data source: LBNL, Tracking the Sun

Storage performance attributes for small commercial standalone storage and solar + storage configurations are presented in Table 3-3. As for residential configurations, although historical and current storage system capacities are presented separately, performance attributes and costs detailed in the next subsections were modeled using the same systems for all configurations. Additionally, DNV assumed the same historical performance attributes shown in Table 3-3 for the larger commercial solar + storage and standalone storage systems and assumed the same historical representative system capacities.

Table 3-3. Small commercial battery storage system performance attributes

Year	Solar + Storage Rep. System Capacity	Round-Trip Efficiency [a]	BESS Inverter Efficiency	AC Line Losses [b]	Cycles/ Year	EUL [c]
2012	19.9 kW-DC	85.0%	95.0%	0.5%	365	15 years
2013	22.0 kW-DC	86.0%	95.0%	0.5%	365	15 years
2014	20.4 kW-DC	86.0%	96.0%	0.5%	365	15 years
2015	19.3 kW-DC	87.0%	96.0%	0.5%	365	15 years
2016	19.5 kW-DC	87.0%	96.0%	0.5%	365	15 years
2017	22.8 kW-DC	87.0%	96.5%	0.5%	365	15 years
2018	23.1 kW-DC	88.0%	96.5%	0.5%	365	15 years
2019	22.5 kW-DC	88.0%	97.0%	0.5%	365	15 years
2020	21.4 kW-DC	89.0%	97.0%	0.5%	365	15 years
2021	19.2 kW-DC	90.0%	97.5%	0.5%	365	15 years
2022	20.0 kW-DC	90.0%	97.5%	0.5%	365	15 years

[a] Round-trip efficiency is the ratio of total energy input from the grid to total energy output by the system.
[b] AC line losses (percentage, %) are included to show the average losses from the delivery of grid power to the on-site storage system. Battery cycling assumes that the average residential system will cycle once per day to minimize grid power consumption or shift energy to lower cost time-of-use (TOU) periods.
[c] EUL=estimated useful life.

Median capacities for representative commercial standalone storage systems within solar + storage configurations have fluctuated over the last 10 years due to a variety of factors, even in smaller commercial installations. The solar + storage median capacities follow a similar trend to standalone solar PV systems. However, performance attributes generally do not change when moving from the smallest representative capacity (less than 20 kW-DC) to the 100 kW-DC system or even to the larger (more than 100 kW-DC) roof-mounted systems. The capacity factor slightly rises when the system capacity rises.

3.1.6 2022 cost data

Capital cost data for battery storage systems were collected for each system configuration for 2020–2022 using NREL's Annual Technology Baseline (ATB) reports and data files and were further segmented to individual states using state-level labor rates, sales tax rates, and developer overhead and margin rates.[33] DNV verified and provided slight cost adjustments where appropriate to align with representative system capacity assumptions based on DNV databases and reported individual project experiences for 2022. The battery storage cost categories and associated assumptions are detailed further in Table 3-4 for residential and commercial sectors.

Table 3-4. Battery storage cost categories and assumptions for residential and commercial systems

Cost Category	Residential	Commercial
Battery pack	▪ Lithium-ion ▪ Applied residential battery supply premium	▪ Lithium-ion ▪ Applied commercial battery supply premium
Battery inverter	Standard battery central inverter price	
Battery cabinet	N/A	Battery packs and containers, thermal management system, and fire suppression system
BOS	Meter, communications device, AC panel & DC disconnect, charge controller, breaker box, and all conduit, wiring, and cabling	▪ SBOS [a]: Foundation, inverter house ▪ EBOS [b]: Conduit, wiring, cabling, energy management system, switchgear, transformer, and container monitoring and controls systems
Supply chain	State-level percentages applied to battery module/pack, battery inverter, and BOS costs	
Sales tax	Blended sales tax for U.S. average, individual state sales tax	
Labor & installation	Includes blended non-unionized labor rates for U.S. average costs, individual non-unionized labor rates by state	▪ Includes blended non-unionized labor rates for U.S. average costs, individual non-unionized labor rates by state ▪ Also includes required rental equipment costs (RS Means)
Engineering	Includes flat engineering design fees	N/A
Permitting, interconnection, and inspection (PII)	Solar and building permit inspection, and residential interconnection	Construction permit, interconnection study, inspection, and fees
Sales & marketing	General sales costs	N/A
Overhead	Includes general project expenses not included in Permitting, Interconnection, and Inspection	▪ EPC overhead included as percentage of equipment costs (inventory, shipping, etc.) ▪ Developer overhead includes payroll, facilities, administration, finance, etc.

[33] Ramasamy, Vignesh and Jarett Zuboy, *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2022*, National Renewable Energy Laboratory, September 2022.

Cost Category	Residential	Commercial
Profit	Fixed rate applied to battery, inverter, BOS, labor, supply chain, and sales tax	▪ Contingency included as markup applied to battery, inverter, BOS, labor, sales tax, and EPC overhead ▪ Fixed rate applied to all costs

[a] SBOS=structural balance of system.
[b] EBOS=electrical balance of system; EPC= engineering, procurement, and construction.

To estimate capital costs for solar + storage systems, DNV applied cost reduction factors for seven of the combined solar + storage cost categories based on DNV project experience and NREL's ATB reports and data files. Different cost reduction factors were applied to both new solar + storage systems and retrofit storage systems added onto existing solar PV systems. These reduction factors were applied due to the cost efficiency improvements achieved when battery and solar PV installations are combined. Capital cost categories assumed to have cost efficiencies for combined systems include electrical and structural balance of system, installation labor, design and engineering, permitting, interconnection, inspection, customer acquisition, supply chain and logistics, and overhead and profit. The associated cost reduction factors are shown in Table 3-5.

Table 3-5. Cost reduction factors for solar + storage systems

Combined Cost Category (Solar PV & Battery Storage)	Residential Solar + Storage (New)	Residential Solar + Storage (Retrofit)	Commercial Solar + Storage (New)
Balance of system	90%	95%	90%
Installation labor	90%	95%	90%
Design and engineering	95%	95%	90%
Permitting, Interconnection, and Inspection	50%	50%	70%
Customer acquisition	50%	50%	90%
Supply chain and logistics	75%	90%	90%
Overhead and profit	80%	80%	90%

3.1.7 Historical cost data

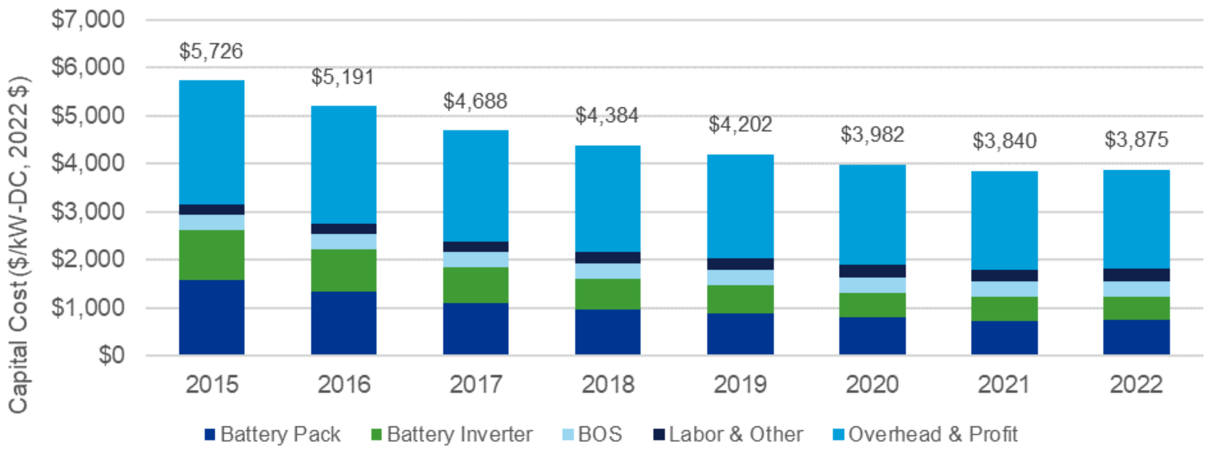
Baseline historical capital cost data were collected from NREL annual cost benchmark reports,[34] including NREL's ATB reports and national-level data files. DNV then disaggregated state-level data for specific cost categories to produce state-level cost estimates for each year in the analysis period. DNV used historic labor costs, sales tax, and calculated supply chain costs to produce state-level estimates. Like current year cost estimates, these cost categories were also used to estimate overhead and margin costs that provided additional state-level disaggregation. Additionally, historical storage system equipment costs were included when available and scaled to 2022 constant (real) dollar values based on annual chain-type price indexes for electrical equipment and associated components available in EIA's *Annual Energy Outlook*. These historical costs were combined with current cost data detailed in the previous subsection.

Residential standalone storage system costs, shown in Figure 3-2, are based on limited historical installation data due to limited use cases on single-family homes. However, increased penetration is occurring in certain markets and could continue given the development of certain incentives or

[34] Ramasamy, Vignesh and Jarett Zuboy, *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2022*, National Renewable Energy Laboratory, September 2022.

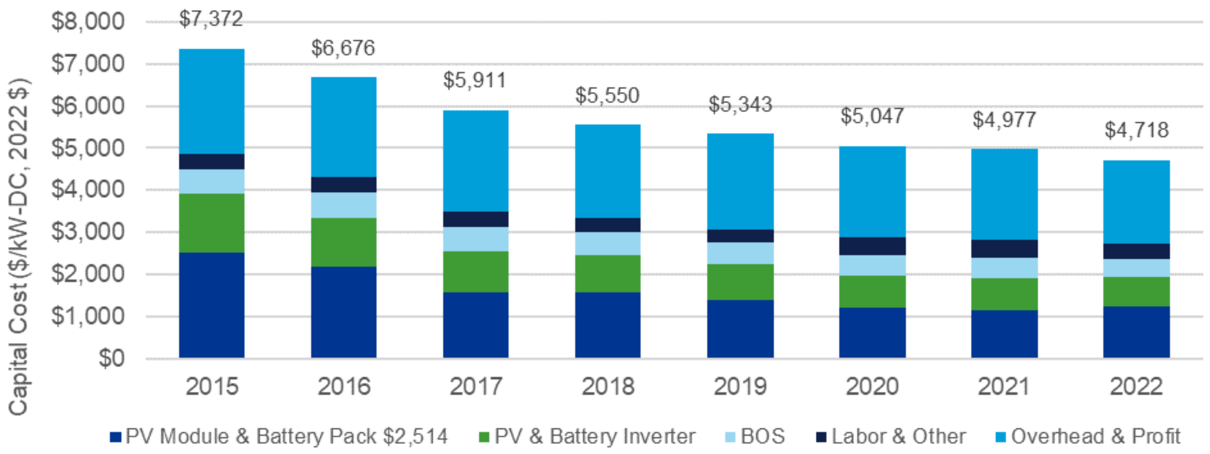
attractive market opportunities that provide additional benefits. For example, to provide resiliency in the event of Public Safety Power Shutoffs (PSPS) in California, some residential customers are exploring the benefits of standalone storage to protect themselves from short and planned grid disruptions. Certain locational constraints (for example, shading, homeowner association restrictions) may limit the ability to install rooftop solar, so standalone battery storage may also be an attractive alternative given the IRA tax credit expansions for standalone storage systems. Similarly, while residential solar + storage systems have experienced limited historical penetration, significant market interest exists given cost declines coupled with additional opportunities for value stacking in recent years.

Figure 3-2. U.S. average residential standalone storage system capital costs ($/kW-DC, 2022 $)



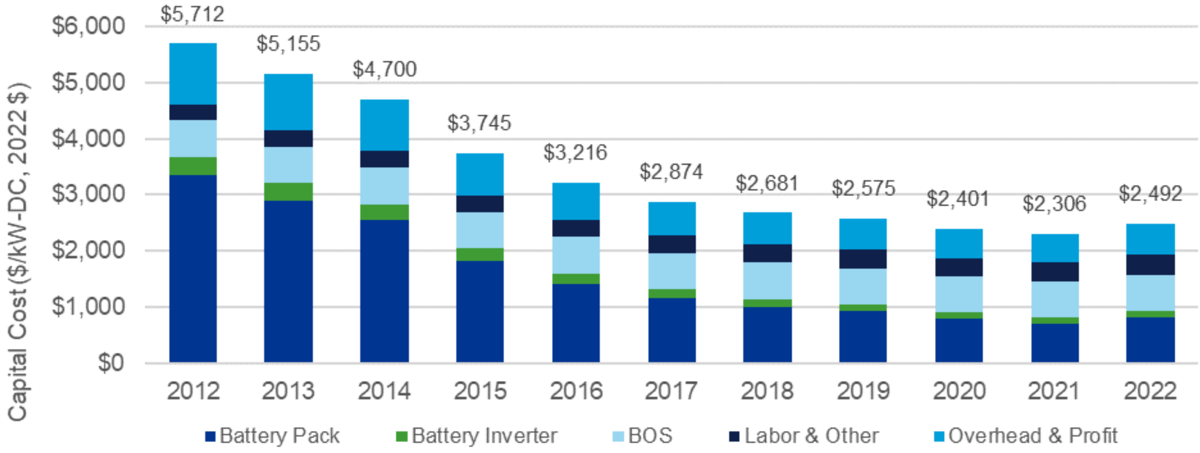
As shown in Figure 3-3 for the residential sector, solar + storage systems are experiencing installation cost reductions in the labor, hardware, permitting, customer acquisition, and overhead and profit categories. Depending on storage duration and total energy capacity, capital cost reductions in the past seven years range between 10% and 25%.

Figure 3-3. U.S. average residential solar + storage system capital costs ($/kW-DC, 2022 $)



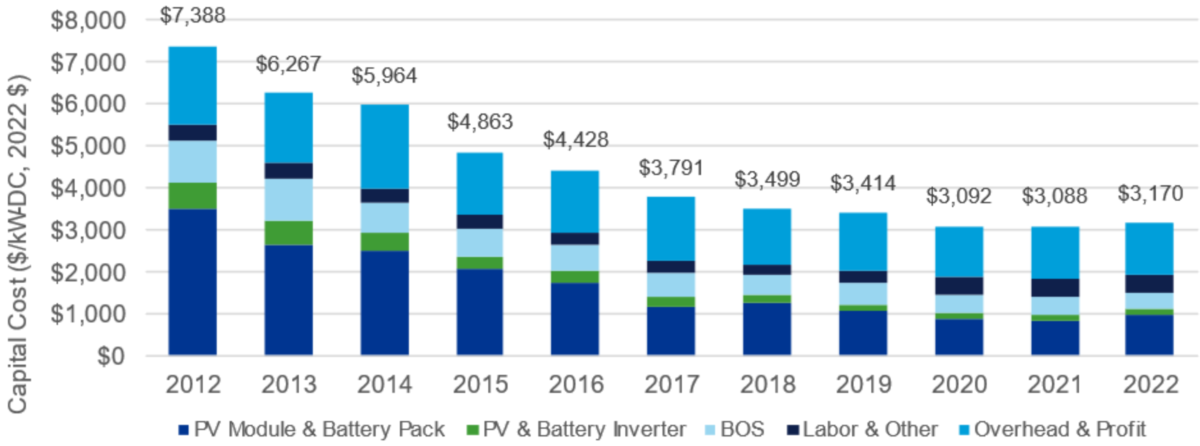
Commercial storage systems have also realized cost reductions over the past 10 years. However, battery pack and cabinet costs increased in 2022, contributing to an average installed cost of $2,492/kW-DC for a medium, 150 kW, 300 kWh system (Figure 3-4).

Figure 3-4. U.S. average commercial standalone storage system (medium, 150 kW-DC, 300 kWh) capital costs ($/kW-DC, 2022 $)



Commercial solar + storage systems also see significant cost reductions when co-locating the solar PV and storage systems (Figure 3-5). Larger cost reductions are realized in overall site preparation, the sharing of hardware, installation labor, and general overhead and profit for solar + storage systems. Capital costs have decreased roughly 50% for solar + storage systems in the commercial sector over the past 10 years.

Figure 3-5. U.S. average commercial solar (250 kW-DC) + storage system (150 kW-DC, 300 kWh battery storage) capital costs ($/kW-DC, 2022 $)

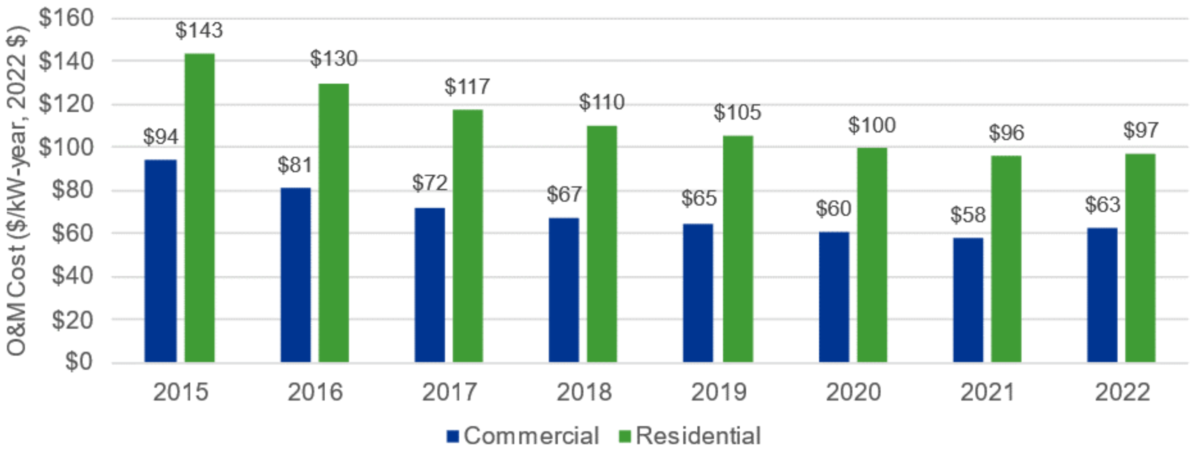


3.1.8 O&M cost data

DNV compiled fixed O&M costs ($/kW-DC) for all storage systems and configurations included in this study. O&M costs for battery storage systems include costs required for normal operation as specified by the manufacturer that adhere to the system design and specified use cases throughout the useful life of the system. Fixed O&M costs are all required costs that are not determined by the systems use case. Variable O&M costs are typically not included and are not a factor in this assessment due to the simplified on-site use cases assessed for the commercial and residential sectors. Battery storage systems typically have O&M costs under $100/kW-DC due to the limited maintenance from less mechanical components and moving parts compared with CHP and wind energy systems. Commercial sector fixed O&M costs include assumed annual component replacements or system augmentation (adding battery modules and/or packs) due to system degradation to return the system to its nameplate capacity. DNV also assumed O&M cost reduction factors similar to capital cost efficiencies for solar + storage configurations.

Compared with solar PV O&M cost categories, battery storage cost categories were simplified for both standalone and solar + storage configurations. DNV compiled annual fixed O&M cost data for current and historical years using NREL annual cost benchmark reports and NREL's ATB reports, and then it scaled this data to real dollar values for additional data years based on blended historical hourly labor rates associated with energy storage O&M activities.[35] Figure 3-6 shows historical O&M cost data by customer sector for battery storage systems.

Figure 3-6. U.S. average battery storage historical O&M cost data ($/kW-yr-DC, 2022 $) by customer sector



Average battery storage system O&M costs typically include asset management and security, periodic parts replacement and cleaning, inverter replacement, general system inspection, and insurance, and these costs have generally decreased over time in both the residential and commercial sectors. Commercial O&M costs have decreased at a faster rate due to cost efficiencies achieved in system maintenance and monitoring over time. Residential O&M costs are typically limited to homeowner discretion and have experienced little change in real dollar value over the past five years.

3.2 Battery storage market discussion

3.2.1 Resource and material availability trends

Batteries consist of three major components: cathode, anode, and electrolyte. These three components make up approximately 60% of a battery's raw material costs. These components together make up the battery cell and can contain critical minerals, which are vulnerable to supply chain disruptions and price fluctuations. The battery cells are put together into a module and then into a container that can be made of metal, usually aluminum or steel, and lastly into a pack that can have a plastic, composite, or metal outer casing. The increased use of batteries, specifically lithium-ion batteries, across industries, such as in consumer electronics, transportation, and energy storage, has led to increased demand for critical and rare minerals needed to produce batteries.

[35] Ramasamy, Vignesh and Jarett Zuboy, U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2022, National Renewable Energy Laboratory, September 2022.

As with other manufacturing sectors, the production of batteries has been affected by supply chain issues due to the COVID-19 pandemic, as well as macroeconomic and geopolitical issues. For instance, battery prices for electric vehicles (EVs) increased in 2022 due to a rise in raw material prices, increase in component prices, inflation, and supply chain constraints. The annual Bloomberg New Energy Finance (BNEF) Battery Price Survey for 2022 found that battery pack prices for EVs had increased by 7% year-on-year in 2022 to $151/kWh, after seeing a continual decline in price since 2010.[36] As a result, carmakers will tend to use lower-cost battery chemistries, such as lithium iron phosphate (LFP) batteries, which contain neither cobalt nor nickel or other battery chemistries that contain lower levels of cobalt. According to the Institute for Energy Research, battery costs make up around 30% to 40% of the total EV cost, and carmakers are looking to reduce this cost to make EVs profitable.[37] In response, battery makers are focusing on developing new, lower-cost battery chemistries and new battery architectures.

The U.S. Geological Survey defines a critical mineral as a non-fuel mineral that is essential to economic or national security and may be vulnerable to supply chain disruptions. Critical minerals include aluminum, cobalt, graphite, lithium, manganese, nickel, and vanadium.[38] Of these, cobalt, lithium, nickel, and vanadium are especially critical to U.S. battery production because these minerals are primarily imported.[39,40,41,42] A battery may contain these critical minerals, however, the actual amounts of these minerals used depends on the type of battery and battery chemistry. The cathode currently makes up the largest part of the battery cost because it contains many critical and rare minerals. The anode is currently made of graphite or sometimes silicon, which are considered critical minerals. Adding to the supply chain risk is that reserves of some of these critical minerals are concentrated in a handful of countries. For example, about 50% of the world's cobalt reserves are in the Democratic Republic of Congo (DRC), and Chile holds the world's largest reserve of lithium.[43,44] Additionally, some of these critical minerals are imported from Russia, and these imports have been curtailed since Russia's full-scale invasion of Ukraine in 2022. The geographical concentration of these critical minerals coupled with ongoing geopolitical issues will continue to affect the availability and price of these raw materials for battery production.

The current production makeup of the battery industry is dominated by non-U.S. entities. According to BNEF, in 2022, 806 gigawatthours (GWh) of batteries were produced globally, of which 74% were produced in China, 16% in Europe, 7% in the United States, 2% in South Korea, and 1% in Japan.[45] The major companies that produce batteries are also non-U.S. companies, with the leading companies headquartered in Asia. The top five battery-producing companies in 2022 were CATL

[36] Bloomberg New Energy Finance, "Lithium-ion Battery Pack Prices Rise for the First Time to an Average of $151/kWh," December 6, 2022.
[37] Institute for Energy Research, Commentary, Electric Vehicle Battery Costs Soar, April 25, 2022.
[38] U.S. Geological Survey, National News Release, U.S. Geological Survey Releases 2022 List of Critical Minerals, Press Release (February 22, 2022).
[39] U.S. Geological Survey, *Cobalt*, 2023.
[40] U.S. Geological Survey, *Lithium*, 2023.
[41] U.S. Geological Survey, *Nickel*, 2023.
[42] U.S. Geological Survey, *Vanadium*, 2023.
[43] White House, FACT SHEET: Biden-Harris Administration Announces Supply Chain Disruptions Task Force to Address Short-Term Supply Chain Discontinuities, June 8, 2021.
[44] Office of the United States Trade Representative, Policy Offices, Press Office, Fact Sheets, 2023, March, FACT SHEET: USTR Releases 2023 Trade Policy Agenda and 2022 Annual Report.
[45] Bloomberg New Energy Finance, Research, Commodities, Race to net zero: Pressures of the battery boom in five charts, July 15, 2022.

(China), BYD (China), LG Chem (South Korea), Panasonic (Japan), and Samsung SDI (South Korea).[46]

In response, the government is trying to spur domestic production of batteries and establish a domestic supply chain. Under the American Battery Innovation Act, DOE issued the *National Blueprint for Lithium Batteries* to assist in developing a domestic lithium-ion battery manufacturing supply chain, from mineral mining to production to recycling, with the Bipartisan Infrastructure Law providing $2.8 billion in grants.[47,48,49] NREL manages the NAATBatt Lithium-Ion Battery Supply Chain Database, which lists North American companies that are active in the lithium-ion supply chain. As of June 2023, 446 companies with 509 facilities are listed in the database.[50] Multilateral efforts to coordinate and cooperate in the supply of critical minerals are also taking place. In August 2023, Australia, Canada, and the United States announced that they would cooperate on sharing technical data related to critical minerals.[51] Argonne National Laboratory estimates that EV battery manufacturing capacity in the United States will increase by almost 20-fold between 2021 and 2030.[52] EV battery manufacturing capacity is interconnected with battery production capacity for energy storage and other uses, as some of this production capacity may be dedicated to non-EV use batteries.[53]

3.2.2 Federal policies

The supply chain disruptions caused by the COVID-19 pandemic, geopolitical events, and trade issues with major U.S. trading partners such as China and Russia have highlighted the need to develop a domestic battery supply chain. Most of the critical minerals needed for the manufacturing of batteries are imported, and leading battery manufacturers are currently headquartered in Asia. All these factors affect battery cost and reliability of supply. The government has begun addressing some of these issues, starting with the Infrastructure Investment and Jobs Act in 2021 and followed by the IRA and CHIPS and Science Act in 2022. These acts combined will provide more than $135 billion to build a battery supply chain, from critical minerals sourcing and processing to manufacturing.[54] Additionally, in October 2022, the American Battery Material Initiative was launched to help develop an end-to-end battery supply chain.[55] As of August 2023, over $55 billion

[46] Irwin, John, "EV growth puts battery suppliers into auto industry's top ranks," *Automotive News* (June 25, 2023).

[47] The White House, FACT SHEET: Biden-Harris Administration Driving U.S. Battery Manufacturing and Good-Paying Jobs, October 19, 2022.

[48] U.S. Department of Energy, Vehicle Technologies Office, National Blueprint for Lithium Batteries, June 7, 2021.

[49] U.S. Department of Energy, "Biden Administration, DOE to Invest $3 Billion to Strengthen U.S. Supply Chain for Advanced Batteries for Vehicles and Energy Storage," February 11, 2022.

[50] National Renewable Energy Laboratory, Transportation & Mobility Research, NAATBatt Lithium-Ion Battery Supply Chain Database, updated June 2023.

[51] U.S. Geological Survey, Technical Announcement, Australia, Canada and US Unify Critical Minerals Data, August 17, 2023.

[52] Sagoff, Jared, "A new look at the electric vehicle supply chain as battery-powered cars hit the roads en masse," Argonne National Laboratory, May 4, 2023.

