Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies

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To accurately reflect the changing cost of new electric power generators in the *Annual Energy Outlook 2025* (AEO2025), EIA commissioned Sargent & Lundy (S&L) to evaluate the overnight capital cost and performance characteristics for 19 electric generator types. The following report represents S&L's findings.

EIA accepted the following report in fulfillment of contract number 89303023-REI000091. All views expressed in this report are solely those of the contractor and acceptance of the report in fulfillment of contractual obligations does not imply agreement with nor endorsement of its findings. Responsibility for accuracy of the information contained in this report lies with the contractor. Although EIA intends to use this report to inform the updating of EIA's Electricity Market Module in the National Energy Model System (NEMS), EIA is not obligated to modify any of its models or data in accordance with the findings of this report.

Contacts

This report, *Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies*, was prepared under the general guidance of Angelina LaRose, Assistant Administrator for Energy Analysis; Jim Diefenderfer, Director of the Office of Long-Term Energy Modeling; and Chris Namovicz (202-586-7120), Team Lead of the Electricity, Coal, and Renewables Modeling Team. Technical information concerning the content of the report also may be obtained from Richard Bowers at 202-586-8586 or Nina Vincent at 202-586-8501.

Introduction

The current projected cost and performance characteristics of new electric generating capacity are critical inputs into the development of energy projections and analyses. The construction and operating costs, along with the performance characteristics, of new generating plants play an important role in determining the mix of capacity additions that will serve future demand for electricity. These parameters also help to determine how new capacity competes against existing capacity and how electric generators will respond to imposed environmental controls on conventional pollutants or any limitations on greenhouse gas emissions.

Consistent with EIA's practice of developing periodic assessments, EIA commissioned an external consultant to develop up-to-date cost and performance estimates for utility-scale electric generating plants for AEO2025. This report is the fifth such report EIA has commissioned since 2010. As with the prior studies, this information allows EIA to compare the costs of different electric generating technologies on a standardized basis and is a key input enhancement to the NEMS.

This report contains cost and performance estimates developed by Sargent & Lundy for 19 reference technology cases for different types of electric generators. To develop the characteristics of each reference technology case, Sargent and Lundy considered the specification of representative plant sizes and configurations and major equipment components, including emission controls, based on current information from similar facilities recently constructed, under development, or proposed for commercial development in the United States and abroad. In each successive study that EIA contracted, the evolution of technology, environmental requirements, and generator preferences influenced the attributes associated with the reference generating technology. Where these characteristics remain substantially similar between the study conducted for AEO2020 and the study conducted for AEO2025, reference technology case costs are comparable and are labeled "updated"; where these characteristics differ significantly between the two studies, the reference technology costs are reported as "new" (Findings).

To produce its overnight capital cost estimates, Sargent & Lundy assumed that the power plant developer or owner will hire an engineering, procurement, and construction (EPC) contractor for turnkey construction of the project. These costs represent the total cost a developer would expect to incur during the construction of a project, excluding financing costs. The specific overnight costs for each type of facility are divided into:

- Civil and structural material and installation cost covering all material and associated labor for civil and structural tasks
- Mechanical equipment supply and installation cost including all mechanical equipment and associated labor for mechanical tasks
- Electrical, instrumentation, controls supply, and installation cost including all costs for transformers, switchgear, control systems, wiring, instrumentation, and raceways.

- Project indirect costs including engineering, construction management, as well as start-up and commissioning. The fees include contractor overhead costs, fees, and profit.

Sargent & Lundy estimated labor, maintenance, minor repairs, and general and administrative (G&A) costs based on multiple sources including actual projects, vendor publications, and internal resources. Variable operations and maintenance costs, such as ammonia, water, and miscellaneous chemicals and consumables, are directly proportional to the electricity generated. Fuel costs were estimated for reference unit types using representative fuel specifications for coal, natural gas, and biomass.

Findings

Table 1 summarizes updated cost estimates for reference case utility–scale generating technologies specifically two powered by coal, five by natural gas, three by solar energy and by wind, two by uranium, and one each by hydroelectric, biomass, geothermal, and battery storage. EIA does not model all these generating plant types but included them in the study to present consistent cost and performance information for a broad range of generating technologies and to aid in the evaluation for potential inclusion of new or different technologies or technology configurations in future analyses. The specific technologies represented in the NEMS model for AEO2025 that use the cost data from this report are identified in the last column of Table 1.

Table 2 provides a comparison of updated overnight cost estimates for technologies substantially similar to those developed for the 2019 report. To facilitate comparisons, the costs are expressed in 2023 dollars.

Impact of location on power plant capital costs

The estimates provided in this report are representative of a generic facility located in a region without any special issues that would alter its cost. However, the cost of building power plants in different regions of the United States can vary significantly. Sargent & Lundy estimated capital cost adjustment factors to account for technology deployment at various U.S. locations using published labor rates for each location to create a wage rate factor for each location against the base rate (the *30 City Average*). The location factors were then improved by adding a regional labor productivity factor. To reflect these costs in EIA's modeling, these adjustments were aggregated to represent the 25 Electricity Market Module regions. EIA also assumes that the development of certain technologies is not feasible in given regions for geographic, logistical, or regulatory reasons. The regional cost adjustments for the reference technologies are summarized in Table 3.

Summary

Although the estimates provided by Sargent & Lundy for this report are key inputs for EIA electric market projections, they are not the sole driver of electric generation capacity expansion decisions. The evolution of the electricity mix in each of the 25 regions modeled in AEO2025 is sensitive to many factors, including the projected evolution of capital costs over the modeling horizon, projected fuel costs, the characteristic of wholesale power markets (regulated or competitive), the existing generation mix, additional costs associated with environmental controls, and future electricity demand.

Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies

Prepared for

U.S. Energy Information Administration and Z Federal

Prepared by Sargent & Lundy

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ACRONYMS AND ABBREVIATIONS

Acronym/Abbreviation	Definition/Clarification
AC	Alternating Current
ACC	Air-Cooled Condenser
ASCE	American Society of Civil Engineers
BESS	Battery Energy Storage System
BFB	Bubbling Fluidized Bed
BOP	Balance-of-Plant
Btu/kWh	British Thermal Units Per Kilowatthour
Btu/lb	British Thermal Unit Per Pound
Btu/scf	British Thermal Unit Per Standard Cubic Foot
CC	Combined-Cycle
CCS	Carbon Capture and Sequestration
CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
COD	Commercial Operation Date
CT	Combustion Turbine
DAC	Direct Air Capture
DC	Direct Current
DCS	Distributed Control System
EGS	Enhanced Geothermal System
EIA	Energy Information Administration
EOH	Equivalent Operating Hours
EPC	Engineering, Procurement, and Construction
FGD	Flue Gas Desulfurization
G&A	General and Administrative
GSU	Generator Step-Up Transformer
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
Hz	Hertz

Acronym/Abbreviation	Definition/Clarification
I&C	Instrumentation and Controls
IBC	International Building Code
IRA	Inflation Reduction Act
ITC	Investment Tax Credit
kV	Kilovolts
kW	Kilowatt
kWh	Kilowatt-hour
lb/MMBtu	Pounds Per One Million British Thermal Units
LNB	Low Nitrogen Oxide Burner
MCC	Motor Control Center
MVA	Megavolt-Ampere
MW	Megawatt
MWAC	Megawatt Alternating Current
MWh	Megawatt-hour
NO_X	Nitrogen Oxide
O&M	Operating and Maintenance
OFA	Overfire Air
PCS	Power Conditioning System
PTC	Production Tax Credit
psia	Pounds Per Square Inch Absolute
PV	Photovoltaic
RH	Relative Humidity
SCADA	Supervisory Control and Data Acquisition
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
STG	Steam Turbine Generator
USC	Ultra-Supercritical
USD	United States Dollar
USDA	U.S. Department of Agriculture

Acronym/Abbreviation	Definition/Clarification
WESP	Wet Electrostatic Precipitator
WFGD	Wet Flue Gas Desulfurization
WTG	Wind Turbine Generator
ZLD	Zero Liquid Discharge

INTRODUCTION

INTRODUCTION

The U.S. Energy Information Administration (EIA) retained Z Federal and Sargent & Lundy to conduct a study of the cost and performance of new utility-scale electric power generating technologies. This report contains Sargent & Lundy's cost and performance estimates for 19 different reference technology cases. The EIA will use these estimates to improve the EIA's Electricity Market Module's ability to represent the changing landscape of electricity generation. With this update, the EIA's improved Electricity Market Module will better represent capital and non-fuel operating costs of generating technologies being installed or under consideration for capacity expansion. The Electricity Market Module is a submodule within the EIA's National Energy Modeling System, a computer-based energy supply modeling system used for the EIA's *Annual Energy Outlook* and other analyses.

Sargent & Lundy developed the characteristics of the power generating technologies in this study based on information about similar facilities recently built or under development in the United States and abroad. Developing the characteristics of each generating technology included the specification of representative plant sizes, configurations, major equipment, and emission controls. Sargent & Lundy's cost assessment included the estimation of overnight capital costs, construction lead times, contingencies, and fixed and variable operating costs. We also estimated the net plant capacity, net plant heat rates, and controlled emission rates, as applicable for each technology studied. We performed our assessments with consistent estimating methodologies across all generating technologies.

COST AND PERFORMANCE OF TECHNOLOGIES

Table 1-1 lists all the power generating technologies that we assessed in this study.

Table 1-1 — List of Reference Technologies

Case No.	Technology	Description
1	Ultra-Supercritical (USC) Coal without Carbon Capture – Greenfield	1 x 735 MW Gross, 650 MW Net
2	USC Coal 95% Carbon Capture	1 x 819 MW Gross, 650 MW Net
3	Aeroderivative Combustion Turbines (CTs) – Simple Cycle	4 x 54 MW Gross Aeroderivative, 211 MW Net
4	CTs – Simple Cycle	1 x H-Class Simple Cycle, 419 MW Net
5	Combined-Cycle (CC) 2x2x1	2 x 1 H Class CC, 1227 MW Net
6	CC 1x1x1, Single Shaft	1 x 1 H Class CC, 627 MW Net
7	CC 1x1x1, Single Shaft, with 95% Carbon Capture	1 x 1 H Class CC, 543 MW Net

Case No.	Technology	Description
8	Biomass Plant with 95% Carbon Capture	1 x Bubbling Fluidized Bed (BFB), 50 MW Net
9	Advanced Nuclear (Brownfield)	2 x AP1000, 2156 MW Net
10	Small Modular Reactor Nuclear Power Plant	6 x 80-MW Small Modular Reactor, 480 MW Net
11	Geothermal	Binary Cycle, 50 MW Net
12	Hydroelectric Power Plant	New Stream Reach Development, 100 MW Net
13	Onshore Wind – Large Plant Footprint: Great Plains Region	200 MW | 2.8-MW Wind Turbine Generator (WTG)
14	Onshore Wind – Repowering/Retrofit	150 MW | 1.5-1.62 MW WTG
15	Fixed-bottom Offshore Wind: Monopile Foundations	900 MW | 15 MW WTG
16	Solar Photovoltaic (PV) with Single-Axis Tracking	150 MW_{AC}
17	Solar PV with Single-Axis Tracking and AC-Coupled Battery Storage	150 MW_{AC} Solar 50 MW | 200 MWh Storage
18	Solar PV with Single-Axis Tracking and DC-Coupled Battery Storage	150 MW_{AC} Solar 50 MW | 200 MWh Storage
19	Battery Energy Storage System (BESS)	Lithium Ion, 150 MW | 600 MWh

As part of the technology assessment, we reviewed recent market trends for the reference technologies using publicly available sources and in-house data. We also used our extensive background in power plant design and experience in performing similar cost and performance assessments. Using a combination of public and internal information sources, we identified the representative costs and performance for the reference technologies.

COST AND PERFORMANCE ESTIMATES SUMMARY

Table 1-2 summarizes all technologies examined, including overnight capital cost information, fixed operating and maintenance (O&M) costs, and variable non-fuel O&M costs as well as emissions estimates for new installations (in pounds per one million British thermal units [lb/MMBtu]).

Table 1-2 — Cost & Performance Summary Table

Case No.	Technology	Description	Net Nominal Capacity (kW)	Net Nominal Heat Rate (Btu/kWh)	Capital Cost ($/kW)	Fixed O&M Cost ($/kW-year)	Variable O&M Cost ($/MWh)	Nitrogen Oxide (NOx) (lb/MMBtu)	Sulfur Dioxide (SO_2) (lb/MMBtu)	Carbon Dioxide (CO_2) (lb/MMBtu)
1	USC Coal without Carbon Capture – Greenfield	1 x 735 MW Gross	650	8,638	$4,103	$61.60	$6.40	0.06	0.09	206
2	USC Coal 95% Carbon Capture	1 x 819 MW Gross	650	12,293	$7,346	$86.70	$13.73	0.06	0.09	10.3
3	Aeroderivative CTs – Simple Cycle	4 x 54 MW Gross	211	9,447	$1,606	$9.56	$5.70	0.0075	0.00	117
4	CTs – Simple Cycle	1 x H-Class	419	9,142	$836	$6.87	$1.24/ MWh, $23,100/ Start	0.0075	0.00	117
5	CC 2x2x1	2 x 1 H Class	1,227	6,266	$868	$12.12	$3.41	0.0075	0.00	117
6	CC 1x1x1, Single Shaft	1 x 1 H Class SS	627	6,226	$921	$15.51	$3.33	0.0075	0.00	117
7	CC 1x1x1, Single Shaft, with 95% Carbon Capture	1 x 1 H Class SS	543	7,239	$2,365	$24.78	$5.05	0.0075	0.00	6
8	Biomass Plant with 95% Carbon Capture	1 x BFB	50	19,965	$12,631	$261.18	$9.65	0.08	<0.03	10.3
9	Advanced Nuclear (Brownfield)	2 x AP1000	2,156	10,608	$7,861	$156.20	$2.52	0	0	0
10	Small Modular Reactor Nuclear Power Plant	6 x 80 MW Small Modular Reactor	480	10,046	$8,936	$121.99	$3.19	0	0	0
11	Geothermal	Binary Cycle	50	N/A	$3,963	$150.60	$0.00	0	0	0
12	Hydroelectric Power Plant	New Stream Reach Development	100	N/A	$7,073	$33.54	$0.00	0	0	0
13	Onshore Wind – Large Plant Footprint: Great Plains Region	200 MW | 2.8 MW WTG	200	N/A	$1,489	$33.06	$0.00	0	0	0
14	Onshore Wind – Repowering/Retrofit	150 MW | 1.5 - 1.62 MW WTG	150	N/A	$1,386	$38.55	$0.00	0	0	0

Case No.	Technology	Description	Net Nominal Capacity (kW)	Net Nominal Heat Rate (Btu/kWh)	Capital Cost ($/kW)	Fixed O&M Cost ($/kW-year)	Variable O&M Cost ($/MWh)	Nitrogen Oxide (NOx) (lb/MMBtu)	Sulfur Dioxide (SO_2) (lb/MMBtu)	Carbon Dioxide (CO_2) (lb/MMBtu)
15	Fixed-bottom Offshore Wind: Monopile Foundations	900 MW | 15 MW WTG	900	N/A	$3,689	$154.00	$0.00	0	0	0
16	Solar PV with Single-Axis Tracking	150 MW_{AC}	150	N/A	$1,502	$20.23	$0.00	0	0	0
17	Solar PV with Single-Axis Tracking and AC-Coupled Battery Storage	150 MW_{AC} Solar 50 MW | 200 MWh Storage	150	N/A	$2,175	$38.39	$0.00	0	0	0
18	Solar PV with Single-Axis Tracking and DC-Coupled Battery Storage	150 MW_{AC} Solar 50 MW | 200 MWh Storage	150	N/A	$2,561	$39.24	$0.00	0	0	0
19	BESS	Lithium Ion, 150 MW | 600 MWh	150	N/A	$1,744, ($436/kWh)	$40.00	$0.00	0	0	0

BASIS OF ESTIMATES

BASE FUEL SELECTION

We used the following fuel specifications as a basis for the cost estimates. Table 1-3, Table 1-4, and Table 1-5 represent typical fuel specifications for coal, natural gas, and wood biomass, respectively.

Table 1-3 — Reference Coal Specification

Rank	Bituminous
Proximate Analysis (weight %)	
Fuel Parameter	As Received
Moisture	11.2
Ash	9.7
Carbon	63.75
Oxygen	6.88
Hydrogen	4.5
Sulfur	2.51
Nitrogen	1.25
Chlorine	0.29
HHV, Btu/lb	11,631
Fixed Carbon/Volatile Matter	1.2

HHV = Higher heating value; Btu/lb = British thermal unit per pound

Table 1-4 — Reference Natural Gas Specification

Component		Volume Percentage	
Methane	CH_4	93.9	
Ethane	C_2H_6	3.2	
Propane	C_3H_8	0.7	
n-Butane	C_4H_{10}	0.4	
Carbon Dioxide	CO_2	1	
Nitrogen	N_2	0.8	
Total		100	
		LHV	HHV
Btu/lb		20,552	22,793
Btu/scf		939	1,040

LHV = Lower heating value; Btu/scf = British thermal unit per standard cubic foot

Table 1-5 — Reference Wood Biomass Specification

Type	Woodchips
Component	Weight %
Moisture	20–50
Ash	0.1–0.7
Carbon	32
Sulfur	0.01
Oxygen	28
Hydrogen	3.8
Nitrogen	0.1–0.3
HHV, Btu/lb	5400–6200

ENVIRONMENTAL COMPLIANCE BASIS

Our technology assessments selected include the best available (emissions) control technology for sulfur dioxide (SO_2), nitrogen oxide (NO_X), particulate matter, mercury, and carbon dioxide (CO_2), where applicable. Best available control technology guidelines are covered by the United States' Clean Air Act Title I, which promotes air quality, ozone protection, and emission limitations. The level of emission controls is based on the following best available control technology guidelines:

- Total source emissions
- Regional environmental impact
- Energy consumption
- Economic costs

Best available control technology is not the most restrictive pollution control standard since it still includes a cost-benefit analysis for technology use. Specific technologies chosen for estimation are further described in their respective cases.

The CO_2 capture systems are commonly referred to as carbon capture and sequestration (CCS) systems; however, for the cost estimates provided in this report, no sequestration costs (CO_2 transportation or storage) have been included. The CO_2 captured is assumed compressed to supercritical conditions and injected into a pipeline terminated at the fence line of the facility. For this report, the terms "CO_2 capture" and "carbon capture" are used interchangeably.

COMBUSTION TURBINE CAPACITY ADJUSTMENTS

Appendix B includes CT capacity adjustments.