[53] Solar Energy Industries Association, *Energizing American Battery Storage Manufacturing*, November 2023, p.7.

[54] The White House, FACT SHEET: Biden-Harris Administration Driving U.S. Battery Manufacturing and Good-Paying Jobs, October 19, 2022.

[55] U.S. Department of Energy, Biden-Harris Administration Awards $2.8 Billion to Supercharge U.S. Manufacturing of Batteries for Electric Vehicles and Electric Grid, October 19, 2022.

in investments in battery-related projects have been announced by numerous companies in the United States.[56]

Some federal resources available for battery storage project developers include the following:

- The Battery Policies and Incentives Search, developed by the NREL, can be accessed from the DOE website.[57] This tool provides access to incentives and policies, both on a state and federal level, related to batteries for EVs and BESS.
- The Battery Energy Storage System Procurement Checklist developed by DOE's Federal Energy Management Program provides federal agencies with a standard set of tasks, questions, and reference points to assist in early stages of BESS project development.[58]
- NREL developed *The Grid-Scale Battery Storage Frequently Asked Questions* report, which can be used as a project toolkit for battery storage projects.[59]
- *The National Blueprint for Lithium Batteries 2021–2030* by the Federal Consortium for Advanced Batteries is aimed at developing and supporting the domestic manufacturing of batteries, increasing a battery supply chain, and creating a battery chain workforce through education and training.[60]

The battery industry is also subject to tariff uncertainty, driven by geopolitical issues. The Uyghur Forced Labor Prevention Act (UFLPA), which was signed into law in December 2021, looks to prevent goods that were made with forced labor from entering the United States.[61] Initially, the UFLPA affected solar modules because polysilicon is listed as high-priority, however, now minerals and components used in lithium-ion batteries are coming under scrutiny.[62] This shift is partially due to the U.S. Department of Labor adding lithium-ion batteries to its list of products produced by forced or child labor in 2022, not only for China but also for the DRC.[63] The CBP had previously placed a Withhold Release Order on artisanal cobalt mined in the DRC.[64] In January 2023, the U.S. government signed a memorandum of understanding with the DRC and Zambia in an effort to make cobalt mining more responsible and strengthen the battery value chain.[65]

To mitigate supply chain risk, the United States has several bilateral and multilateral trade agreements in place, as well as some that are under negotiation, that include batteries and critical minerals:

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[56] Moore, Daniel, "US Battery Hype Spurred by Climate Law Faces Hurdles From China," *Bloomberg Law* (August 28, 2023).

[57] U.S. Department of Energy, Vehicle Technologies Office, Battery Policies and Incentives Search, accessed November 13, 2023.

[58] U.S. Department of Energy, Battery Energy Storage System Procurement Checklist, February 3, 2023.

[59] National Renewable Energy Laboratory, Grid-Scale Battery Storage – Frequently Asked Questions, updated September 2019.

[60] Federal Consortium for Advanced Batteries, *Executive Summary: National Blueprint for Lithium Batteries 2021–2030,* June 2021.

[61] U.S. Customs and Border Protection, Trade, Forced labor, Uyghur Forced Labor Prevention Act, updated January 26, 2024.

[62] Groom, Nichola, "EV battery imports face scrutiny under US law on Chinese forced labor," Reuters (August 19, 2023).

[63] U.S. Department of Labor, *2022 List of Goods Produced by Child Labor or Forced Labor,* September 2022.

[64] U.S. Customs and Border Protection, Withhold Release Orders and Findings List, accessed November 13, 2023.

[65] U.S. Department of State, "The United States Releases Signed Memorandum of Understanding with the Democratic Republic of Congo and Zambia to Strengthen Electric Vehicle Battery Value China," Press Release (January 18, 2023).

- The U.S.–Japan Agreement on Strengthening Critical Minerals Supply Chains was announced in March 2023, establishing commitments for cooperation on critical minerals for batteries.[66]
- U.S.–EU negotiations regarding an agreement on critical minerals was announced in March 2023.[67]
- The U.S.–Mexico–Canada Agreement went into force in 2020. It replaces the North American Free Trade Agreement and includes provisions to facilitate trade in energy products and critical minerals.[68]
- The U.S.–EU Trade and Technology Council was established in 2021 and aims to foster cooperation and coordination on a range of trade and technology issues, such as the development of secure and sustainable supply chains for critical technologies, including batteries.[69]
- The U.S.–UK Trade Agreement has been under negotiation since 2020. It covers a range of sectors, including critical minerals and battery components, and in June 2023, critical minerals were specifically added, similar to the EU agreement being negotiated.[70]
- In April 2023, the Indonesian government announced it would propose a limited Free Trade Agreement to cover critical minerals, in particular nickel, of which Indonesia is the largest producer globally.[71]

Currently, China is the largest producer of batteries globally, and many of the critical minerals are either mined in China or Chinese companies have access to these minerals through investments in various producing countries. In 2020, the Chinese government put into place the Export Control Law, which allows the government to restrict the exports of goods and technologies that are deemed a national security risk, which could include critical minerals, especially rare earth minerals.[72] Accordingly, in July 2023, the Chinese government announced that it would restrict the export of gallium and germanium, which are primarily used in semiconductor production. Semiconductors are used in the power electronics for wind turbines, solar modules, BESS, and battery management systems.[73] As a result, U.S.–China trade relations can affect supply chains across energy industries, not only for batteries.

3.2.3 Market incentives

The capital and cost estimates made in this report do not take into consideration any ITCs and PTCs that are available for renewable energy projects under the IRA or any other applicable tax incentives.

[66] U.S. Trade Representative, Agreement Between the Government of the United States of America and the Government of Japan on Strengthening Critical Minerals Supply Chains, March 28, 2023.

[67] European Commission, Statement, Joint Statement by President Biden and President von der Leyen, March 10, 2023.

[68] U.S. Trade Representative, United-States-Mexico-Canada Agreement, accessed November 13, 2023.

[69] U.S. Trade Representative, Countries & Regions, Europe & Middle East, Europe, Trade and Technology Council (TTC), U.S.-E.U. Trade and Technology Council (TTC), accessed November 13, 2023.

[70] U.S. Trade Representative, Countries & Regions, Europe & Middle East, Europe, United Kingdom, accessed November 13, 2023.

[71] Medina, Ayman Falak, "Indonesia Proposed Limited FTA with the United States," *ASEAN Briefing* (June 28, 2023).

[72] U.S. Department of Commerce, International Trade Administration, China - Country Commercial Guide, U.S. Export Controls, updated April 7, 2023.

[73] Areddy, James T. and Sha Hua, "China Restricts Exports of Two Minerals Used in High-Performance Chips," *The Wall Street Journal* (July 4, 2023)

The IRA, which was signed into law by the Biden administration in August 2022, extended tax credits to promote the adoption of renewable energy systems.[74] ITCs and PTCs are available for renewable energy projects, but generally a project cannot claim both; however, a project could claim different credits for co-located systems, such as solar + storage, depending on Internal Revenue Service (IRS) guidance.[75,76]

One change the IRA brings is the decoupling of storage and generation. Section 13102 of the IRA amends Section 48 of the Internal Revenue Code of 1986 to add an ITC for standalone energy storage technology, which previously was only available to storage projects that were part of a new solar generation facility and only if the storage facility was charged 80% by the solar facility. The new ITC applies to standalone energy storage technology with a minimum capacity of 5 kWh, is not limited to batteries, and includes other storage technologies. Additionally, Section 13702 of the IRA provides ITC for clean energy generation and energy storage projects placed in service after December 31, 2024. Battery storage projects could qualify for a bonus rate of 30% if they satisfy wage and apprenticeship requirements. Further ITCs could be applied for meeting domestic content requirements and for being located within an energy community. The IRS also outlines credits and deductions available for individuals under the Residential Clean Energy Credit.

In addition to the federal-level incentives, some states are offering financial incentives and/or tax incentives for BTM battery storage projects to businesses and/or consumers. In some states, utilities are offering incentives for battery storage projects to customers within their service territory. For example, a Vermont utility, Green Mountain Power (GMP), offers a range of programs for a residential energy storage program called Bring Your Own Device, where homeowners can install a storage system and enroll in GMP's program. Table 3-6 lists examples of state-level incentives. A more comprehensive database of state-level incentives and policies can be accessed through the Database of State Incentives for Renewables and Efficiency (DSIRE), which has an interactive map that is searchable by state.

Table 3-6. Example state-level battery storage incentives

State	Incentive Program	Scope/Incentive
California	Self-Generation Incentive Program (SGIP)	$1 billion through 2024; $850/kWh for equity and $1,000/kWh for equity resiliency (each has its own eligibility criteria)
Connecticut	Public Utilities Regulatory Authority (PURA) Energy Storage Solutions Program	Residential customers can receive around $200/kWh, with a maximum of $7,500 per project; commercial and industrial customers can receive a maximum incentive of 50% of the project cost
Hawaii	Green Energy Market Securitization (GEMS) Program	Provides long-term financing with no upfront costs for residential and commercial BESS
Maryland	Maryland Energy Storage Income Tax Credit Program	$750,000 in energy storage income tax credit certificates available per year on a first come, first served basis through 2024

[74] The White House, Building A Clean Energy Economy: A Guidebook to the Inflation Reduction Act's Investments in Clean Energy and Climate Action, Version 2, January 2023.
[75] U.S. Department of Energy, Energy Efficiency & Renewable Energy, Solar Energy Technologies Office, Federal Solar Tax Credits for Businesses, updated June 2023.
[76] U.S. Environmental Protection Agency, Renewable Electricity Production Tax Credit information, updated February 22, 2023.

State	Incentive Program	Scope/Incentive
New York	NYSERDA's Retail Energy Storage Incentives	$3 million budget with $498,210 available; incentive is $250/kWh; aim to reach 1,500 MW-DC of energy storage by 2025 and 3,000 MW-DC by 2030
Oregon	Oregon Solar + Storage Rebate Program	$1.2 million in funding available for low- and moderate-income households; $2.1 million non-income restricted; rebates are issued to approved contractors that pass savings on to customers
Vermont	Bring Your Own Device (BYOD)	Energy storage owners can enroll in the BYOD program and receive an upfront payment of $850/kW-DC for a three-hour discharge and $950/kW-DC for a four-hour discharge. If customers retrofit their existing solar system with storage in a constrained area of the grid, they can receive an extra $100/kW-DC per discharge.

Data source: DSIRE, state, and utility websites.
Note: MW-DC=megawatt direct current.

3.2.4 Relationship to other DG technologies

While solar PV benefits from being a familiar option to customers as method of procuring clean energy under favorable economic conditions, battery storage systems are typically not purchased solely on the basis of customer economics. Adoption of battery storage systems by customers is largely dependent on the value the customer places on accessing reliable backup power. Thus, battery storage adoption is more closely linked to the customer's perception and quantification of resiliency needs, and solar is more closely linked to a customer's desire to achieve energy savings or access clean energy.

Storage adoption can be motivated by severe weather events leading to outages. Natural disasters such as hurricanes, floods, wildfires, and other events can leave marked impressions on the customer's psyche and will influence how the customer prioritizes resiliency and backup power for everyday needs. The ability of a battery storage system to provide backup power in the event of an outage or other emergency is an important attribute that sets these systems apart from the broad category of DERs. Most utilities adhere to safety and interconnection rules that prevent customers with PV-only (not solar + storage) from using PV electricity during an outage event. Incorporating battery storage along with solar enables customers to use their system in response to different events. Solar + storage is unique in that it empowers customers to bolster their resiliency at their home or business while also reducing greenhouse gas emissions by generating and storing clean power. Pairing generating capacity with BESS is increasingly being deployed to enhance grid reliability, flexibility, and efficiency. Batteries can be used to store energy during low demand times and dispatched during periods of peak demand.

Literature and research on BTM standalone batteries is limited, likely due to the overwhelming customer preference for solar + storage co-adoption. Currently, standalone battery systems are ineligible for the federal ITC and therefore have a higher $/kW-DC cost than a solar + storage system after applying the tax incentives.

Battery storage pairs well with renewable energy sources, such as solar and wind. These energy sources are intermittent, meaning that they do not generate electricity all the time and they require energy storage to match demand and supply. Battery storage can be used to store excess electricity generation during periods of low demand then discharge it back into the grid during periods of high demand, allowing for price arbitrage. Consumers are also investing in battery storage to reduce energy bills and add reliability. Some of this demand will be coupled with the growth in EV adoption, as companies such as Tesla offer consumers combined EV charging and energy storage products, such as the Powerwall, which can also be coupled with solar energy.[77]

The potential value of a battery storage system that a customer can obtain is dependent on the programs and pricing structures available. Peak shaving and dispatching a battery storage system in response to pricing or outage events on the grid will be influenced by the dispatching incentives, peak pricing, and other factors determined by the grid energy provider.[78] According to a recent survey of residential utility customers across the United States, demand response participants have a significantly higher rate of battery adoption and battery EVs than the national average.[79]

3.2.5 Technology research and development rates

Battery energy storage systems can provide value through a variety of services or use cases, but the key values of distributed BTM storage are backup power and bill savings. For the purposes of this study, this section will focus on technology R&D in distributed BTM battery storage applications. Lithium-ion battery technology was first researched in the 1970s and has been the battery of choice in consumer electronics since the 1990s.[80] Lithium-ion batteries remain the technology of choice for the vast majority of EVs and BTM energy applications and are projected to continue to lead in market share. Transportation sector applications are expected to be the primary driver of battery technology development and potential cost declines.

3.2.6 Current and anticipated rates of market adoption by sector

Recent studies from NREL found that cost reductions and the value of backup power increase adoption of BTM battery storage.[81] Between 2021 and 2022, both residential and commercial and industrial (C&I) battery storage deployment in terms of megawatthour (MWh) capacity increased by 36% and 115%, respectively. Wood Mackenzie's 2022–2026 U.S. energy storage forecast expects annual growth of 2.1 GW of residential and 1 GW of non-residential new BTM battery capacity.[82]

3.2.7 Relationship between battery chemistry and applications

New battery chemistries and architectures are emerging and are being tested for both energy storage and the transportation sector, but lithium-ion batteries will continue to be the current mainstay for both sectors. Some of the changes in what battery chemistry will be used for certain applications and the demand for certain battery chemistries will be driven by cost and the performance requirements of the battery.

The largest consumer of lithium-ion batteries currently is the transportation sector, and the rate of adoption of EVs globally will directly affect demand and battery prices.[83] This increase in demand will also drive R&D in batteries to develop new battery chemistries and battery technologies, which in the long term is expected to create cheaper, more energy dense, and safer batteries. Six common

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77 Tesla, Powerwall, accessed November 13, 2023.
78 Prasanna, Ashreeta and Kevin McCabe, *Storage Futures Study: Distributed Solar and Storage Outlook: Methodology and Scenarios*, National Renewable Energy Laboratory, 2021.
79 Smart Energy Consumer Collaborative, *Distributed Energy Resources: Meeting Consumer Needs*, 2019.
80 Augustine, Chad and Nate Blair, *Storage Futures Study – Storage Technology Modeling Input Data Report*, National Renewable Energy Laboratory, 2021.
81 Blair, Nate and Chad Augustine, *Storage Futures Study – Key Learnings for the Coming Decades*, National Renewable Energy Laboratory, 2022.
82 Wood Mackenzie, Q2 2022 US Energy Storage Monitor, 2022.
83 U.S. Department of Energy, Vehicle Technologies Office, National Blueprint for Lithium Batteries, June 7, 2021.

types of lithium-ion batteries are used in various types of EVs as outlined in Table 3-7 with NMC being the most common battery chemistry.

Table 3-7. Common EV battery chemistries globally

Battery Type	Battery Chemistry	Used in EVs in 2022
NMC	Lithium nickel manganese cobalt	60%
LFP	Lithium iron phosphate	30%
NCA	Lithium nickel cobalt aluminum	8%
LCO	Lithium cobalt oxide	<1%
LMO	Lithium manganese oxide	<1%
LTO	Lithium titanium oxide	<1%

Data Source: International Energy Agency

Carmakers have been favoring NMC batteries because this battery chemistry has been available since the 1980s and has one of the higher energy densities among existing, commercially available battery chemistries—NCA batteries also have a high energy density, however, this battery chemistry was developed by Panasonic in 2019 for Tesla. Energy density refers to how much energy can be stored in each battery and is usually measured by volume. NMC batteries today have an energy density range of between 150 watthours per kilogram (Wh/kg) to 250 Wh/kg, compared with LFP batteries with an energy density range of 150 Wh/kg–190 Wh/kg, and NCA batteries with 200 Wh/kg–260 Wh/kg.[84] Research is continuing to try to develop new battery chemistries that are lower in cost and high in energy density. For example, sodium-ion batteries are being commercialized, which are lower in cost, as they do not contain critical minerals, but can only provide about 160 Wh/kg in energy density.[85]

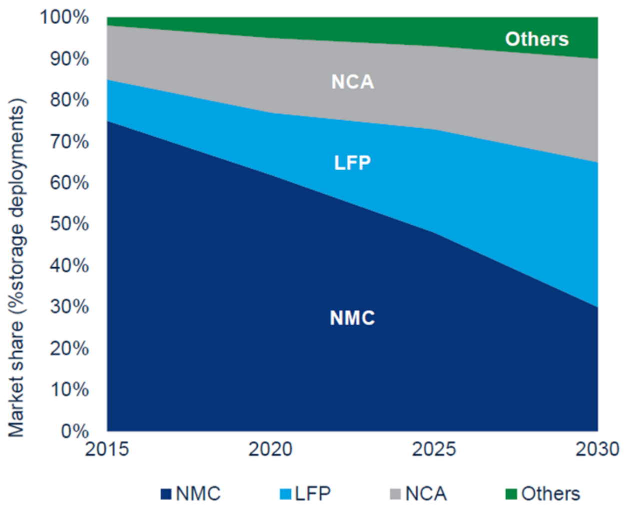
Energy density is an important characteristic for EVs because cars have limited space to house a battery and the weight of the battery affects vehicle performance. However, for most BESS, the size and weight of the battery are not major restricting factors for deployment, and in that sense, customers have more flexibility to consider battery chemistries that have lower energy densities or are heavier. For example, lead acid batteries (LABs) are still widely used in mini-grid and off-grid applications in developing countries, because these batteries are low cost, use proven technology, and in most cases are part of a circular economy and are easily recycled.[86] However, LABs typically have a very low energy density of around 30 Wh/kg–40 Wh/kg.[87] Another option for stationary battery storage is the vanadium redox flow battery, which has a much longer life cycle and lower level of degradation when compared with lithium-ion batteries. However, it uses a critical mineral, vanadium, as well as a more complex and large pump mechanism, making it unsuitable for EVs or

[84] Pacios, Roberto and Inigo Careaga, "Cathode Composition of Battery Cells: A Three-way War," *CIC energi GUNE* (January 18, 2022).
[85] CATL, "CATL Unveils Its Latest Breakthrough Technology by Releasing Its First Generation of Sodium-ion Batteries," Press Release (July 29, 2021).
[86] Augustine, Chad and Nate Blair, *Storage Futures Study – Storage Technology Modeling Input Data Report*, National Renewable Energy Laboratory, 2021.
[87] Crawford, Alasdair J. and Qian Huang, "Lifecycle comparisons of selected Li-ion battery chemistries under grid and electric vehicle duty cycle combinations," *Journal of Power Sources* (March 15, 2018), p.185–193.

consumer electronics applications. The Pacific Northwest National Laboratory (PNNL) is working with companies to commercialize this technology for BESS.[88]

Figure 3-7 shows the market share of various battery chemistry types from 2015 forecast to 2030. Since 2019, lithium-ion batteries have been the most common type of batteries used in BESS.[89] Batteries used in energy storage tend to prioritize energy density over power density, whereas EV batteries prioritize power density over energy density. Power density refers to the amount of power a battery can deliver per volume or mass. To date, NMC batteries have been the most common battery chemistry for BESS, and for the cost profile used in this report, NMC storage batteries were modeled. However, NREL's ATB for utility-scale battery storage found that LFP batteries are becoming the primary chemistry for stationary storage batteries.[90] Home or consumer battery storage units used NMC or NCA batteries because of the limited space available and higher energy density requirement.[91] However, these systems may be shifting from NMC to LFP batteries, primarily due to battery cost.[92] For instance, Tesla announced in April 2023 that it will be switching the batteries it uses in its Powerwall3 for homes from NMC to LFP.[93]

Figure 3-7. Stationary energy storage battery chemistry market share and forecast all sectors, 2015–2030



Data source: Wood Mackenzie

Developing new chemistries that use fewer critical minerals without loss of energy density or creating new higher energy density batteries are R&D goals for battery developers and carmakers.[94] Additionally, developing batteries that are safer and less susceptible to thermal runaway (which can lead to fires) and improving the life cycle of batteries (the number of times a battery can be charged

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[88] Maisch, Marija, "New US license to bring vanadium Redox flow batteries to market," *pv magazine* (March 3, 2022).

[89] Augustine, Chad and Nate Blair, *Storage Futures Study - Storage Technology Modeling Input Data Report*, National Renewable Energy Laboratory, 2021.

[90] National Renewable Energy Laboratory, Annual Technology Baseline, Utility-Scale Battery Storage, 2023.

[91] International Energy Agency, Energy system, Electricity, Grid-scale Storage, accessed November 13, 2023.

[92] Wood Mackenzie. News Release, "LFP to overtake NMC as dominant stationary storage chemistry by 2030," Press Release (August 17, 2020).

[93] Agatie, Cristian, "Tesla Switches to Using LFP Prismatic Cells in Upcoming Powerwall 3," *Autoevolution* (April 14, 2023).

[94] International Energy Agency, *Global EV Outlook 2023*—Trends in Batteries, April 2023.

and discharged) are also important. Numerous new battery chemistries are currently under development, but solid-state batteries, of which there are various chemistries, are considered the most promising, especially for EVs. Solid-state batteries do not use a liquid electrolyte, which increases safety, requires less cooling, uses fewer critical minerals, and could potentially have much higher energy density than the current lithium-ion batteries.[95,96] In October 2023, Toyota announced that it will be ready to mass produce solid-state batteries for EVs by 2027–2028.[97] These technological developments in EV batteries are important because they are likely to impact BESS technologies and costs as well.

New developments in battery architecture are also helping to reduce battery cost and improve reliability. Japan's Panasonic developed the cylindrical electrode design in its 4680 batteries for Tesla, which reduces the electrical path and increases power output.[98] China's BYD developed the cell-to-pack, or module-free, battery architecture, which eliminates battery modules and directly integrates the battery cells into the pack, reducing materials used, increasing space utilization, and reducing battery weight.[99] Such changes in battery architecture could reduce material usage, reduce battery cost, and increase battery safety for BESS as well.

3.2.8 Trends in battery disposal, recycling, or repurposing

Lithium-ion batteries contain critical minerals, such as aluminum, cobalt, lithium, and nickel, which can be recycled to supplement the supply chain, reduce cost, and help create a more sustainable circular economy. Recycling batteries is currently not an easy, cheap, or environmentally friendly process; however, new and different methods of recycling batteries and materials are beginning to emerge. The International Energy Agency (IEA) estimates that globally only 5% of lithium-ion batteries are currently being recycled. In contrast, LABs, which have been around for much longer, have a well-developed circular economy and have a recycling rate of over 90%.[100] Increasing the level of recycling for lithium-ion batteries will help reduce the need for sourcing additional critical minerals as well as reduce material cost and make battery production more sustainable. However, currently, very little regulation for battery recycling exists, and regulation will have to grow in tandem to build up a circular economy for lithium-ion batteries. According to Call2recycle, 19 states currently have battery recycling requirements in effect, and 11 states require battery producers to offer or fund battery recycling.[101]

Recycling lithium-ion batteries is a growing business and an estimated 70%–90% of critical minerals can be recovered during the recycling process.[102] According to NREL's NAATBatt Lithium-Ion Battery Supply Chain Database, 44 companies are currently active in the EOL/recycling supply chain in the United States. The three leading companies in the United States are Li-Cycle Corporation, Redwood Materials, and Retriev Technologies. These recycling companies have partnered with battery makers, carmakers, and other companies to recycle batteries. For example,

95 Harmon, Joseph E., "New design for lithium-air battery could offer much longer driving range compared with the lithium-ion battery," Argonne National Laboratory, Press Release (February 22, 2023).
96 International Energy Agency, *Global EV Outlook 2023*, April 2023.
97 Toyota Motors, "Idemitsu and Toyota Announce Beginning of Cooperation towards Mass Production of All-Solid-State Batteries for BEVs," Press Release (October 12, 2023).
98 Panasonic Energy, Technological Strategy of Panasonic Energy - for Sustainability and Well-Being, Presentation, February 8, 2023.
99 BYD, BYD's New Blade Battery Set to Redefine EV Safety Standards, accessed November 13, 2023.
100 International Energy Agency, *Global EV Outlook 2023*, April 2023.
101 Call2recycle, Recycling Laws By State, accessed November 13, 2023.
102 Gregoir, Liesbet, *Metals for Clean Energy: Pathways to solving Europe's raw material challenge*, KU Leuven, April 2022.

Li-Cycle recycles various types of lithium-ion batteries at four operating plants and claims it can recover up to 95% of the critical materials in lithium-ion batteries.[103] However, recycling lithium-ion batteries faces numerous hurdles:

- **Lack of regulation:** Little regulation exists throughout the recycling process, from the mandate to recycle, assessment of batteries, the recycling process, and quality of recycled output.
- **Cost:** Costs vary depending on the recycling process that is used, with the most common processes being mechanical, hydrometallurgy, and pyrometallurgy. Depending on the recycling process, the disassembly of batteries can be labor intensive and costly. For example, the battery pack for the Nissan Leaf EV is considered to have the highest disassembly cost, followed by the Porsche Taycan EV, while the Tesla battery pack is considered the least costly.[104] Costs also exist beyond the recycling process, such as the transportation costs of the EOL batteries to the recycling facility, the cost of transporting the recycled materials, and the cost of disposal of the waste material from the recycling process itself. The cost distribution of who will pay for what or if some of these costs can be subsidized will affect the recycling industry. Cost distribution could potentially include a combination of manufacturers, consumers, companies, and the U.S. government. The DOE, under the BIL, is providing about $74 million in funding for 10 projects to advance EV battery recycling and reuse.[105]
- **Types of batteries:** Currently, batteries come in numerous varieties, both in capacity, size, type, and chemistry, that recycling companies need to be able to process. The bulk of the EV batteries currently being recycled are those replaced under vehicle warranty, and the EV battery replacement cycle will begin in about five years, when the first wave of EV batteries reaches their EOL. In 2018, more than 300,000 EVs were sold in the United States, and assuming a 10- to 15-year battery lifecycle, 2028–2033 would mark an increase in [106] Battery recycling companies have stated that EV batteries will be the bulk of their business, but whether they recycle batteries from EVs or BESS does not affect their cost or business model—the [107] Different minerals and amounts of minerals will be recovered depending on the battery chemistry. For battery recycling companies, which battery chemistry will ultimately become the mainstay chemistry remains uncertain, and until that it is clear, it is difficult to streamline, concentrate, or scale the recycling process, as well as project the profitability of recycling.
- **Profits:** The profits of recycling companies will depend on the materials that can be recovered from the recycled batteries. If future batteries contain fewer or no critical minerals, then recycling becomes less commercially viable for these companies. This possibility

[103] Li-Cycle, Creating a Circular and Sustainable Battery Supply Chain, Investor Presentation, August 2023.
[104] Lander, Laura and Tom Cleaver, "Financial viability of electric vehicle lithium-ion battery recycling," *iScience* (July 23, 2021).
[105] U.S. Department of Energy, Biden-Harris Administration Announced Nearly $74 Million To Advance Domestic Battery Recycling And Reuse, Strengthen Nation's Battery Supply Chain, November 16, 2022.
[106] U.S. Department of Energy, Alternative Fuels Data Center, U.S. Plug-in Electric Vehicle Sales by Model, January 2020.
[107] Colthorpe, Andy, "North America's largest Li-ion battery recycling giga-facility to 'take on as much as possible' from ESS sector," *Energy Storage News* (January 14, 2022).

cannot be determined until the mainstay battery chemistry for each application is determined, which currently is unclear.

The level of recycling of lithium-ion batteries, at least for EVs, may be spurred by the Clean Vehicle Tax Credit (CVTC), which applies to vehicles purchased after April 18, 2023, that meet critical mineral and battery component requirements to qualify. The CVTC requires 40% or more of the battery's critical minerals be extracted or processed in the United States or have been recycled in North America. This requirement gradually increases to 80% in 2027.[108] These requirements could be a catalyst to increase the recycling of batteries for all sectors that use batteries, not just EVs.

Unlike recycling lithium-ion batteries, some batteries have been repurposed for other applications, mostly for BESS. Repurposing batteries has its own challenges and costs. Battery cells need to be assessed and tested before they can be repurposed, and currently no standards for repurposing exist, which makes quality control difficult. This market is still limited, but this may change if EVs make up a larger portion of total vehicle stock and more EV batteries reach their EOL.

In Asia and Europe, EV batteries are being repurposed as energy storage batteries, as more EVs have been sold there than in the United States. In Japan, Toyota has been repurposing EOL EV batteries together with electric utilities for energy storage since 2018.[109] Repurposing EV batteries for energy storage usually requires batteries modules and packs to be disassembled, cells tested, and bad cells replaced. The cells then reconnected and reconfigured to create a larger integrated system. In terms of cost of repurposing EV batteries, NREL provides a free tool to model the cost of repurposing EV batteries in a secondary market, Battery Second-Use Repurposing Cost Calculator. According to this tool, the total cost of a second-life EV battery could be in the range of $40/kWh–$160/kWh, which can be compared with BNEF's 2022 EV battery pack cost of $151/kWh.[110] It is expected that as more EV batteries reach EOL, more will be repurposed into BESS. It Is estimated that 2.1 terawatthours (TWh) to 4.8 TWh of repurposed batteries could become available globally by 2050.[111] To put this amount in context, the International Renewable Energy Agency estimates a global need for 9 TWh of energy storage by 2050.[112]

Many U.S. states have regulations regarding the disposal of batteries, which can include LABs, lithium-ion batteries, nickel-metal hydride batteries, and others. However, states must follow federal regulatory requirements for waste batteries as issued by the U.S. Environmental Protection Agency.[113] DOE's Vehicle Technologies Office also offers an online tool, the Battery Policies and Incentives Search, which allows users to look for federal and state policies and incentives related to batteries for EVs and energy storage, including waste regulations and incentives.

[108] Internal Revenue Service, Credits for New Clean Vehicles Purchased in 2023 or After, updated June 22, 2023.
[109] Cogan, Ron, "Toyota Aims at Reuse of EV Batteries," *Green Car Journal* (March 30, 2018).
[110] Bloomberg New Energy Finance, "Lithium-ion Battery Pack Prices Rise for the First Time to an Average of $151/kWh," December 6, 2022.
[111] Xu, Chengjian and Paul Behrens, "Electric vehicle batteries alone could satisfy short-term grid storage demand by as early as 2030," *Nature Communications* (January 17, 2023).
[112] International Renewable Energy Agency, *Global Renewables Outlook: Energy Transformation 2050*, 2020.
[113] U.S. Environmental Protection Agency, Hazardous Waste, Used Lithium-Ion Batteries, accessed November 13, 2023.

4 WIND ENERGY SYSTEMS

DNV developed technology attributes and cost data for BTM wind energy systems for three representative commercial sector customer segments and one residential sector customer segment. These attributes and cost data were developed at the national level and assumed to be relatively similar throughout individual states. DNV then modeled annual hourly generation profiles for each wind energy configuration to gather detailed operational data, and it further assembled additional relevant performance data for all system configurations. The final step was to develop current year (2022) cost estimates from available data and align associated cost estimates and attributes with previous years of EIA's RECS, CBECS, and MECS. The process is described in the following subsections.

4.1 Wind energy systems technology attributes and cost data

4.1.1 System configurations

DNV used PNNL's distributed wind database and its most recent *Distributed Wind Market Report* to identify and classify representative residential and commercial system capacities for the development of performance attributes and cost data.[114, 115] This information was verified by reviewing DNV proprietary project trackers for distributed wind energy systems. DNV's tracker database contains over 2,500 unique projects of varying sizes of distributed or BTM wind installed within the last 25 years. DNV consolidated all relevant commercial installation types (agriculture, government, and institutional subsectors) where project capacities aligned with representative commercial size ranges and identified representative sizes based on the distribution of installed commercial projects within the last 10 years. Additionally, DNV updated residential installation data to only include relevant representative system capacities based on the representative capacity range categorized for residential installations in this analysis. For example, DNV assumed larger installations classified as residential (more than 40 kW-AC) would better align with another customer segment (that is, agricultural) and so removed them from residential analysis.

Residential wind systems installed in the United States are almost all small, distributed wind projects (less than 100 kW-AC) and are typically closer to between 5 kW-AC and 25 kW-AC in capacity. Small and large distributed projects (more than 1 MW-AC) represent the majority of installations and overall installed capacity in the commercial distributed wind market. The medium commercial size range (100 kW-AC–1 MW-AC) represents a very small portion of total installations and installed capacity in recent years (2019–2022) due to the limited turbine products available in this size range. However, costs for a midsize system were modeled and included as a representative system size, given that installed capacity for midsize turbine installations historically represented a larger portion than current annual penetration, the stimulating effect of the IRA incentives available in the future, and increasing interest in midsize turbines among developers and R&D efforts.

Table 4-1 shows the residential and commercial wind energy representative system capacities and additional relevant characteristics used to develop performance attributes and cost estimates. The data used to classify representative system sizes were filtered to remove installations with insufficient data to accurately include as representative for the respective size bin.

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[114] Pacific Northwest National Laboratory, Research, Sustainable Energy, Renewable Energy, Wind Energy, Distributed Wind, Distributed Wind Market Report, Distributed Wind Project Database, accessed November 13, 2023.

[115] Pacific Northwest National Laboratory, *Distributed Wind Market Report: 2023 Edition*, August 2023.

Table 4-1. Technology attributes for residential and commercial wind configurations and representative systems

System Configuration	Representative System Capacity Range	Representative System Capacity	Historical Installations and Installed Capacity
Residential Distributed Wind	1–40 kW-AC	9.3 kW-AC	127 installations, ~1.35 kW-AC (2015–2022)
Small Distributed Wind	<100 kW-AC	40 kW-AC	710 installations, ~32.2 MW-AC (2012–2022)
Medium Distributed Wind	100–1,000 kW-AC	300 kW-AC	63 installations, ~44.5 MW-AC (2012–2022)
Large Distributed Wind	>1,000 kW-AC	2,000 kW-AC	125 installations, ~480 MW-AC (2012–2022)

4.1.2 Technology attributes and generation shapes

After developing technology system configurations and representative capacities for 2022, DNV modeled each individual system using NREL's SAM to collect hourly generation shapes and associated performance metrics. DNV modeled representative locations in individual states to generate a blended U.S. average of annual system performance data for residential and individual commercial systems. The blended approach involved weighting representative locations based on the number of recent installations and installed capacity for each segment and capacity range.

States such as Iowa, Minnesota, California, Ohio, and Massachusetts were weighted higher for large installations, whereas states such as New York, Nevada, Alaska, and California were weighted higher for smaller installations. This weighting directly influenced modeled annual system production (kWh) and ultimately the average capacity factor for representative commercial wind energy systems.

4.1.3 System performance attributes

Table 4-2 shows performance attributes for representative U.S. residential and commercial wind energy systems summarized from the data developed in the previous subsections. The data are presented to align with current year (2022) performance attributes but were collected to represent previous years of EIA segment-level surveys for the residential sector from 2015 to 2022 and the commercial sector from 2012 to 2022.

Table 4-2. Residential and commercial wind system performance attributes (2022)

Performance Attribute	Residential (1-40 kW-AC)	Small (<100 kW-AC)	Medium (100-1,000 kW-AC)	Large (>1,000 kW-AC)
Turbine Rating	9.3 kW-AC	40 kW-AC	300 kW-AC	2,000 kW-AC
Number of Turbines	1	1	1	1
Power Rating	165 W/m^2	167 W/m^2	170 W/m^2	325 W/m^2
Hub Height	25 m	32.5 m	45 m	90 m
Rotor Diameter	12.5 m	20 m	60 m	120 m
Average Net Capacity Factor	18.9%	20.2%	20.4%	26.5%
Availability [a]	99.0%	99.0%	99.0%	99.0%
Total System Losses	11.5%	11.5%	11.5%	11.5%

[a] Availability percentage (%) refers to system availability considering planned downtime for maintenance and not as a function of system performance related to overall capacity factor.

Overall, larger commercial systems have a higher capacity factor due to turbine configuration and assuming a pitch-regulated power curve. Availability and total system losses are assumed to be the same for all system sizes.

4.1.4 2022 cost data

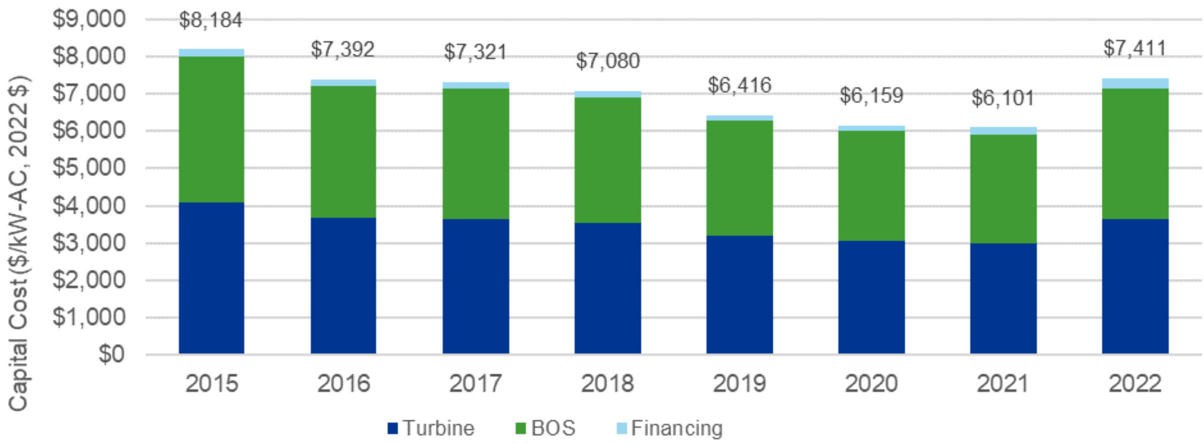
Capital cost data for commercial wind energy systems were collected at a national level for each system capacity for 2020–2022 using NREL's recent cost of wind energy review.[116] DNV verified and provided slight cost adjustments where appropriate to align with exact representative system capacity assumptions, based on DNV proprietary project databases and reported individual project experience for 2022, and PNNL's *Distributed Wind Market Report* capacity-weighted installed costs. Distributed wind energy capital cost categories are split entirely between turbine (that is, equipment) costs and BOS costs. Turbine costs consist of a rotor, nacelle, and tower, whereas BOS costs consist of general foundation and site costs, electrical infrastructure, and relevant development, engineering, and labor costs.

4.1.5 Historical cost data

Baseline historical capital cost data were collected from NREL's ATB reports and data files at the national level for both the residential and commercial sectors. DNV used historical labor costs, sales taxes, and calculated supply chain costs to further scale individual cost categories to align with BOS cost subcategories in historical years. These historical costs, presented in 2022 constant (real) dollars, were combined with current cost data detailed in the previous subsection and summarized for the residential and commercial system capacities in Figure 4-1 through Figure 4-4.

Similar to other technologies, residential distributed wind has the highest capital costs compared with various capacities of commercial installations (Figure 4-1). Capital costs in the residential sector has been declining over the past seven years. Cost increases in the most recent data year (2022) are largely due to higher BOS costs and increases in turbine costs in 2022.

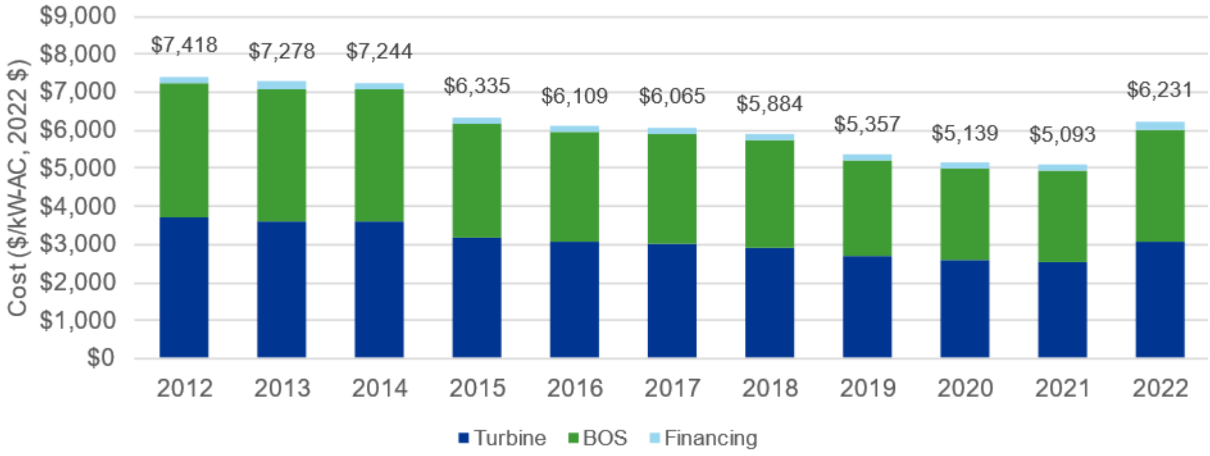
Figure 4-1. U.S. average residential distributed wind project cost data (2015–2022, 2022 $)



Small, distributed wind project costs increased in 2022 on a $/kW-AC basis, largely due to higher BOS costs and slight increases in turbine costs, while costs generally declined in the preceding years back through 2012 (Figure 4-2). Out of all installation sizes, $/kW-AC installed costs for small and medium distributed wind installations increased the most in 2022.

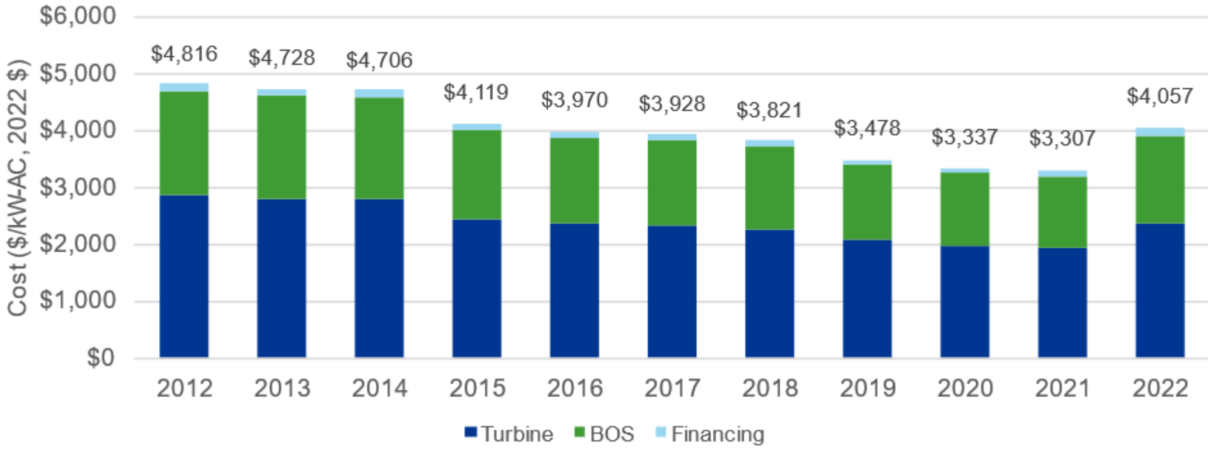
[116] Stehly, Tyler and Patrick Duffy, "2021 Cost of Wind Energy Review," National Renewable Energy Laboratory, Presentation (December 2022).

Figure 4-2. U.S. average small commercial distributed wind project cost data (2012–2022, 2022 $)



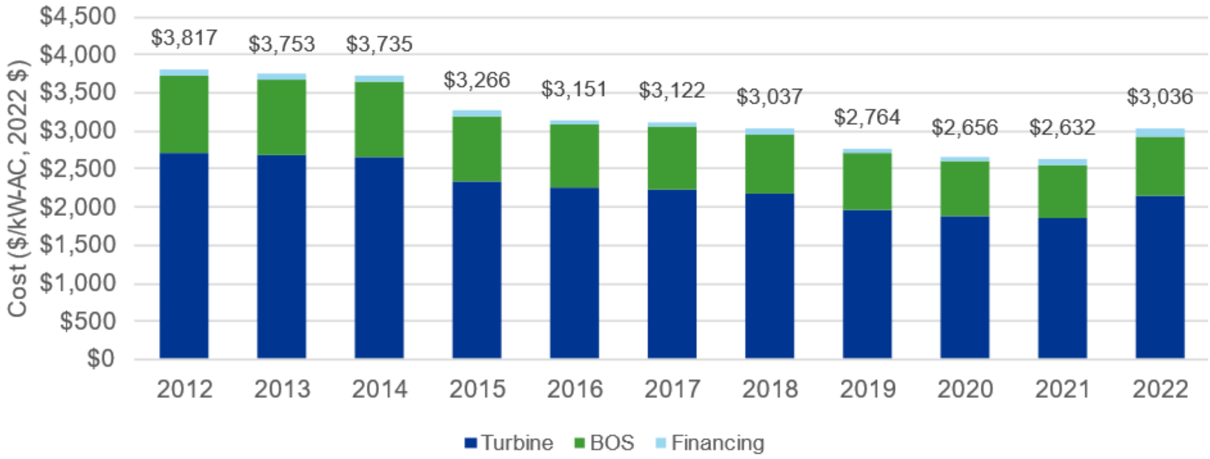
Cost similarly rose for medium (Medium or midsize) commercial distributed wind projects in 2022, with an average installed cost of $4,057/kW-AC (Figure 4-3). Medium commercial wind installations have been limited in recent years, so DNV also used PNNL's *Distributed Wind Market Report* and associated data, as well as proprietary DNV project tracker data, as an additional verification of cost data from 2017 to 2022.

Figure 4-3. U.S. average medium commercial distributed wind project cost data (2012–2022, 2022 $)



Large commercial distributed wind projects hold the largest market share by total number of installations and capacity and are the most cost-effective distributed wind projects based on $/kW-AC installed costs (Figure 4-4). Although capital costs for large distributed systems increased in 2022 ($3,036/kW-AC), the average cost remains below the average system cost for small and midsize systems and continues to be a strong market segment for end users.

Figure 4-4. U.S. average large commercial distributed wind project cost data (2012–2022, 2022 $)



4.2 Wind market discussion

Distributed wind technology is a relatively mature DER. Wind turbines generate electricity by converting kinetic energy in the wind into rotating shaft power that spins an AC generator. BTM small-scale wind systems typically serve rural homes, farms, and manufacturing facilities due to their size and land requirements. Wind resource, high retail electricity prices, and favorable policies are the key contributing factors to favorable BTM wind system economics.

According to a recent survey of residential utility customers across the United States, perceptions of not having access to small wind turbines is the main barrier for adoption of this DER in the residential sector. Residential wind system adoption is quite low in the United States—the survey found that system owners represent a very small portion of total residential utility customers.[117] Adoption is constrained to properties with at least one acre of land and no local ordinances against tall towers, so adoption typically only occurs outside of metropolitan and urban regions.

Cumulative installed capacity of BTM wind turbines in the United States is 1,075 MW-AC, as of 2021. The 2023 PNNL *Distributed Wind Market Report* found that 13 states added 29.5 MW-AC of new distributed wind capacity in 2022, which represents a $84 million investment in 1,755 turbine units.[118] Of the 29.5 MW-AC of distributed wind added in 2022, 92% came from projects using large turbines (greater than 1 MW-AC), no new capacity came from medium turbines (100 kW-AC–1,000 kW-AC), and the remaining 8% came from small turbines (less than 100 kW-AC). In terms of capacity installed by customer type, utility customers represented 78% of the new capacity installed in 2022, followed by industrial customers at 20%.

4.2.1 Resource and material availability trends

BTM distributed wind potential applications are constrained by local load, and NREL's most recent *Distributed Wind Energy Futures Study* found that adoption is most correlated with electricity consumption, electricity rates, and windy land.[119] Wind energy is dependent on a number of factors,

[117] Smart Energy Consumer Collaborative, *Distributed Energy Resources: Meeting Consumer Needs*, 2019.
[118] Pacific Northwest National Laboratory, *Distributed Wind Market Report: 2023 Edition*, August 2023.
[119] McCabe, Kevin and Ashreeta Prasanna, *Distributed Wind Energy Futures Study*, National Renewable Energy Laboratory, May 2022.

including the characteristics of the machine (for example, rotor, gearbox, tower, controls), the location of the system, and the wind regime (for example, speed, timing, predictability).

The power available in wind depends on the size of the wind turbine and the length of its blades. The power output is proportional to the swept area of the turbine rotor and the cube of the wind speed. For example, doubling the wind speed increases the power by eight-fold. Most wind turbines are not turned on in low-speed winds, so site selection for small-scale wind systems is a key constraining factor to resource availability. Wind power is proportional to the square of the wind turbine blade diameter, so doubling the blade diameter increases the power available by a factor of four. This observation drives the economies of scale that go with larger wind turbines. However, the cost of a wind turbine increases with the increased blade diameter. According to NREL, wind turbines are predominantly made of steel.[120] Reducing the overall size and weight of the generator affects the weight and cost of the wind turbine tower and foundation.[121] Research supported by DOE is looking to develop lightweight and long wind turbine blades by using carbon fiber composites rather than fiberglass. Carbon fiber materials are considered a key technology to enable larger wind turbine blades at a lower overall cost. Other areas of growth in wind turbine materials include the development of next-generation drivetrain technologies that are lighter than the current technology. Lightweight generators are being developed with high-temperature and low-temperature superconducting materials that reduce generator mass as compared with current technologies.

4.2.2 Federal policies and market incentives

DOE has a Wind Energy Technologies Office (WETO) that provides global leadership in all areas aimed at enabling low-cost wind energy. For distributed wind, WETO has funded research projects to advance wind technology competitiveness as a DER.[122]

Since the passing of the IRA of 2022, the federal ITC has been extended for 10 years past its original expiration date. For facilities beginning construction before January 1, 2025, the IRA will extend the ITC for up to 30% of the cost of installed equipment. The ITC steps down to 26% in 2033 and 22% in 2034. For projects that began construction after 2019 and were placed into service before January 1, 2022, the ITC was set at 26%. Small-scale wind projects are eligible for the federal ITC.

Additionally, the IRA provided $820.25 million through fiscal year 2031 for the Rural Energy for America Program (REAP). REAP provides grants and guaranteed financing to small businesses and agricultural producers in areas with populations of 50,000 or fewer. Funds can be used to support small and large wind generation along with other DERs and energy efficiency upgrades.

Incentives for commercial wind include but are not limited to:

- Federal and state tax incentives
- State and/or utility rebates
- Avoided cost of kWh not purchased from utility
- kWh sold back to the grid (net metering or net billing export credits)

4.2.3 Relationship to other technologies

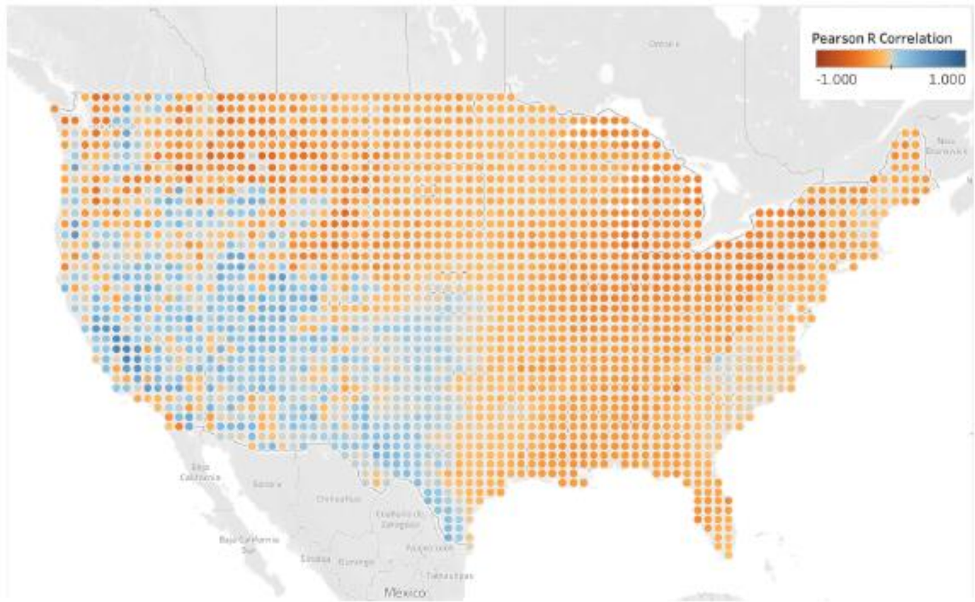
Distributed wind turbines and solar PV systems, sometimes paired with batteries, can offer complementary solutions for the supply of clean electricity at the customer site. Complementarity depends on the location of the system. Highly complementary applications would be installed

[120] Mone, Christopher and Maureen Hand, 2015 Cost of Wind Energy Review, National Renewable Energy Laboratory, revised May 2017.
[121] U.S. Department of Energy, 2020 Wind Energy Research and Development Highlights, January 2021.
[122] Ibid

somewhere that has a high solar resource during the day and a high wind resource at night. Lower complementarity occurs in locations where the timing of the wind and solar resources overlap, creating periods of too much and too little electricity. A recent study conducted by NREL studied seasonal and diurnal patterns in wind and solar profiles across the contiguous United States to illustrate sites where the combined wind and solar profiles were complementary.[123] The study used the Pearson coefficient, where a positive value means the generation from each resource type occurs at the same time and a negative value means they occur at different times (making the resources complementary). Figure 4-5 shows the results of this study, where dark orange represents sites that have more complementary resource profiles and dark blue represents non-complementary resource profiles.