Adjustments for local ambient conditions were made for power plants using CTs. Since CTs produce power proportional to mass flow and ambient air temperature, relative humidity, and elevation affect air density, these conditions also affect CT performance. These conditions affect CT performance in the following ways:

- Temperature affects air density in an inversely proportional relationship. Higher ambient temperature lowers the density of the inlet air which reduces the mass flow through the CT and the consequent power output. Inlet cooling technology on a CT can increase the air density and recover lost performance.
- Relative humidity affects air density in an inversely proportional relationship as components of water vapor are less dense than air. Higher relative humidity lowers density and mass flow through the CT which reduces the power output. For plants with wet cooling (evaporative coolers, wet cooling towers, etc.), relative humidity and temperature determine the effectiveness of that equipment as well. Cooling technologies that depend on evaporation are most effective when the temperature is high and the relative humidity low.
- Elevation affects air pressure and density in an inversely proportional relationship. Ambient air density was calculated in this study by using the air pressure related to site elevation above sea level. This gives the average impact of air pressure on performance, ignoring the short-term effects of weather.

Temperatures and relative humidity used in the Appendix B adjustment table are based on annual averages for the locations specified. An adjustment factor for the various technologies were compared across locations on a consistent basis.

CAPITAL COST ESTIMATING

Sargent & Lundy used a top-down capital cost estimating methodology derived from parametric evaluations of costs from actual or planned projects with similar scope and configurations to the generating technology considered. We have used both publicly available information and internal sources to establish the representative costs and appropriate scaling parameters. In some cases, we have use used portions of more detailed cost estimates to adjust the parametric factors.

The capital cost estimates represent a complete power plant facility on a generic site at a non-specific location in the United States. The basis of the capital costs is defined as all costs to engineer, procure, construct, and commission all equipment within the plant facility fence line, as well as interconnections to electrical transmission and fuel distribution networks, as applicable. As described in the following section, we have also estimated location adjustments to help establish the cost impacts to project implementation in more specific areas or regions within the United States. Capital costs account for all costs incurred during construction of the power plant before the commercial operation date (COD). The capital costs are divided between the engineering, procurement, and construction (EPC) contractor and owner's costs. Sargent & Lundy assumes that the power plant developer or owner will hire an EPC contractor for turnkey construction of the project. Unless noted otherwise, the estimates assume that the EPC contractor cost will include procurement of equipment, materials, and all construction labor associated with the project. The capital costs provided are overnight capital costs in 2023 price levels. Overnight capital costs represent the total cost a developer would expect to incur during the construction of a project, excluding financing costs. The capital cost breakdowns for the EPC contractor are as follows:

- Direct Costs: EPC direct costs are broken down in formats applicable to the reference technology. In some cases, the cost breakdown includes major scope work packages that are inclusive of equipment, materials, and direct labor costs. Other cases have equipment and material procurement costs separated from the construction labor.
    - Major Work Scope Costs: Costs for major project scopes of work such as "Civil/Structural/Architectural" or "Nuclear Island" include the equipment, materials, and construction labor associated with scope described.
    - Equipment and Material Costs: For some cases, the costs for the primary generation technologies are listed explicitly (for example, solar PV "Module Supply," "WTG Procurement and Supply," etc.), or grouped into balance-of-plant (BOP) equipment line items such as "Racking, Tracker and BOP Equipment Supply." Where no other descriptors are present, "Other Equipment" generally refers to ancillary equipment, such as pumps, tanks, motor control centers, condensers, cooling towers, switchgear, transformers, and any other major inside-the-fence process equipment required for the complete facility. "Materials" include all construction materials associated with the EPC scope of work and consumables during construction. Equipment and material costs are intended to be the delivered costs inclusive of purchase price, duties, and freight, (but excluding any sales tax) and are clarified with additional descriptors and notes, as needed.
    - Construction Labor Costs: Construction labor costs are intended to represent the fully burdened cost of labor to the EPC contractor for the project construction activities. Construction labor costs may be listed for individual activities as "installation" costs, included with the equipment/material costs where the description includes "supply and installation," or aggregated as "construction labor" for all labor directly attributed to onsite civil/structural work and erection/installation of the equipment included in the EPC contractor's scope.
- Indirect Costs: Indirect costs include engineering, procurement, project services, construction management, field engineering, start-up, and commissioning services provided by the EPC contractor.
- EPC Fee and Contingency: The EPC fee is included to represent the premium applied by the EPC contractor for profit and management of subcontracts within their scope. EPC contingency includes costs for the "known unknowns" that are not defined explicitly but would be expected to be managed

by the EPC contractor while delivering a fully functional generation facility. Contingencies are added because experience has shown that such costs are likely, and expected, to be incurred even though they cannot be explicitly determined at the time the estimate is prepared. The percentages used to calculate these values are generally representative of the degrees of uncertainty, risk, and complexity of the generation and any environmental control technologies. These percentages are listed in the cost tables and represent values generally accepted within their respective markets.

Owner’s costs represent costs to the owner that would typically be incurred outside the scope of the EPC contract. These primarily consist of costs incurred to develop and manage the project as well as land and utility interconnection costs.

- Owner’s Services: The owner’s services include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's participation in start-up and commissioning.
- Land: project land requirements are based on typical land requirements for each technology with per-acreage costs based on a survey of vacant land listings zoned for industrial use within the United States. For certain technologies, land is assumed to be leased and those costs are included in the operations and maintenance costs instead.
- Electrical Interconnection: Transmission costs are based on a one-mile transmission line (unless otherwise stated) with voltage ranging from 115 kilovolts (kV) to 500 kV depending on the unit capacity. We have also assumed that no substation upgrades would be required for the electrical interconnections.
- Gas Interconnection: Natural gas interconnection and metering costs are generic and based on nominal one-mile gas pipeline laterals. Per-mile costs are assumed based on historical costs for pipeline laterals serving similar generation facilities. Owner’s Contingency: An owner’s contingency is also included to account for undefined project scope and pricing uncertainty within owner’s cost components. Like the EPC contingency, the levels of owner’s contingencies differ from case to case, and do so for many of the same reasons, including project uncertainty, risk, and complexity.

Locational Adjustments

We estimated the capital costs adjustment factors account for technology implementation at various locations in the United States. Appendix A provides locational adjustment factors.

Craft labor rates for each location were developed from the publication *RS Means Labor Rates for the Construction Industry*, 2023 edition. Costs were added to cover social security, workmen’s compensation, and federal and state unemployment insurance. The resulting burdened craft rates were used to develop typical crew rates applicable to the task performed. For each technology, up to 26 different crews were used to determine the average wage rate for each location. For several technologies, relevant internal Sargent & Lundy estimates were used to further refine the average wage rate by using the weighted average based on the crew composition for the specific technology.

Sargent & Lundy used a “30 City Average” based on *RS Means Labor Rates for the Construction Industry* to establish the base location for all the technologies. We measured the wage rate factor for each location against the base rate (the “30 City Average”). The location factors were then improved by adding the regional labor productivity factor; these factors are based on the publication *Compass International Global Construction Costs Yearbook*, 2022 edition. Even though *Compass International Global Construction Costs Yearbook* provides productivity factors for some of the major metro areas in the United States, the productivity factors on the state level were mostly used to represent the typical construction locations of plants for each of the technologies. The final location factor was measured against average productivity factor, which is based on the same 30 cities that are included in the “30 City Average” wage rate.

Environmental Location Factors

Capital cost adjustment factors have also been estimated to account for environmental conditions at various locations in the United States. These environmental location factors, however, do not account for any state or local jurisdictional amendments or requirements that modify the national design codes and standards (for example: American Society of Civil Engineers [ASCE], International Building Code, etc.). Soil Site Class D for stiff soils was assumed; geotechnical investigation is required to account for site-specific soil conditions that will need to be considered during detailed design. Risk Category II was assumed for all power generating technologies. Each environmental factor was baselined, and the geometric mean was used to determine the combined environmental location factor that accounts for the wind, seismic, snow, and tsunami effects, as applicable. To distribute the environmental location factor to the material costs for the civil, mechanical, electrical, carbon capture, and other works for each of the 19 cases, the factor was proportioned based on the assumed effect environmental loading would have on the works. In other words, the concrete foundations support most of the design loading; therefore, the percentage of the environmental loading factor that was distributed to the civil works was typically the highest. The distribution of the environmental loading factor was based on typical general arrangements of major equipment, buildings, and balance of plant for each of the 19 cases.

The environmental location factor for wind is based on ASCE 7-16, and it is based on velocity pressure for enclosed, rigid buildings with flat roofs, which is the most widely used building configuration at power generating stations. The baseline was the approximate average velocity pressure for the location data set; therefore, the factor was reduced for locations lower than the average and increased for locations above the average.

The environmental location factor for seismic is based on the "Seismic Design" category, which is determined based on site-specific coefficients[1] and the calculated mapped spectral response or design spectral acceleration. The baseline was Seismic Design Category B; therefore, the factor was reduced for Seismic Design Category A and increased for Seismic Design Category C and D. None of the locations selected were Seismic Design Category E or F due in part to the assumed soil Site Class D.

The environmental location factor for snow loading is based on an importance factor of 1.00. The ground snow load was determined using the ASCE 7-16 Hazard Tool; however, the value for Boise, Idaho, was based on data from ASCE 7-10 because data from ASCE 7-16 was unavailable. The ground snow load for case study areas assumed 50 pounds per square foot. The baseline was the approximate average ground snow load for the location data set; therefore, the factor was reduced for locations lower than the average and increased for locations above the average.

The environmental location factor for tsunami loading is based on ASCE 7-16 methodology and an article published by *The Seattle Times* regarding the cost implications of incorporating tsunami-resistant features into the first building designed using the methodology. The environmental location factor included tsunami effects for one location: Seattle, Washington.

Additional Location Factor Considerations

Base costs for the thermal power cases were determined assuming no significant constraints with respect to available water resources, wastewater discharge requirements, and ambient temperature extremes. In areas where these constraints are expected to add significantly to the installed equipment, we applied location adjustments to the capital costs. To account for locations with limited water resources, such as California, the southwest, and the mountain west regions, air-cooled condensers (ACCs) are used in lieu of mechanical draft cooling towers. In regions where wastewater loads to rivers and reservoirs are becoming increasingly restricted, zero liquid discharge (ZLD) equipment is added. ZLD wastewater treatment equipment is assumed to include reverse osmosis, evaporation/crystallization, and fractional electrode ionization. To reduce the loading for the ZLD systems, it is assumed that cases where ZLD is applied will also have equipment in place to reduce wastewater such as ACCs or cooling tower blowdown treatment systems.

To account for ambient temperature extremes, costs for boiler enclosures have been included as part of the location factors in areas where ambient temperatures will be below freezing for significant periods of

[1] Determined using the web interface on https://seismicmaps.org/. The Structural Engineers Association of California and California's Office of Statewide Health Planning and Development developed this web interface that uses the open-source code provided by the United States Geological Survey to retrieve the seismic design data. This website does not perform any calculations to the table values.

time. Costs for boiler enclosures are applied to the coal-fired cases and the biomass cases, but not to the CC heat recovery steam generators (HRSGs), which are assumed to open in all regions. It is assumed that the steam turbine generator (STG) equipment will be enclosed for all cases in all locations.

OPERATING AND MAINTENANCE COST ESTIMATING

Once a plant enters commercial operation, the plant owners incur ongoing costs for the operation and maintenance (O&M) of the facility. These costs are categorized into fixed O&M costs which are incurred each year independent of the facility dispatch, and variable O&M costs which vary with the hours of operation. Operations and maintenance costs presented in this report do not include the costs for fuel or fuel procurement activities.

Fixed Operations and Maintenance

Fixed O&M costs include costs directly related to the generation technology and facility design which do not vary with dispatch. These typically include labor, materials, contract services for routine O&M, general and administrative (G&A) costs. Costs were estimated based on a variety of sources including actual projects, vendor publications, and Sargent & Lundy's internal resources. Property taxes and insurance would also typically be considered fixed O&M but are excluded from our estimates.

Where sufficient data was available, fixed O&M cost breakouts are provided in $/year annual costs with brief descriptors of the cost components. Typical fixed O&M costs include:

- Routine Labor
- Materials and Contract Services
- Administrative and General Expenses

Routine labor includes the regular maintenance of the equipment as recommended by the equipment manufacturers. This includes maintenance of pumps, compressors, transformers, instruments, controls, and valves. The power plant's typical design is such that routine labor activities do not require a plant outage.

Materials and contract services include the materials associated with the routine labor as well as contracted services such as those covered under a long-term service agreement, which has recurring monthly payments.

General and administrative expenses are operation expenses, which include leases, management salaries, and office utilities.

These annual costs are combined in the fixed O&M subtotal and levelized by dividing by the net kW capacity of the facility to deliver values in $/kW-year. For the geothermal, hydro, wind, solar, and battery energy storage cases, all O&M costs are treated as fixed costs.

Variable Operations and Maintenance

Variable O&M costs are costs that vary based on the amount of electrical generation at the power plant. These expenses may include water consumption, waste and wastewater discharge, chemicals such as selective catalytic reduction ammonia, and consumables including lubricants and calibration gas. Because these costs are generation dependent, the values are levelized by the cost per unit of energy generation and presented in $/MWh.

INFLATION REDUCTION ACT CONSIDERATIONS

The Inflation Reduction Act (IRA), signed into law in August of 2022, introduced a comprehensive set of tax credits, grants, and loan programs aimed at financing and expediting the deployment of clean energy technologies. The capital and operating cost estimates included in this report do not account for investment tax credits, production tax credits, or any other tax credit incentives that may be applicable to the reference technology. These credits would, however, represent critical components of the financial considerations for several of the cases presented herein. For this reason, a brief discussion of some of the available credits and their qualification requirements is included below.

CARBON CAPTURE TECHNOLOGIES

Carbon capture technologies may be eligible for several incentives under the IRA, including the Energy Infrastructure Reinvestment Financing, and USDA Assistance for Rural Electric Cooperatives; but the most impactful feature pertaining to carbon capture is the extension and expansion of the Internal Revenue Code's (IRC) 45Q tax credit for Credit for Carbon Oxide Sequestration. The IRA extends the preexisting 45Q tax credit availability timeline, adds an enhanced credit for direct air capture (DAC), and lowers the carbon capture threshold requirements for certain facilities to benefit from the credit. Facilities meeting prevailing wage and registered apprenticeship requirements can qualify for bonus credits as well.

The base credit amount is $17 per metric ton of carbon dioxide captured and sequestered or $12 per metric ton for carbon dioxide that is injected for enhanced oil recovery or utilized. Those amounts are $36 and $26, respectively, for direct air capture facilities. Recipients may qualify for bonus credits worth 5 times these amounts if the facilities meet the IRA's prevailing wage and registered apprenticeship requirements.

Facilities claiming the 45Q credit must be constructed in the U.S. before January 1, 2023, and must capture the necessary minimum annual volumes of CO_2 as determined by the type of facility:

- 1,000 metric tons of CO_2 per year for DAC facilities
- 18,750 metric tons for electricity generating facilities (with carbon capture capacity of 75% of baseline CO_2 production)
- 12,500 metric tons for other facilities

The 45Q credits may be claimed for 12 years after an eligible facility is placed in service.

NUCLEAR TECHNOLOGIES

Nuclear power generators are also eligible for several credits, most notably, the IRC section 45J credit for the production of electricity from advanced nuclear power facilities. This credit was originally enacted by section 1306 of the Energy Policy Act of 2005, offering 1.8 cents per kWh of energy produced and sold by qualifying advanced nuclear facilities – with certain caps and limitations – which were placed in service before January 1, 2021. The IRA does not modify the 45J credit but adds an alternative Zero-Emission Nuclear Power Production Credit in the IRC section 45U. This credit applies to existing nuclear power plants which at time of enactment, are not eligible for the 45J credit. The base credit amount is 0.3 cents per kWh and will be inflation adjusted after 2024. The credit amount phases down depending on the amount of energy produced and the gross receipts of the nuclear power facility.

The 45U credit will be made available for electricity produced at qualifying facilities and sold after December 31, 2023, and in tax years beginning after that date, expiring in 2032. 45U recipients may qualify for bonus credits worth five times the base credit amount if the facility meets the IRA's prevailing wage requirements.

CLEAN ENERGY PRODUCTION AND INVESTMENT TAX CREDITS

The Clean Energy Production and Investment Tax Credits ("PTC" and "ITC") extended in the IRA offer financial relief to qualifying entities by offsetting a portion of the costs associated with implementing or operating renewable energy technologies. These two credit structures, more commonly known by their Internal Revenue Code sections 45Y (PTC) and 48E (ITC) reduce a renewable energy developer's federal tax liability in the following ways:

- The investment tax credit is a tax credit that reduces the federal income tax liability for a percentage of the cost of a qualifying renewable energy system that is installed during the tax year.
- The production tax credit is a per kilowatt-hour (kWh) tax credit for electricity generated by qualifying technologies for the first 10 years of a system's operation. It reduces the federal income tax liability and is adjusted annually for inflation.

These IRA tax credits may be applied to a diverse range of renewable energy technologies including wind, solar, bioenergy, geothermal, small irrigation, landfill and trash, hydropower, fuel cells, and several more. Under the IRA, eligible renewable energy projects may qualify for various bonus credits that further increase the tax incentives. Criteria for these bonus credits include labor requirements, energy community requirements, and domestic content requirements. These additional qualifications aim to promote fair wages, support impacted communities, and foster domestic energy independence. A summary of these credits, their values, and their phase-out schedules is presented in Figure 1.

Figure 1 — Summary of Investment Tax Credits and Production Tax Credits Over Time

			Start of Construction						
			2006 to 2019	2020 to 2021	2022	2023 to 2033	The later of 2034 (or two years after applicable year[a])	The later of 2035 (or three years after applicable year[a])	The later of 2036 (or four years after applicable year[a])
ITC	Full rate (if project meets labor requirements[b])	Base Credit	30%	26%	30%	30%	22.5%	15%	0%
		Domestic Content Bonus				10%	7.5%	5%	0%
		Energy Community Bonus				10%	7.5%	5%	0%
	Base rate (if project does not meet labor requirements[b])	Base Credit	30%	26%	6%	6%	4.5%	3%	0%
		Domestic Content Bonus				2%	1.5%	1%	0%
		Energy Community Bonus				2%	1.5%	1%	0%
	Low-income bonus (1.8 GW/yr cap)	<5 MW projects in LMI communities or Indian land				10%	10%	10%	10%
		Qualified low-income residential building project / Qualified low-income economic benefit project				20%	20%	20%	20%
PTC for 10 years ($2022)	Full rate (if project meets labor requirements[b])	Base Credit			2.75 ¢	2.75 ¢	2.0 ¢	1.3 ¢	0.0 ¢
		Domestic Content Bonus				0.3 ¢	0.2 ¢	0.1 ¢	0.0 ¢
		Energy Community Bonus				0.3 ¢	0.2 ¢	0.1 ¢	0.0 ¢
	Base rate (if project does not meet labor requirements[b])	Base Credit			0.55 ¢	0.55 ¢	0.4 ¢	0.3 ¢	0.0 ¢
		Domestic Content Bonus				0.1 ¢	0.0 ¢	0.0 ¢	0.0 ¢
		Energy Community Bonus				0.1 ¢	0.0 ¢	0.1 ¢	0.0 ¢

a "Applicable year" is defined as the later of (i) 2032 or (ii) the year the Treasury Secretary determines that there has been a 75% or more reduction in annual greenhouse gas emissions from the production of electricity in the United States as compared to the calendar year 2022.

b "Labor requirements" entail certain prevailing wage and apprenticeship conditions being met.