The results of the NREL analysis show that regions in the Great Plains, Midwest, and Southeast are well-suited for co-located distributed wind and solar systems. The regions in blue, where wind and solar are not complementary, would be better suited for wind and battery co-located systems.

Figure 4-5. Annual daily-averaged complementarity (represented by the Pearson Correlation Metric) for 2013 in the contiguous United States



Data source: NREL

4.2.4 Technology research and development rates

Distributed wind technology is a relatively mature DER. Distributed wind research areas in the United States have a large focus on improving the competitiveness of the technology through system design optimization, uniform testing and certification for turbines and power electronics, and reducing hardware costs through advanced manufacturing processes.[124] Discussion of materials research and development rates can be found in Section 4.2.1.

[123] Clark, Caitlyn E. and Aaron Barker, *Wind and Solar Hybrid Power Plants for Energy Resilience*, National Renewable Energy Laboratory, January 2022.

[124] U.S. Department of Energy, 2020 Wind Energy Research and Development Highlights, January 2021.

5 FUEL CELLS

5.1 Fuel cell technology attributes and cost data

5.1.1 Overview

Fuel cells are a distributed generation technology that generate electricity without fuel combustion but rather through an electrochemical process that converts chemical energy contained within fuel into electricity. Similar to battery energy storage, a single fuel cell element contains a cathode, anode, and an electrolyte. Hydrogen is fed to the anode and oxygen to the cathode, generating a chemical reaction in the presence of a catalyst to generate DC electricity and water. Fuel cells consist of a cell “stack” typically made up of at least 100 individual cells as well as a fuel processor to convert the fuel supply into hydrogen for the stack and a power conditioner to convert the DC electricity generated into AC power.

DNV developed technology attributes and cost data for behind-the-meter fuel cell systems aligned with relevant residential and commercial customer segments. We assumed a combination of PEM CHP configuration and SOFC CHP configuration for the residential fuel cell application and a combination of MCFC and PAFC CHP configuration for the commercial fuel cell application. Although most stationary fuel cells installed in the United States at commercial sites are SOFC, we used MCFC and PAFC to represent CHP configurations more accurately at commercial sites with power requirements of more than 25 kW.

DNV reviewed fuel cell installation data in the United States and globally to identify recent system deployment trends in the residential and commercial market sectors and confirm appropriate system configurations and associated performance attributes and costs. We used industry reports to gather relevant U. S. fuel cell attribute and cost data and scaled costs to align with current year (2022) cost estimates for this analysis. We also used developer data sheets for specific products to confirm accurate performance attributes for the most relevant systems installed in the United States today. Finally, we used historical industry cost reports to identify and scale cost estimates and attributes with previous years of EIA segment-level surveys: RECS, CBECS, and MECS. The process is described in the following sections.

5.1.2 System configurations

DNV used CHP fuel cell installation data from DOE’s Advanced Manufacturing Office (AMO), stationary fuel cell (≥ 25 kW-AC) installation data from the Hydrogen Analysis Resource Center (HARC), and project data from California’s Self-Generation Incentive Program (SGIP) to identify representative system capacities for both the residential and commercial sectors and the appropriate fuel cell technologies assigned to each segment. These data were also useful in identifying fuel cell types, developers, and specific models installed in recent years.

Table 5-1. Fuel cell configurations, types, and representative system capacity

Market Segment	Configuration	Fuel Cell Type	Fuel Type	Representative Fuel Cell System Capacity
Residential	CHP Fuel Cell	PEMFC [a], SOFC [a]	Natural Gas	5 kW-AC
Commercial	CHP Fuel Cell	MCFC [c], PAFC [d]	Natural Gas	300 kW-AC

[a] PEMFC=polymer electrolyte membrane fuel cell.
[b] SOFC=solid oxide fuel cells.
[c] MCFC=molten carbonate fuel cell.
[d] PAFC= phosphoric acid fuel cell.

The majority (>95%) of U.S. CHP fuel cell installations in the last 10 years in the representative residential sector have been from developer ClearEdge who has since filed for bankruptcy and was acquired by Doosan in 2014.[125] Although its 5 kW-AC modular PEM fuel cell was used in residential applications, it was also installed commercially in multifamily buildings, schools, and hotels. Although data from residential installations in Japan and Europe support smaller systems (1 kW-AC to 2 kW-AC), data from the DOE CHP Installation Database and California's SGIP (CPUC 2023) support the 5 kW-AC representative system size. The availability of micro-CHP (less than (<50kW-AC) fuel cell products is currently limited in the United States, with only a small number of non-fuel cell micro-CHP systems available for installation. Additionally, micro-CHP residential CHP installations in the United States are typically installed in larger homes with higher energy requirements than the average U.S. home.

Information from additional developers present in the global market was also used to confirm attribute and cost data for polymer electrolyte membrane fuel cell (PEMFC) and SOFC systems, given the lack of developer data for this size and application in the United States. The PEMFC and SOFC types were chosen to represent the residential sector given the availability of relevant developer attribute and cost data and their popularity outside the United States. The majority of non-CHP stationary fuel cell commercial installations in the United States within the last 10 years have been SOFC, mainly from developer Bloom Energy with its Bloom Energy Server 5 and Energy Server 5.5 products at 300 kW-AC and 310 kW-AC, respectively.[126,127] Other developers with success deploying CHP fuel cells in the United States market include Doosan Fuel Cell with phosphoric acid fuel cells and Fuel Cell Energy with molten carbonate fuel cells and SOFCs.

Japan and Europe have experienced significant market growth compared to the respective history in deployment of PEMFC, SOFC, MCFC, and PAFC fuel cell CHP installations, with over 400,000 units installed in Japan through 2022[128] and over 18,000 in Europe through 2020.[129] This growth is largely due to incentives for residential applications and government deployment and pilot programs significantly reducing unit costs. Additionally, high electricity prices contribute to a more attractive spark spread[130] when compared with the U.S. market, further stimulating market growth in these regions. Data from developers such as Panasonic, Elcore, and PowerCell Group were also used to further align industry attribute and cost data for current year (2022) estimates, and used to update relevant attributes and cost metrics where limited data was available due to the lack of current U.S. market activity in specific segments.

5.1.3 Technology attributes

DNV assumed representative residential and commercial fuel cell systems are installed at sites with the appropriate space characteristics to site the system and accept the underground utilities

[125] "South Korea's Doosan buys U.S. fuel cell maker ClearEdge for $32.4 million," *Reuters* (July 20, 2014).
[126] Bloomenergy, The Bloom Energy Server, accessed February 25, 2024.
[127] Bloomenergy, The Bloom Energy Server 5.5, accessed February 25, 2024.
[128] Simander, Guenter and Patrick Vidovic, "Success factors for demonstration projects of small-scale stationary fuel cells in residential buildings," E3S Web Conference, Presentation, 2022.
[129] European Parliament FCH 2 JU Governing Board, *Assessment of the Fuel Cells and Hydrogen 2 Joint Undertaking (FCH 2 JU) Consolidated Annual Activity Report (AAR) 2020 by the FCH 2 JU Governing Board*, 2020.
[130] Spark spread is a metric commonly used to estimate the viability for CHP and other fuel-based systems given differences between electricity and natural gas (or other fuel prices) between different regions. The spark spread identifies the difference between the cost of electricity and the cost of fuel on a per energy unit basis, indicating if the cost of additional fuel needed for the system would be cheaper than purchasing electricity.

required for system operation (for example, fuel, water, electric).[131] Although low-temperature (LTPEM) and high-temperature (HTPEM) systems exist, DNV used only LTPEM systems when developing attribute and cost data due to the maturity of LTPEM stack technology and lack of market availability of HTPEM systems.[132] For commercial systems, while DNV assumed a nominal power output of 300 kW-AC as the representative system size for an average commercial installation, the modularity of these units could be used to achieve a higher power output for other commercial applications.

Additionally, DNV assumed these systems were not installed in remote locations where no grid power is available, but instead it assumed systems were installed in sites connected to the utility grid. In other words, systems had relatively consistent operational parameters over the life of the system, even if load following requires significant swings in power output to the site, typically provided by grid power. DNV also assumed natural gas was the primary fuel for each system, with additional discussion related to hydrogen-fueled systems and the relevant attribute and cost metrics.

5.1.4 System performance attributes

Table 5-2 details performance attributes for fuel cell systems installed in the United States for representative residential installations. The data are presented to align with previous years of EIA segment-level surveys for each customer segment starting with the residential sector from 2015 to 2022. Performance attributes for micro-CHP PEMFC and SOFC systems are similar and therefore are represented as a combined single system type for the residential sector. The performance attributes of this representative residential fuel cell system have not changed significantly over the last eight years, with overall system efficiency at nearly 80%.

Table 5-2. Residential fuel cell system performance attributes

Year	Fuel Cell Rep. System Capacity	Overall Efficiency	Capacity Factor	Fuel Input	Useful Thermal Output	Heat Rate	EUL
2015	4.5 kW-AC	85.0%	95%	8,764 MMBtu/hr (HHV)	2,385 MMBtu/hr	7,668 Btu/kWh	10 years
2016	4.5 kW-AC	85.0%	95%	8,764 MMBtu/hr (HHV)	2,385 MMBtu/hr	7,664 Btu/kWh	10 years
2017	5.0 kW-AC	85.2%	95%	8,764 MMBtu/hr (HHV)	2,385 MMBtu/hr	7,660 Btu/kWh	10 years
2018	5.0 kW-AC	85.2%	95%	8,764 MMBtu/hr (HHV)	2,385 MMBtu/hr	7,655 Btu/kWh	10 years
2019	5.0 kW-AC	85.2%	95%	8,764 MMBtu/hr (HHV)	2,385 MMBtu/hr	7,651 Btu/kWh	10 years
2020	5.0 kW-AC	85.4%	95%	8,764 MMBtu/hr (HHV)	2,385 MMBtu/hr	7,647 Btu/kWh	10 years
2021	5.0 kW-AC	85.5%	95%	8,764 MMBtu/hr (HHV)	2,385 MMBtu/hr	7,642 Btu/kWh	10 years
2022	5.0 kW-AC	85.5%	95%	8,764 MMBtu/hr (HHV)	2,385 MMBtu/hr	7,638 Btu/kWh	10 years

Note: MMBtu/hr=million British thermal units per hour; Btu/kWh=British thermal units per kilowatthour.

Table 5-3 highlights performance attributes for fuel cell systems installed in the United States for representative commercial installations aligning with previous years of EIA sector-level surveys for the commercial sector from 2012 to 2022. As in the residential sector, performance attributes for the combined representative commercial micro-CHP PEMFC and SOFC systems have not changed significantly over the last 10 years, while average representative commercial system capacities have generally increased.

[131] For commercial systems, sufficient space is assumed to be 40,000 square feet.

[132] Battelle Memorial Institute, *Manufacturing Cost Analysis: 1, 5, 10 and 25 kW Fuel Cell Systems for Primary Power and Combined Heat and Power Applications*, January 2017.

Table 5-3. Commercial fuel cell performance attributes

Year	Fuel Cell Rep. System Capacity	Overall Efficiency	Capacity Factor	Fuel Input (Btu/hr, HHV)	Useful Thermal	Heat Rate (Btu/kWh)
2012	200 kW-AC	80.0%	95%	3,480 MMBtu/hr (HHV)	929 Btu/hr	8,118 Btu/kWh
2013	200 kW-AC	80.0%	95%	3,477 MMBtu/hr (HHV)	927 Btu/hr	8,073 Btu/kWh
2014	200 kW-AC	80.2%	95%	3,473 MMBtu/hr (HHV)	926 Btu/hr	8,057 Btu/kWh
2015	250 kW-AC	80.2%	95%	3,464 MMBtu/hr (HHV)	925 Btu/hr	8,050 Btu/kWh
2016	250 kW-AC	80.4%	95%	3,449 MMBtu/hr (HHV)	922 Btu/hr	8,044 Btu/kWh
2017	250 kW-AC	80.5%	95%	3,449 MMBtu/hr (HHV)	922 Btu/hr	8,034 Btu/kWh
2018	250 kW-AC	80.5%	95%	3,449 MMBtu/hr (HHV)	922 Btu/hr	8,022 Btu/kWh
2019	300 kW-AC	80.5%	95%	3,449 MMBtu/hr (HHV)	922 Btu/hr	8,019 Btu/kWh
2020	300 kW-AC	80.6%	95%	3,448 MMBtu/hr (HHV)	922 Btu/hr	8,019 Btu/kWh
2021	300 kW-AC	80.6%	95%	3,448 MMBtu/hr (HHV)	922 Btu/hr	8,017 Btu/kWh
2022	300 kW-AC	80.6%	95%	3,447 MMBtu/hr (HHV)	922 Btu/hr	8,012 Btu/kWh

Note: Btu/hr=British thermal units per hour; Btu/kWh=British thermal units per kilowatthour.

5.1.5 System cost data

Capital costs for residential and commercial fuel cells were collected for multiple categories to accurately represent the differences in component costs and labor and installation costs throughout the analysis timeframe. The five cost categories were:

- Stack capital costs
- Manufacturing capital costs
- CHP hardware costs
- Fuel cell BOP hardware costs
- System assembly and installation costs

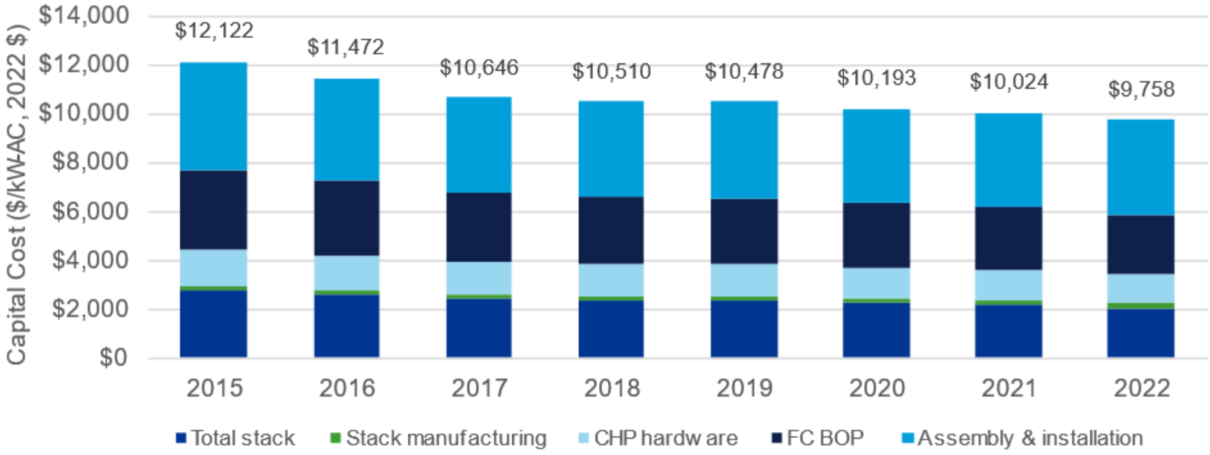
Capital cost data for fuel cell systems were collected for each system configuration using a blended approach from multiple data sources to capture the average representative system cost characteristics in 2022 constant (real) dollars. Historical cost data for the residential segment (PEMFC and SOFC) was gathered from Battelle's cost analysis for 1-, 5-, 10-, and 25-kW-AC fuel cell CHP systems and from the California Energy Commission's (CEC) assessment of small CHP applications in California.[133,134] This cost data were then scaled to the current year (2022) using relevant labor and manufacturing costs for their respective cost categories and appropriate GDP chain-type price indices to scale hardware costs when costs were not explicitly available.

As mentioned previously, residential fuel cell CHP installations in the United States have experienced overall limited growth in deployment in recent years due to high capital costs and the lack of market applicability and consumer demand for these systems at the residential level. However, cost declines (supported by markets outside of the United States) in recent years due to technology advances which could stimulate increased market growth in the residential sector,

[133] Battelle Memorial Institute, *Manufacturing Cost Analysis: 1, 5, 10 and 25 kW Fuel Cell Systems for Primary Power and Combined Heat and Power Applications*, January 2017.
[134] California Energy Commission, *A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California*, March 2019.

especially if a continued need exists for more resilient backup systems in single-family and smaller multifamily applications (Figure 5-1).

Figure 5-1. U.S. average residential fuel cell system capital costs ($/kW-AC, 2022 $)



Capital cost data for commercial fuel cell systems were collected using a similar blended approach from multiple data sources to capture the average representative system cost characteristics presented in 2022 constant (real) dollars. Historical cost data for the commercial segment (MCFC and PAFC) were gathered from DOE's CHP Cost and Performance fact sheet for fuel cells and from the CEC's assessment of small CHP applications in California.[135,136] These cost data were then scaled to the current year (2022) using relevant labor and manufacturing costs for their respective cost categories and appropriate GDP chain-type price indices to scale hardware costs when not explicitly available.[137] DNV also used actual installed system costs for multiple systems in different years throughout the analysis timeframe to benchmark and scale base-year and current-year system costs. These costs were gathered from the DOE CHP Project Profiles Database[138] and from conversations with select developers.

Figure 5-2 shows U.S. average commercial fuel cell system capital costs. Although costs are high compared with other distributed generation technologies, commercial fuel cell CHP systems are more cost-effective than residential installations, largely due to economies of scale in unit production, general customer awareness and aligned use cases in the commercial sector, and more appropriate facility attributes such as more stable load profiles and aligned thermal and power requirements. Capital and performance incentives as well as alternative CHP fuel rates (depending on the jurisdiction anywhere between the wholesale and retail fuel rates) present in some jurisdictions have made commercial fuel cell CHP systems cost-effective in many cases, and declining system costs have also contributed to steady deployment in the commercial sector.

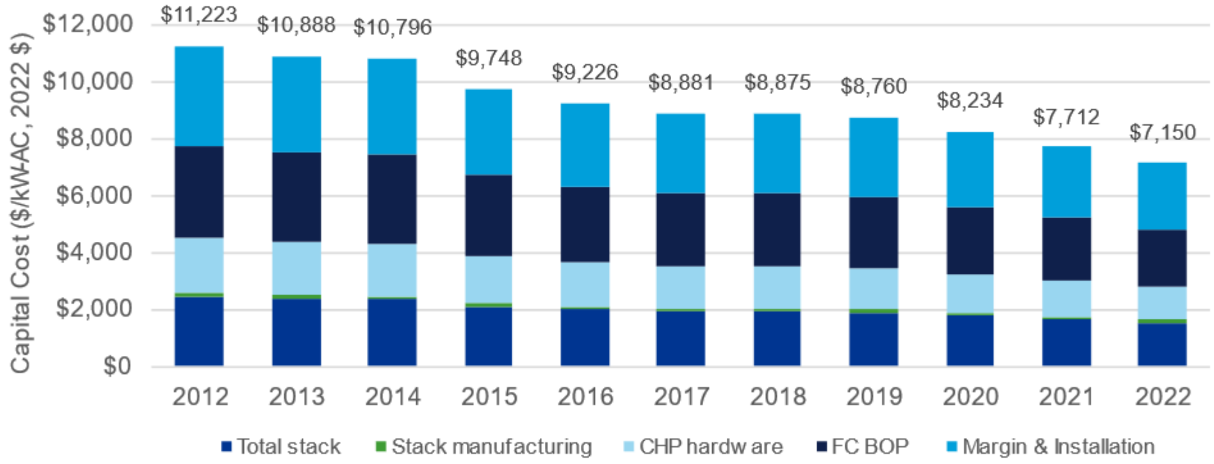
[135] U.S. Department of Energy, Better Buildings, Onsite Energy, CHP Project Profiles Database, accessed October 11, 2023.

[136] U.S. Department of Energy, Energy Efficiency & Renewable Energy, Combined Heat and Power Technology Fact Sheet Series, Fuel Cells, July 2016.

[137] California Energy Commission, *A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California*, March 2019.

[138] U.S. Department of Energy, Better Buildings, Onsite Energy, CHP Project Profiles Database, accessed October 11, 2023.

Figure 5-2. U.S. average commercial fuel cell system capital costs ($/kW-AC, 2022 $)



5.1.6 O&M cost data

DNV compiled variable O&M costs ($/kWh) in 202 constant (real) dollars for all fuel cell systems, including estimates for both general system maintenance and parts replacement as well as fuel costs. DNV assumed annual contracted maintenance costs for both residential and commercial systems were included, representing general maintenance labor costs for routine system inspection, ancillary part (for example, filters, sensors, spark plugs, gaskets, valves) adjustments, and/or replacements. Major system overhauls and large parts (for example, catalyst, stack) replacement were also included and annualized over a 5–10-year period to determine the final $/kWh costs component. DNV did not include a separate discounted CHP fuel rate but instead used U.S. average residential and commercial natural gas delivery rates over the analysis timeframe (2012--2022) from EIA.[139]

DNV assembled variable O&M costs using DOE's CHP Fact Sheet Series and from the CEC's assessment of small CHP applications in California as a baseline and supplemented with developer data where appropriate.[140,141] Baseline O&M costs for general system maintenance and stack replacement were gathered for 2019 and scaled to the current year (2022) and subsequent historical years (2021 and 2020) using relevant U.S. average labor costs and the annual consumer price index (CPI) to adjust for inflation.

Figure 5-3 shows U.S. average residential fuel cell system O&M costs. O&M costs for fuel cell CHP systems have generally been consistent over the past 10 years for both residential and commercial applications. Labor costs and part replacement costs have not changed significantly enough to produce large cost swings in either the residential or commercial sectors.

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[139] U.S. Energy Information Administration, Natural Gas Prices annual data, accessed November 8, 2023.

[140] U.S. Department of Energy, Energy Efficiency & Renewable Energy, Combined Heat and Power Technology Fact Sheet Series, Fuel Cells, 2016.

[141] California Energy Commission, *A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California*, March 2019.

Figure 5-3. U.S. average residential fuel cell system O&M costs ($/kWh, 2022 $)

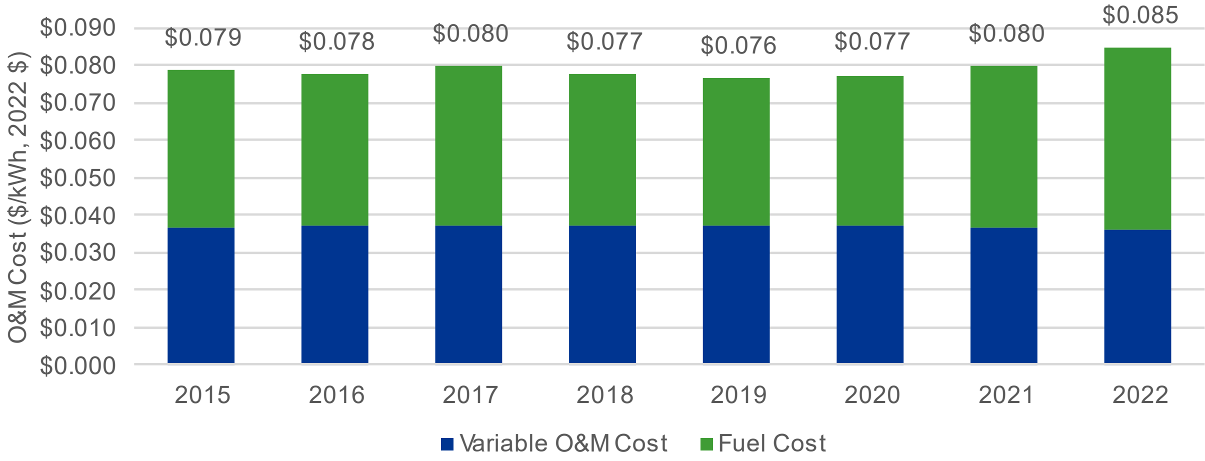
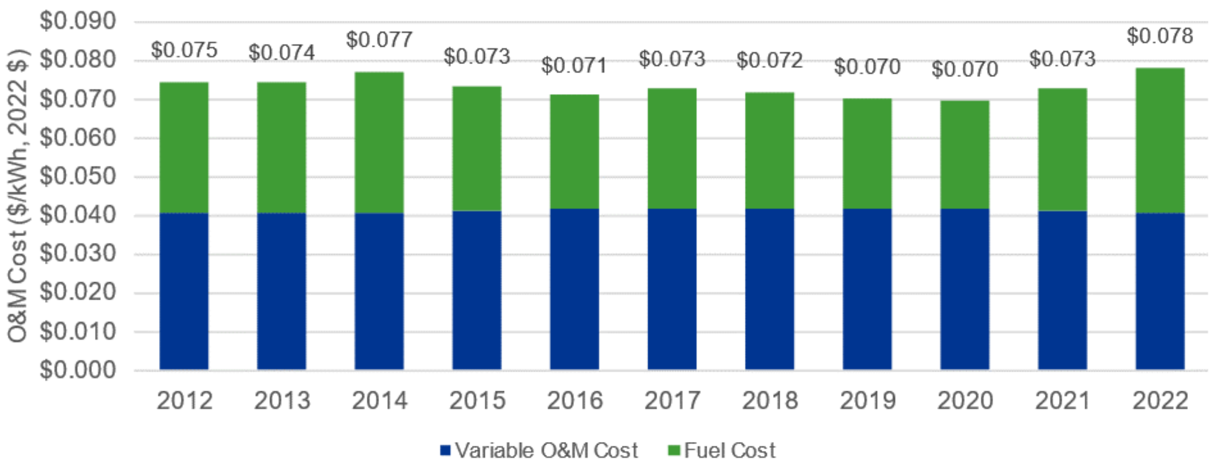


Figure 5-4 shows U.S. average commercial fuel cell system O&M costs. Total (including fuel costs) commercial variable O&M costs are generally lower than residential O&M costs for fuel cell systems largely due to lower fuel costs for the commercial sector. Routine maintenance, inspection, and general parts replacement is lower in residential systems due to the smaller system size and simpler system complexity compared with the variety of commercial installation types and use cases.

Figure 5-4. U.S. average commercial fuel cell system O&M costs ($/kWh, 2022 $)



5.2 Fuel cell market discussion

5.2.1 Resource and material availability trends

The fuel cells analyzed in this study require a source of hydrogen for the anodic reactions. Systems that operate at higher temperatures, MCFCs and SOFCs, can include a methane reformation process to produce hydrogen as a part of the fuel cell system itself.[142] However, generally obtaining a supply of hydrogen of sufficient purity and at a reasonable cost is the biggest resource availability hurdle that fuel cells face. Hydrogen is not naturally available in the environment, like natural gas, so it must be manufactured. Manufacturing hydrogen requires an energy investment to create the

[142] This study modeled MCFCs and SOFCs that include a methane reformer.

desired hydrogen fuel. The main technologies currently in use for hydrogen production are steam reforming of methane, partial oxidation, and electrolysis of water. Steam reforming of methane accounts for almost all the commercially available hydrogen produced in the United States.[143]

5.2.2 Government policies and market incentives

The United States has identified fuel cells as a key component of its U.S. National Clean Hydrogen Strategy and Roadmap.[144] DOE's Hydrogen and Fuel Cell Technologies Office supports the fuel cell industry by supporting research, development, and demonstrations of fuel cell technologies.[145] Currently, the United States' interventions relating to fuel cells focus mostly on supporting R&D, which is discussed in more detail in Section 5.2.4. In addition to R&D programs, the United States offers various financial incentives to support the implementation of fuel cell projects.

The main federally offered financial incentive for fuel cells is the 2022 expansion by the IRA of the 48C Advanced Energy Project Credit.[146] The expansion increased the funding of this competitively awarded tax credit to $10 billion. Projects can receive an investment tax credit of up to 30%. Property must be placed in service after being awarded the 48C credit by the IRS to be eligible for the credit. The IRS will award all Round 1 48C credits by March 31, 2024.[147] Any project that expands clean energy manufacturing and recycling, further develops critical material refining, or reduces greenhouse gas (GHG) emissions at industrial facilities can qualify. About 40% of funds are dedicated to projects in communities with closed coal plants or mines. The IRA also includes the Elective Payment for Energy Property credit, which allows non-tax-paying organizations such as government and non-profits to transfer the 48C tax credit to a tax-paying entity such as a contractor who can then discount the project for the end user.

For homeowners, the Residential Clean Energy Tax Credit supports fuel cells. For projects placed in service in 2022 through 2032, the tax credit can cover 30% of the project costs at a maximum of $500 per half kW-AC of power capacity. Qualifying fuel cells must have at least 0.5 kW-AC of capacity and an electricity-only generation efficiency of at least 30%. Qualifying project costs for the Residential Clean Energy Tax Credit for fuel cells include property costs for "an integrated system comprised of a fuel cell stack assembly and associated balance of plant components that convert a fuel into electricity using electrochemical means" as well as "any labor costs properly allocable to the on-site preparation, assembly, or original installation of the [fuel cell] property and for piping or wiring to interconnect such property to the home."[148]

Seventeen states offer financial incentives for fuel cells and an additional four states have legislation to encourage the growth of fuel-cell industries within their borders.[149] The vast majority of the incentive programs focus on fuel cell use in vehicles including for facility fleets that may be behind-the-meter; however, the states of New Jersey, Virginia, Colorado, and South Carolina have initiatives that could support fuel cells in buildings. In 2020, New Jersey created the New Jersey Fuel Cell Task Force tasked with increasing the use of fuel cells in the state through supporting fuel

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[143] U.S. Energy Information Administration, Hydrogen explained: Production of hydrogen, accessed October 11, 2023.
[144] U.S. Department of Energy, *U.S. National Clean Hydrogen Strategy and Roadmap*, accessed October 11, 2023.
[145] U.S. Department of Energy, Hydrogen and Fuel Cells Technology Office, accessed October 6, 2023.
[146] U.S. Department of Energy, Qualifying Advance Energy Project Credit (48C) Program, accessed October 6, 2023.
[147] U.S. Internal Revenue Service, Frequently Asked Questions about the Qualifying Advanced Energy Project (48C) Credit, accessed January 2, 2024.
[148] U.S. Internal Revenue Service, Instruction for Form 5695, accessed January 2, 2024.
[149] U.S Department of Energy, Hydrogen Laws and Incentives, accessed October 6, 2023.

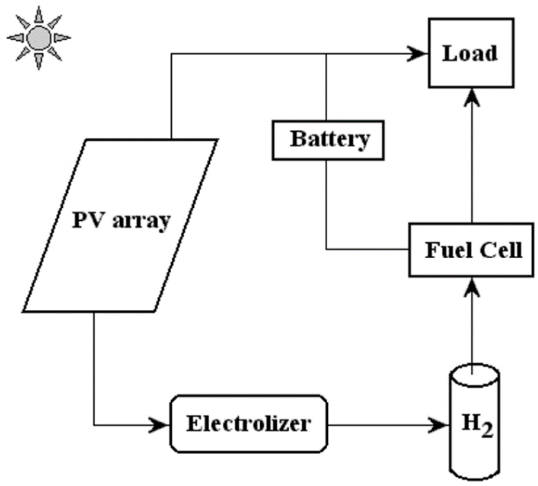
cell infrastructure and public education. Additionally, New Jersey's Clean Energy Program offers financial incentives for CHP and Fuel Cell installations.[150] Projects can receive a maximum of 30% of project costs up to $1 million if they achieve an annual electric system efficiency of at least 40%. Virginia's Green Jobs Tax Credit offers employers a $500 tax credit for each new green job created with a salary of $50,000 or more and targets the hydrogen and fuel cell industry. In 2021, Colorado directed its Department of Natural Resources to create an industry-driven energy sector career pathway for the 2022–2023 academic year that includes careers relating to hydrogen fuel cell technology. South Carolina offers a 100% sales tax exemption to any equipment powered by fuel cells or any equipment used predominantly to manufacture fuel cells.[151] Lastly, utility companies have provided some incentives for fuel cell technologies. For example, PSEG Long Island offered a Fuel Cell Feed-in Tariff with enrollment from 2016 to 2017 to encourage the connection of fuel cell technologies to the grid. Ultimately, three commercial or industrial projects representing 39.8 MW were accepted into the program.[152]

5.2.3 Relationship to other technologies

Hydrogen produced by electrolysis has the advantage of being highly purified, which eliminates the problems of catalytic carbon-monoxide poisoning that some fuel cells are subject to. When the electricity for electrolysis is generated using a renewable energy system, such as wind or solar PV, the hydrogen is produced without emitting any GHGs.

Figure 5-5 illustrates how a solar PV system can be paired with battery storage and a fuel cell to produce carbon-free electricity at the building site. Hybrid fuel cell systems paired with a renewable DER system can provide energy to the building site whenever it is needed, while a small-scale wind or solar PV DER system is subject to the diurnal nature of the wind and solar resource. The hybrid system depicted in the figure below consists of a solar PV system coupled with an electrolyzer to produce hydrogen, a fuel cell that converts hydrogen to electricity, a hydrogen storage tank, and a battery storage system.

Figure 5-5. Diagram of a solar PV + fuel cell hybrid energy system



Data source: Solar PV-Hydrogen-PEM Fuel Cell System[153]

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[150] New Jersey Clean Energy Program, Combined Heat and Power, accessed October 6, 2023.
[151] U.S Department of Energy, Hydrogen Laws and Incentives, accessed October 6, 2023.
[152] PSEG Long Island, Fuel Cell Feed-in Tariff IV, accessed January 2, 2024.
[153] Al-Baghdadi, Maher, Solar PV-Hydrogen-PEM Fuel Cell System, Scholarly Community Encyclopedia, updated October 29, 2020.

5.2.4 Technology research and development rates

Although this study aims to characterize the stationary fuel cell market, most R&D efforts in the United States have focused on the automotive industry. The automotive industry's fuel cell R&D can be used to scale up fuel cell production and help reduce costs for other markets such as for buildings. The focus of R&D for heavy duty applications is on materials and components as well as systems in the United States. These efforts support clean hydrogen end use and broader market adoption objectives as outlined in the National Clean Hydrogen Strategy and Roadmap.[154]

Material and components research areas include:

- High activity, durable catalysts and electrodes
- Innovative membranes and ionomers
- Durable high-performance membrane-electrode assemblies
- Advanced bipolar plates and coatings

Systems research includes:

- System design and operating conditions
- Standardized stacks and modular systems
- Improved manufacturing and supply chain
- Advanced BOP components and subsystems
- Advanced recycling of systems and stacks

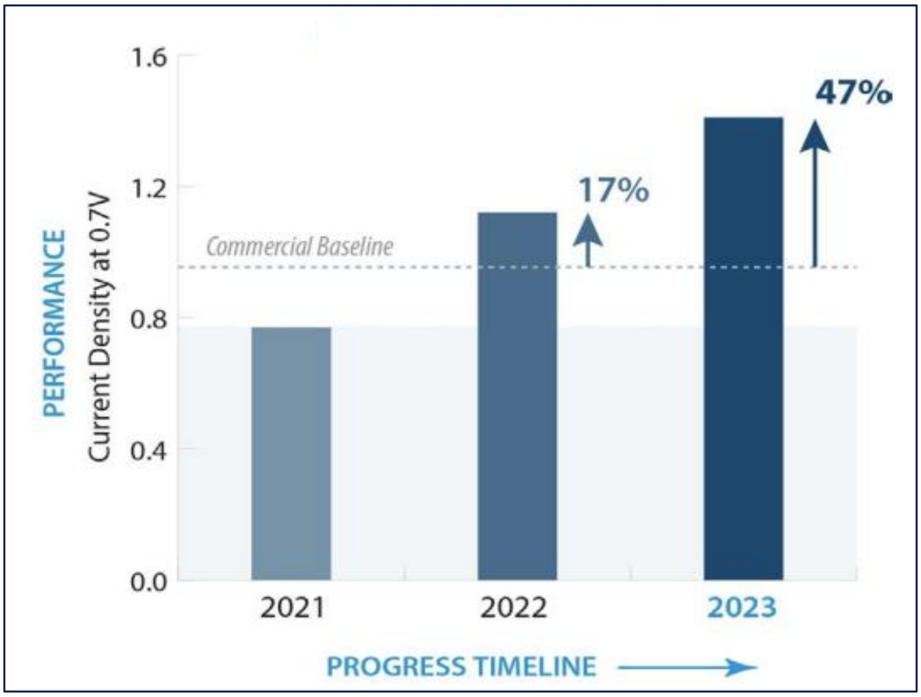
DOE's Hydrogen and Fuel Cell Technologies Office (HFTO) has funded fuel cell R&D since 2006. The fuel cell R&D activities are to address critical technical hurdles including, "cost, durability, efficiency, and overall performance of components such as the polymer electrolyte membranes, oxygen reduction electrodes, advanced catalysts, bipolar plates, etc."[155] The HFTO is targeting achieving long-haul truck fuel systems that cost $80/kW-AC and have 25,000 hours of durability by 2030.[156] Other areas of research include advanced manufacturing to reduce cost and enhance reliability, as well as hydrogen fuel production and delivery (commonly referred to as hydrogen infrastructure). Many fuel cell companies are transitioning their manufacturing processes to high-throughput methods to meet volume and cost targets. As previously discussed in Section 5.2.2, the 2022 IRA includes tax credits and other incentives for clean hydrogen and fuel cell technologies—either by extending existing federal tax credits, increasing existing federal tax credits, or creating new federal tax credits. The new Clean Hydrogen Production tax credit (45V) creates a new 10-year incentive for clean hydrogen production that can be further increased by tax credits claimed under Section 48. This new tax credit is expected to jump-start the domestic hydrogen fuel industry.

The Million Mile Fuel Cell Truck Consortium (M2FCT) is a DOE-funded consortium of national labs that was formed to overcome durability and efficiency challenges in Polymer electrolyte membrane fuel cells (PEMFCs) for heavy-duty vehicle applications. The M2FCT uses a "team of teams approach" with many private companies to advance efficiency and durability of PEMFCs for heavy duty vehicle applications at a lower cost than what is currently available. This consortium has had several recent breakthroughs in the research it is conducting in materials and components—

[154] U.S. Department of Energy, *U.S. National Clean Hydrogen Strategy and Roadmap*, accessed October 11, 2023.
[155] U.S. Department of Energy, Hydrogen and Fuel Cell Technologies Office Budget, accessed October 11, 2023.
[156] Papageorgopoulos, Dimitrios, Fuel Cell Technologies Overview, U.S. Department of Energy, The Hydrogen and Fuel Cell Technologies Office, Presentation, June 6, 2023.

specifically, high-performance, membrane-electrode assemblies. Recent M2FCT research on new electrode design in PEMFCs showed improved performance of up to 50%, compared to PEMFCs with state-of-the-art conventional electrodes.[157] Another recent development by the M2FCT improved membrane-electrode assembly performance by more than 45% compared with a commercial baseline. Innovations in catalysts developed by the consortium led to the performance improvement.[158] Figure 5-6 shows the progress timeline of the M2FCT research between 2021 and 2023.

Figure 5-6. Progress of end of test membrane electrode assembly performance with M2FCT developed catalysts, 2021–2023



Data source: U.S. Department of Energy Hydrogen and Fuel Cell Technologies Office

Fuel cell research and development rates are expected to continue increasing in the United States, with the increased funding and interest in hydrogen as a means to reduce fossil fuel use.

5.2.5 Hydrogen use for fuel cells

With the exception of direct methanol fuel cells, fuel cells require a source of hydrogen for the anodic reactions. Hydrogen can either be supplied directly from a supply tank or it can be produced on-site. The main technologies in use for hydrogen production are steam reforming of methane, partial oxidation, gasification of biomass or other solid fuels (for example, coal and municipal waste), and electrolysis of water.

Currently, DOE does not use a color code to characterize the source, production technology, and carbon capture of hydrogen—which is something that some producers and other organizations use to categorize hydrogen. For example, green hydrogen is commonly categorized as hydrogen formed through electrolysis powered by renewable electricity. Green hydrogen is produced without any greenhouse gas emissions, but it currently makes up a small portion of the overall hydrogen

[157] Choi, Charles, "Hydrogen Fuel Cells Find Their Groove," *IEEE Spectrum* (June 14, 2023).
[158] Papageorgopoulos, Dimitrios, Fuel Cell Technologies Overview, U.S. Department of Energy, The Hydrogen and Fuel Cell Technologies Office, Presentation June 6, 2023.

produced because its production is expensive. Current green hydrogen production is very limited, and large upscaling in electrolyzer capacity would be necessary to expand production.

Although many current natural gas-fired equipment may be adapted to operate with a blended hydrogen and natural gas mixture, fuel cells require pure hydrogen. In the future, where hydrogen may be blended into existing natural gas pipelines, hydrogen separation technologies would be required at the point of use for fuel cells. On-site hydrogen production for fuel cells is one of the biggest limiting factors for customer-sited systems. In the residential sector, the majority of the fuel cell installations are at the demonstration level, and they use an on-site electrolyzer and solar panels to convert solar energy to hydrogen.

Hydrogen end users need access to hydrogen, either through production of hydrogen on-site or from a nearby hydrogen production facility to avoid high transportation costs, and their facility needs hydrogen storage and handling equipment. According to DNV proprietary project data, blending of hydrogen with natural gas is already possible, and demonstration projects are ongoing for both blending into natural gas pipelines and site-level blending at the point of use. The maximum blending percentage possible in existing equipment depends on the burner type. The current industry assumption for industrial end users is that blending up to 20% (by volume) can be safely done without changing the burners of the hydrogen-fired equipment. This assumption is generally the same assumption made for hydrogen fuel blending in commercial and industrial CHP equipment, based on DNV proprietary project data.

6 COMBINED-HEAT-AND-POWER SYSTEMS

6.1 CHP system technology attributes and cost data

6.1.1 Overview

DNV developed technology attributes and cost data for behind-the-meter CHP systems aligned with relevant commercial and industrial customer segments. CHP, or cogeneration, is a set of mature technologies that provide both electricity and thermal energy from a single generation source. Distributed CHP systems are installed at individual customer sites and are typically sized to meet a site's thermal energy requirements (heating and/or cooling) and can offset a portion of the site's electricity, as well as inject power back into the grid when applicable. DNV reviewed CHP installation data in the United States to identify recent system deployment trends in the commercial and industrial market sector and confirm appropriate system configurations and associated performance attributes and costs. This data informed the selection of specific prime mover types and sizes to accurately reflect installation trends within the most prominent market segments and associated site characteristics within the commercial and industrial sectors. The term *prime mover* refers to the specific engine, turbine, or fuel cell converting the air and fuel supply into kinetic energy used in a generator or heat exchanger to produce electricity or thermal energy for on-site use.

DNV used DOE and U.S. Environmental Protection Agency (EPA) reports and fact sheets to gather current and historical CHP performance and historical cost data, and then it scaled costs to align with 2022 constant (real) dollar cost estimates for this analysis. Additionally, DNV also used developer data sheets for specific products and DOE CHP project profiles to confirm accurate performance attributes for the most relevant systems installed within the analysis timeframe. Finally, DNV used historical industry cost reports to identify and scale cost estimates and attributes with previous years of EIA's CBECS and MECS. The process is described in the following subsections.

6.1.2 System configurations and technology attributes

DNV used CHP installation data from DOE[159] supplemented with project data from California's SGIP[160] to identify representative system capacities for both the commercial and industrial sectors and the appropriate CHP prime mover types assigned to each sector. DNV identified three separate prime movers and capacities to represent commercial CHP systems, and it identified three prime movers and eight capacities to represent industrial CHP systems.

Annual installations and overall capacity installed in the commercial CHP sector has decreased over the past five years largely due to price competitiveness with other distributed generation technologies and the increasing ability for other technology configurations to provide similar resiliency and reliability benefits for commercial end uses. The COVID-19 pandemic also contributed to a decrease in the number of installations within the past three years.

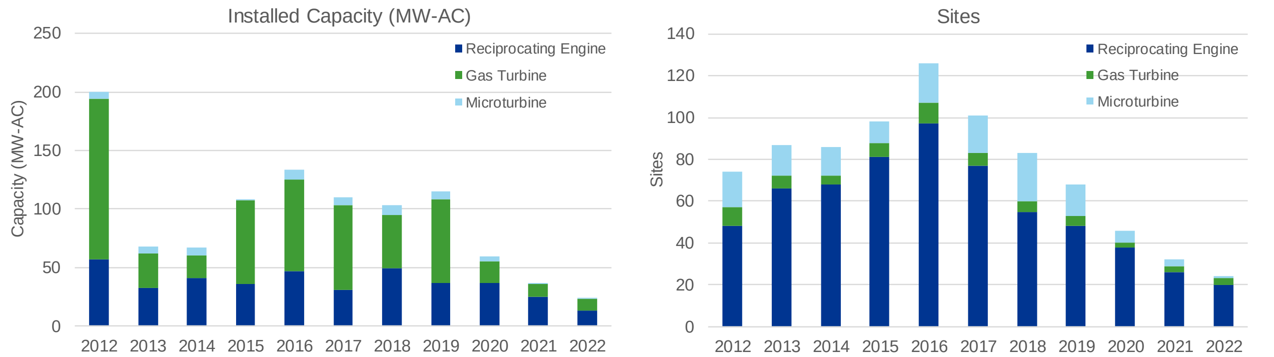
Figure 6-1 shows annual commercial CHP installations, annual capacity installed over the last 10 years, and average site-level system capacities for each year by prime mover type. This commercial data includes natural gas- and oil-fueled reciprocating engines, natural gas-fueled gas turbines, and microturbine CHP systems to align with the commercial systems included in this analysis. The emergence of packaged CHP systems during this time period allowed for smaller systems to be

[159] U.S. Department of Energy, Better Buildings, Onsite Energy, Microgrid and CHP Installation Databases, accessed October 11, 2023.

[160] California Public Utilities Commission, Download Data, Self Generation Incentive Program (SGIP) Data, accessed October 11, 2023.

installed in commercial and institutional facilities,[161] further aligning with the system capacities evaluated for the commercial sector. Commercial CHP installations in the last 10 years have largely been natural gas reciprocating engines, whereas the majority of commercial CHP capacity is from gas turbines installed in commercial facilities with greater power and thermal requirements. Microturbines also make up a small portion of installations and overall capacity in the commercial sector.

Figure 6-1. U.S. annual commercial CHP installations (2012–2022)

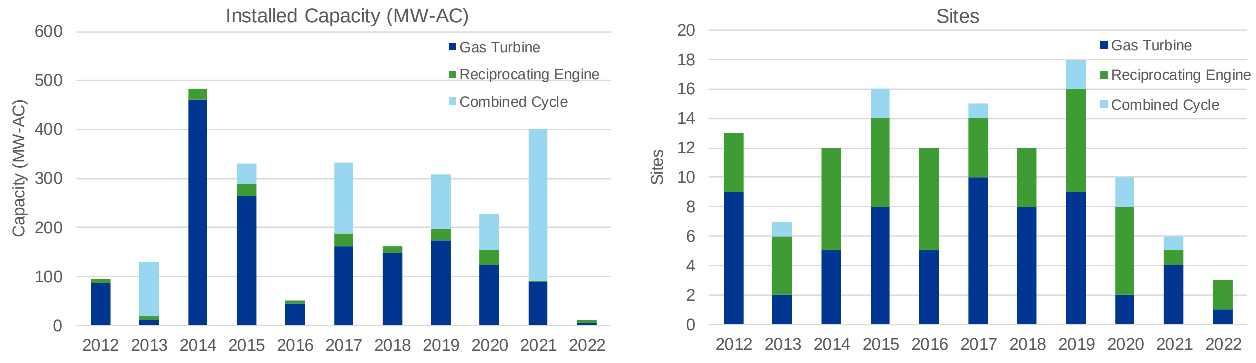


Average Capacity (MW-AC)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Reciprocating Engine	1.2	0.5	0.6	0.4	0.5	0.4	0.9	0.8	1.0	1.0	0.7
Gas Turbine	15.3	4.9	4.8	10.1	7.9	12.0	9.1	14.2	9.4	3.6	3.4
Microturbine	0.4	0.4	0.5	0.1	0.4	0.4	0.4	0.5	0.7	0.3	0.3

Figure 6-2 shows U.S. industrial CHP installations from 2012 through 2022. Average system capacities for industrial CHP applications are much larger than commercial installations when comparing based on the prime movers included in this analysis. However, given the large system capacities and complex engineering required to deploy systems in the industrial sector, annual installation trends are more variable than in the commercial sector. Largely due to the effects of the COVID-19 pandemic, industrial installations also declined from 2020 to 2022. Figure 6-2 shows annual industrial CHP installations and capacity installed over the last 10 years, including reciprocating engines, gas turbines, and combined-cycle CHP systems fueled only by natural gas to align with the industrial systems included in this analysis.

[161] Institutional facilities in this context are a subset of the commercial sector, representing facilities typically pursuing social, charitable, religious, and educational activities, such as colleges and universities, prisons, and other government and/or campus-type facilities.

Figure 6-2. U.S. annual industrial CHP installations (2012–2022)



Average Capacity (MW-AC)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Gas Turbine	9.6	5.4	92.2	33.0	9.0	16.2	18.3	19.3	61.5	22.3	4.6
Reciprocating Engine	2.2	2.1	3.2	3.9	0.8	6.4	3.7	3.6	5.1	2.3	2.5
Combined Cycle	-	111.0	-	21.1	-	145.0	-	54.7	37.0	309.8	-

DNV collected performance and cost data on the following representative CHP systems to reflect recent capacity trends in the commercial and industrial CHP sectors. DNV based representative system capacities on the most common commercial and industrial segments to align with previous years of EIA's CBECS and MECS. DNV also based performance and cost data on the most common thermal recovery option for selected systems where applicable as identified in DOE's CHP Fact Sheet Series[162] for specific technologies. Different prime movers are configured for specific thermal applications at specific capacities, and different prime movers have multiple thermal recovery options based on the end-use application. These selections also aligned with thermal recovery types for the most prevalent commercial and industrial subsectors. Table 6-1 shows the CHP configuration, prime mover and thermal recovery types, and representative system capacities used in this study.

Table 6-1. CHP configurations, types, and representative system capacities

Market Segment	Prime Mover Type	Thermal Recovery	Fuel Type	Representative System Capacity
Commercial	Reciprocating Engine (Gas)	Hot Water (Rich burn)	Natural Gas	300 kW-AC
	Reciprocating Engine (Oil)	Hot Water	Distillate fuel oil	350 kW-AC
	Gas Turbine	Hot Water & Steam	Natural Gas	3,300 kW-AC
	Microturbine	Hot Water & Steam	Natural Gas	200 kW-AC
Industrial	Reciprocating Engine (Gas)	Hot Water & Steam (Lean burn)	Natural Gas	1,000 kW-AC
				3,000 kW-AC
	Gas Turbine	Process Heat, Hot Water & Steam	Natural Gas	5,000 kW-AC
				10,000 kW-AC
		Process Heat & Steam		25,000 kW-AC
				40,000 kW-AC
	Combined Cycle	Process Heat & Steam	Natural Gas	100,000 kW-AC
				375,000 kW-AC

162 U.S. Department of Energy, Better Buildings, Onsite Energy, CHP Technology Fact Sheets, accessed October 11, 2023.

DNV assumed representative commercial and industrial CHP systems are installed at sites with the appropriate space characteristics to site the system and accept the underground utilities required for system operation (for example, fuel, water, electric). DNV assumed all representative systems were fueled by natural gas, except for the oil-fired reciprocating engine, which was assumed to be fueled by distillate fuel oil. In some instances when developing cost and performance attributes, assumptions for low-sulfur diesel engines were used given its similarity to distillate fuel oil. Additionally, while CHP installations that serve remote communities and/or off-grid sites are common, DNV only used cost and performance characteristics for natural gas systems assumed to be already connected to the utility grid and not installed in remote locations where no grid power is available. This approach assumes relatively consistent operational parameters over the lifetime of the system, even if load following requires significant swings in power output to the site, typically provided by grid power. Oil-fired reciprocating engines have largely been installed for utility or municipal sites to enhance resiliency and redundancy and to provide for standby applications at remote locations. Therefore, we have focused on cost and performance data that align with these characteristics for oil-fired reciprocating engine CHP systems.

6.1.2.2 Natural gas reciprocating engine CHP Systems

The most commonly used (by both installed capacity and number of installations) CHP technology in the commercial and industrial sectors are natural gas reciprocating engines, providing hot water, chilled water, steam, and (in some cases) chilled thermal fluid for a variety of thermal end-uses. Gas reciprocating engines less than 1 MW-AC are typically installed in multifamily buildings, office buildings, athletic facilities, hotels, nursing homes, schools, small hospitals, and small universities. Institutional installations are commercial facilities or groups of facilities that typically require larger than 1 MW-AC CHP systems. Industrial installations are also typically larger than 1 MW-AC and can be installed in a variety of industries such as chemicals, food processing, and general manufacturing. Gas reciprocating engine installations larger than 1 MW-AC are also common at institutional buildings and campuses such as hospitals, universities, and nursing homes. Although diesel reciprocating engines are more efficient than gas engines, gas engines are now widely used in CHP applications due to their lower emissions.

Natural gas reciprocating engines operate using a spark ignition cycle (that is, Otto Cycle). DNV assumed hot water thermal recovery for the representative commercial reciprocating engine and hot water and steam for industrial systems. Rich burn engines have higher thermal efficiencies in the production of hot water and are common in smaller systems; therefore, they were used for performance and cost data when assessing smaller systems. Rich burn engines operate with a match of air and fuel quantities that result in complete combustion, whereas lean burn engines operate with air-to-fuel ratios higher than the stoichiometric ratio. For lean burn engines, this higher ratio results in lower combustion chamber temperatures and therefore results in lower nitrogen oxide (NOx) emissions. Lean burn engines are common in systems above 1 MW and were used when collecting performance and cost data based on hot water and steam recovery in industrial systems.