Source: https://www.energy.gov/eere/solar/federal-solar-tax-credits-businesses

Additional discussion of the qualification requirements for prevailing wage labor, domestic content, and energy community bonus credits is included in the subsections below.

LABOR REQUIREMENTS

To meet the labor requirements under the IRA, all wages for construction, alteration, and repair—for the first 5 years of the project for the investment tax credit and the first 10 years of the project for the production tax credit—must be paid at the prevailing rates of that location. Additionally, a certain percentage of the total construction labor hours for a project must be performed by an apprentice. Qualifying projects must meet the following minimum percentages of apprentice labor:

- 0% for projects beginning construction in 2022
- 12.5% for projects beginning construction in 2023
- 15% for projects beginning construction after 2023

If the prevailing wage or apprenticeship requirements were not originally satisfied, a project may still obtain the bonus credit by paying the affected employees the difference in wages plus interest and paying a $5000 fee to the United States Department of Labor for each impacted individual. The apprenticeship requirements also can be satisfied if a good faith effort was made to comply or if a penalty is paid to the United States Department of the Treasury in the amount of $50/hour of noncompliance.

DOMESTIC CONTENT REQUIREMENTS

The domestic content requirements under the IRA aim to support and strengthen United States 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 facility need to be mined, produced, or manufactured in the United States. The minimum required percentage of manufactured products for bonus qualification is as follows:

- 40% for all projects beginning construction before 2025
- 45% for projects beginning construction in 2025
- 50% for projects beginning construction in 2026
- 55% for projects beginning construction after 2026

The percentage is calculated by dividing the cost of all domestically manufactured products and components by the total cost of all manufactured products.

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 deep dive assessments of supply chains for eleven different technology sectors. These assessments illustrate the limited domestic production capacity available for many renewable technologies from raw material and feedstock processing to finished product manufacturing and assembly. A brief summary of their findings for solar photovoltaics, wind, and energy storage technologies is included in the subsections below.

Solar Photovoltaic Supply Chains

In the United States, two primary types of solar PV modules dominate the market: crystalline silicon (c-Si) modules, constituting approximately 84%, and cadmium telluride (CdTe) modules, making up the remaining 16%. Both these module types require mounting structures, commonly referred to as racking, for mechanical support, which can either track the sun's movement (tracking) or remain fixed at a specific angle (fixed tilt). PV modules produce direct current (DC) output, typically converted into alternating current (AC) through an inverter. However, they can also be used directly to charge nearby battery energy storage in "DC-coupled" configurations. A breakdown of key components within the solar PV supply chain is illustrated in Figure 2.

Figure 2 — The Solar Photovoltaics Supply Chain

Source: US Department of Energy. “Solar Photovoltaics Supply Chain." Image. Energy.Gov. February 24, 2022. https://www.energy.gov/sites/default/files/2022-02/Solar%20Energy%20Supply%20Chain%20Report%20-%20Final.pdf

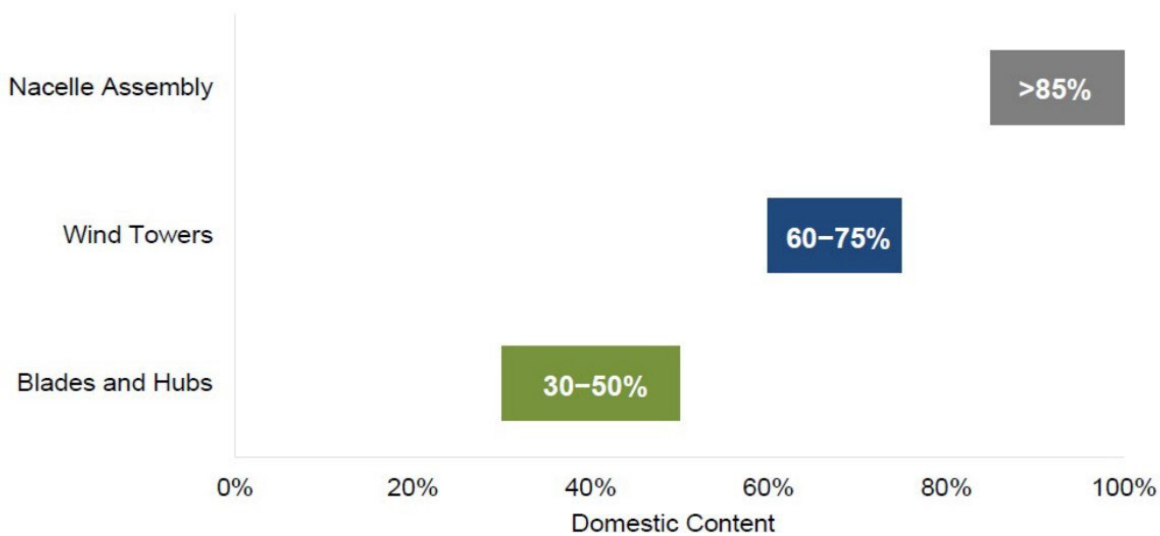
The supply chain for crystalline silicon (c-Si) modules begins with the refinement of high-purity polycrystalline silicon, commonly referred to as polysilicon. This essential component's raw material is metallurgical-grade silicon (MGS), also known as silicon metal, which is derived from high-grade quartz. Approximately 12% of the global MGS production is dedicated to the production of high-purity polysilicon for the solar industry. Polysilicon undergoes a melting process to cultivate monocrystalline silicon ingots which are subsequently sliced into thin silicon wafers. These wafers are then processed to create the solar cells that are interconnected and enclosed between layers of glass and plastic, forming the c-Si modules. A significant proportion of silicon wafer production, approximately 97%, is concentrated in China, with these wafers being exported to manufacturing facilities worldwide, including the United States. Nearly three-quarters of the silicon solar cells integrated into modules installed in the United States are manufactured by Chinese subsidiaries located in just three Southeast Asian countries: Vietnam, Malaysia, and Thailand. Despite announced plans for domestic manufacturing facilities, the United States presently lacks active production capacity for c-Si ingots, wafers, or cells.

The United States does possess domestic production capacity for thin-film Cadmium Telluride (CdTe) modules, a technology that does not rely on materials sourced from Chinese companies. The 16% of PV installations in the United States utilizing CdTe modules were exclusively supplied by a single American company. This U.S.-based company is responsible for producing roughly one-third of these CdTe modules within the United States, contributing to the diversification of the country's solar module manufacturing supply chain.

Wind Energy Supply Chains

Wind power plants are composed of five primary components: towers, rotors/blades, nacelle/drivetrain, foundations, and grid interconnection equipment. Domestic content is readily available for larger components of land-based wind plants, such as towers, nacelles, and blades (Figure 3), though domestic content in blades has declined in recent years. For offshore wind technologies there was no domestic supply chain capacity in 2021, apart from some manufacturing of applicable electrical equipment and cabling. However, several manufacturers have announced their intent to begin production at U.S. facilities in the coming years. The domestic supply chain in 2020 was capable of producing10-15 GW/year for each primary land-based turbine component (towers, blades, and nacelles) (Wiser et al. 2021). BloombergNEF estimated that a typical onshore wind project in the U.S. sources 57% of its components (by dollar value) domestically (Goldie-Scot, Zindler, and Wang 2021).

Figure 3 — Domestic Manufacturing Content for Onshore Wind Power in 2020



Source: Lawrence Berkeley National Laboratory Analysis

Energy Storage Supply Chains

There are five major components of a lithium-ion battery: anode, cathode, electrolyte salts, electrolyte solutions, and separators. China has a dominant market presence in terms of both current and planned capacity for all subcomponents. The United States has less than 10% of global capacity for any subcomponent and has very little, if any, capacity planned or under construction. The markets for lithium-ion batteries, are evolving quickly, primarily in the transportation sector. New facilities are announced almost weekly, and data from government sources such as those in China, often lag announcements from industry by several months. Table 3 summarizes the subcomponent market positions of the U.S. and China as of 2021.

Table 1-6 — United States' and China's Existing and Under Development Shares of Global Lithium-Ion Battery Subcomponent Capacity

	2021		Under Development	
Battery Component	U.S.	China	U.S.	China
Cathode	0.70%	63%	0%	84%
Anode Materials	0.60%	84%	0%	91%
Separator	3%	66%	0%	76%
Electrolyte	7%	69%	2%	75%

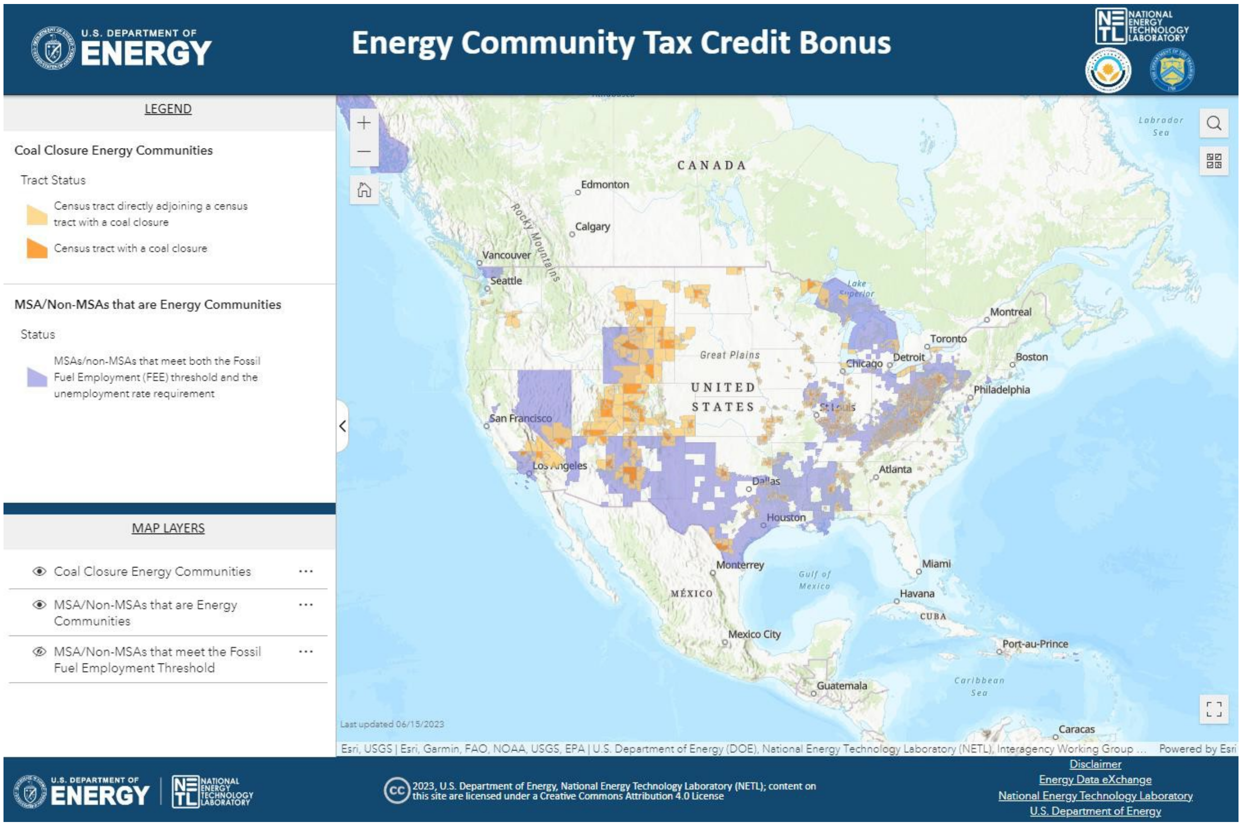
Source: BloombergNEF (2021)

Future estimates change often due to new policies related to decarbonization and country-level competitiveness. These figures thus indicate overall industry dominance of China over the United States across the battery component supply chain rather than absolute market size.

ENERGY COMMUNITY REQUIREMENTS

The energy community requirements set forth by the IRA encourage the development of new energy projects in economically distressed or traditional energy communities. Energy communities include areas that (i) a coal mine or coal-fired power plant has closed or (ii) have been economically reliant on the extraction, processing, transport, or storage of coal, oil, or natural gas but now face higher-than-average unemployment. The DOE maintains an interactive map of metropolitan statistical areas and non-metropolitan statistical areas that qualify for the energy community bonus under the present definition.

Figure 4 — Map of Census Tracts Eligible for Energy Community Bonus



Source: https://energycommunities.gov/energy-community-tax-credit-bonus/

CASE 1. ULTRA-SUPERCRITICAL COAL PLANT WITHOUT CARBON CAPTURE, 650 MW NET

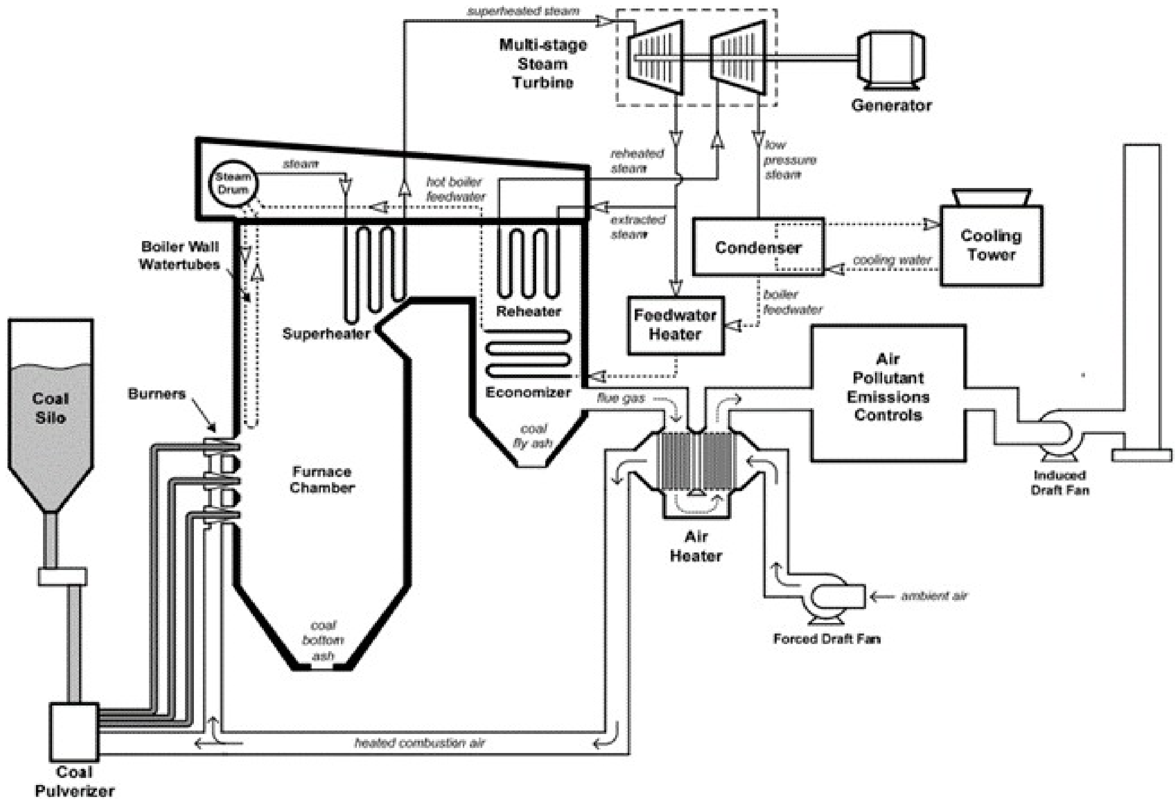
1.1. CASE DESCRIPTION

This case comprises a greenfield coal-fired power plant with a nominal net capacity of 650 megawatts (MW) with a single steam generator and steam turbine with coal storage and handling systems, balance-of-plant (BOP) systems, and emissions control systems; there are no carbon dioxide (CO_2) capture systems in this case.

This case employs a modified Rankine cycle, referred to as an ultra-supercritical (USC) thermal cycle, which is characterized by the operation at supercritical pressures; approximately 3750 psia (pounds per square inch absolute) and at steam temperatures above 1100°F (degrees Fahrenheit). This increase in steam pressure and temperature provides more energy per pound of fuel able to be converted to shaft power in the steam turbine.

The USC steam cycles are a significant improvement from the more common subcritical cycles. Therefore, USC technology represents the most efficient steam cycle configuration currently available. These higher efficiency boilers and turbines require less coal and subsequently produce less greenhouse gases and lower emissions. Throughout the past two decades, many USC coal power plants have been placed in operation, although most of these facilities have been constructed in outside of the United States. The AEP John Turk Plant, commissioned in 2012, is the only USC power facility constructed in the United States. Figure 1-1 represents a flow diagram of a generic USC coal facility.

Figure 1-1 — USC Coal Boiler – Flow Diagram



Source: U.S. Environmental Protection Agency,
Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units PDF
Accessed from EPA.gov, https://www.epa.gov/sites/production/files/2015-12/documents/electricgeneration.pdf

The base configuration used for the cost estimate is a single unit station constructed on a greenfield site of approximately 400 acres with rail access for coal deliveries. The facility has a nominal net generating capacity of 650 MW and is assumed to fire a high sulfur bituminous coal (approximately 4 MMBtu/hour SO_2) with fuel moisture at 11% to 13% by weight and ash at 9% to 10%. Mechanical draft cooling towers are used for cycle cooling, and the water utilized for cycle cooling and steam cycle makeup is provided by an assumed adjacent freshwater reservoir or river.

1.1.1. Mechanical Equipment and Systems

1.1.1.1. USC Steam Cycle

The steam turbine is a tandem compound reheat machine consisting of a high-pressure turbine, an intermediate-pressure turbine, and two double-flow low-pressure turbines with horizontal casing splits. The USC thermal cycle comprises eight feedwater heaters. The eighth heater is supplied with extraction steam from the high-pressure turbine. This heater configuration is commonly referred to as a “HARP” system, which is “Heater Above Reheat Point” of the turbine steam flow path. Boiler feedwater is supplied to the cycle with a single steam driven boiler feedwater pump. with the turbine exhaust directed to the low-pressure condenser. Steam leaves the boiler to a high-pressure steam turbine designed for the USC pressures and temperatures. Steam leaving the high-pressure turbine is reheated in the boiler and directed to the intermediate-pressure turbine. The low-pressure turbine sections are twin dual flow turbines. The condensers are multi-flow units, one per each dual flow low-pressure turbine, operated at 2.0 inches of mercury absolute. The plant cooling system uses mechanical draft cooling towers with a circulated water temperature rise of 20°F.