6.1.2.3 Oil-fired reciprocating engine CHP systems

Oil-fired reciprocating engines are a mature technology that have been installed in the United States for traditional power applications throughout the past century and for CHP applications since the 1980s. Oil-fired reciprocating engines operate using a compression ignition cycle, which makes them more efficient than spark ignition engines because of the higher compression ratio. The majority of oil-fired reciprocating engine CHP systems are installed at remote sites to provide backup power, improve resiliency and power reliability, and supplement grid power and thermal energy.

These installations generally provide power applications that serve remote government facilities, critical infrastructure, and remote community and village sites.[163]

Based on the data from DOE's CHP Installation Database, only nine oil-fired reciprocating engine CHP systems have been installed in the United States since 2012, and the last was installed in 2016 to provide power and thermal energy to Saint Paul Island, a remote island in Alaska.[164] As mentioned above, while federal and state emission requirements have limited the deployment of oil-fired CHP systems compared with natural gas-fired systems, fuel costs have played a bigger role in limiting the deployment of these systems to remote locations where access to natural gas is limited.

6.1.2.4 Gas turbine CHP systems

Gas turbine CHP systems are available in larger capacities and serve different application types compared with the other representative commercial and industrial CHP systems. Compared with larger combined-cycle gas turbine systems, the representative systems in this category are all simple cycle and typically serve 5 MW-AC to 40 MW-AC applications. Microturbines are also smaller simple cycle gas turbines but are characterized differently based on their applications serving lower power and thermal requirements.

Representative gas turbines are common at a variety of industrial and institutional sites (e.g., large colleges and universities and hospital campuses) because the turbines can produce high-temperature exhaust efficiently. High-temperature exhaust is typically used as process heat in industrial applications or to generate steam for industrial and institutional facilities and/or campuses. Hot water and chilled water can also be produced, and this ability is more common among smaller gas turbine installations. Gas turbine efficiency generally increases according to size. The smallest representative size system in the commercial sector is the least efficient and least cost-effective, on a per-unit basis, and large industrial systems (more than 20 MW-AC) are more efficient and highly cost-effective compared with other prime mover types.

6.1.2.5 Microturbine CHP systems

Although larger gas turbine CHP systems have existed for several decades, microturbine CHP systems have been installed in greater frequency recently compared to historical installation trends due to their flexibility in interconnection and ability to serve smaller, diverse loads efficiently. Similar to gas turbines, microturbines produce high exhaust heat that can be used directly or used to produce hot water, chilled water, and steam.

Although microturbines are used at small industrial applications, the representative commercial systems included in this analysis assume common application types such as office buildings, hotels, and other similar commercial sites. Even though capacity requirements within these application types typically vary from 50 kW-AC to 1 MW-AC, a representative microturbine capacity of 200 kW-AC was used to capture the most common packaged system capacity and the ability for microturbine packages to be stacked to serve larger loads.

6.1.2.6 Combined-cycle CHP systems

Combined-cycle gas turbine power plants are a common form of electric power generation in the United States that include heat recovery steam generators (HRSG) and can provide large-scale CHP applications for large industrial sites and campuses. The use of HRSGs to recover heat from traditional gas turbine power plants for additional power through a steam turbine can improve overall

[163] Residential sites are excluded from analysis but are included in the discussion identifying the existing market.

[164] U.S. Department of Energy, Better Buildings, Onsite Energy, Microgrid and CHP Installation Databases, accessed October 11, 2023.

generation efficiency compared to traditional power generation by roughly 10%. However, they have limited applications due to the size required to be cost-effective and limited number of sites that can support 100 MW-AC to 400 MW-AC installations.

Combined-cycle CHP systems contribute significantly to meeting site baseload power needs and can also provide financial benefits when configured to export power back onto the grid. When used at institutional settings such as college campuses, combined-cycle CHP systems typically produce hot water and steam for use in a district energy system that can distribute heat to multiple buildings throughout the campus.

6.1.3 System performance attributes

System performance data for CHP systems is intended to represent average systems available in the marketplace for each year in the analysis timeframe. Where appropriate, DNV proprietary individual project data and/or developer data was used, but performance data was primarily collected for each system for specific years from DOE and EPA reports and fact sheets.[165, 166] These data were then scaled to the remaining years using data from the DOE project profiles database[167] for specific installations and the DOE packaged CHP eCatalog[168] for specific commercially available systems. The data were supplemented further from the CEC's assessment of small CHP applications in California.[169] Table 6-2 through Table 6-8 detail performance attributes for CHP systems installed in the United States for representative commercial installations, and Table 6-6 through Table 6-8 detail the performance attributes for representative industrial installations. The data are presented to align with previous years of EIA sector-level surveys for the commercial sector from 2012 to 2022 and the industrial sector for 2015 and 2018–2022.

Natural gas reciprocating engine performance characteristics for the commercial sector have shown minor improvements over the past 10 years due to e product maturity and widespread deployment among CHP technologies (Table 6-2). The representative reciprocating engine is the most efficient among the selected commercial systems with an overall system efficiency approaching 80%.

[165] U.S. Department of Energy, Better Buildings, Onsite Energy, CHP Technology Fact Sheets, accessed October 11, 2023.
[166] U.S. Environmental Protection Agency, Combined Heat and Power (CHP) Partnership, CHP Technologies, accessed October 11, 2023.
[167] U.S. Department of Energy, Better Buildings, Onsite Energy, CHP Project Profiles Database, accessed October 11, 2023.
[168] U.S. Department of Energy, Combined Heat & Power eCatalog, DOE Recognized CHP Packaged Systems and Suppliers, accessed October 11, 2023.
[169] California Energy Commission, *A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California*, March 22, 2019.

Table 6-2. Commercial natural gas reciprocating engine (300 kW-AC) CHP performance attributes

Year	Overall Efficiency	Fuel Input	Useful Thermal Output	Electric Heat Rate	Equipment Life
2012	78.8% (HHV)	3,298 Btu/hr (HHV)	1,480 Btu/hr	10,995 Btu/kWh	25 years
2013	79.0% (HHV)	3,297 Btu/hr (HHV)	1,479 Btu/hr	10,990 Btu/kWh	25 years
2014	79.2% (HHV)	3,291 Btu/hr (HHV)	1,477 Btu/hr	10,969 Btu/kWh	25 years
2015	79.6% (HHV)	3,285 Btu/hr (HHV)	1,475 Btu/hr	10,950 Btu/kWh	25 years
2016	79.6% (HHV)	3,263 Btu/hr (HHV)	1,471 Btu/hr	10,877 Btu/kWh	25 years
2017	79.7% (HHV)	3,241 Btu/hr (HHV)	1,470 Btu/hr	10,805 Btu/kWh	25 years
2018	79.7% (HHV)	3,229 Btu/hr (HHV)	1,470 Btu/hr	10,763 Btu/kWh	25 years
2019	79.7% (HHV)	3,222 Btu/hr (HHV)	1,470 Btu/hr	10,740 Btu/kWh	25 years
2020	79.7% (HHV)	3,134 Btu/hr (HHV)	1,470 Btu/hr	10,445 Btu/kWh	25 years
2021	79.7% (HHV)	3,130 Btu/hr (HHV)	1,470 Btu/hr	10,434 Btu/kWh	25 years
2022	79.7% (HHV)	3,129 Btu/hr (HHV)	1,470 Btu/hr	10,431 Btu/kWh	25 years

Note: MMBtu/hr=million British thermal units per hour; Btu/kWh=British thermal units per kilowatthour; HHV=Higher heating value.

Oil-fired reciprocating engine performance characteristics have remained relatively constant over the last 10 years due to diesel engine maturity and the large-scale production history for traditional and backup power generation (Table 6-3). Although oil-fired reciprocating engines have lower capital costs compared with other CHP prime mover technologies, they produce more emissions than other comparative natural gas systems.

Table 6-3. Commercial oil-fired reciprocating engine (350 kW-AC) CHP performance attributes

Year	Overall Efficiency	Fuel Input	Useful Thermal Output	Electric Heat Rate	Equipment Life
2012	80.5% (HHV)	3,594 Btu/hr (HHV)	1,665 Btu/hr	10,269 Btu/kWh	30 years
2013	80.9% (HHV)	3,591 Btu/hr (HHV)	1,664 Btu/hr	10,260 Btu/kWh	30 years
2014	81.1% (HHV)	3,586 Btu/hr (HHV)	1,662 Btu/hr	10,246 Btu/kWh	30 years
2015	81.1% (HHV)	3,581 Btu/hr (HHV)	1,661 Btu/hr	10,232 Btu/kWh	30 years
2016	81.2% (HHV)	3,576 Btu/hr (HHV)	1,659 Btu/hr	10,217 Btu/kWh	30 years
2017	81.3% (HHV)	3,568 Btu/hr (HHV)	1,657 Btu/hr	10,195 Btu/kWh	30 years
2018	81.3% (HHV)	3,560 Btu/hr (HHV)	1,656 Btu/hr	10,173 Btu/kWh	30 years
2019	81.3% (HHV)	3,555 Btu/hr (HHV)	1,655 Btu/hr	10,158 Btu/kWh	30 years
2020	81.3% (HHV)	3,551 Btu/hr (HHV)	1,655 Btu/hr	10,146 Btu/kWh	30 years
2021	81.3% (HHV)	3,550 Btu/hr (HHV)	1,654 Btu/hr	10,141 Btu/kWh	30 years
2022	81.3% (HHV)	3,549 Btu/hr (HHV)	1,653 Btu/hr	10,139 Btu/kWh	30 years

Note: MMBtu/hr=million British thermal units per hour; Btu/kWh=British thermal units per kilowatthour; HHV=Higher heating value.

Similarly, gas turbine performance characteristics have shown minor efficiency improvements over the past 10 years due to its maturity in CHP applications (Table 6-4). Natural gas turbine efficiency generally increases as capacity increases, with the smallest representative capacity system (included in Table 6-4) in the commercial segment being the least efficient and least cost-effective, and large industrial systems (capacities more than 20 MW-AC) being more efficient and highly cost-effective compared with other prime mover types. Smaller gas turbine systems can still provide benefits to sites where power and thermal needs for the site match with that of the natural gas turbine system.

Table 6-4. Commercial natural gas turbine (3,300 kW-AC) CHP performance attributes

Year	Overall Efficiency	Fuel Input	Useful Thermal Output	Electric Heat Rate	Equipment Life
2012	65.5% (HHV)	47,094 Btu/hr (HHV)	18,802 Btu/hr	14,271 Btu/kWh	25 years
2013	65.5% (HHV)	47,079 Btu/hr (HHV)	18,798 Btu/hr	14,266 Btu/kWh	25 years
2014	65.7% (HHV)	47,044 Btu/hr (HHV)	18,773 Btu/hr	14,256 Btu/kWh	25 years
2015	65.7% (HHV)	47,015 Btu/hr (HHV)	18,765 Btu/hr	14,247 Btu/kWh	25 years
2016	65.7% (HHV)	46,619 Btu/hr (HHV)	18,747 Btu/hr	14,127 Btu/kWh	25 years
2017	65.8% (HHV)	46,224 Btu/hr (HHV)	18,729 Btu/hr	14,007 Btu/kWh	25 years
2018	65.8% (HHV)	45,960 Btu/hr (HHV)	18,718 Btu/hr	13,927 Btu/kWh	25 years
2019	65.8% (HHV)	45,585 Btu/hr (HHV)	18,710 Btu/hr	13,814 Btu/kWh	25 years
2020	65.8% (HHV)	45,575 Btu/hr (HHV)	18,710 Btu/hr	13,811 Btu/kWh	25 years
2021	65.8% (HHV)	45,564 Btu/hr (HHV)	18,709 Btu/hr	13,807 Btu/kWh	25 years
2022	65.8% (HHV)	45,543 Btu/hr (HHV)	18,708 Btu/hr	13,801 Btu/kWh	25 years

Note: MMBtu/hr=million British thermal units per hour; Btu/kWh=British thermal units per kilowatthour; HHV=Higher heating value.

Microturbine overall efficiency has improved most among representative commercial systems over the past 10 years, largely due to new packaged systems being developed and introduced into the marketplace (Table 6-5). Although not as efficient as reciprocating engines, microturbines still provide benefits for commercial facilities in their thermal flexibility and emissions reduction potential. They can provide both heating and cooling for year-round applications in small hotels, and office buildings, among many other commercial applications.

Table 6-5. Commercial microturbine (200 kW-AC) CHP performance attributes

Year	Overall Efficiency	Fuel Input	Useful Thermal Output	Electric Heat Rate	Equipment Life
2012	66.4% (HHV)	2,582 Btu/hr (HHV)	888 Btu/hr	11,999 Btu/kWh	25 years
2013	66.8% (HHV)	2,580 Btu/hr (HHV)	887 Btu/hr	11,985 Btu/kWh	25 years
2014	66.8% (HHV)	2,573 Btu/hr (HHV)	886 Btu/hr	11,972 Btu/kWh	25 years
2015	66.9% (HHV)	2,565 Btu/hr (HHV)	885 Btu/hr	11,958 Btu/kWh	25 years
2016	67.2% (HHV)	2,517 Btu/hr (HHV)	884 Btu/hr	11,945 Btu/kWh	25 years
2017	67.8% (HHV)	2,468 Btu/hr (HHV)	882 Btu/hr	11,918 Btu/kWh	25 years
2018	68.0% (HHV)	2,419 Btu/hr (HHV)	880 Btu/hr	11,890 Btu/kWh	25 years
2019	68.2% (HHV)	2,365 Btu/hr (HHV)	870 Btu/hr	11,755 Btu/kWh	25 years
2020	68.5% (HHV)	2,328 Btu/hr (HHV)	867 Btu/hr	11,715 Btu/kWh	25 years
2021	68.6% (HHV)	2,317 Btu/hr (HHV)	855 Btu/hr	11,553 Btu/kWh	25 years
2022	68.8% (HHV)	2,300 Btu/hr (HHV)	840 Btu/hr	11,350 Btu/kWh	25 years

Note: MMBtu/hr=million British thermal units per hour; Btu/kWh=British thermal units per kilowatthour; HHV=Higher heating value.

Similar to the commercial sector reciprocating engine CHP system, the representative industrial systems show minor performance improvements over the past 10 years due to their maturity within industrial applications. The most common industrial subsectors that use reciprocating engines within the 1 MW-AC to 3 MW-AC capacity range are chemical manufacturing and food processing facilities that typically use the process heat or process cooling with the addition of an absorption chiller as the type of thermal recovery.[170]

[170] U.S. Department of Energy, Better Buildings, Onsite Energy, Microgrid and CHP Installation Databases, accessed October 11, 2023.

Table 6-6. Industrial natural gas reciprocating engine (1,000 kW-AC and 3,000 kW-AC) CHP performance attributes

Year	Capacity	Overall Efficiency	Fuel Input	Useful Thermal Output	Electric Heat Rate	Equipment Life
2015	1,000 kW-AC	78.4% (HHV)	9,206 Btu/hr (HHV)	4,320 Btu/hr	9,206 Btu/kWh	25 years
2018	1,000 kW-AC	78.5% (HHV)	9,209 Btu/hr (HHV)	4,044 Btu/hr	9,209 Btu/kWh	25 years
2019	1,000 kW-AC	78.7% (HHV)	9,210 Btu/hr (HHV)	4,015 Btu/hr	9,210 Btu/kWh	25 years
2020	1,000 kW-AC	78.7% (HHV)	9,210 Btu/hr (HHV)	3,880 Btu/hr	9,210 Btu/kWh	25 years
2021	1,000 kW-AC	78.7% (HHV)	9,210 Btu/hr (HHV)	3,885 Btu/hr	9,210 Btu/kWh	25 years
2022	1,000 kW-AC	78.7% (HHV)	9,210 Btu/hr (HHV)	3,890 Btu/hr	9,210 Btu/kWh	25 years
2015	3,000 kW-AC	78.3% (HHV)	25,232 Btu/hr (HHV)	10,670 Btu/hr	8,411 Btu/kWh	25 years
2018	3,000 kW-AC	78.6% (HHV)	25,240 Btu/hr (HHV)	10,250 Btu/hr	8,413 Btu/kWh	25 years
2019	3,000 kW-AC	78.8% (HHV)	25,251 Btu/hr (HHV)	10,120 Btu/hr	8,417 Btu/kWh	25 years
2020	3,000 kW-AC	78.8% (HHV)	25,251 Btu/hr (HHV)	9,710 Btu/hr	8,417 Btu/kWh	25 years
2021	3,000 kW-AC	78.8% (HHV)	25,251 Btu/hr (HHV)	9,695 Btu/hr	8,417 Btu/kWh	25 years
2022	3,000 kW-AC	78.8% (HHV)	25,251 Btu/hr (HHV)	9,680 Btu/hr	8,417 Btu/kWh	25 years

Note: MMBtu/hr=million British thermal units per hour; Btu/kWh=British thermal units per kilowatthour; HHV=Higher heating value.

Gas turbine CHP systems are more common in the industrial sector compared with commercial sector gas turbine installations, given the wide range of industrial facility types and site power and thermal requirements. The four systems represent the potential range of common industrial installations. Given their popularity for power generation and CHP applications since the 1990s, the performance characteristics of gas turbine CHP systems for industrial applications has seen minor improvements over the last eight years. When comparing individual systems, overall system efficiencies generally improve as system capacity increases.

Table 6-7. Industrial gas turbine (5,000 kW-AC, 10,000 kW-AC, 25,000 kW-AC, and 40,000 kW-AC) CHP performance attributes

Year	Capacity	Overall Efficiency	Fuel Input	Useful Thermal Output	Electric Heat Rate	Equipment Life
2015	5,000 kW-AC	67.6% (HHV)	64,560 Btu/hr (HHV)	28,115 Btu/hr	12,912 Btu/kWh	30 years
2018	5,000 kW-AC	67.6% (HHV)	63,186 Btu/hr (HHV)	27,212 Btu/hr	12,637 Btu/kWh	30 years
2019	5,000 kW-AC	67.6% (HHV)	62,144 Btu/hr (HHV)	27,355 Btu/hr	12,429 Btu/kWh	30 years
2020	5,000 kW-AC	68.8% (HHV)	60,924 Btu/hr (HHV)	27,497 Btu/hr	12,185 Btu/kWh	30 years
2021	5,000 kW-AC	68.8% (HHV)	60,924 Btu/hr (HHV)	27,444 Btu/hr	12,185 Btu/kWh	30 years
2022	5,000 kW-AC	68.8% (HHV)	60,924 Btu/hr (HHV)	27,415 Btu/hr	12,185 Btu/kWh	30 years
2015	10,000 kW-AC	68.0% (HHV)	124,799 Btu/hr (HHV)	60,358 Btu/hr	12,480 Btu/kWh	30 years
2018	10,000 kW-AC	68.0% (HHV)	123,328 Btu/hr (HHV)	60,209 Btu/hr	12,333 Btu/kWh	30 years
2019	10,000 kW-AC	68.1% (HHV)	122,053 Btu/hr (HHV)	59,506 Btu/hr	12,205 Btu/kWh	30 years
2020	10,000 kW-AC	68.2% (HHV)	120,779 Btu/hr (HHV)	58,803 Btu/hr	12,078 Btu/kWh	30 years
2021	10,000 kW-AC	68.3% (HHV)	121,294 Btu/hr (HHV)	58,708 Btu/hr	12,129 Btu/kWh	30 years
2022	10,000 kW-AC	68.4% (HHV)	120,907 Btu/hr (HHV)	58,338 Btu/hr	12,091 Btu/kWh	30 years
2015	25,000 kW-AC	69.3% (HHV)	256,619 Btu/hr (HHV)	85,230 Btu/hr	10,265 Btu/kWh	30 years
2018	25,000 kW-AC	69.3% (HHV)	253,383 Btu/hr (HHV)	85,015 Btu/hr	10,135 Btu/kWh	30 years
2019	25,000 kW-AC	69.3% (HHV)	251,508 Btu/hr (HHV)	84,655 Btu/hr	10,060 Btu/kWh	30 years
2020	25,000 kW-AC	69.3% (HHV)	249,634 Btu/hr (HHV)	84,296 Btu/hr	9,985 Btu/kWh	30 years
2021	25,000 kW-AC	69.3% (HHV)	249,506 Btu/hr (HHV)	84,135 Btu/hr	9,980 Btu/kWh	30 years
2022	25,000 kW-AC	69.3% (HHV)	243,004 Btu/hr (HHV)	83,974 Btu/hr	9,720 Btu/kWh	30 years
2015	40,000 kW-AC	68.8% (HHV)	384,993 Btu/hr (HHV)	135,760 Btu/hr	9,625 Btu/kWh	30 years
2018	40,000 kW-AC	69.3% (HHV)	384,993 Btu/hr (HHV)	134,180 Btu/hr	9,625 Btu/kWh	30 years
2019	40,000 kW-AC	69.8% (HHV)	384,993 Btu/hr (HHV)	133,201 Btu/hr	9,625 Btu/kWh	30 years
2020	40,000 kW-AC	70.2% (HHV)	384,993 Btu/hr (HHV)	132,222 Btu/hr	9,625 Btu/kWh	30 years
2021	40,000 kW-AC	70.3% (HHV)	384,711 Btu/hr (HHV)	132,112 Btu/hr	9,618 Btu/kWh	30 years
2022	40,000 kW-AC	70.3% (HHV)	384,429 Btu/hr (HHV)	132,003 Btu/hr	9,611 Btu/kWh	30 years

Note: MMBtu/hr=million British thermal units per hour; Btu/kWh=British thermal units per kilowatthour; HHV=Higher heating value.

Only 10 combined-cycle CHP systems have been installed in the United States since 2015 because of their limited applicability to specific industrial installation types and need for high site power and thermal requirements. These systems have been installed primarily in large manufacturing applications such as petroleum refining, food processing, chemical manufacturing, and pulp and paper manufacturing.[171] They have also been used in district energy applications serving large campuses, such as the Holland Energy Plant in Holland, Michigan.[172] Performance characteristics have seen minor improvements over the past eight years due to high technology maturity. Compared with all other CHP systems, combined-cycle plants have the longest average equipment life at 35 years.

[171] U.S. Department of Energy, Better Buildings, Onsite Energy, Microgrid and CHP Installation Databases, accessed October 11, 2023.

[172] Holland Energy Park, Holland Energy Park cogeneration plant commissioned, October 3, 2017.

Table 6-8. Industrial combined-cycle (100,000 kW-AC and 375,000 kW-AC) CHP performance attributes

Year	Capacity	Overall Efficiency	Fuel Input	Useful Thermal Output	Electric Heat Rate	Equipment Life
2015	100,000 kW-AC	64.9% (HHV)	683,820 Btu/hr (HHV)	347,100 Btu/hr	6,838 Btu/kWh	35 years
2018	100,000 kW-AC	65.2% (HHV)	680,251 Btu/hr (HHV)	345,381 Btu/hr	6,803 Btu/kWh	35 years
2019	100,000 kW-AC	65.4% (HHV)	678,533 Btu/hr (HHV)	344,491 Btu/hr	6,785 Btu/kWh	35 years
2020	100,000 kW-AC	65.5% (HHV)	676,814 Btu/hr (HHV)	343,602 Btu/hr	6,768 Btu/kWh	35 years
2021	100,000 kW-AC	65.5% (HHV)	675,882 Btu/hr (HHV)	342,414 Btu/hr	6,759 Btu/kWh	35 years
2022	100,000 kW-AC	65.5% (HHV)	674,895 Btu/hr (HHV)	341,226 Btu/hr	6,749 Btu/kWh	35 years
2015	375,000 kW-AC	62.6% (HHV)	2,389,541 Btu/hr (HHV)	694,032 Btu/hr	6,372 Btu/kWh	35 years
2018	375,000 kW-AC	63.2% (HHV)	2,356,891 Btu/hr (HHV)	688,925 Btu/hr	6,285 Btu/kWh	35 years
2019	375,000 kW-AC	63.2% (HHV)	2,350,986 Btu/hr (HHV)	687,015 Btu/hr	6,269 Btu/kWh	35 years
2020	375,000 kW-AC	63.3% (HHV)	2,350,986 Btu/hr (HHV)	685,104 Btu/hr	6,269 Btu/kWh	35 years
2021	375,000 kW-AC	63.3% (HHV)	2,345,429 Btu/hr (HHV)	684,162 Btu/hr	6,254 Btu/kWh	35 years
2022	375,000 kW-AC	63.3% (HHV)	2,342,123 Btu/hr (HHV)	683,247 Btu/hr	6,246 Btu/kWh	35 years

Note: MMBtu/hr=million British thermal units per hour; Btu/kWh=British thermal units per kilowatthour; HHV=Higher heating value.

6.1.4 System cost data

Capital costs for commercial and industrial CHP systems were collected for multiple categories to accurately represent the differences in component and equipment costs, BOP, and labor and installation costs throughout the analysis timeframe. The cost categories were summarized across all representative systems to include:

- CHP equipment costs
- BOP and installation costs (includes labor costs)

Capital cost data for CHP systems represent an average of typical systems available in the marketplace for each year in the analysis timeframe. Where appropriate, individual project data and/or developer data were used, but cost data were gathered to reflect a blended average of commercially available systems for both the commercial and industrial sectors. Cost data were primarily collected for each representative system for specific years in the analysis timeframe from DOE and EPA reports and fact sheets[173, 174] where applicable and scaled to the remaining years using data from the DOE project profiles database,[175] the DOE packaged CHP eCatalog,[176] and the CEC's assessment of small CHP applications in California.[177] Labor and installation costs were scaled within specific years to reflect annual wages included in the labor and installation portion of overall system capital costs. These cost data were then scaled to 2022 constant (real) dollars using appropriate GDP chain-type price indices to scale hardware costs when not explicitly available.

[173] U.S. Department of Energy, Better Buildings, Onsite Energy, CHP Technology Fact Sheets, accessed October 11, 2023.

[174] U.S. Environmental Protection Agency, Combined Heat and Power (CHP) Partnership, CHP Technologies, accessed October 11, 2023.