The plant performance estimate is based on ambient conditions of 59°F, 60% relative humidity, and sea level elevation. The boiler efficiency is assumed to be 87.5%. The gross plant output is estimated to be 735 MW with a net output of 650 MW. The net heat rate is estimated to be 8638 Btu/kWh (British thermal unit per kilowatt-hour) based on the higher heating value (HHV) of the fuel and the net electrical output.

1.1.1.2. Steam Generator

For the base case design, the single steam generator is designed for an outdoor location. The steam generator is a USC, pulverized-coal-fired type, balanced draft, once-through unit equipped with superheater, reheater, economizer, and regenerative air heaters. All materials of construction are selected to withstand the pressures and temperatures associated with the USC conditions and are in accordance with Section 1 of the ASME Boiler Pressure Vessel Code. The boiler is fired with pulverized bituminous coal through six pulverizers. The boiler-firing system consists of low-nitrogen oxide (NO_X) burners (LNBs) and overfire air (OFA). A submerged flight conveyor system is used for bottom ash removal. An economizer preheats the feedwater prior to entering the boiler water walls. Combustion air is preheated with two parallel trisector air preheaters. Combustion air is delivered to the boiler by two forced draft fans and two primary air fans. Two axial induced draft fans are used to transfer combustion gases through a baghouse, wet flue gas desulfurization (WFGD) system, wet electrostatic precipitator (WESP), and wet chimney.

1.1.1.3. Water Treatment

The facility's water treatment plant consists of pretreatment and demineralization. All raw water entering the facility is first sent to the pretreatment system, which mainly consists of two redundant clarifiers where chemicals are added for disinfection and suspended solids removal. The pretreatment system includes lime addition. The lime addition allows for the partial removal of hardness and alkalinity from the raw water, if required. After pretreatment, the water is sent to a storage tank and then directed to the service and firewater users. A demineralizer system is used to provide steam cycle makeup water of sufficient quality for the once-through system. All wastewater from the demineralizer system is either recycled to the WFGD system or sent to the wastewater neutralization and discharge system.

1.1.1.4. Material Handling

The coal handling system includes rail car unloading, reclaim systems, a dual coal conveyor system, transfer towers, and coal crushers. The fly ash handling system includes equipment to remove ash from the boiler, economizer, air heater, and baghouse. Fly ash is collected dry and conveyed to a storage silo. Fly ash is collected from the storage by truck for offsite disposal.

1.1.2. Electrical and Control Systems

The USC facility generator is rated at approximately 780 megavolt-ampere (MVA) with an output of 24 kilovolts (kV) and is connected via generator circuit breakers to a generator step-up transformer (GSU). The GSU increases the voltage from the generator voltage level to the transmission system high-voltage level. The electrical system includes auxiliary transformers and reserve auxiliary transformers. The facility and most of the subsystems are controlled using a central distributed control system (DCS).

1.1.3. Offsite Requirements

Coal is delivered to the facility by rail. The maximum daily coal rate for the facility is approximately 4600 tons per day. The number of rail cars to support this facility is estimated at approximately 330 rail cars per week.

The site is assumed to be located adjacent to a river or reservoir that can be permitted to supply a sufficient quantity of cooling water. The total volume of water consumption for cooling tower makeup, cycle makeup, and other demands is estimated to be approximately 7000 gallons per minute. Wastewater is sent to the adjacent waterway from one or more outfalls from a water treatment pond or wastewater treatment system.

The facility is assumed to start up on natural gas; therefore, the site is connected to a gas distribution system. Natural gas interconnection costs are based on a new lateral connected to existing gas pipeline.

The electrical interconnection costs are based on a one-mile distance from the facility switchyard to the terminal point on an existing utility substation. For the purposes of this estimate, any costs associated with expansion of the substation is excluded.

1.2. CAPITAL COST ESTIMATE

Table 1-1 summarizes the cost components for this case. The basis of the estimate assumes that the site is constructed in a United States region that has good access to lower-cost construction labor and has reasonable access to water resources, coal, natural gas, and existing utility transmission substations or existing transmission lines. The geographic location is assumed to be characterized by seismic, wind, and other loading criteria that do not add significantly to the capital costs. An outdoor installation is assumed—meaning that the boiler building is not enclosed—and no special systems are required to prevent freezing or to account for structural snow loading.

To determine the capital costs adjustments in other United States regions where the assumptions listed above are not applicable, location factors have been calculated to account for variations in labor wage rates and access to construction labor, labor productivity, water and wastewater resource constraints, wind and seismic criteria, and other environmental criteria.

To account for locations where water resources are limited, such as California, the southwest and the mountain west regions, ACCs are used in lieu of mechanical draft cooling towers. In regions where wastewater loads to rivers and reservoirs are becoming increasingly restricted, zero liquid discharge (ZLD) equipment is added. ZLD wastewater treatment equipment is assumed to include reverse osmosis, evaporation/crystallization, and fractional electrode ionization. To reduce the loading for the ZLD systems, it is assumed that cases where ZLD is applied will also have equipment in place, such as ACCs or cooling tower blowdown treatment systems, to reduce wastewater.

To account for ambient temperature extremes, costs for boiler enclosures have been included as part of the location factors in areas where ambient temperatures will be below freezing for significant periods of time. It is assumed that the steam turbine generator (STG) equipment will be enclosed in all locations.

Table 1-1 — Case 1 Capital Cost Estimate

Case 1 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration	**650 MW Net** **USC Coal without Carbon Capture** 1 x 735 MW Gross	
Combustion Emissions Controls	Low NOx Burners / OFA	
Post-Combustion Emissions Controls	Selective Catalytic Reduction (SCR) / Baghouse / WFGD / WESP	
Fuel Type	High Sulfur Bituminous	
	Units	
Plant Characteristics		
Net Plant Capacity (60°F, 60% RH)	MW	650
Heat Rate, HHV Basis	Btu/kWh	8638
Capital Cost Assumptions		
Engineering, Procurement, and Construction (EPC) Contracting Fee	% of Direct and Indirect Costs	10%
EPC Contingency	% of EPC Costs	10%
Owner's Services	% of EPC Costs	7%
Owner's Contingency	% of Owner's Costs	12%

Case 1 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration	**650 MW Net** **USC Coal without Carbon Capture** 1 x 735 MW Gross	
Combustion Emissions Controls	Low NOx Burners / OFA	
Post-Combustion Emissions Controls	Selective Catalytic Reduction (SCR) / Baghouse / WFGD / WESP	
Fuel Type	High Sulfur Bituminous	
	Units	
Estimated Land Requirement	acres	400
Estimated Land Cost	$/acre	24,000
Interconnection Costs		
Electrical Transmission Interconnection Costs		
Transmission Line Cost	$/mile	3,040,000
Miles	miles	1.00
Substation Expansion Cost	$	0
Gas Interconnection Costs		
Pipeline Cost	$/mile	2,900,000
Miles	miles	0.50
Metering Station	$	1,900,000
Typical Project Timelines		
Development, Permitting, Engineering	months	24
Plant Construction Time	months	36
Total Lead Time Before Commercial Operation Date (COD)	months	60
Operating Life	years	40
EPC Cost Components (Note 1)		
Civil/Structural/Architectural - Equipment and Materials	$	139,293,000
Boiler Plant - Equipment and Materials	$	395,674,000
Turbine Plant - Equipment and Materials	$	124,949,000
Main and Auxiliary Power System - Equipment and Materials	$	41,759,000
Balance of Plant and I&C - Equipment and Materials	$	272,534,000
Substation and Switchyard Costs	$	23,254,000
Construction Labor Costs	$	783,122,000
Indirect Costs	$	249,366,000
EPC Fee	$	202,995,000
EPC Contingency	$	223,295,000
EPC Subtotal	$	**2,456,241,000**
Owner's Cost Components (Note 2)		
Owner's Services	$	171,937,000
Land	$	9,600,000

Case 1 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration	**650 MW Net** **USC Coal without Carbon Capture** 1 x 735 MW Gross	
Combustion Emissions Controls	Low NOx Burners / OFA	
Post-Combustion Emissions Controls	Selective Catalytic Reduction (SCR) / Baghouse / WFGD / WESP	
Fuel Type	High Sulfur Bituminous	
	Units	
Electrical Interconnection	$	3,040,000
Gas Interconnection	$	3,350,000
Owner's Contingency	$	22,551,000
Owner's Cost Subtotal	$	210,478,000
Total Capital Cost	**$**	**2,666,719,000**
	$/kW net	**4,103**
Capital Cost Notes		
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include construction equipment, cranes and vehicles, project management, engineering, construction management, start-up, and commissioning. EPC fees are applied to the sum of direct and indirect costs.		
2. Owner’s costs include project development, studies, permitting, legal, owner’s project management, owner’s engineering, and owner’s start-up and commissioning costs. Other owner’s costs include electrical interconnection costs, gas interconnection costs, and land acquisition costs.		

1.3. OPERATIONS AND MAINTENANCE COST ESTIMATE

The operating and maintenance (O&M) costs for the USC coal-fired power generation facility are summarized in Table 1-2. The fixed costs cover the O&M labor, materials, and contracted maintenance services, and general and administrative (G&A). Major overhauls for the facility are generally based on a three-year/six-year basis, depending on the equipment. Major steam turbine maintenance work is generally performed on a five to six-year cycle. Shorter outages—such as changing out SCR catalyst—are generally performed on a three-year cycle.

Non-fuel variable costs for this technology case include flue gas desulfurization (FGD) reagent costs, SCR catalyst replacement costs, ammonia costs, SCR reagent costs, water treatment costs, wastewater treatment costs, fly ash and bottom ash disposal costs, bag replacement for the fabric filters, and FGD waste disposal costs.

Table 1-2 — Case 1 Operational Cost Estimate

Case 1 EIA – Non-Fuel O&M Costs – 2023 $ USD		
650 MW Net, USC Coal without Carbon Capture		
Fixed O&M – Plant (Note 1)	**Units**	**Value**
Labor	$/year	19,403,000
Materials and Contract Services	$/year	15,788,000
Administrative and General	$/year	4,851,000
Subtotal Fixed O&M	$/year	**40,042,000**
	$/kW-year	**61.60**
Variable O&M (Note 2)	$/MWh	**6.40**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. Variable O&M costs include catalyst replacement, ammonia, activated carbon, limestone, water, ash disposal, FGD waste disposal, and water discharge treatment cost.		

The post-combustion environmental controls for this technology case include an SCR NO_X system with aqueous ammonia as the reagent, a fabric-filter baghouse ash collection system with pulse jet cleaning, and a limestone-based forced-oxidation WFGD for the removal of SO_2 and sulfur trioxide. A WESP is included to mitigate sulfuric acid emissions. The flue gas pressure drops incurred from these backend controls have been accounted for in the induced draft fan sizing and the resultant auxiliary power demands in addition to the auxiliary power demands for the emissions control systems themselves.

For this case, no CO_2 emissions controls are assumed to be applicable. Refer to Case 2 for the implementation of a 95% carbon capture system to the USC coal power generation facility.

1.4. ENVIRONMENTAL AND EMISSIONS INFORMATION

The emissions for the major criteria pollutants are summarized in Table 1-3. The NO_X emissions assume that the in-furnace controls such as LNB, OFA, and SCR systems are employed to control emissions to 0.06 lb/MMBtu. The WFGD system is assumed to be capable of 98% reduction of SO_2 from an inlet loading of 4.3 lb/MMBtu to an emission rate of 0.09 lb/MMBtu. The CO_2 emissions estimate is derived from 40 CFR, Subpart C, Table C-1, as 206 lb/MMBtu.

Table 1-3 — Case 1 Emission Rates

Case 1 EIA – Emissions Rates		
650 MW Net, USC Coal without Carbon Capture		
Predicted Emissions Rates (Note 1)	**Units**	**Value**
NOx	lb/MMBtu	0.06 (Note 2)
SO_2	lb/MMBtu	0.09 (Note 3)
CO_2	lb/MMBtu	206 (Note 4)
Emissions Control Notes		
1. High sulfur bituminous coal, 4 lb/MMBtu SO_2 coal		
2. NOx removal using LNBs with OFA, and SCR		
3. SO_2 removal by forced-oxidation, limestone-based WFGD; 98% reduction		
4. Per 40 CFR 98, Subpart C, Table C-1		

The post-combustion environmental controls for this technology case include an SCR NO_X system with aqueous ammonia as the reagent, a fabric-filter baghouse ash collection system with pulse jet cleaning, and a limestone-based forced-oxidation WFGD for the removal of SO_2 and sulfur trioxide. A WESP is included to mitigate sulfuric acid emissions. The flue gas pressure drops incurred from these backend controls have been accounted for in the induced draft fan sizing and the resultant auxiliary power demands in addition to the auxiliary power demands for the emissions control systems themselves.

For this case, no CO_2 emissions controls are assumed to be applicable. Refer to Case 2 for the implementation of a 95% carbon capture system to the USC coal power generation facility.

CASE 2. ULTRA-SUPERCRITICAL COAL PLANT WITH 95% CARBON CAPTURE, 650 MW NET

2.1. CASE DESCRIPTION

This case comprises a coal-fired power plant with a nominal net capacity of 650 MW with a single steam generator and steam turbine with coal storage and handling systems, balance-of-plant (BOP) systems, emissions control systems, and a 95% CO_2 capture system. This case is similar to the plant description provided in Case 1; however, this case employs a 95% CO_2 capture system for the entire flue gas stream, which requires an increased boiler size and higher heat input to account for the low-pressure steam extraction and larger auxiliary loads required for the CO_2 capture technology employed.

The steam cycle is generally similar to that of the ultra-supercritical USC case, Case 1. As with Case 1, the base configuration utilized for the cost estimate is a single-unit station constructed on a greenfield site with rail access for coal deliveries. The estimated land requirement for this facility is of approximately 430 acres to account for the carbon capture equipment.

The facility has a nominal net generating capacity of 650 MW and is assumed to fire a high sulfur bituminous coal (approximately 4 MMBtu/hour SO_2) with fuel moisture at 11% to 13% by weight and ash at 9% to 10%. The gross plant output is estimated to be 819 MW to account for the additional parasitic and auxiliary loads due to the implementation of the CO_2 capture system. Mechanical draft cooling towers are used for cycle cooling, and the water used for cycle cooling and steam cycle makeup is provided by an assumed adjacent freshwater reservoir or river.

2.1.1. Mechanical Equipment And Systems

Refer to Case 1 for a description of the major mechanical equipment and systems associated with the USC power generation facility. This section provides a description of the major equipment and systems for the CO_2 capture plant used as the basis for the capital and operating and maintenance (O&M) cost estimates.

2.1.1.1. General CO_2 Capture Description

The most commercially available CO_2 capture technology for coal-fired power plants is amine-based scrubbing technology. This technology requires an absorption column to absorb the CO_2 from the flue gas and a stripping column to regenerate the solvent and release the CO_2. Amine-based solvents are used in the absorption column and require periodic makeup streams and waste solvent reclamation. Steam is used to break the bond between the CO_2 and solvent. CO_2 leaves the stripper with moisture prior to being dehydrated and compressed. The product CO_2 is pipeline quality at 99.5% purity and approximately 2215 psia. The amine-based solvent systems are typically designed for 95% CO_2 capture in the absorption column.

2.1.1.2. CO_2 Capture Systems

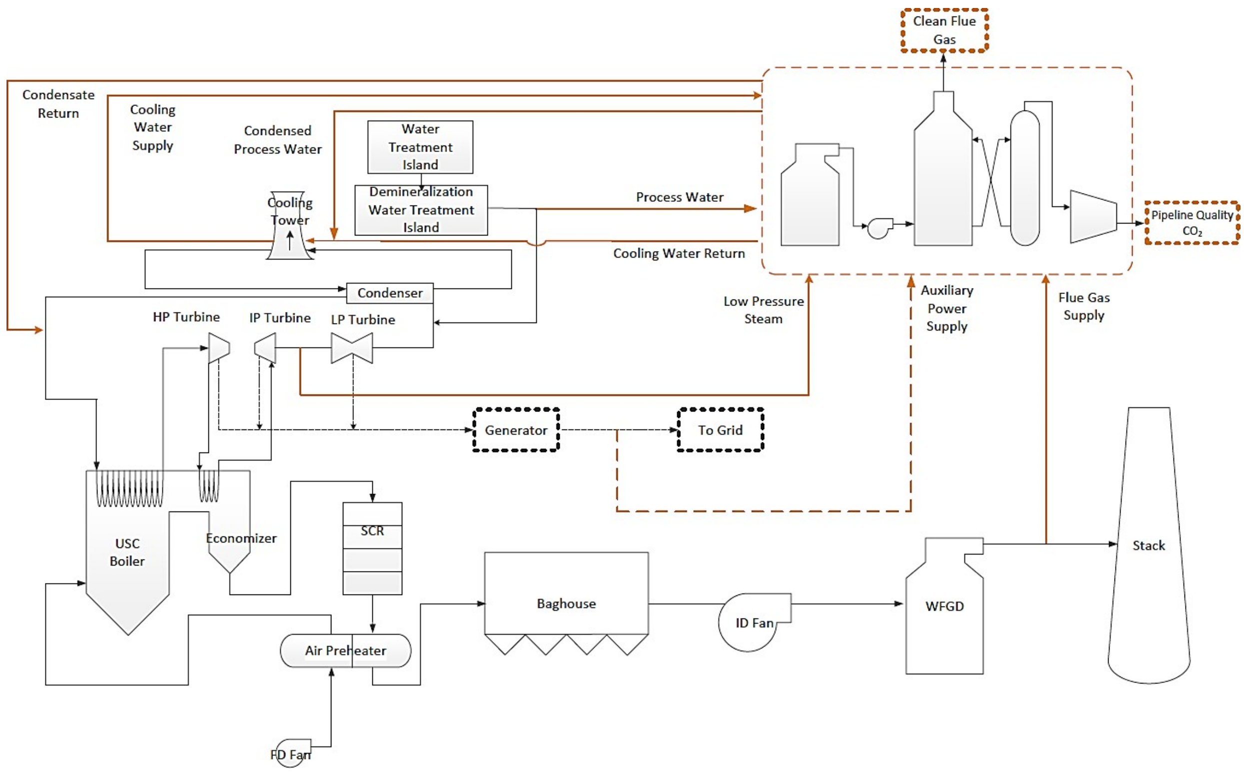
This case assumes full integration of the CO_2 capture facility with the boiler/turbine system design. The CO_2 capture technology uses various utilities to operate, including low-quality steam and auxiliary power. Steam can be extracted between the intermediate pressure and low-pressure turbine sections that will provide the least amount of capacity derate while maintaining the necessary energy to drive the CO_2 capture system. Extracting steam prior to the low-pressure turbine section requires additional fuel to be fired to account for the lost generation potential. As such, the boiler, turbine, and associated systems would be required to be made larger to maintain the same net power production. Additionally, the CO_2 capture facility and BOP associated with the CO_2 capture system requires a significant amount of auxiliary power to drive the mechanical equipment. Most of the power consumption is used to drive the CO_2 compressors to produce pipeline quality CO_2 at approximately 2215 psia. The increase in auxiliary power consumption due to the CO_2 facility usage will require a larger turbine throughput to produce the added output. Overall, CO_2 capture system integration can account for approximately 60% of the total full load auxiliary power demand.