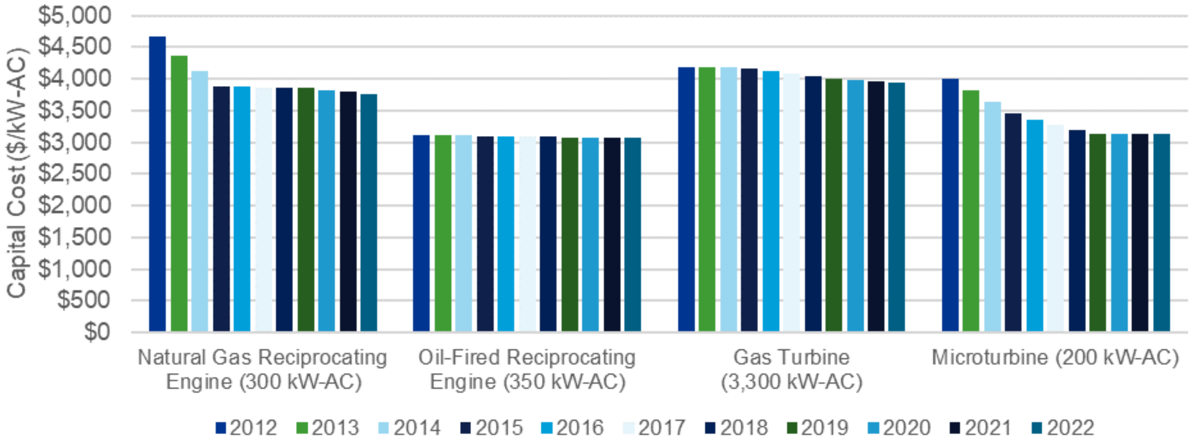
[175] U.S. Department of Energy, Better Buildings, Onsite Energy, CHP Project Profiles Database, accessed October 11, 2023.

[176] U.S. Department of Energy, Combined Heat & Power eCatalog, DOE Recognized CHP Packaged Systems and Suppliers, accessed October 11, 2023.

[177] California Energy Commission, *A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California*, March 22, 2019.

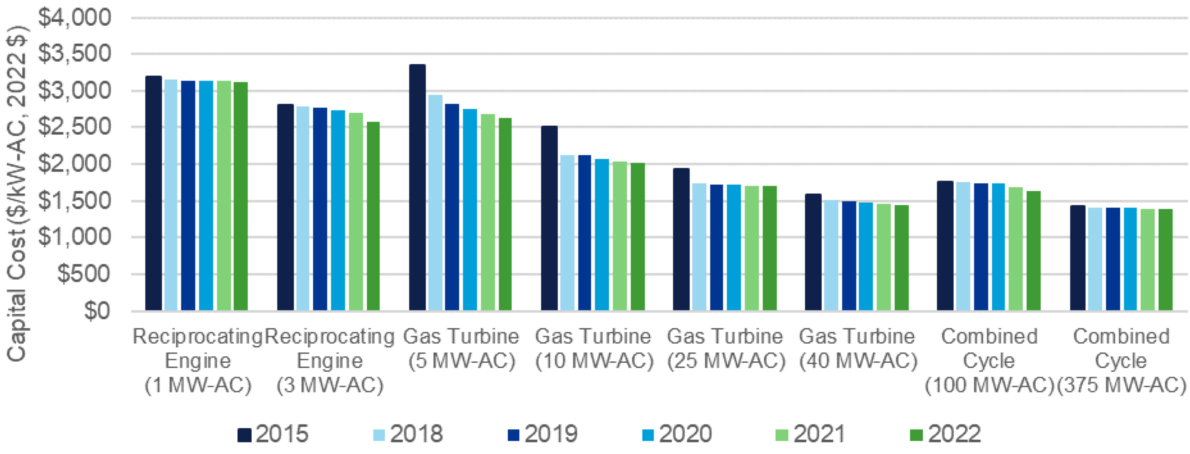
Capital costs for the representative natural gas reciprocating engine and microturbine decreased the most in the past 10 years, largely due to the emergence of packaged systems becoming available for each of these prime mover types, which reduced site engineering and design costs and interconnection costs and alleviated installation challenges through replicability. Microturbines generally present the most cost-effective option for smaller commercial applications largely due to the improvements in packaged CHP systems and lower interconnection costs for microturbines. The representative gas turbine system does not provide for the same types of applications as the representative reciprocating engine and microturbine, but capital costs for the system still slightly declined over the past 10 years. The oil-fired reciprocating engine capital costs have remained relatively constant over the same period because the technology is largely mature and has limited application types.

Figure 6-3. U.S. average commercial CHP system capital costs ($/kW-AC, 2022 $)



Similar to the commercial sector, capital costs for all representative industrial CHP systems have declined over the last five years (only 2015 and 2018–2022 costs are shown in Figure 6-4 due to limited data availability from 2016 to 2017). Capital costs for nearly all prime mover types slightly decreased due to system technical maturity and these systems' long history of deployment in the industrial sector. In particular, system capital costs for the 5 MW-AC gas turbine have decreased the most since 2015. As mentioned previously, gas turbine efficiency and cost-effectiveness increase as capacity increases, as demonstrated in the declining capital costs moving from the lowest capacity system (5 MW-AC) to the highest (40 MW-AC).

Figure 6-4. U.S. average industrial CHP system capital costs ($/kW-AC, 2022 $)



6.1.5 O&M cost data

DNV compiled variable O&M costs ($/kWh) for all CHP systems, including estimates for both general system maintenance and parts replacement. DNV assumed annual contracted maintenance costs for both commercial and industrial systems were included, representing general maintenance labor costs for routine system inspection, ancillary part (for example, filters, sensors, spark plugs, gaskets, valves) adjustments, and/or replacements. Fixed costs including major system overhauls and large parts (for example, catalyst, stack) replacement were also included and annualized over a 5–10-year period to incorporate them into the final $/kWh cost component. DNV also characterized these major system overhauls or system components that are typically replaced prior to complete system shutdown for each system in Table 6-9. These categories include average replacement costs and the typical interval timeline for overhaul or major parts replacement.

Table 6-9. CHP system major overhaul components and replacement timeline

CHP System	Sector	Components Included in Major Overhaul	Average Interval of Major Overhaul
Natural Gas Reciprocating Engine (300 kW-AC) **Oil-Fired Reciprocating Engine (350 kW-AC)**	Commercial	Complete inspection and piston/liner replacement, replacement of bearings and seals, and crankshaft inspection	~55,000 hours (~10 years)
Gas Turbine (3,300 kW-AC)	Commercial	Complete inspection (turbine and compressor, dimensional inspections, etc.) and rebuild of turbine components (rotor, bearings, blades, seals, etc.)	~40,000 hours (~8 years)
Microturbine (200 kW-AC)	Commercial	Replacement of electronic components (electronic control module, power boards, etc.) and engine	~40,000 hours (~8 years)
Reciprocating Engine (1 MW-AC) **Reciprocating Engine (3 MW-AC)**	Industrial	Complete inspection and piston/liner replacement, replacement of bearings and seals, and crankshaft inspection	~55,000 hours (~8 years)
Gas Turbine (5 MW-AC) **Gas Turbine (10 MW-AC)** **Gas Turbine (25 MW-AC)** **Gas Turbine (40 MW-AC)**	Industrial	Complete inspection (turbine and compressor, dimensional inspections, etc.) and rebuild of turbine components (rotor, bearings, blades, seals, etc.)	~40,000 hours (~6 years)
Combined Cycle (100 MW-AC) **Combined Cycle (375 MW-AC)**	Industrial	Complete inspection (turbine, compressor, and electric generator) and rebuild of turbine components (rotor, bearings, blades, seals, etc.)	~50,000 hours (~8 years)

DNV assembled variable O&M costs using DOE's CHP Fact Sheet Series and the CEC's assessment of small CHP applications in California as a baseline, and it supplemented these costs with DNV proprietary developer data where appropriate.[178,179] Baseline O&M costs for general system maintenance and equipment replacement were gathered for multiple years throughout the analysis timeframe and scaled to 2022 constant (real) dollars and subsequent historical years using relevant U.S. average labor costs and annual CPI to adjust for inflation. Figure 6-5 shows commercial CHP system average O&M costs over the past 10 years. O&M costs have generally been consistent with minor fluctuations due to labor costs changes within the past five years, and parts replacement costs have not changed significantly enough to introduce large O&M cost swings.

Figure 6-5. U.S. average commercial CHP system O&M costs ($/kWh, 2022 $)

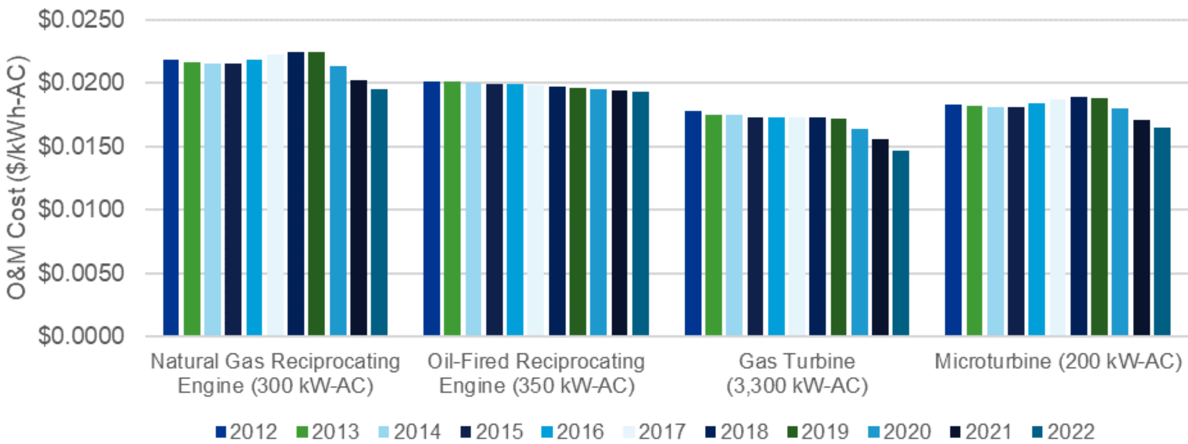
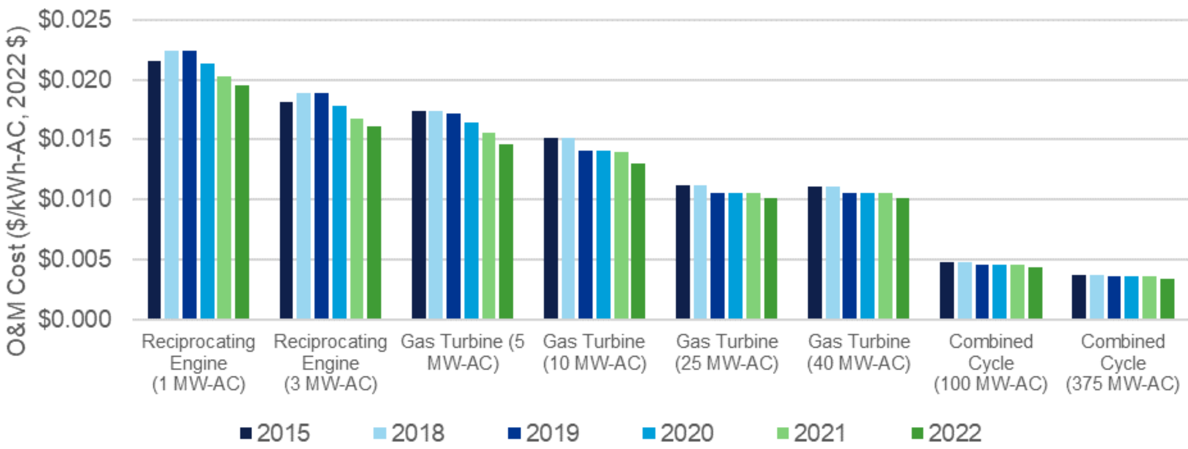


Figure 6-6 shows industrial CHP system average O&M costs. Reciprocating engines which typically have the highest O&M cost of any prime mover type. The lower costs in the industrial sector are largely due to economies of scale when servicing larger installations because smaller sites may have more variety in system configurations, interconnection applications, and other related components. Combined-cycle CHP plants have significantly lower O&M costs when compared with other prime mover types mainly due to economies of scale.

Figure 6-6. U.S. average industrial CHP system O&M costs ($/kWh, 2022 $)



[178] U.S. Department of Energy, Better Buildings, Onsite Energy, CHP Technology Fact Sheets, accessed October 11, 2023.
[179] California Energy Commission, *A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California*, March 22, 2019.

7 COMMERCIAL AND INDUSTRIAL MARKET DISCUSSION

The following subsections provide an overview of key factors influencing future CHP pricing, adoption, and technology deployment trends in the commercial and industrial (C&I) sectors. Additionally, the following subsections include findings from interviews conducted between October and November of 2023 with eight installers/developers and five end users of CHP systems. These conversations also sought to gain insights into whether prospects for non-CHP (e.g., conventional generators and intermittent DERs) self-generation exist and to characterize economic, technical, regulatory, and general issues surrounding motivations and barriers to CHP or non-CHP adoption.

Systems that produce both electricity and useful thermal energy in a sequential process from a single source of fuel can be referred to as cogeneration systems, or CHP systems. The waste heat produced by heat engines producing electricity can be captured and used for water heating, space heating, or process heat for industry. Waste heat can also be used to cool buildings using absorption or adsorption heat pumps.

Burning a fuel to generate electricity and then capturing and using the waste heat produced can reduce primary energy demand by as much as 40% compared with separate grid electricity and fuel-fired boilers. The efficiency gains in energy demand also translate into GHG emissions reductions. The temperature of the waste heat produced determines its applicable end uses; high temperature waste heat is more versatile, while low temperature heat may only be applicable for water heating and heating/cooling conditioned space (including cooling tower water or other water used for cooling systems). Finding applications where the timing and magnitude of electric and thermal demands are aligned is a key consideration for CHP project economics. For example, if the waste heat is used for space heating alone, then the heat may have no value during summertime; whereas if it is used for space heating and cooling, it may be useful all year. Steady heating demand in industrial processes is the prime target for CHP. Project economics are also enhanced when the waste heat is displacing the need to purchase a more expensive fuel.

Non-CHP generation includes grid-connected renewables such as solar or wind as well as other technologies such as power-only fuel cells, batteries, and gas-fired generators. Renewables have zero or low GHG emissions. However, the intermittency of solar and wind generation means that they cannot guarantee reduced customer peak electricity and corresponding peak demand charges (this limitation is especially true in two- and three-shift facilities). Also, due to the typical long duration of this peak demand, the battery capacity required to reduce demand charges presents a barrier. On-site gas generators offer on-demand, non-intermittent, power but they are only generators that do not recover waste heat to displace fuel use elsewhere at the site. Finally, non-CHP systems often require more space to produce the same amount of electricity when compared to CHP systems. Generally, CHP systems tend to serve different needs than non-CHP systems, and therefore are not competing with each other. Going forward, on-site industrial generation will likely include a mix of technologies depending on the specific needs, goals, and location of each facility.

7.1 In-depth interview methodology

The remainder of Section 7 details the findings from in-depth interviews with installers/developers and end users of CHP systems as well as secondary research on economic, technical, regulatory, and general topics surrounding CHP and non-CHP systems. DNV interviewed eight installers/developers. Four operate nationwide: one operates in the Northeast, Midwest, and eastern Canada; one targets the Eastern Seaboard from Maine to Maryland; one targets the Midwest; and one operates in Indiana. DNV also interviewed six end users (one of which was only a partial interview). Two interviewees worked in the industrial sector in a beverage manufacturer and a semiconductor company. The remaining end-user interviews were with commercial end users, namely, two health care systems, one university, and a partial interview with a community center.

The interviews and research sought to answer the following questions:

- How do the economics and risks (for example, environmental or regulatory) of installing a CHP system compare with a conventional boiler?
- To what degree is the ability to sell electricity to the grid important in CHP installation decisions?
- What factors affect the industrial use of purchased electricity versus non-CHP self-generation?
- How widespread is the use of non-CHP self-generation in the industrial sector, in what industries is non-CHP self-generation likely to grow most in the future, and what type of self-generation (for example, renewable, natural gas) is likely to prevail?
- Is the regulatory environment for CHP different in regions with independent system operators or regional transmission operators than in regions where a local utility operates the transmission system?
- How has state regulation affected installation of industrial CHP?
- How has the IRA affected plans for industrial CHP capacity?
- Which regulations most influence whether a facility uses purchased electricity versus non-CHP industrial self-generation?
- Are facilities with CHP more likely to be designed as using CHP, or does adoption occur in existing facilities? And for those existing facilities adopting CHP to replace existing boiler heat, which industries are the most apt to switch? What innovations have occurred in the CHP industry or technology in the past five years?
- What, if any, cultural (that is, non-economic and non-regulatory) factors influence CHP installation (for example, CHP is not installed when there is a good business case for it)?
- What are the primary barriers to CHP adoption?

7.2 Economic

7.2.1 Spark spread

The economics of CHP systems are largely driven by the difference between the cost of electricity and price of natural gas, called the “spark spread.” CHP systems reduce the amount of electricity purchased from the grid and replace it with electricity generated on-site using natural gas. The lower the price of natural gas is relative to the price of electricity, the more economically beneficial CHP becomes. In contrast, facilities facing higher natural gas rates and lower electric rates would achieve less economic advantage from installing CHP.

One installer interviewed cited Maine as an example of how a changing spark spread increased the demand for CHP. Historically, Maine had low electric rates when compared with natural gas rates resulting in a spark spread that was unfavorable to CHP, despite having long, cold winters where the technology would otherwise seem beneficial. Recently, Maine has seen an increase in electricity costs, which the respondent indicated had opened the market for CHP. Another installer identified the Pacific Northwest and the “southern belt” as having electricity rates that were too low (an unfavorable spark spread) for CHP to make economic sense for most facilities.

7.2.2 Reliability

Two end-user survey respondents and four surveyed installers mentioned reliability or resiliency as factors that could influence a facility’s decision to install CHP, even in situations where the spark spread is less favorable. Although difficult to quantify, reliable power is critical for some customers. For example, it is a key reason that hospitals choose CHP. In the manufacturing sector, power outages shut down production lines, cause loss of materials and production time, and potentially damage equipment. An example of the latter is plastics extrusion, where an extended loss of power could cause melted plastic to cool and set inside the machine thereby damaging the equipment. Industries such as pharmaceuticals, biotechnology, and food processing often rely on refrigeration to preserve perishable raw materials and/or finished products necessitating reliable power because outages can result in costly spoilage or contamination.

In addition to variation across business activities, the value of the resiliency that CHP offers depends on the reliability of utility power, which is driven by many factors, including weather, utility infrastructure, transmission grid reliability, and a facility's location on the grid (that is, remote locations are at higher risk for prolonged outages). For example, in California, utilities may shut off power to certain areas when the risk of damaged power lines sparking a wildfire is high (typically in high wind conditions in late summer and fall).

7.2.3 Incentives and tax credits

Programs and government policies can help defray the cost of CHP. According to DOE, 22 utilities spanning at least 12 states offered CHP incentive programs as of 2020.[180] Those totals include both electric and gas utilities but do not include small or municipal utilities. One installer interviewed noted that fewer utilities were offering incentives in the Midwest, although secondary research showed programs exist in Illinois, Wisconsin, and Iowa.

Additional financial incentives are available under the IRA in the form of tax credits for qualifying CHP systems that begin construction before January 1, 2025. The base tax credit rate is 6%, but it increases to 30% if the project meets or is exempt from prevailing wage and apprenticeship requirements.

The installers interviewed uniformly saw market benefits or anticipated future benefits resulting from these IRA tax credits. Some reported impacts have been limited so far due to uncertainty about how the IRA would be implemented and its governing rules and guidelines. However, installers indicated the IRA has increased awareness of and interest in CHP, and they are mentioning the IRA's incentives in their marketing. One installer noted that the inclusion of CHP in the IRA increases awareness of CHP technology for customers who may otherwise only consider renewable technologies.

7.2.4 Exporting electricity to the grid

DNV asked both installers and end users whether the ability to export electricity to the grid was important in the decision to install CHP. Typically, CHP systems are sized to the thermal load of the facility. One end user characterized the sizing decision this way: "In order to get the payback you have to be able to use 100% of the steam you produce." When system sizing is driven by thermal load, exporting electricity is often not the driving factor in the decision-making process. To design a CHP system based on electrical need, the systems would most likely need to be designed larger than to meet thermal needs and would therefore be more expensive. Additionally, when the systems are bigger, they run at a lower percentage of output and thus do not operate as cost effectively even with the ability to export or sell power back to the grid. One installer noted that for CHP systems designed to provide peak saving power (that is, providing power during peak periods to offset load and reduce peak), the ability to produce electricity is more valuable because rates are generally higher during peak periods and the generated electricity could reduce peak demand, thereby

[180] U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, *Utility Combined Heat and Power Programs,* April 2020.

reducing demand charges.[181] However, based on interviews, CHP system sizing for peak savings is less common than sizing the system for base thermal load.

Of the six installers who indicated that exporting to the electric grid was possible in their service territory, four said that the ability to export was unimportant in their decision to install CHP. Similarly, four of the five end users interviewed did not export electricity to the grid, although one of the four that did not export electricity said that could change after the facility completes a solar PV project.

Some industries produce biogas as part of their processing, for example landfills, wastewater treatment facilities, dairy farms, including food processing facilities using anaerobic digesters. A facility that produces biogas would be an exception to the aforementioned decision-making criteria because a CHP system for these facilities would be sized based on the amount of biogas produced rather than the facility's base thermal load requirement.

7.3 Economic risk

Potential changes in spark spread introduces risk to a CHP project. A facility owner bases the financial decision to install a CHP project on expectations (that is, forecasts) about future electricity rates, rate structures, and gas prices, which are uncertain. One end user interviewed indicated that they would not have installed the CHP project if they had foreseen the rate structure changes implemented by the utility after the project was committed. Although the environmental benefits met expectations, the spark spread dropped when the utility rate structure changed from one with a relatively low demand charge and higher energy rates to one with a higher demand charge and lower energy rates. In other words, unless the CHP unit operated without interruption and reduced demand charges, it would not affect total energy cost savings as much as it would have under the previous rate structures.

One end user interviewed indicated that while utility incentives helped justify the purchase of the CHP system by supporting a quicker payback, some concern existed about whether the company would receive the incentive. One of the installers noted that it was sometimes easier not to deal with the utility because the incentive and interconnection processes could slow down the project. This comment suggests that at least some of the projects completed by this installer are not connected to the grid; however, most responses that mentioned interconnection (from both installers and end users) focused on navigating the interconnection process rather than avoiding it.

Additional economic risks associated with CHP systems result from their complexity. CHP installations are more complex than boilers and may require additional staff or at least training for existing staff for long-term operations and maintenance. One facility manager representing an end user during interviews described a challenge in training staff on the CHP system: "fourteen staff members were trained and seven of them embraced it. Some of them are afraid of the CHP system and would prefer to let others take care of it."[182]

7.4 Environmental

CHP typically increases Scope 1 emissions (direct GHG emissions from the fuel used on-site) but decreases Scope 2 emissions (indirect emissions associated with electricity from the utility, accounting for transmission and distribution losses). CHP has an environmental benefit if it results in a small increase in Scope 1 emissions but a large decrease in Scope 2 emissions. Or if a company

[181] As per installer interview.
[182] As per end-user interview.

decides to use renewable fuel, CHP increases Scope 1 emissions with no effect on Scope 2 emissions.[183]

There are different ways to assess the environmental impacts of a CHP project. The industry standard for GHG emission reporting, the *GHG Protocol's GHG Inventory Accounting* methodology, uses the average grid emissions as the basis for Scope 2 reporting. The GHG Inventory Accounting methodology can sometimes estimate CHP systems to result in negative GHG emissions savings as Scope 1 emissions can increase more than Scope 2 emissions decrease. Another methodology, the *GHG Protocol's Project Protocol* is based on marginal emissions. The Project Protocol can allow companies to report Scope 2 savings in ways similar to how Renewable Energy Credits are reported.

7.5 Regulatory

7.5.1 Federal regulations

Two of the end users interviewed mentioned Title V of the Clean Air Act,[184] which requires any "major source" of actual or potential emissions above a specified threshold to obtain an operating permit. One end user indicated that the end user's facility was not a Title V facility prior to the CHP installation, but is now well under the threshold. The CHP system of the second end user was owned and operated by the end user's utility, so the system was outside the end user's emissions reporting responsibility. The end user expected that the utility's ownership of the CHP system would allow the end user to phase out of Title V to an air quality permit with less demanding requirements. It was not clear, due to the ownership structure, whether the CHP system had reduced emissions compared with the original system. These two end users had emissions nearing the Title V threshold. For facilities farther from the Title V threshold, a CHP system would not likely affect permitting requirements. A third end user mentioned having to revise the air quality permit but presented it as a routine compliance hurdle.

7.5.2 State and local regulations

CHP installers indicated concern about electrification trends from both a regulation standpoint and a public relations standpoint. They cited New York and Massachusetts as states that have adopted electrification goals. On a local level, New York City passed Local Law 97, which requires most buildings over 25,000 square feet to meet GHG emissions limits starting in 2024.[185]

One stated concern about such regulations is that they may indirectly affect attitudes toward natural gas use across the board. One installer supported CHP by suggesting it could reduce emissions now while electrification from renewables will take years and require infrastructure upgrades. Moreover, an installer indicated the industrial sector is more difficult to electrify compared with the buildings sector, and some industrial processes may require other approaches to decarbonization, such as low carbon fuels or carbon capture and storage. Installers also mentioned that CHP can reduce emissions now while the supply chain for hydrogen grows and then be converted to hydrogen fuel once hydrogen is more widely available.

One installer commended the DOE CHP e-database for supporting CHP with agencies, utilities, and advocates. The installer described the Maryland Energy Commission as forward leaning on CHP

183 While Title V is discussed below, the discussion here on Scope 1 and Scope 2 is not a Title V issue.
184 U.S. Environmental Protection Agency, Current Regulation and Regulatory Actions, Recent Regulatory Actions Related to Title V, accessed October 11, 2023.
185 City of New York, NYC Sustainable Buildings, Local Law 97, accessed October 11, 2023.

and noted that the Delaware Department of Natural Resources and Environmental Control offers CHP incentives.

One end user also indicated needing to conduct a noise study before installing the system due to the end user's location near a residential area.

7.5.3 Utility processes

Four of the five end users interviewed mentioned utility interconnections as at least a minor hurdle. Half of the installers also mentioned utility interconnection regulations or processes as barriers. They noted that different utilities have different rules and processes, but they also said that municipal utilities are often unfamiliar with CHP and often have no defined CHP interconnection process.

7.5.4 Regulatory environment: ISOs versus utility-operated systems

When asked, none of the end users or installers interviewed mentioned any regulatory differences between regions with independent system operators (ISOs) and regions where a local utility operates the transmission system. Generally, CHP systems are connected at the local distribution level, so variation between utilities is more significant than how the transmission grid is operated.

7.6 Technical

7.6.1 New versus retrofit

Most CHP systems are installed in existing facilities (that is, retrofit). Only one of the eight installers interviewed said that his or her business was mostly new facilities, and another said that his or her business was 50/50 retrofit/new. The remaining installers said their business was mostly retrofit. For the five end users interviewed, the CHP system was installed in an existing facility.

Rather than replacing an existing boiler, most CHP systems are add-ons, running in parallel to the heating system or retaining the old boilers as back-up. One installer commented, "We almost always tell [the customer], 'Leave the existing boiler in place.'" The CHP system, as noted earlier, is typically sized for base thermal load, so the boilers are available for heating peaks and to provide redundancy.