Other utilities that are integrated with the base plant are demineralized water and cooling water. Demineralized water is used to maintain a water balance within the amine process or in the solvent regeneration stages. The demineralized water consumption rate for the CO_2 capture facility is typically minor in comparison with base-plant utilization rates. As such, the demineralized water is expected to be fed from the base facility. This cost is accounted for in the O&M estimate only. Conversely, cooling water demands for the carbon capture process is significant. CO_2 capture systems require circulating cooling water rates similar to that of the condensers. As such, the cooling system, in this case evaporative cooling towers, are required to be expanded to account for the large amount of additional heat rejection. This cost is accounted for in the capital and O&M estimates. The increase in cooling tower size also requires a higher cooling tower blowdown rate that needs to be treated at the wastewater treatment system. This cost is reflected in the capital and O&M estimates.

Commercial amine-based CO_2 capture technology requires a quencher to be located upstream of the CO_2 absorber vessel. The quencher cools the flue gas to optimize the kinetics and efficiency of the CO_2 absorption process via the amine-based solvent. During the quenching process, a significant amount of flue gas moisture condenses into the vessel and requires a significant amount of blowdown to maintain the level in the vessel. This blowdown quality is not good enough to reuse in the absorber system for water balance, but it is an acceptable quality to either reuse in the cooling towers or wet flue gas desulfurization (WFGD) for makeup water. Due to the reuse, it does not require additional O&M costs.

A generic flow diagram for post-combustion carbon capture system is provided in Figure 2-1. The termination of the process of the CO_2 capture facility is the new emissions point, which is a small stack at the top of the CO_2 absorber vessel. For this configuration, a typical free-standing chimney is not required. Additionally, the compressed product CO_2 is the other boundary limit. This estimate does not include pipeline costs to transport the CO_2 to a sequestration or utilization site.

Figure 2-1 — Carbon Capture Flow Diagram



Source: Author © Sargent & Lundy, L.L.C

2.1.1.3. 95% CO_2 Capture

For the case where a new USC coal-fired facility is required to provide 95% CO_2 reduction, the full flue gas path must be treated. As referenced previously, 95% capture is the typical design limit for CO_2 reduction in the absorber. Therefore, 100% of the plant's flue gas would need to be treated to provide 95% reduction efficiency. In this scenario, a significant amount of steam and auxiliary power is required to drive the large CO_2 capture system, ultimately increasing the size of the boiler to generate the additional steam and power required to maintain a net power output of 650 MW. As the boiler gets larger, more flue gas must be treated. As such, it is an iterative process to determine the new boiler size necessary to treat 100% of the flue gas from a new USC coal-fired boiler.

2.1.1.4. Plant Performance

For this case, all the flue gas is discharged from the carbon capture system, so no additional wet chimney is included in the capital cost estimate.

The plant performance estimate is based on ambient conditions of 59°F, 60% relative humidity, sea level elevation, and 95% CO_2 capture. Approximately 2,238,000 lb/hr of low-pressure steam is required for the CO_2 system. The boiler efficiency is assumed to be 87.5%, and the estimated gross size of the boiler is 1013 MW, which is approximately 40% larger than the case without carbon capture (Case 1). The generator gross output is approximately 819 MW. The estimated total auxiliary load for the plant is 169 MW, with 106 MW required for the for the CO_2 system. The net heat rate is estimated to be 12,293 Btu/kWh based on the higher heating value (HHV) of the fuel and the net electrical output.

2.1.2. Electrical and Control Systems

The electrical equipment includes the turbine generator, which is connected via generator circuit breakers to a generator step-up transformer (GSU). The GSU increases the voltage from the generator voltage level to the transmission system high-voltage level. The electrical system is essentially similar to the USC case without carbon capture (Case 1); however, there are additional electrical transformers and switchgear for the CO_2 capture systems. The electrical system includes auxiliary transformers and reserve auxiliary transformers. The facility and most of the subsystems are controlled using a central distributed control system (DCS).

2.1.3. Offsite Requirements

Coal is delivered to the facility by rail. The maximum daily coal rate for the facility is approximately 6500 tons per day. The number of rail cars to support this facility is estimated at approximately 460 rail cars per week.

The site is assumed to be located adjacent to a river or reservoir that can be permitted to supply a sufficient quantity of cooling water. The total volume of water required for cooling tower makeup, cycle makeup, and cooling for the CO_2 system is estimated to be approximately 17,500 gallons per minute. Wastewater is sent to the adjacent waterway from one or more outfalls from a water treatment pond or wastewater treatment system.

The CO_2 captured will need to be sequestered in a geologic formation or used for enhanced oil recovery. The viability of this technology case will be driven, to a large extent, by the proximity of the facility to the appropriate geologic formations. The costs presented herein do not account for equipment, piping, or structures associated with CO_2 sequestration.

The facility is assumed to start up on natural gas. Therefore, the site is connected to a gas distribution system. Natural gas interconnection costs are based on a new lateral connected to existing gas pipeline.

The electrical interconnection costs are based on a one-mile distance from the facility switchyard to the terminal point on an existing utility substation. For the purposes of this estimate, the cost associated with the expansion of the substation is excluded.

2.2. CAPITAL COST ESTIMATE

Table 2-1 summarizes the cost components for this case. The basis of the estimate assumes that the site is constructed in a United States region that has good access to lower-cost construction labor and has reasonable access to water resources, coal, natural gas, and existing utility transmission substations or existing transmission lines. The geographic location is assumed to be characterized by seismic, wind, and other loading criteria that do not add significantly to the capital costs. An outdoor installation is assumed, meaning that the boiler building is not enclosed, and no special systems are required to prevent freezing or to account for structural snow loading.

To determine the capital costs adjustments in other United States regions where the assumptions listed above are not applicable, location factors have been calculated to account for variations in labor wage rates and access to construction labor, labor productivity, water and wastewater resource constraints, wind and seismic criteria, and other environmental criteria.

To account for locations where water resources are limited, such as California, the southwest and the mountain west regions, air-cooled condensers (ACCs) are used in lieu of mechanical draft cooling towers. In regions where wastewater loads to rivers and reservoirs are becoming increasingly restricted, ZLD equipment is added. ZLD wastewater treatment equipment is assumed to include reverse osmosis, evaporation/crystallization, and fractional electrode ionization. To reduce the loading for the ZLD systems, it is assumed that cases where ZLD is applied will also have equipment in place, such as ACCs or cooling tower blowdown treatment systems, to reduce wastewater.

To account for ambient temperature extremes, costs for boiler enclosures have been included as part of the location factors in areas where ambient temperatures will be below freezing for significant periods of time. It is assumed that the steam turbine generator (STG) equipment will be enclosed in all locations.

Table 2-1 — Case 2 Capital Cost Estimate

Case 2 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration	**650 MW Net** **USC Coal** **95% Carbon Capture System** 1 x 819 MW Gross	
Combustion Emissions Controls	Low NOx Burners (LNBs) / Overfire Air (OFA)	
Post-Combustion Emissions Controls	Selective Catalytic Reduction (SCR) / Baghouse/ WFGD / WESP / Amine-Based Carbon Capture and Sequestration (CCS)	
Fuel Type	High Sulfur Bituminous	
	Units	
Plant Characteristics		
Net Plant Capacity (60°F, 60% RH)	MW	650
Heat Rate, HHV Basis	Btu/kWh	12,293
Capital Cost Assumptions		
Engineering, Procurement, and Construction (EPC) Contracting Fee	% of Direct and Indirect Costs	10%
EPC Contingency	% of EPC Costs	12%
Owner's Services	% of EPC Costs	7%
Owner's Contingency	% of Owner's Costs	12%
Estimated Land Requirement	acres	430
Estimated Land Cost	$/acre	23,000
Interconnection Costs		
Electrical Transmission Interconnection Costs		
Transmission Line Cost	$/mile	3,040,000
Miles	miles	1.00
Substation Expansion Cost	$	0
Gas Interconnection Costs		
Pipeline Cost	$/mile	2,900,000
Miles	miles	0.50
Metering Station	$	1,900,000
Typical Project Timelines		
Development, Permitting, Engineering	months	30
Plant Construction Time	months	44
Total Lead Time Before Commercial Operation Date (COD)	months	74
Operating Life	years	40
EPC Cost Components (Note 1)		
Civil/Structural/Architectural - Equipment and Materials	$	174,284,000
Boiler Plant - Equipment and Materials	$	434,360,000
Turbine Plant - Equipment and Materials	$	158,270,000
Main and Auxiliary Power System - Equipment and Materials	$	55,194,000

Case 2 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration	**650 MW Net** **USC Coal** **95% Carbon Capture System** 1 x 819 MW Gross	
Combustion Emissions Controls	Low NOx Burners (LNBs) / Overfire Air (OFA)	
Post-Combustion Emissions Controls	Selective Catalytic Reduction (SCR) / Baghouse/ WFGD / WESP / Amine-Based Carbon Capture and Sequestration (CCS)	
Fuel Type	High Sulfur Bituminous	
	Units	
Balance of Plant and I&C - Equipment and Materials	$	283,960,000
Substation and Switchyard Costs	$	23,254,000
Carbon Capture System Plant – Equipment and Materials	$	615,388,000
Construction Labor Costs	$	1,562,601,000
Indirect Costs	$	272,942,000
EPC Fee	$	358,025,000
EPC Contingency	$	472,593,000
EPC Subtotal	$	**4,410,871,000**
Owner's Cost Components (Note 2)		
Owner's Services	$	308,761,000
Land	$	9,890,000
Electrical Interconnection	$	3,040,000
Gas Interconnection	$	3,350,000
Owner's Contingency	$	39,005,000
Owner's Cost Subtotal	$	**364,046,000**
Total Capital Cost	**$**	**4,774,917,000**
	$/kW net	**7,346**
Capital Cost Notes		
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include engineering, construction management, start-up, and commissioning. EPC fees are applied to the sum of direct and indirect costs.		
2. Owner’s costs include project development, studies, permitting, legal, owner’s project management, owner’s engineering, and owner’s start-up and commissioning costs. Other owner’s costs include electrical interconnection costs, gas interconnection costs, and land acquisition costs.		

2.3. OPERATIONS AND MAINTENANCE COST ESTIMATE

The O&M costs for the USC coal-fired power generation facility with 95% carbon capture are summarized in Table 2-2. The fixed costs cover the O&M labor, materials and contract services, and general and administrative (G&A). Major overhauls for the facility are generally based on a three-year/six-year basis depending on the equipment. Major steam turbine maintenance work is generally performed on a five to six-year cycle. Shorter outages, such as changing out the SCR catalyst, are generally performed on a three-year cycle. It is assumed that the carbon capture equipment would have major overhauls on a three-year cycle, but there is not a sufficient operating base to confidently predict the required frequency of major maintenance. The carbon capture equipment will require additional O&M labor. It is assumed that some form of service agreement would be needed for the compressors, absorbers, strippers, and other specialized equipment.

Non-fuel variable costs for this technology case include glue gas desulfurization (FGD) reagent costs, SCR catalyst replacement costs, ammonia, SCR reagent costs, water treatment costs, wastewater treatment costs, fly ash and bottom ash disposal costs, bag replacement for the fabric filters, FGD waste disposal costs, and solvent makeup. For the CO_2 capture system, variable costs include solvent makeup and disposal costs—usually offsite disposal—as the spent solvent may be considered hazardous waste; additional wastewater treatment costs (predominantly cooling tower blowdown treatment); and additional demineralized makeup water costs.

Table 2-2 — Case 2 Operational Cost Estimate

Case 2 EIA – Non-Fuel O&M Costs – 2023 $ USD		
650 MW Net, USC Coal with 95% Carbon Capture		
Fixed O&M – Plant (Note 1)	**Units**	**Value**
Labor	$/year	27,313,000
Materials and Contract Services	$/year	23,173,000
Administrative and General	$/year	5,872,000
Subtotal Fixed O&M	$/year	**56,358,000**
	$/kW-year	**86.70**
Variable O&M (Note 2)	$/MWh	**13.73**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. Variable O&M costs include catalyst replacement, ammonia, limestone, water, ash disposal, FGD waste disposal, solvent and water costs for the CCS, and water discharge treatment cost.		

2.4. ENVIRONMENTAL AND EMISSIONS INFORMATION

The emissions for the major criteria pollutants are summarized in Table 2-3. The NO_X emissions assume that the in-furnace controls, such as LNB, OFA, and SCR systems, are employed to control emissions to 0.06 lb/MMBtu. The WFGD system is assumed to be capable of 98% reduction of SO_2 from an inlet loading of 4.3 lb/MMBtu to an emission rate of 0.09 lb/MMBtu. The CO_2 emissions estimate is based on a 95%

reduction in base emissions, which are derived from 40 CFR, Subpart C, Table C-1 as 206 lb/MMBtu, giving a CO_2 emission rate of 10.3 lb/MMBtu.

Table 2-3 — Case 2 Emission Rates

Case 2 EIA – Emissions Rates		
650 MW Net, USC Coal with 95% Carbon Capture		
Predicted Emissions Rates (Note 1)	**Units**	**Value**
NOx	lb/MMBtu	0.06 (Note 2)
SO_2	lb/MMBtu	0.09 (Note 3)
CO_2	lb/MMBtu	10.3 (Note 4)
Emissions Control Notes		
1. High sulfur bituminous coal, 4 lb/MMBtu SO_2 Coal		
2. NOx removal using LNBs with OFA, and SCR		
3. SO_2 removal by forced-oxidation, limestone-based WFGD; 98% Reduction		
4. Per 40 CFR 98, Subpart. C, Table C-1 in conjunction with 95% reduction of emissions through the carbon capture system.		

CASE 3. COMBUSTION TURBINE - SIMPLE CYCLE PLANT, 4 X AERODERIVATIVE, 211 MW NET

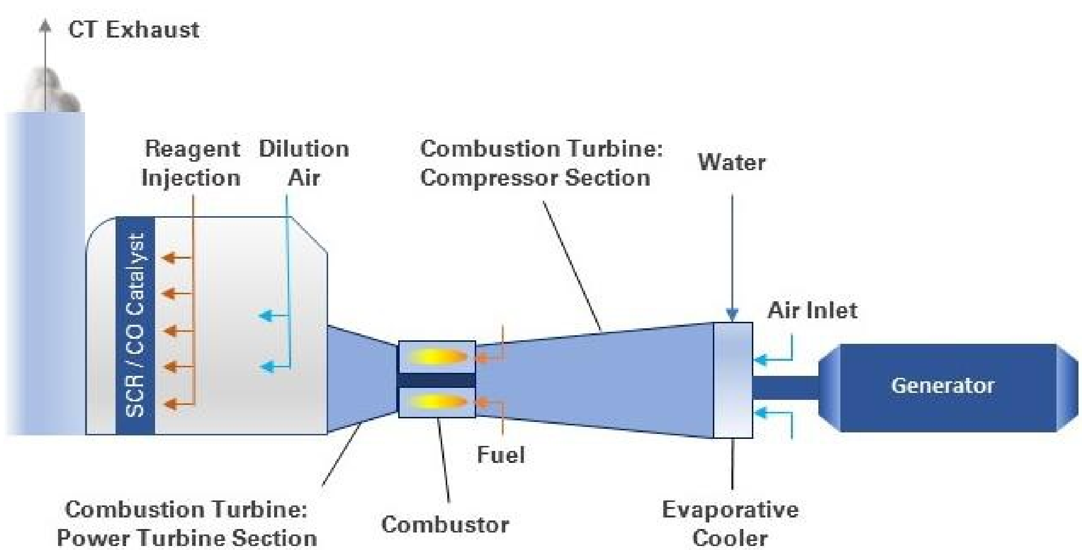
3.1. CASE DESCRIPTION

This case is comprised of four identical aeroderivative combustion turbines (CTs) in a simple-cycle configuration. It is based on the use of natural gas as fuel, although dual-fuel capability is provided. Output power voltage is stepped up for transmission to the external grid through an onsite switchyard.

3.1.1. Mechanical Equipment and Systems

Case 3 is comprised of four of aeroderivative dual-fuel CTs in a simple-cycle configuration, with a nominal output of approximately 54 MW gross per turbine. After deducting internal auxiliary power demand, the net output of the plant is approximately 211 MW. Each CT's inlet air duct has an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT output. Each CT is also equipped with burners designed to reduce the CT's emission of NO_X. Included in Case 3 are selective catalytic reduction (SCR) units for further reduction of NO_X emissions and CO catalysts for further reduction of CO emissions. Refer to Figure 3-1 for a diagram of the CT systems.

Figure 3-1 — Case 3 Configuration



Note: Only one CT shown. All CTs has the same configuration. **Source:** *Author* © Sargent & Lundy, L.L.C.

Aeroderivative CTs differ from industrial frame CTs in that aeroderivative CTs have been adapted from an existing aircraft engine design for stationary power generation applications. Consequently, compared to industrial frame CTs of the same MW output, aeroderivative CTs are lighter weight, have a smaller size footprint, and have more advanced materials of construction. Additionally, aeroderivative CTs generally operate at higher pressure ratios, have faster start-up times, faster ramp rates, and higher efficiencies compared to industrial frame CTs.

3.1.2. Electrical and Control Systems

Case 3 includes one 60-hertz (Hz) electric generator per CT with an approximate rating of 54 MVA and output voltage of 13.8 kV. The generator output power is converted to a higher voltage by generator step-up transformers (GSUs) for transmission to the external grid transmitted via an onsite switchyard.

The simple-cycle facility is controlled by a control system provided by the CT manufacturer, supplemented by controls for the balance-of-plant (BOP) systems (for example, water supply to evaporative coolers, and fuel supply).

3.1.3. Offsite Requirements

Offsite provisions in Case 3 include the following:

- **Fuel Gas Supply:** A half-mile-long pipeline and a dedicated metering station.
- **High-Voltage Transmission Line:** A one-mile-long transmission line.
- **Water Supply for Evaporative Cooler and Miscellaneous Uses:** It is assumed that the water supply source, such as a municipal water system, is near the power plant site and the interconnection for water is at the plant's site boundary. Blowdown waste from the evaporative cooler is sent to an approved discharge location after appropriate treatment of the wastewater, and the wastewater interconnection's location is assumed at the power plant's site boundary.

3.2. CAPITAL COST ESTIMATE

Table 3-1 summarizes the cost components for this case. This estimate is based on an engineering, procurement, and construction (EPC) contracting approach.

In addition to EPC contract costs, the capital cost estimate in Table 3-1 covers owner's costs. Owner's costs include owner's services, which include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's start-up and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs, and land acquisition costs. The estimate is presented as an overnight cost in 2023 dollars and thus excludes allowance for funds used during construction or interest during construction. In addition to the cost of external systems noted above (for example, fuel gas supply and transmission line), an estimated amount is included for the cost of land.

Table 3-1 — Case 3 Capital Cost Estimate

Case 3 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**CT – Simple Cycle** 4 x Aeroderivative Class
Combustion Emissions Controls		Dry Low Emissions Combustor
Post-Combustion Emissions Controls		SCR Catalyst, CO Catalyst
Fuel Type		Natural Gas / No. 2 Backup 4 x 54 MW rating
	Units	
Plant Characteristics		
Net Plant Capacity (60°F, 60% RH)	MW	211
Heat Rate, Higher Heating Value (HHV) Basis	Btu/kWh	9447
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct & Indirect Costs	9%
EPC Contingency	% of EPC Costs	10%
Owner's Services	% of Project Costs	12%
Owner's Contingency	% of Owner's Costs	8%
Estimated Land Requirement	acres	20
Estimated Land Cost	$/acre	62,000
Interconnection Costs		
Electrical Transmission Interconnection Costs		
Transmission Line Cost	$/mile	2,412,000
Miles	miles	1.00
Substation Expansion	$	0
Gas Interconnection Costs		
Pipeline Cost	$/mile	3,500,000
Miles	miles	0.50
Metering Station	$	2,200,000
Typical Project Timelines		
Development, Permitting, Engineering	months	18
Plant Construction Time	months	22
Total Lead Time Before Commercial Operation Date (COD)	months	40
Operating Life	years	40
EPC Cost Components (Note 1)		
Major Owner-Furnished Equipment (Note 2)	$	155,900,000
Other Equipment (Note 3)	$	22,800,000
Construction Labor (Note 4)	$	35,500,000
Indirect Costs (Note 5)	$	19,278,000

Case 3 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**CT – Simple Cycle** 4 x Aeroderivative Class
Combustion Emissions Controls		Dry Low Emissions Combustor
Post-Combustion Emissions Controls		SCR Catalyst, CO Catalyst
Fuel Type		Natural Gas / No. 2 Backup 4 x 54 MW rating
	Units	
Materials (Note 6)	$	10,722,000
EPC Fee	$	21,978,000
EPC Contingency	$	26,618,000
EPC Subtotal	$	292,796,000
Owner's Cost Components (Note 7)		
Owner's Services	$	35,136,000
Land	$	1,240,000
Electrical Interconnection	$	2,412,000
Gas Interconnection	$	3,950,000
Owner's Contingency	$	3,419,000
Owner's Subtotal	$	46,157,000
Total Capital Cost	**$**	**338,953,000**
	$/kW net	**1,606**
Capital Cost Notes		

1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. EPC fees are applied to the sum of direct and indirect costs.
2. Major owner-furnished equipment includes CTs, SCRs, and CO catalysts.
3. Other equipment includes pumps, tanks, MCCs, switchgear, transformers, and any other major inside-the-fence process equipment required for the complete facility (excluding major owner-furnished equipment).
4. Construction labor costs are directly attributed to onsite civil/structural work and erection/installation of the equipment included in the EPC's scope.
5. Indirect costs are attributed to engineering, procurement, project services, construction management, field engineering, start-up, and commissioning services.
6. Materials include all construction materials associated with the EPC scope of work, material freight costs, and consumables during construction.
7. Owner's services include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's start-up and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs, and land acquisition costs.

3.3. OPERATIONS AND MAINTENANCE COST ESTIMATE

Table 3-2 shows operating and maintenance (O&M) costs. Fixed O&M costs include staff and administrative costs, supplies, and minor routine maintenance. (Not included are property taxes and insurance.) Fixed costs also include the fixed payment portion of a long-term service agreement for the CTs.

Variable O&M costs include consumable commodities, such as water, lubricants, and chemicals. Also included is the average annual cost of the planned maintenance events for the CTs over the long-term maintenance cycle, based on the number of equivalent operating hours (EOH) the CT has run. A significant overhaul is typically performed for this type of CT every 30,000 EOH, and a major overhaul is performed every 60,000 EOH. CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of EOH. The aeroderivative CTs in Case 3 always use an EOH-driven maintenance overhaul schedule regardless of the operating profile. (Refer to Case 4 for a starts-based overhaul schedule.) An additional advantage of an aeroderivative CTs is that, depending on the long-term service agreement terms, sections of the CT can be changed out with replacement assemblies, reducing the outage time of major overhauls to less than one week (compared to more than a two-week outage for industrial frame CTs).

Table 3-2 — Case 3 O&M Cost Estimate

Case 3 EIA – Non-Fuel O&M Costs – 2023 $ USD		
CT – Simple Cycle		
Fixed O&M – Plant (Note 1)	**Units**	**Value**
Subtotal Fixed O&M	$/kW-year	**9.56 $/kW-year**
Variable O&M (Note 2)	$/MWh	**5.70 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and general and administrative (G&A) costs. O&M costs exclude property taxes and insurance. 2. Variable O&M costs include water and water discharge treatment cost. These include turbine major maintenance activities which are based on an operating hours-dependent maintenance cycle.		

3.4. ENVIRONMENTAL AND EMISSIONS INFORMATION

For the Case 3 simple-cycle configuration, SCR and CO catalysts are included to reduce emissions of NO_X and CO below the emission levels in the CT exhaust gas. Table 3-3 indicates predicted NO_X, SO_2, and CO_2 emissions assuming natural gas firing.

Table 3-3 — Case 3 Emissions

Case 3 EIA – Emissions Rates		
CT – Simple Cycle		
Predicted Emissions Rates (Note 1)	**Units**	**Value**
NOx	lb/MMBtu	0.0075
SO_2	lb/MMBtu	0.00
CO_2	lb/MMBtu	117
Emissions Control Notes		
1. Natural gas fuel, emissions controlled with SCR, no water injection		

CASE 4. COMBUSTION TURBINE - SIMPLE CYCLE PLANT, H CLASS, 419 MW NET

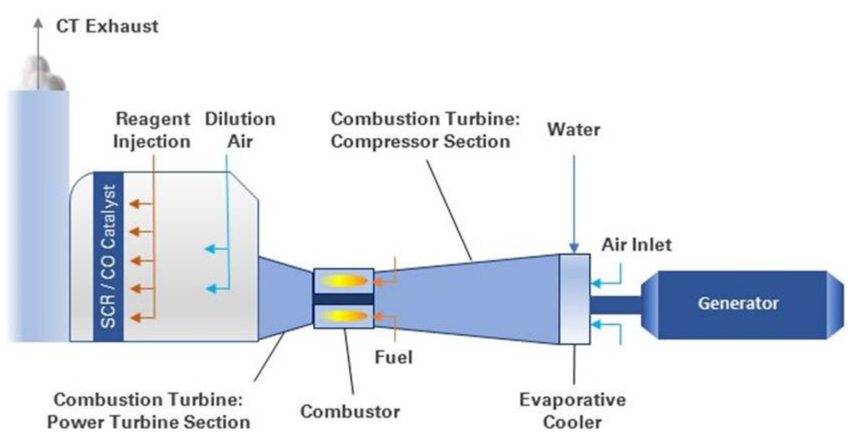
4.1. CASE DESCRIPTION

This case is comprised of one industrial frame Model H combustion turbine (CT) in simple-cycle configuration. It is based on natural gas firing of the CT, although dual-fuel capability is provided. Output power voltage is stepped up for transmission to the external grid through an onsite switchyard.

4.1.1. Mechanical Equipment and Systems

Case 4 is comprised of one industrial frame Model H dual-fuel CT in simple-cycle configuration with a nominal output of approximately 430 MW gross. After deducting internal auxiliary power demand, the net output of the plant is approximately 419 MW. The inlet air duct for the CT is equipped with an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT output. The CT is also equipped with burners designed to reduce the CT's emission of NO_X. Included in the Case 4 configuration is a selective catalytic reduction (SCR) unit for further reduction of NO_X emissions and a CO catalyst for further reduction of CO emissions. Figure 4-1 shows a diagram of the CT systems.

Figure 4-1 — Case 4 Configuration



Source: *Author* © Sargent & Lundy, L.L.C.

Frame CTs differ from aeroderivative CTs in that the industrial frame CT's performance characteristics generally are more conducive to improved performance in combined-cycle (CC) applications; that is, industrial frame CTs have a greater amount of exhaust energy to produce steam for the CC's steam turbine portion of the plant. Industrial frame CT sizes, over 400 MW in 60-Hz models, far exceed the maximum aeroderivative size, and on a $/kW basis, industrial frame turbines are less costly.

4.1.2. Electrical and Control Systems

Case 4 includes one 60-Hz CT electric generator with an approximate rating of 430 MVA and output voltage of 13.8 kV. The generator output power is converted to a higher voltage by generator step-up transformers (GSUs) for transmission to the external grid, transmitted through an onsite facility switchyard.

The simple-cycle facility is controlled by a control system provided by the CT manufacturer, supplemented by controls for the balance-of-plant (BOP) systems (for example, water supply to evaporative coolers, and fuel supply).

4.1.3. Offsite Requirements

Offsite provisions in Case 4 include the following:

- **Fuel Gas Supply:** A half-mile-long pipeline and a dedicated metering station.
- **High-Voltage Transmission Line:** A one-mile-long transmission line.
- **Water Supply for Evaporative Cooler and Miscellaneous Uses:** It is assumed that the water supply source, such as a municipal water system, is near the power plant site and the interconnection for water is at the plant's site boundary. Blowdown waste from the evaporative cooler is sent to an approved discharge location after appropriate treatment of the wastewater, and the wastewater interconnection is assumed at the power plant's site boundary.

4.2. CAPITAL COST ESTIMATE

Table 4-1 summarizes the cost components for this case. This estimate is based on an engineering, procurement, and construction (EPC) contracting approach.

In addition to EPC contract costs, the capital cost estimate in Table 4-1 covers owner's costs. Owner's costs include owner's services which include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's start-up and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs, and land acquisition costs. The estimate is presented as an overnight cost in 2023 dollars and thus excludes allowance for funds used during construction or interest during construction. In addition to the cost of external systems noted above (for example, fuel gas supply), an estimated amount is included for the cost of land.

Table 4-1 — Case 4 Capital Cost Estimate

Case 4 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**CT – Simple Cycle** H-Class
Combustion Emissions Controls		Dry Low Emissions Combustor
Post-Combustion Emissions Controls		SCR Catalyst, CO Catalyst
Fuel Type		Natural Gas / No. 2 Backup 1 x 430 MW rating
	Units	
Plant Characteristics		
Net Plant Capacity (60°F, 60% RH)	MW	419
Heat Rate, Higher Heating Value (HHV) Basis	Btu/kWh	9142
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct and Indirect Costs	9%
EPC Contingency	% of EPC Costs	10%
Owner's Services	% of Project Costs	12%
Owner's Contingency	% of Owner's Costs	8%
Estimated Land Requirement	acres	20
Estimated Land Cost	$/acre	62,000
Interconnection Costs		
Electrical Transmission Interconnection Costs		
Transmission Line Cost	$/mile	3,040,000
Miles	miles	1.00
Substation Expansion	$	0
Gas Interconnection Costs		
Pipeline Cost	$/mile	4,800,000
Miles	miles	0.50
Metering Station	$	2,800,000
Typical Project Timelines		
Development, Permitting, Engineering	months	18
Plant Construction Time	months	22
Total Lead Time Before Commercial Operation Date (COD)	months	40
Operating Life	years	40
EPC Cost Components (Note 1)		
Major Owner-Furnished Equipment (Note 2)	$	132,800,000
Other Equipment (Note 3)	$	30,800,000
Construction Labor (Note 4)	$	57,600,000
Indirect Costs (Note 5)	$	19,908,000

Case 4 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**CT – Simple Cycle** H-Class
Combustion Emissions Controls		Dry Low Emissions Combustor
Post-Combustion Emissions Controls		SCR Catalyst, CO Catalyst
Fuel Type		Natural Gas / No. 2 Backup 1 x 430 MW rating
	Units	
Materials (Note 6)	$	9,816,000
EPC Fee	$	22,583,000
EPC Contingency	$	27,351,000
EPC Subtotal	$	300,858,000
Owner's Cost Components (Note 7)		
Owner's Services	$	36,103,000
Land	$	1,240,000
Electrical Interconnection	$	3,040,000
Gas Interconnection	$	5,200,000
Owner's Contingency	$	3,647,000
Owner's Subtotal	$	49,230,000
Total Capital Cost	**$**	**350,088,000**
	$/kW net	**835.5**
Capital Cost Notes		

1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. EPC fees are applied to the sum of direct and indirect costs.
2. Major owner-furnished equipment includes CTs, SCRs, and CO catalysts.
3. Other equipment includes pumps, tanks, MCCs, switchgear, transformers, and any other major inside-the-fence process equipment required for the complete facility (excluding major owner-furnished equipment).
4. Construction labor costs are directly attributed to onsite civil/structural work and erection/installation of the equipment included in the EPC's scope.
5. Indirect costs are attributed to engineering, procurement, project services, construction management, field engineering, start-up, and commissioning services.
6. Materials include all construction materials associated with the EPC scope of work, material freight costs, and consumables during construction.
7. Owner's services include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's start-up and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs, and land acquisition costs.

4.3. OPERATIONS AND MAINTENANCE COST ESTIMATE

Operating and maintenance (O&M) costs are indicated in Table 4-2. Fixed O&M costs include staff and administrative costs, supplies, and minor routine maintenance. (Not included are property taxes and insurance.) Fixed costs also include the fixed payment portion of a long-term service agreement for the CT.

Variable O&M costs include consumable commodities, such as water, lubricants, and chemicals. Also included is the average annual cost of the planned maintenance events for the CT over the long-term maintenance cycle. Planned maintenance costs for the CT in a given year are based on the number of equivalent starts the CT has accumulated. A hot path gas inspection is performed for this type of CT every 900 equivalent starts, and a major inspection is performed every 1800 equivalent starts. CTs generally have two criteria to schedule overhauls: number of equivalent starts or number of equivalent operating hours [EOH], whichever occurs first. In Case 4, it is assumed the operating profile results in a starts-driven maintenance overhaul schedule. (Refer to Case 3 for an EOH-based overhaul schedule.) In Table 4-2, the cost per start is broken out from the variable O&M costs that cover the consumables.

Table 4-2 — Case 4 O&M Cost Estimate

Case 4 EIA – Non-Fuel O&M Costs – 2023 $ USD		
CT – Simple Cycle		
Fixed O&M – Plant (Note 1)	**Units**	**Value**
Subtotal Fixed O&M	$/kW-year	**6.87 $/kW-year**
Variable O&M		
Consumables (Note 2)	$/MWh	**1.24 $/MWh**
CT Major Maintenance (Note 2)	$/Start	**23,100**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and general and administrative (G&A) costs. O&M costs exclude property taxes and insurance. 2. Variable O&M consumables costs include water, water discharge treatment cost, etc. based on $/MWh. In addition to the consumables costs, add CT major maintenance variable costs, which are based on a start-dependent maintenance cycle, with cost per start indicated.		

4.4. ENVIRONMENTAL AND EMISSIONS INFORMATION

For the Case 4 simple-cycle configuration, SCR and CO catalysts are included to reduce emissions of NO_X and CO below the emission levels in the CT exhaust gas. Table 4-3 indicates predicted NO_X, SO_2, and CO_2 emissions assuming natural gas firing.

Table 4-3 — Case 4 Emissions

Case 4 EIA – Emissions Rates		
CT – Simple Cycle		
Predicted Emissions Rates (Note 1)	**Units**	**Value**
NOx	lb/MMBtu	0.0075
SO_2	lb/MMBtu	0.00
CO_2	lb/MMBtu	117
Emissions Control Notes		
1. Natural gas fuel, emissions controlled with SCR, no water injection		

CASE 5. COMBINED-CYCLE PLANT, H CLASS, 1227 MW NET

5.1. CASE DESCRIPTION

This case is comprised of one block of a combined-cycle (CC) power generation unit in a 2x2x1 configuration. The plant includes two industrial frame Model H "advanced technology" combustion turbines (CTs) and one steam turbine generator (STG). Case 5 is based on natural gas firing of the CTs, although dual-fuel capability is provided. Main plant cooling is accomplished with a wet cooling tower system. Output power voltage is stepped up for transmission to the external grid through an onsite switchyard.

5.1.1. Mechanical Equipment and System

Case 5 is comprised of a pair of Model H, dual-fuel CTs in a 2x2x1 CC configuration (two CTs, two heat recovery steam generators [HRSGs], and one steam turbine). Each CT generates approximately 436 MW gross; the STG generates approximately 393 MW gross. After deducting internal auxiliary power demand, the net output of the plant is 1227 MW. Refer to Figure 5-1 for a diagram of the Case 5 configuration.

Each CT's inlet air duct has an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT and plant output. Each CT is also equipped with burners designed to reduce NO_X emissions. Included in the Case 5 configuration are selective catalytic reduction (SCR) units for further NO_X emissions reduction and CO catalysts for further CO emissions reduction.