7.6.2 CHP versus boiler

Neither the installers nor the end users interviewed saw CHP as a replacement for a boiler, so rather than the question, "Should I choose a CHP system or a boiler?", it was "Should I add a CHP system to my boilers?" One installer described CHP as a "nice to have rather than a need to have," saying that someone who needs to replace a boiler probably wouldn't have the funds to also install a CHP system, especially since CHP is significantly more expensive than a boiler.

Adding a CHP system may extend the life of the existing boiler, which can then operate less often and at lower capacity. CHP also provides resiliency. In contrast, installing a boiler system without CHP may only provide efficiency improvements.

CHP systems are more complex than boilers, and therefore, installers and end users note increased long term operation and maintenance risk. Utility interconnections potentially affect project timelines and cost. A CHP system needs to tie into electrical, gas, and thermal systems, making it challenging to avoid operation disruptions during installation. If a company acquires CHP under an energy services agreement (ESA), where the system is owned and operated by an energy services company, the long-term contract may also be viewed as a risk.

With respect to regulation, installers saw little difference between CHP and boilers.

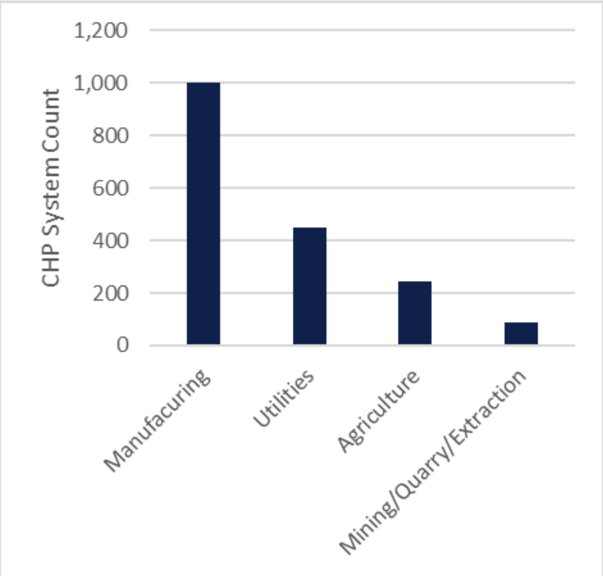
7.6.3 Where is CHP a good fit?

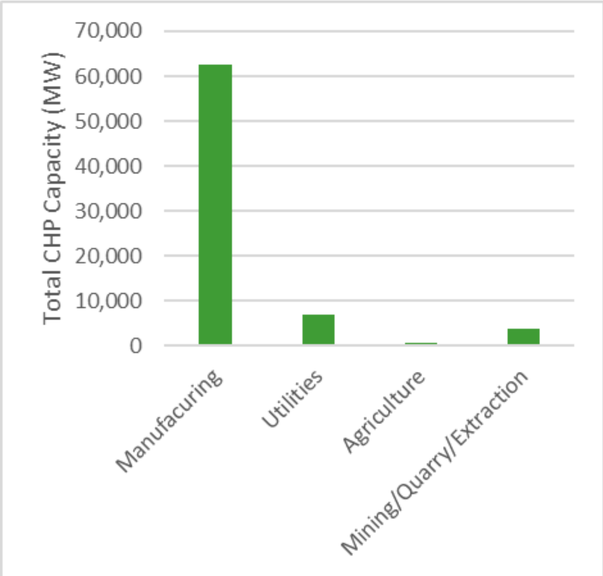
Installers were asked what industries were the most likely candidates for CHP. In response, they identified characteristics that would most benefit from CHP systems. These characteristics include:

- Large electrical and thermal loads
- Use for heat generated from an engine or unit
- Need for hot water both for space heating and domestic water heating (applies to commercial and multifamily residential facilities more than industrial facilities)
- 24/7/365 thermal loads, for example a three-shift industrial facility. Also, colleges, universities, and hospitals.
- Need for resiliency
- High electric rates with comparatively low natural gas rates (favorable spark spread)
- Available biogas, biomass, or other “waste” fuels (such as still gas in the petroleum industry) from industrial operations that can be used as fuel for the CHP

We reviewed DOE’s CHP project profiles database to see what types of industrial facilities were installing CHP systems. We looked at 1,786 CHP systems that could broadly be classified as industrial in agriculture; mining, quarrying, and oil and gas extraction; utilities; construction; and manufacturing. Figure 7-1 shows the breakout of both number of systems and installed capacity by category (Construction, with only 6 systems and 20 MW of capacity, was omitted from the chart).

Figure 7-1. CHP System Counts and Total Capacity by Industry Sector by Count and MW-AC

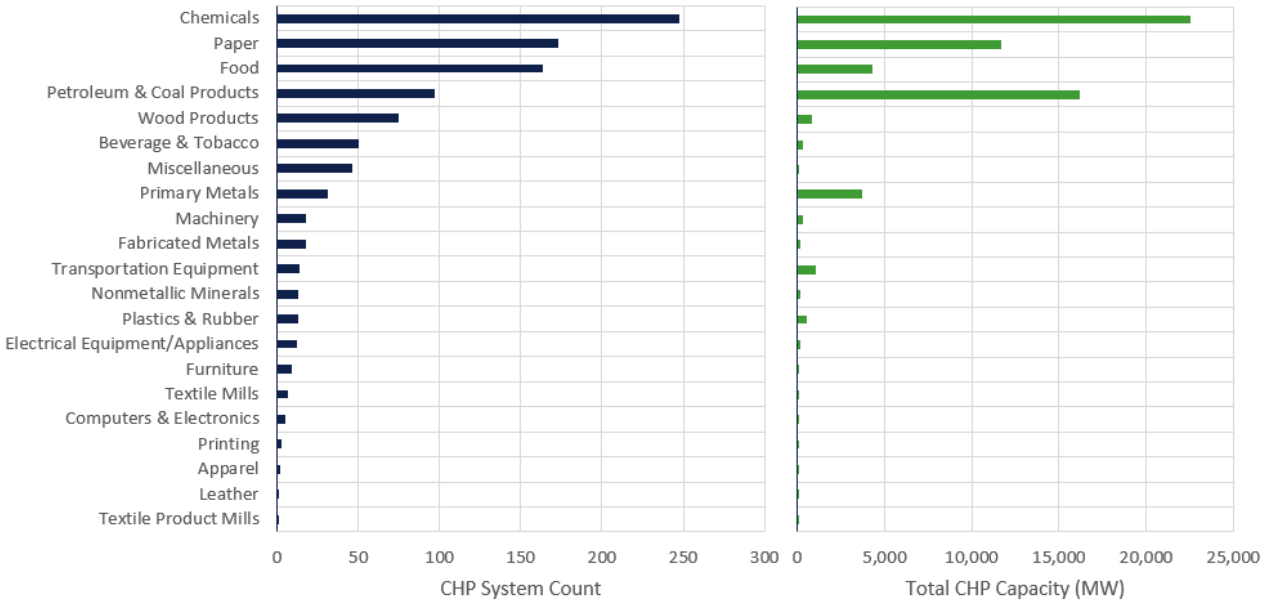




While manufacturing makes up 56% of systems, it represents 85% of capacity, reflecting larger-than-average system sizes. Utilities and agriculture, in contrast, have a smaller average system size making their capacity share much smaller than their system share.

We took a deeper look at the manufacturing sector at the three-digit North American Industry Classification System (NAICS) level, shown in Figure 7-2. Chemicals, an energy-intensive industry with high thermal loads, had the largest share by both number of systems (14%) and capacity (31% of all industrial capacity). Paper had the second highest system count (10%) and third highest capacity (16%). In addition to being an energy-intensive industry with high thermal loads, the nature of the raw materials to make paper products results in biomass that can be used as fuel (this characteristic is shared by the wood products industry, which represents 4% of systems, and to a lesser extent by the food industry). The petroleum and coal products industry ranks second by capacity (fourth by number of systems). As crude oil is refined into salable products, some components remain that the industry uses for fuel. This fuel source makes CHP a cost-effective choice for the industry. Food and primary metals round out the top 5 industries by capacity (6% and 5% of total, respectively), with the food industry accounting for 9% of systems.

Figure 7-2. CHP System Counts and Total Capacity for Manufacturing Industries by Count and MW-AC (at 3-Digit NAICS)

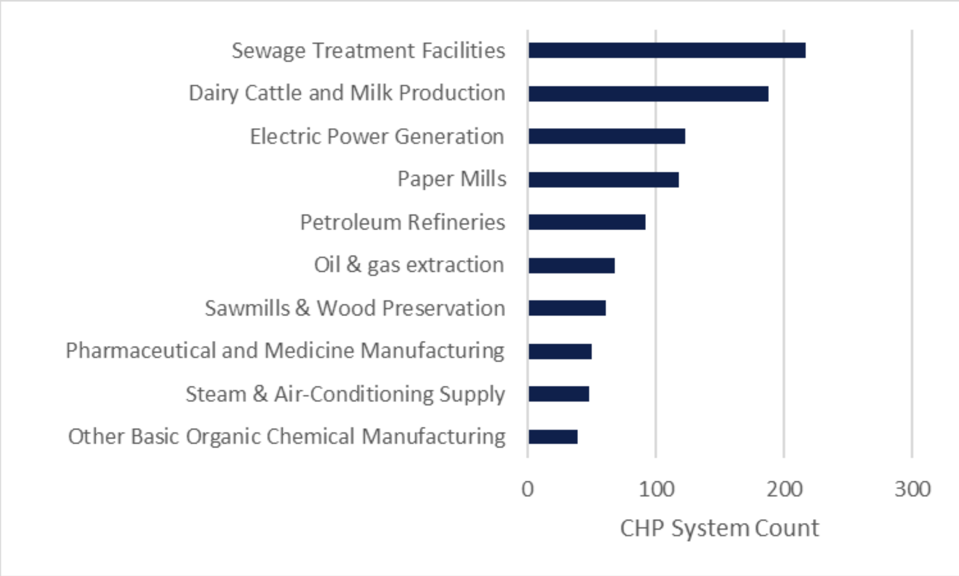


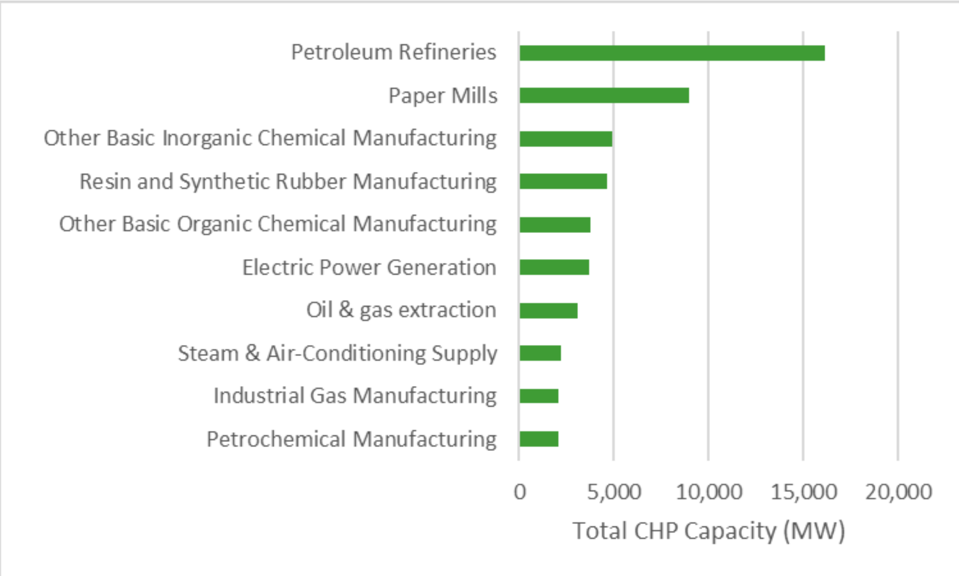
To further refine which industry sectors opt for CHP, we looked at the 5-digit NAICS level across all industries. Figure 7-3 shows the top 10 industries by number of systems (blue), accounting for 56% of total systems, and by capacity (green), accounting for 70% of total capacity.

There is substantial overlap between the two top 10 lists, with 6 industries appearing on both: petroleum refineries, paper mills, other basic organic chemical manufacturing, electric power generation, oil and gas extraction,[186] and steam and air conditioning supply (e.g., district heat). Of the top 10 by number of systems that do not appear on both lists, three have available biomass or biogas (sewage treatment, dairy cattle and milk production, and sawmills). This fuel availability makes CHP cost effective at a smaller scale. Rounding out the capacity top 10 list are other basic inorganic chemical manufacturing, resin and synthetic rubber manufacturing, industrial gas manufacturing, and petrochemical manufacturing. Seven of the capacity top ten are manufacturing industries, characterized by high thermal load and high overall energy demand. District heat is similar in those characteristics. The electric power generation capacity is almost all fossil fuel generation (97% NAICS 221112).

[186] The facilities included in this category are listed in the DOE CHP database as NAICS 21111, which is not a valid NAICS code. We categorized it as oil and gas extraction based on the first four digits.

Figure 7-3. CHP System Counts and Total Capacity: Top 10 Five-Digit NAICS Industries by Count and MW-AC





7.6.4 Technological innovations

CHP systems produce electricity and useful thermal energy in a sequential process from a single source of fuel. As a result, CHP systems often operate with an overall efficiency of 70% to 80%. Installers cited a number of technological and other innovations in the CHP market.

- Inverter-based generators are increasingly supplanting synchronous and induction generators for CHP, particularly for smaller systems.[187] Inverter-based CHP has several advantages over the older technologies, notably a standardized interconnection following the UL 1741

[187] Davidson, Keith, and Rod Hite, *A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California*, California Energy Commission, updated March 22, 2019.

standard.[188] This nationally recognized standard allows CHP to be treated more like solar when connecting to the distribution network. About seven years ago, the CHP market began adopting inverter-based technology in smaller reciprocating engine systems for the utility interconnect, allowing this CHP technology to also be treated more like solar. With that change, the utility must be able to control the inverter. Synchronous and induction generators, in contrast, often face greater utility resistance and hurdles to interconnection. Other advantages of inverter-based CHP over induction generators include black start capability (the system can operate during a blackout), high power quality, no reactive power, and variable-speed capability that provides efficient part-load performance.

- Through technology advancements, CHP systems can provide frequency regulation benefits to the end user and the utility through grid service market participation.
- CHP start times have improved, with units achieving full speed much faster than in the past.
- One installer noted that some third-party heat exchangers have improved.

Customer-sited CHP systems in the commercial building and industrial sectors are considered a mature DER technology, and the use of clean hydrogen in CHP systems is seen as the next step in the technology's evolution. These systems will need access to hydrogen, either through production of hydrogen on-site or by selecting a location near a hydrogen production facility to avoid high transportation costs. Their facility also needs hydrogen storage and handling equipment. Blending hydrogen with natural gas is already possible, and demonstration projects are ongoing for both blending into natural gas pipelines and site-level blending at the end-use customer location. If configuring CHP with a boiler, the maximum blending percentage possible depends on the boiler burner type. The current industry assumption for industrial end users is that blending up to 20% (by volume) can be safely done without changing the burners of the end-using equipment. This assumption is generally the same assumption made for hydrogen fuel blending in commercial and industrial CHP equipment. Manufacturers are working to decarbonize natural gas by blending it with different fuels such as hydrogen, renewable natural gas, and possibly even ammonia. Four installers mentioned transitioning to engines that burn hydrogen, with one stating that he or she has 22 units operating on pure hydrogen, although we were not able to confirm that number and it was not clear if all those units were part of CHP systems. The DOE CHP eCatalog lists 63 CHP packages with hydrogen blending capability ranging from 5% to 40% and five 100% hydrogen systems.[189]

In May 2022, Caterpillar announced a demonstration project of a hydrogen-fueled CHP system to start in 2023.[190,191] The company offers a 1,250 kW-AC generator set that can operate on 100% hydrogen, although it is only available on a designed-to-order basis. Among its standard product offerings are models that can operate with natural gas/hydrogen blends with up to 25% hydrogen.[192] A Siemens industrial gas turbine featured in a demonstration project in France produced and stored

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188 Panora, Robert and Jean Roy, "Top 10 Reasons to Choose Inverter-Based Engine CHP," Tecogen, accessed October 11, 2023

189 U.S. Department of Energy, Combined Heat & Power eCatalog, DOE Recognized CHP Packaged Systems and Suppliers, accessed October 11, 2023.

190 Caterpillar, News, Corporate Press Releases, Corporate Press Release Archive, "Caterpillar to Launch Demonstration Project Using Hydrogen-Fueled Combined Heat and Power," Press Release (May 31, 2022).

191 Singh, Jaswinder, "Flexible Natural Gas/Hydrogen CHP System Development & Demonstration," Caterpillar, Presentation, June 5–8, 2023.

192 Caterpillar, New Products, Power Systems, Electric Power, Gas Generator Sets, accessed October 11, 2023.

100% renewable hydrogen and then used it to fuel the turbine to produce electricity.[193] Capstone released a CHP product that runs on a blend of up to 10% hydrogen and is working to develop products that run on fuel mixes with a higher hydrogen content.[194] The current cost of hydrogen, whether renewably produced or produced from natural gas, is higher than natural gas.

Lastly, one installer mentioned the role of CHP in microgrids. With other distributed energy technologies, such as solar plus battery storage, CHP can allow a building, campus, or community to operate independently of the grid when necessary, improving resilience.

Although not a technological innovation, the business model of an energy services company (or in the case of one end user, the utility) owning and operating a CHP system for the end user is making CHP accessible to a wider range of customers.

7.7 General

7.7.1 Cultural factors influencing adoption

Many companies have environmental, social, and governance (ESG) goals or policies. One element of such policies can be GHG emission reduction goals. CHP can further such goals by trading an increase in Scope 1 emissions for a larger decrease in Scope 2 emissions. However, some companies may see burning fossil fuels in any capacity as in opposition to their ESG goals.

Corporate decision-making can stymie an investment in CHP. In any given year, a company may have multiple capital projects under consideration. Replacing an aging boiler may be seen as more urgent than adding CHP. That perspective may be exacerbated by lack of knowledge about CHP, which one installer said was viewed as “exotic.” Many facilities could benefit from CHP but are unaware of the technology or don’t fully understand its benefits and risks. One installer interviewed cited the need for someone within an organization to be knowledgeable about the technology and act as a champion. Corporate decision-makers need to understand the technology, financing, and benefits to authorize the capital investment required for a CHP system.

Installers’ concerns about the impacts of electrification policies tie into cultural factors. One of their fears is that such policies convey the message, intentionally or not, that all gas use is bad and that therefore CHP is an undesirable technology. One comment installers made about the IRA was that providing tax credits for CHP conveyed fuel neutrality with solar and storage.

7.7.2 Barriers to CHP adoption

Both technical and informational barriers exist for CHP adoption.

Technical barriers to CHP adoption include:

- Some facilities do not have the physical space to house the CHP equipment.
- Depending on a facility’s thermal needs, a CHP system may not be able to provide enough steam at the necessary temperature to support processes which require high temperatures.
- CHP is most applicable for applications where the timing and magnitude of electric and thermal demands are aligned, and may not be appropriate technology for all types of facilities/industries.

[193] Siemens Energy, ”HYFLEXPOWER consortium successfully operates a gas turbine with 100 percent renewable hydrogen, a world first,” Press Release (October 13, 2023).

[194] Capstone Green Energy, News, Press Releases, “Capstone Green Energy Corporation (NASDAQ: CGRN) outlines its ongoing hydrogen development program and pursuit of external funding opportunities,” Press Release (April 26, 2021).

Information barriers include:

- Facility owners might not be aware of CHP technology and its benefits.
- Installers and end users may not understand the overall environmental impact of CHP.
- In areas with aggressive decarbonization/electrification policies, the future use, cost, and availability of natural gas is uncertain.
- Federal, state, and local regulations might be triggered due to an increase in fossil fuel use for the CHP.
- CHP systems are complex, with electrical, thermal, and gas connections that require complex engineering and understanding.

With the installation of CHP systems, hidden costs and cost uncertainty exist. Utility interconnections could add time and cost, for example, if the customer has to pay for an impact study that could identify costly substation upgrades.

7.8 Non-CHP generation

7.8.1 Non-CHP versus CHP self-generation

Conventional (non-CHP) electricity generation is also present in the industrial sector at facilities that have reliability needs but do not have the heating loads to justify CHP.

However, conventional generation accounts for a much smaller share of industrial electricity generation than CHP. MECS reports fuel consumption for both CHP and conventional electricity generation. The 2018 MECS reports non-negligible values for fuel use for conventional electricity generation for only four industrial subsectors (at the NAICS three-digit level): petroleum, paper, food, and chemicals. In contrast, 14 subsectors had non-negligible consumption for CHP. Across all manufacturing subsectors and fuels, more than 1,900 trillion British thermal units went to CHP, compared with 31 trillion British thermal units going to conventional electricity generation (only 1.6% of the CHP value). Even with conservative estimates of power-to-heat ratios, conventional generation accounts for only a small share of the total electricity produced.[195,196]

Non-CHP self-generation also includes intermittent renewables, such as solar, which can be paired with storage to partially address the issue of intermittency. These technologies are different from CHP, which addresses base load and thermal load, and provides resiliency. Because of these different operational characteristics, CHP and non-CHP technologies are generally not seen as being in competition with each other, but rather they are complementary technologies serving different needs. To the extent that any interviewees saw them as competing, it was related to marketing, awareness, incentives, and electrification policies rather than performance and suitability.

Two CHP installers interviewed mentioned installing CHP as one component of a microgrid that also included solar and energy storage. For one project, the CHP was sized around thermal needs (thermal load), while the solar and storage were designed to address electric needs (electric load). However, such systems are more common for residential and commercial projects than for industrial.

Roof and/or land availability can be a limiting factor when designing a solar system. CHP can generate more electricity than solar. One CHP installer said that the amount of solar that could be

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[195] New technologies typically have power-to-heat ratios of 1.0 or higher, while older systems could have ratios as low as 0.3.

[196] Fahl, Ulrich and Audrey Dobbins, *Europe's Energy Transition*, Chapter 29 – District Heating in Europe: Opportunities for Energy Savings, Business, and Jobs, 2017, p.249–259.

installed would be “window dressing” and “a drop in the bucket” relative to the energy needs of the typical CHP-using facility.

For companies with ESG goals, renewables may be adopted to achieve those goals, regardless of limiting factors. For example, solar provides a visible sign of commitment to GHG reduction that may have public relations value.

Two of the CHP end users interviewed had rejected solar or solar plus storage solutions due to intermittency and reliability issues, such as storage only being appropriate for bridging short-term needs at current prices and performance factors. One end user cited the need for redundancy during storms when outages are more likely but solar production may be minimal or offline.

The value of solar and wind depend on location. Wind speeds and consistency differ widely by region, and insolation varies with latitude, weather patterns, and season. At northern latitudes, solar production is lower in the winter, which reduces its value for space heating loads or for industrial process loads that tend to be consistent across the year.

7.8.2 Economics of non-CHP self-generation

7.8.2.1 Rates

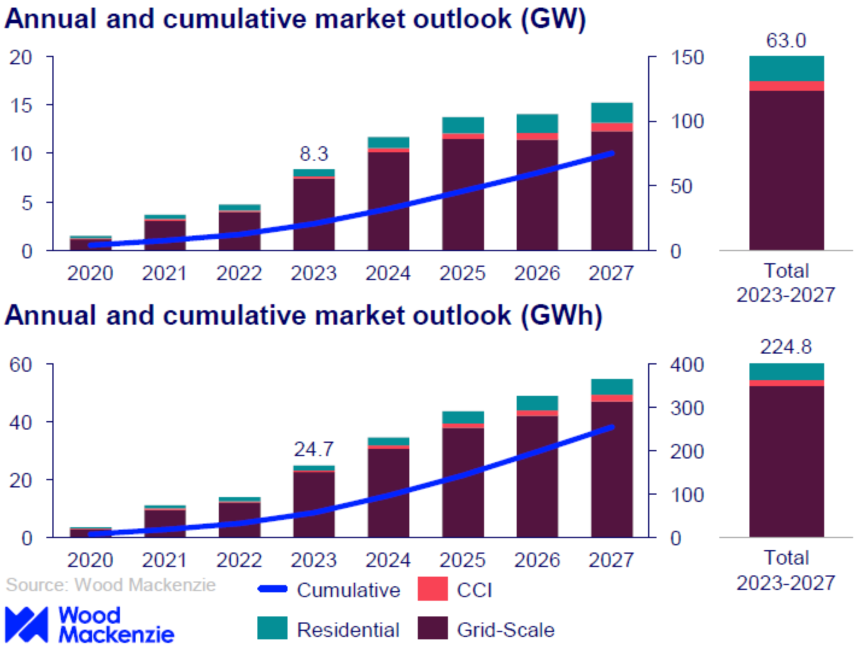
Rates are a critical factor in determining the economic feasibility of renewables. Much like the spark spread for CHP, renewables are attractive when the cost of self-generation is less than the cost to purchase energy from the utility. Industrial electric tariffs are usually demand based except for the smallest facilities. Demand rates charge customers based on the facility’s maximum monthly kilowatts of demand for a specified duration, for example, the facility’s highest 15-minute demand for the month. The financial benefits that intermittent renewables have on energy bills may decrease as demand charges increase, because the potential of the renewable resource (e.g., wind or solar power) generation being non-coincident with facility’s peak demand. The question is not just how much self-generation the system (kilowatthour) produces—it matters when that energy is produced and whether it can consistently coincide with the facility’s peak.

Small industrial customers are numerous but represent only a small share of total industrial energy use. Small industrial customers are more likely to be on an energy-based small general service rate along with small commercial customers. For example, a one-person jewelry-making studio would be classified as industrial but would have low electricity consumption and have less process energy use relative to space heating and space cooling. For these customers, the economic proposition for solar is similar to that of small commercial. The calculation is simply whether it is less expensive per kilowatthour to produce electricity than to buy it from the utility.

7.8.2.2 Predominance and growth of non-CHP self-generation

We found limited literature discussing how widespread non-CHP self-generation is in the industrial sector. Wood Mackenzie forecasts battery storage adoption in the non-residential sector (not industrial specifically), which is often paired with renewables. This forecast provides an indirect indicator of the growth in non-CHP self-generation, with the non-residential sector called “CCI” and displayed in red (Figure 7-4).

Figure 7-4. Annual and cumulative market forecast for battery storage



Data source: Wood Mackenzie, *US Energy Storage Monitor Q4 2023*

As with CHP, industry subsector is not the key factor in determining where growth will occur in non-CHP self-generation. Factors that will determine growth include:

- Electricity rate structure
- Cost of purchased electricity
- Facility load shapes, for example, facilities with flat loads benefit less from storage
- Corporate ESG goals and policies

7.8.2.3 Regulations affecting non-CHP industrial self-generation

No regulations limiting non-CHP self-generation for industrial facilities were identified. However, installers perceived that certain policies favored renewables over CHP. Particularly, under electrification initiatives, renewables can be seen more favorably than natural-gas-based technology. Historically, federal tax credits have been higher for renewables than for CHP (although the IRA has leveled the playing field through the end of 2024).

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