The CTs are Model H industrial frame-type CTs with an advanced technology design, since they incorporate the following features:

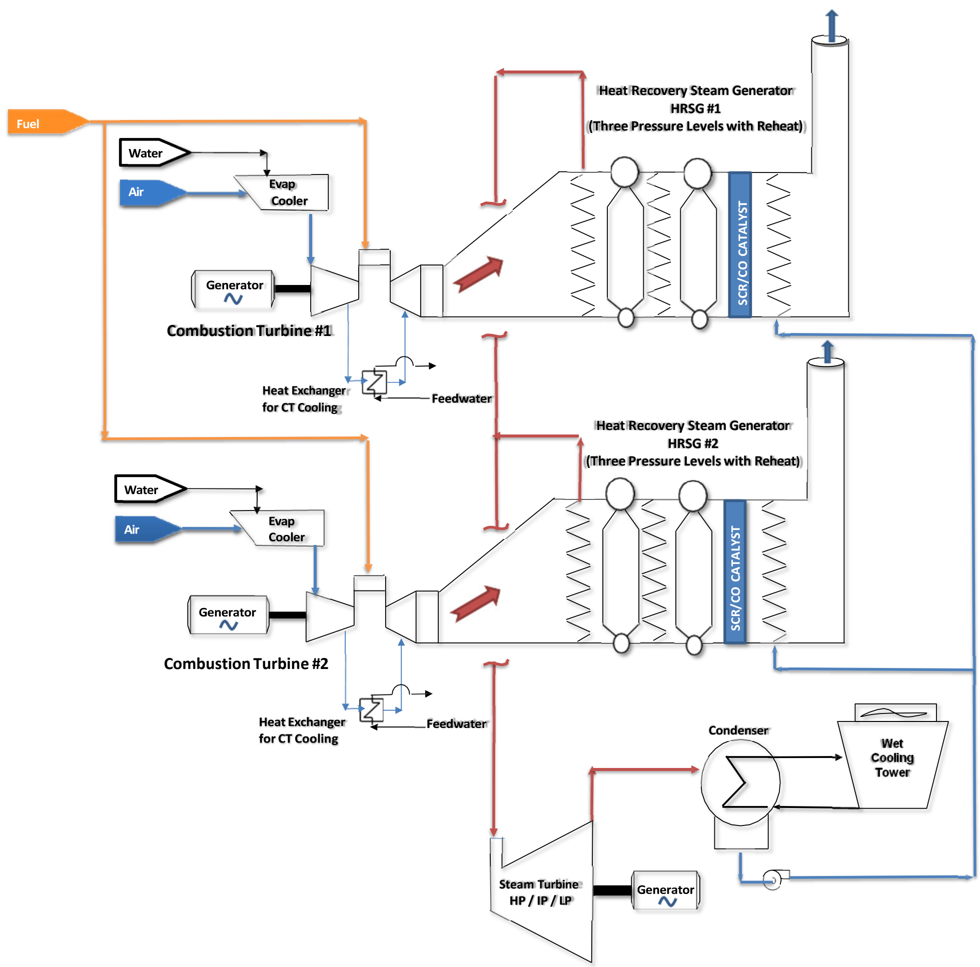
- High firing temperatures (~2900°F)
- Advanced materials of construction
- Advanced thermal barrier coatings
- Additional cooling of CT assemblies (depending on the CT model, additional cooling applies to the CT rotor, turbine section vanes, and the combustor). Refer to Figure 5-1, which depicts a dedicated additional cooler for the CT assemblies in Case 5.

The high-firing temperature and additional features listed above result in increased MW output and efficiency of the CT as well as in the CC plant.

Hot exhaust gas from each CT is directed to a HRSG, with one HRSG per CT. Steam generated in the HRSGs is directed to the STG. HRSGs may be optionally equipped with additional supplemental firing, however, this feature is not included in Case 5. (Supplemental HRSG firing, while increasing the MW output of the STG, reduces plant efficiency.)

A wet cooling tower system provides plant cooling for Case 5. A wet cooling tower is preferred over the alternative air-cooled condensers (ACC) approach since plant performance is better (that is, greater MW output and higher efficiency) and capital cost is generally lower. However, ACCs are often selected in areas where the supply of makeup water needed for a wet cooling tower is scarce or expensive, such as in desert areas in the southwestern United States.

Figure 5-1 — Case 5 Configuration



Source: *Author* © Sargent & Lundy, L.L.C.

5.1.2. Electrical and Control Systems

Case 5 includes one 60-Hz electric generator per CT with an approximate rating of 436 MVA and output voltage of 13.8 kV. The STG includes one 60-Hz electric generator with an approximate 393 MVA rating. The output power from the three generators is converted to a higher voltage by generator step-up transformers (GSUs) for transmission to the external grid, transmitted through an onsite facility switchyard.

The CC facility is controlled by a central distributed control system (DCS), which is linked to a CT control system provided by the CT manufacturer. This DCS includes controls for the steam cycle systems and equipment as well as balance-of-plant (BOP) systems and equipment (for example, water systems, fuel systems, and main cooling systems).

5.1.3. Offsite Requirements

Offsite provisions Case 5 include the following:

- **Fuel Gas Supply:** A half-mile-long pipeline and a dedicated metering station.
- **High-Voltage Transmission Line:** A one-mile-long transmission line.
- **Water Supply for Cooling Tower, Evaporative Coolers, Makeup to Steam Cycle, and Miscellaneous Uses:** It is assumed that the water supply source is near the power plant site and the interconnection for water is at the plant's site boundary. Blowdown waste from the cooling tower and other areas of the plant is sent to an approved discharge location after appropriate treatment of the wastewater, and the wastewater interconnection is assumed to be located at the power plant's site boundary.

5.2. CAPITAL COST ESTIMATE

Table 5-1 summarizes the cost components for this case. This estimate is based on an engineering, procurement, and construction (EPC) contracting approach.

In addition to EPC contract costs, the capital cost estimate in Table 5-1 covers owner's costs. Owner's costs include owner's services which include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's start-up and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs, and land acquisition costs. The estimate is presented as an overnight cost in 2023 dollars and thus excludes allowance for funds used during construction or interest during construction. In addition to the cost of external systems noted above (for example, fuel gas supply and transmission line), an estimated amount is included for the cost of land.

Table 5-1 — Case 5 Capital Cost Estimate

Case 5 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**CC 2x2x1** H-Class
Combustion Emissions Controls		Dry Low NOx combustor
Post-Combustion Emissions Controls		SCR Catalyst, CO Catalyst
Fuel Type		Natural gas / No. 2 Backup
Post Firing		No Post Firing
	Units	
Plant Characteristics		
Net Plant Capacity (60°F, 60% RH)	MW	1227
Net Plant Heat Rate, Higher Heating Value (HHV) Basis	Btu/kWh	6266
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct and Indirect Costs	10%
EPC Contingency	% of EPC Costs	11%
Owner's Services	% of Project Costs	9%
Owner's Contingency	% of Owner's Costs	7%
Estimated Land Requirement	acres	30
Estimated Land Cost	$/acre	54,000
Interconnection Costs		
Electrical Transmission Interconnection Costs		
Transmission Line Cost	$/mile	3,040,000
Miles	miles	1.00
Substation Expansion	$	0
Gas Interconnection Costs		
Pipeline Cost	$/mile	6,000,000
Miles	miles	0.50
Metering Station	$	3,400,000
Typical Project Timelines		
Development, Permitting, Engineering	months	18
Plant Construction Time	months	24
Total Lead Time Before Commercial Operation Date (COD)	months	42
Operating Life	years	40
EPC Cost Components (Note 1)		
Major Owner-Furnished Equipment (Note 2)	$	319,400,000
Other Equipment (Note 3)	$	119,700,000
Construction Labor (Note 4)	$	200,000,000
Indirect Costs (Note 5)	$	63,910,000

Case 5 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**CC 2x2x1** H-Class
Combustion Emissions Controls		Dry Low NOx combustor
Post-Combustion Emissions Controls		SCR Catalyst, CO Catalyst
Fuel Type		Natural gas / No. 2 Backup
Post Firing		No Post Firing
	Units	
Materials (Note 6)	$	83,429,000
EPC Fee	$	78,644,000
EPC Contingency	$	95,159,000
EPC Subtotal	$	960,242,000
Owner's Cost Components (Note 7)		
Owner's Services	$	86,422,000
Land	$	1,620,000
Electrical Interconnection	$	3,040,000
Gas Interconnection	$	6,400,000
Owner's Contingency	$	6,824,000
Owner's Subtotal	$	104,306,000
Total Capital Cost	**$**	**1,064,548,000**
	$/kW net	**867.6**

Capital Cost Notes

1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. EPC fees are applied to the sum of direct and indirect costs.
2. Major owner-furnished equipment includes CTs, HRSG, SCRs, CO catalysts, and steam turbines.
3. Other equipment includes pumps, tanks, MCCs, condensers, cooling towers, switchgear, transformers, and any other major inside-the-fence process equipment required for the complete facility (excluding major owner-furnished equipment).
4. Construction labor costs are directly attributed to onsite civil/structural work and erection/installation of the equipment included in the EPC's scope.
5. Indirect costs are attributed to engineering, procurement, project services, construction management, field engineering, start-up, and commissioning services.
6. Materials include all construction materials associated with the EPC scope of work, material freight costs, and consumables during construction.
7. Owner's services include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's start-up and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs, and land acquisition costs.

5.3. OPERATIONS AND MAINTENANCE COST ESTIMATE

Table 5-2 indicates operating and maintenance (O&M) costs. Fixed O&M costs include staff and administrative costs, supplies, and minor routine maintenance. (Not included are property taxes and insurance.) Fixed costs also include the fixed payment portion of a long-term service agreement for the

CTs. Additional O&M costs for firm gas transportation service are not included as the facility has dual-fuel capability.

Variable O&M costs include consumable commodities, such as water, lubricants, and chemicals. It also includes the periodic costs to change out the SCR and CO catalysts. The variable O&M costs also include the average annual cost of the planned maintenance events for the CTs and the STG over the long-term maintenance cycle. Planned maintenance costs for the CTs in a given year are based on the number of equivalent operating hours (EOH) the CT has run. A hot path gas inspection is performed for this type of CT every 900 equivalent starts, and a major inspection is performed every 1800 equivalent starts. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of EOH. Case 5 assumes the operating profile results in an EOH-driven maintenance overhaul schedule. Refer to Case 4 for a starts-based overhaul schedule.)

Table 5-2 — Case 5 O&M Costs

Case 5 EIA – Non-Fuel O&M Costs – 2023 $ USD		
CC 2x2x1		
Fixed O&M – Plant (Note 1)	**Units**	**Value**
Subtotal Fixed O&M	$/kW-year	**12.12 $/kW-year**
Variable O&M (Note 2)	$/MWh	**3.41 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and general and administrative (G&A) costs. O&M costs exclude property taxes and insurance. 2. Variable O&M costs include water and water discharge treatment cost. These include turbine major maintenance activities which are based on an operating hours-dependent maintenance cycle.		

5.4. ENVIRONMENTAL AND EMISSIONS INFORMATION

For the Case 5 CC configuration, NO_X emissions from the HRSG stacks when firing gas are indicated in Table 5-3. SCRs and CO catalysts are included in the HRSGs to reduce HRSG stack emissions of NO_X and CO below the emission levels in the CT exhaust gas.

Table 5-3 — Case 5 Emissions

Case 5 EIA – Emissions Rates		
CC 2x2x1		
Predicted Emissions Rates (Note 1)	**Units**	**Value**
NOx	lb/MMBtu	0.0075 (Note 1)
SO_2	lb/MMBtu	0.00
CO_2	lb/MMBtu	117
Emissions Control Notes		
1. Natural gas, SCR, no water injection		

CASE 6. COMBINED-CYCLE PLANT, H CLASS, SINGLE SHAFT, 627 MW NET

6.1. CASE DESCRIPTION

This case is comprised of one block of a combined-cycle (CC) power generation unit. The plant includes one industrial frame Model HL derived from an H-Class technology combustion turbine (CT), one steam turbine generator (STG), and one electric generator that is common to the CT and the STG. Case 6 is based on natural gas firing of the CT, although dual-fuel capability is provided. Main plant cooling is accomplished with a wet cooling tower system. Output power voltage is stepped up for transmission to the external grid through an onsite switchyard.

6.1.1. Mechanical Equipment and Systems

Case 6 is comprised of one Model HL dual-fuel CT in a 1x1x1 single-shaft CC configuration. The CT generates approximately 453 MW gross and the STG generates 192 MW gross. After deducting internal auxiliary power demand, the net output of the plant is approximately 627 MW.

Case 6 layout differs from Case 5 in that Case 6 is a single-shaft CC plant. That is, the Case 5 CT, STG, and electric generator all share one horizontal shaft. Therefore, it has a more compact footprint than a plant like Case 5, where the CTs and STG have separate shafts and generators. Refer to Figure 6-1 for a simplified sketch of a single-shaft CT/steam turbine/generator unit. Generally, there are no major performance advantages of a single-shaft CC unit. Instead, the advantages are in costs; that is, in the case of a 1x1x1 CC configuration, the single-shaft unit will have only one electric generator whereas a multiple shaft 1x1x1 CC configuration will have two generators. Also, the smaller footprint of the single-shaft unit will lessen balance-of-plant (BOP) costs, such as foundations, piping, and cabling costs.

The inlet air duct for the CT is equipped with an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT and plant output. The CT is also equipped with burners designed to reduce the CT's emission of NO_X. Included in the Case 6 configuration is a selective catalytic reduction (SCR) unit for further reduction of NO_X emissions and a CO catalyst for further reduction of CO emissions.

The CT is categorized as derived from H Class industrial frame-type CT with an advanced technology design since it incorporates in the design the following features:

- High-firing temperatures (~2900°F)
- Advanced materials of construction

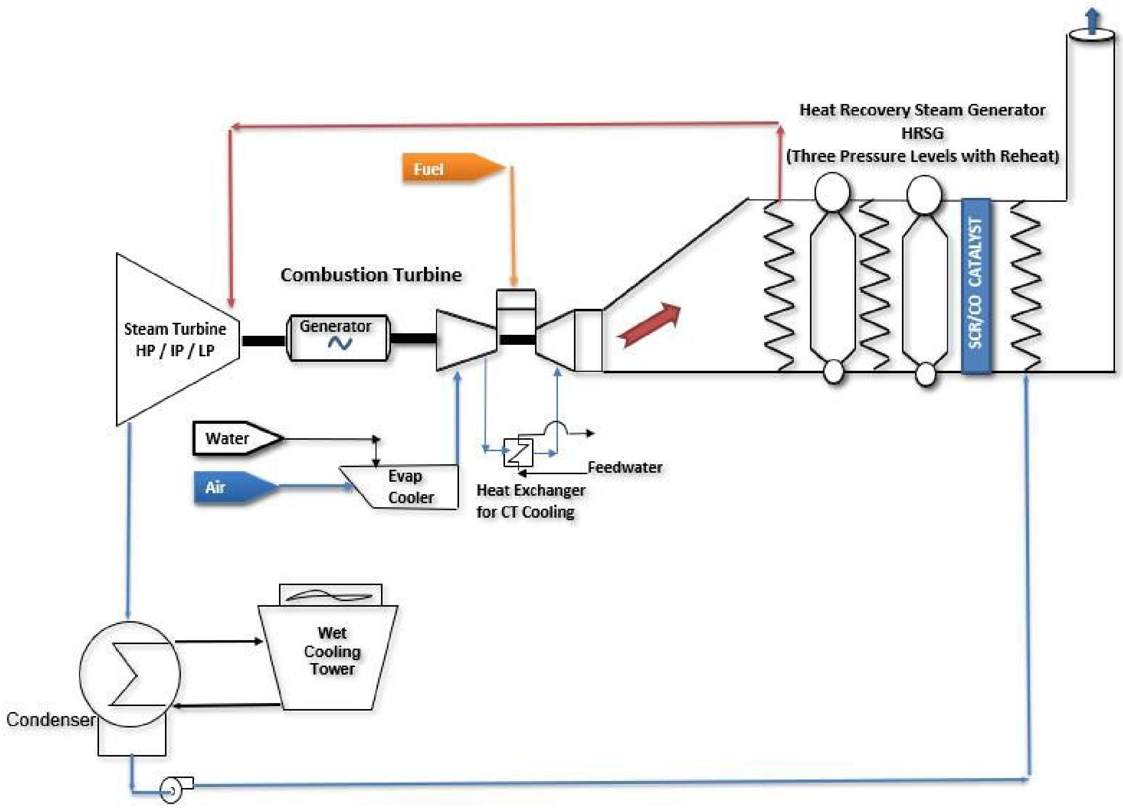
- Advanced thermal barrier coatings
- Additional cooling of CT assemblies (depending on the CT model, additional cooling applies to the CT rotor, turbine section vanes, and the combustor). The high-firing temperature and additional features listed above result in an increase in MW output and efficiency of the CT as well as in the CC plant.

In addition, the HL class industrial frame-type CT utilizes a modular design approach and is designed for operational flexibility.

Hot exhaust gas from the CT is directed to a heat recovery steam generator (HRSG). Steam generated in the HRSG is directed to the STG. An HRSG may be optionally equipped with additional supplemental firing to boost steam turbine output, but this feature is not included in Case 6. (Supplemental HRSG firing, while increasing the MW output of the STG, reduces plant efficiency.)

Plant cooling for Case 6 is provided by a wet cooling tower system. Generally, a wet cooling tower is preferred over the alternative air-cooled condensers (ACC) approach since plant performance is better (that is, greater MW output and higher efficiency) with a wet tower and capital cost is generally lower. However, ACCs are often selected in areas where the supply of makeup water needed for a wet cooling tower is scarce, expensive, or difficult to permit such as in desert areas in the southwestern United States.

Figure 6-1 — Case 6 Configuration – Simplified Sketch



Conceptual sketch of a 1x1x1 single-shaft CT/steam turbine/generator plant

Source: Author © Sargent & Lundy, L.L.C

6.1.2. Electrical and Control Systems

Case 6 includes one 60-Hz electric generator for both the CT and steam turbine, with an approximate rating of 453 MVA and output voltage of 13.8 kV. The output power from the generator is converted to a higher voltage by a generator step-up transformer (GSU) for transmission to the external grid, transmitted through an onsite facility switchyard.

The CC facility is controlled by a central distributed control system (DCS), which is linked to a CT control system provided by the CT manufacturer. The DCS system includes controls for the steam cycle systems and equipment as well as the BOP systems and equipment (for example, water systems, fuel systems, and main cooling systems).

6.1.3. Offsite Requirements

Offsite provisions in Case 6 include the following:

- **Fuel Gas Supply:** A half-mile-long pipeline and a dedicated metering station.

- **High-Voltage Transmission Line:** A one-mile-long transmission line.
- **Water Supply for Cooling Tower, Evaporative Coolers, Makeup to Steam Cycle, and Miscellaneous Uses:** It is assumed that the water supply source is near the power plant site and the interconnection for water is at the plant's site boundary. Blowdown waste from the cooling tower and other areas of the plant is sent to an approved discharge location after appropriate treatment of the wastewater, and the wastewater interconnection is assumed to be located at the power plant's site boundary.

6.2. CAPITAL COST ESTIMATE

Table 6-1 summarizes the cost components for this case. The capital cost estimate is based on an engineering, procurement, and construction (EPC) contracting approach.

In addition to EPC contract costs, the capital cost estimate in Table 6-1 covers owner's costs. Owner's costs include owner's services which include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's start-up and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs, and land acquisition costs. The estimate is presented as an overnight cost in 2023 dollars and thus excludes allowance for funds used during construction or interest during construction. In addition to the cost of external systems noted above (for example, fuel gas supply and transmission line), an estimated amount is included for the cost of land.

Table 6-1 — Case 6 Capital Cost Estimate

Case 6 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**CC 1x1x1, Single Shaft** H Class
Combustion Emissions Controls		Dry Low Emissions Combustor
Post-Combustion Emissions Controls		SCR Catalyst, CO Catalyst
Fuel Type		Natural Gas / No. 2 Backup
Post Firing		No Post Firing
	Units	
Plant Characteristics		
Net Plant Capacity (60°F, 60% RH)	MW	627
Heat Rate, Higher Heating Value (HHV) Basis	Btu/kWh	6226
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct and Indirect Costs	10%
EPC Contingency	% of EPC Costs	11%
Owner's Services	% of Project Costs	9%
Owner's Contingency	% of Owner's Costs	7%

Case 6 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**CC 1x1x1, Single Shaft** H Class
Combustion Emissions Controls		Dry Low Emissions Combustor
Post-Combustion Emissions Controls		SCR Catalyst, CO Catalyst
Fuel Type		Natural Gas / No. 2 Backup
Post Firing		No Post Firing
	Units	
Estimated Land Requirement	acres	30
Estimated Land Cost	$/acre	54,000
Interconnection Costs		
Electrical Transmission Interconnection Costs		
Transmission Line Cost	$/mile	3,040,000
Miles	miles	1.00
Substation Expansion	$	0
Gas Interconnection Costs		
Pipeline Cost	$/mile	4,800,000
Miles	miles	0.50
Metering Station	$	2,800,000
Typical Project Timelines		
Development, Permitting, Engineering	months	18
Plant Construction Time	months	22
Total Lead Time Before Commercial Operation Date (COD)	months	40
Operating Life	years	40
EPC Cost Components (Note 1)		
Major Owner-Furnished Equipment (Note 2)	$	158,000,000
Other Equipment (Note 3)	$	80,400,000
Construction Labor (Note 4)	$	105,400,000
Indirect Costs (Note 5)	$	34,380,000
Materials (Note 6)	$	45,296,000
EPC Fee	$	42,348,000
EPC Contingency	$	51,241,000
EPC Subtotal	$	517,065,000
Owner's Cost Components (Note 7)		
Owner's Services	$	46,536,000
Land	$	1,620,000
Electrical Interconnection	$	3,040,000
Gas Interconnection	$	5,200,000

Case 6 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**CC 1x1x1, Single Shaft** H Class
Combustion Emissions Controls		Dry Low Emissions Combustor
Post-Combustion Emissions Controls		SCR Catalyst, CO Catalyst
Fuel Type		Natural Gas / No. 2 Backup
Post Firing		No Post Firing
	Units	
Owner's Contingency	$	3,948,000
Owner's Subtotal	$	60,344,000
Total Capital Cost	**$**	**577,409,000**
	$/kW net	**920.9**
Capital Cost Notes		

1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. EPC fees are applied to the sum of direct and indirect costs.
2. Major owner-furnished equipment includes CTs, HRSG, SCRs, CO catalysts, and steam turbines.
3. Other equipment includes pumps, tanks, MCCs, condensers, cooling towers, switchgear, transformers, and any other major inside-the-fence process equipment required for the complete facility (excluding the major owner-furnished equipment).
4. Construction labor costs are directly attributed to onsite civil/structural work and erection/installation of the equipment included in the EPC's scope.
5. Indirect costs are attributed to engineering, procurement, project services, construction management, field engineering, start-up, and commissioning services.
6. Materials include all construction materials associated with the EPC scope of work, material freight costs, and consumables during construction.
7. Owner's services include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's start-up and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs, and land acquisition costs.

6.3. OPERATIONS AND MAINTENANCE COST ESTIMATE

Operating and maintenance (O&M) costs are indicated in Table 6-2. Fixed O&M costs include staff and administrative costs, supplies, and minor routine maintenance. (Not included are property taxes and insurance.) Fixed costs also include the fixed payment portion of a long-term service agreement for the CT.

Variable O&M costs include consumable commodities, such as water, lubricants, and chemicals and periodic costs to change out the SCR and CO catalysts. The variable O&M costs also include the average annual cost of the planned maintenance events for the CT and the STG over the long-term maintenance cycle. Planned maintenance costs for the CT in a given year are based on the number of equivalent operating hours (EOH) the CT has run. A hot gas path inspection is typically performed for this type of CT every 25,000 EOH, and a major inspection is performed every 66,400 EOH. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of EOH. In Case 6, it is assumed the operating profile results in an EOH-driven maintenance overhaul schedule. Refer to Case 4 for a starts-based overhaul schedule.)

Table 6-2 — Case 6 O&M Cost

Case 6 EIA – Non-Fuel O&M Costs – 2023 $ USD		
Combined-Cycle 1x1x1, Single Shaft		
Fixed O&M – Plant (Note 1)	**Units**	**Value**
Subtotal Fixed O&M	$/kW-year	**15.51 $/kW-year**
Variable O&M (Note 2)	$/MWh	**3.33 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and general and administrative (G&A) costs. O&M costs exclude property taxes and insurance. 2. Variable O&M costs include water and water discharge treatment cost. These include turbine major maintenance activities which are based on an operating hours-dependent maintenance cycle.		

6.4. ENVIRONMENTAL AND EMISSIONS INFORMATION

For the Case 6 CC configuration, NO_X emissions from the HRSG stack when firing gas are indicated in Table 6-3. An SCR and a CO catalyst are included in the HRSG to reduce HRSG stack emissions of NO_X and CO below the emission levels in the CT exhaust gas.

Table 6-3 — Case 6 Emissions

Case 6 EIA – Emissions Rates		
Combined-Cycle 1x1x1, Single Shaft		
Predicted Emissions Rates (Note 1)	**Units**	**Value**
NO_x	lb/MMBtu	0.0075 (Note 1)
SO_2	lb/MMBtu	0.00
CO_2	lb/MMBtu	117
Emissions Control Notes		
1. Natural gas, SCR, no water injection		

CASE 7. COMBINED-CYCLE PLANT, H CLASS, SINGLE SHAFT, WITH 95% CARBON CAPTURE, 543 MW NET

7.1. CASE DESCRIPTION

This case includes one block of a combined-cycle (CC) power generation unit in a 1x1x1 single-shaft configuration. The plant includes one industrial frame Model HL derived from H-Class combustion-turbine (CT) technology, one steam turbine generator (STG), and one electric generator that is common to the CT and the STG. Case 7 is based on natural gas firing of the CT, although dual-fuel capability is provided. Main plant cooling is accomplished with a wet cooling tower system. Output power voltage is stepped up for transmission to the external grid through an onsite switchyard.

In addition, a system is included to remove and capture 95% of the CO_2 in the CT exhaust gas.

Refer to Case 6 for a description the power generation systems since Case 7 is the same in this regard.

7.1.1. Mechanical Equipment and Systems

This technology case adds a 95% CO_2 capture system to an industrial frame Siemens Energy Model SGT6-9000HL dual-fuel CTs in a 1x1x1 single-shaft CC configuration. The nominal output of the CC plant unit without carbon capture is 627 MW gross. The major power cycle equipment and configurations are described in Case 6. The CO_2 capture systems are commonly referred to as carbon capture and sequestration (CCS) systems; however, for cost estimates provided in this report, no sequestration costs have been included. For this case, the CO_2 captured is assumed to be compressed to supercritical conditions and injected into a pipeline that terminates at the facility's fence line. For this report, the terms "CO_2 capture" and "carbon capture" are used interchangeably.

As with the technology of Case 6, the base configuration used for the cost estimate is a single CC unit power generation plant station constructed on a greenfield site of approximately 30 acres. Case 7 CC unit power generation plant station constructed with a 95% CC system on a greenfield site increase to approximately 60 acres or required land. A wet mechanical draft cooling tower is used for plant cycle cooling and the makeup water used for cycle cooling and steam cycle makeup is provided by an adjacent fresh water source, reservoir, or river.

7.1.2. 95% CO_2 Capture

For Case 7, to obtain 95% CO_2 removal from the flue gas generated from the CT, the full flue gas path must be treated. The flue gas generated from natural gas-fired CT combustion results in a much lower CO_2 concentration in the flue gas than flue gas from a coal-fired facility. As such, the flue gas absorber and quencher would be much larger in scale on a per ton of CO_2 treated basis than with a coal facility. The stripper and compression system, however, would scale directly with the mass rate of CO_2 captured.

In this scenario, it is not practical to increase the CT size or STG size to account for the steam extraction and added auxiliary power required by the CO_2 capture system. The net power output in the CO_2 capture case is significantly less than Case 6.

The flue gas path differs from the base case (Case 6) in that 100% of the gas is directed to the carbon capture system located downstream of the preheater section of the heat recovery steam generator (HRSG). The selective catalytic reduction (SCR) and CO catalysts would operate the same and the flue gas mass flows would be the same. Rather than exiting a stack, the flue gases would be ducted to a set of booster fans that would feed the CO_2 absorber column. The total gross power generated from the CT is approximately the same as Case 6 with no carbon capture.

Steam for the CO_2 stripper is to be extracted from the intermediate-pressure turbine to low-pressure turbine crossover line; however, the steam must be attemporated to meet the requirements of the carbon capture system. The total process steam flow required for the carbon capture system is approximately 571,514 pounds per hour. As a result of the steam extraction, the gross STG generation outlet decreases from approximately 192 MW to 151 MW.

The total auxiliary power required by the plant is approximately 61 MW, of which approximately 44 MW is used by the carbon capture system. The net output decreases from the base case (Case 6) from 627 MW to 543 MW. The net plant heat rate for the 95% carbon capture case is 7,239 Btu/kWh, higher heating value (HHV) basis (compared to 6,226 Btu/kWh, HHV basis, for Case 6).

7.1.3. Electrical and Control Systems

The electrical and controls systems for this case are similar in scope to Case 6's electrical system; however, the auxiliary power system supplies a much larger amount of medium voltage load for the 95% carbon capture case.

The CC facility and the CO_2 capture plant are controlled by a central distributed control system (DCS), which is linked to a CT control system provided by the CT manufacturer. It includes controls for the steam cycle systems and equipment as well as the balance-of-plant (BOP) systems and equipment (for example, water systems, fuel systems, main cooling systems).

7.1.4. Offsite Requirements

Offsite provisions in Case 7 include the following:

- **Fuel Gas Supply:** A half-mile-long pipeline and a dedicated metering station.
- **High-Voltage Transmission Line:** A is a one-mile-long transmission line.
- **Water Supply for Cooling Tower, Evaporative Coolers, Makeup to Steam Cycle, and Miscellaneous Uses:** It is assumed that the water supply source is near the power plant site and the interconnection for water is at the plant's site boundary. The volume of water needed for this 95% carbon capture case is significantly higher than for the base CC case (Case 6). Blowdown waste from the cooling tower and other areas of the plant is sent to an approved discharge location after appropriate treatment of the wastewater, and the wastewater interconnection is assumed to be located at the power plant's site boundary.

7.2. CAPITAL COST ESTIMATES

Table 7-1 summarizes the cost components for this case. The capital cost estimate is based on an engineering, procurement, and construction (EPC) contracting approach.

In addition to EPC contract costs, the capital cost estimate in Table 7-1 covers owner's costs. Owner's costs include owner's services which include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's start-up and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs, and land acquisition costs. The estimate is presented as an overnight cost in 2023 dollars and thus excludes allowance for funds used during construction or interest during construction. In addition to the cost of external systems noted above (for example, fuel gas supply and transmission line), an estimated amount is included for the cost of land.

Table 7-1 — Case 7 Capital Cost Estimate

Case 7 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**CC 1x1x1, Single Shaft, with 95% Carbon Capture**
Combustion Emissions Controls		H-Class Dry Low Emissions Combustor
Post-Combustion Emissions Controls		SCR Catalyst, CO Catalyst
Fuel Type		Natural gas / No. 2 Backup
Post Firing		No Post Firing
	Units	
Plant Characteristics		
Net Plant Capacity (60°F, 60% RH)	MW	543
Heat Rate, HHV Basis	Btu/kWh	7239
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct and Indirect Costs	10%
EPC Contingency	% of EPC Costs	12%
Owner's Services	% of Project Costs	9%
Owner's Contingency	% of Owner's Costs	7%
Estimated Land Requirement	acres	60
Estimated Land Cost	$/acre	44,000
Interconnection Costs		
Electrical Transmission Interconnection Costs		
Transmission Line Cost	$/mile	3,040,000
Miles	miles	1.00
Substation Expansion	$	0
Gas Interconnection Costs		
Pipeline Cost	$/mile	4,800,000
Miles	miles	0.50
Metering Station	$	2,800,000
Typical Project Timelines		
Development, Permitting, Engineering	months	24
Plant Construction Time	months	30
Total Lead Time Before Commercial Operation Date (COD)	months	54
Operating Life	years	40
EPC Cost Components (Note 1)		
CC: Major Owner-Furnished Equipment (Note 2)	$	158,000,000
CC: Other Equipment (Note 3)	$	80,400,000

Case 7 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**CC 1x1x1, Single Shaft, with 95% Carbon Capture** H-Class
Combustion Emissions Controls		Dry Low Emissions Combustor
Post-Combustion Emissions Controls		SCR Catalyst, CO Catalyst
Fuel Type		Natural gas / No. 2 Backup
Post Firing		No Post Firing
	Units	
CC: Construction Labor (Note 4)	$	105,400,000
CC: Indirect Costs (Note 5)	$	34,380,000
CC: Materials (Note 6)	$	45,296,000
Carbon Capture: Equipment and Materials	$	251,424,000
Carbon Capture: System Labor	$	267,469,000
EPC Fee	$	94,237,000
EPC Contingency	$	124,393,000
EPC Subtotal	$	1,160,999,000
Owner's Cost Components (Note 7)		
Owner's Services	$	104,490,000
Land	$	2,640,000
Electrical Interconnection	$	3,040,000
Gas Interconnection	$	5,200,000
Owner's Contingency	$	8,076,000
Owner's Subtotal	$	123,446,000
Total Capital Cost	**$**	**1,284,445,000**
	$/kW net	**2,365**

Capital Cost Notes

1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. EPC fees are applied to the sum of direct and indirect costs.
2. CC: major owner-furnished equipment for the CC Unit includes CT, HRSG, SCRs, CO catalyst, and steam turbine.
3. CC: other equipment includes pumps, tanks, MCCs, condensers, cooling towers, switchgear, transformers, and any other major inside-the-fence process equipment required for the complete facility (excluding the major owner furnished equipment).
4. CC: construction labor costs are directly attributed to onsite civil/structural work and erection/installation of the equipment included in the EPC's scope.
5. CC: indirect costs are attributed to engineering, procurement, project services, construction management, field engineering, start-up, and commissioning services.
6. CC: materials include all construction materials associated with the EPC scope of work, material freight costs, and consumables during construction.

Case 7 EIA – Capital Cost Estimates – 2023 $ USD	
Configuration	**CC 1x1x1, Single Shaft, with 95% Carbon Capture** H-Class
Combustion Emissions Controls	Dry Low Emissions Combustor
Post-Combustion Emissions Controls	SCR Catalyst, CO Catalyst
Fuel Type	Natural gas / No. 2 Backup
Post Firing	No Post Firing
Units	
7. Owner's services include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's start-up and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.	

7.3. OPERATIONS AND MAINTENANCE COST ESTIMATE

Operation and maintenance costs are indicated in Table 7-2. Fixed operating and maintenance (O&M) costs include staff and administrative costs, supplies, and minor routine maintenance. (Not included are property taxes and insurance.) Fixed costs also include the fixed payment portion of a long-term service agreement for the CT and carbon capture system equipment.

Variable O&M costs include consumable commodities such as water, lubricants, chemicals, solvent makeup, and periodic costs to change out the SCR and CO catalysts. The variable O&M costs also include the average annual cost of the planned maintenance events for the CT and the STG over the long-term maintenance cycle. Planned maintenance costs for the CT in a given year are based on the number of equivalent operating hours (EOH) the CT has run. A hot gas path inspection is typically performed for this type of CT every 25,000 EOH, and a major inspection is performed every 66,400 EOH. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of EOH. In Case 7, it is assumed the operating profile results in an EOH-driven maintenance overhaul schedule. Refer to Case 4 for a start-based overhaul schedule.) Planned major outage work on the STG is scheduled less frequently than the CT; it is typically planned for every six to eight years.

For the CO_2 capture system, variable costs include solvent makeup and disposal costs (usually offsite disposal; the spent solvent may be considered hazardous waste), additional wastewater treatment costs (predominantly CT blowdown treatment), and additional demineralized makeup water costs.

Table 7-2 — Case 7 O&M Cost Estimates

Case 7 EIA – O&M Costs – 2023 $ USD		
CC 1x1x1, Single Shaft, with 95% Carbon Capture		
Fixed O&M – Plant (Note 1)	**Units**	**Value**
Subtotal Fixed O&M	$/kW-year	**24.78 $/kW-year**
Variable O&M (Note 2)	$/MWh	**5.05 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials, and contracted services, and general and administrative (G&A) costs. O&M costs exclude property taxes and insurance. 2. Variable O&M costs include water and water discharge treatment cost. These include turbine major maintenance activities which are based on an operating hours-dependent maintenance cycle.		

7.4. ENVIRONMENTAL AND EMISSIONS INFORMATION

For the Case 7 CC configuration with 95% carbon capture, NO_X emissions from the plant when firing gas are indicated in Table 7-3. An SCR and a CO catalyst are included in the HRSG to further reduce plant emissions of NO_X and CO below the emissions levels in the CT exhaust gas. The CO_2 in the CT exhaust gas is reduced by 95% for Case 7.

Table 7-3 — Case 7 Emissions

Case 7 EIA – Emissions Rates		
CC 1x1x1, Single Shaft, with 95% Carbon Capture		
Predicted Emissions Rates (Note 1)	**Units**	**Value**
NOx	lb/MMBtu	0.0075 (Note 1)
SO_2	lb/MMBtu	0.00
CO_2	lb/MMBtu	6
Emissions Control Notes		
1. Natural gas, SCR, CCS, no water injection		

CASE 8. WOODY BIOMASS PLANT, WITH 95% CARBON CAPTURE, 50 MW NET

8.1. CASE DESCRIPTION

This case comprises a greenfield biomass-fired power generation facility with a net capacity of 50 MW with a single steam generator and condensing steam turbine with biomass storage and handling systems, balance-of-plant (BOP) systems, in-furnace and post-combustion emissions control systems, and a 95% CO_2 capture system. The CO_2 capture systems are commonly referred to as carbon capture and sequestration (CCS) systems; however, for the cost estimates provided in this report, no sequestration costs have been included. For this case, the CO_2 captured is assumed to be compressed to supercritical conditions and injected into a pipeline terminated at the fence line of the facility. For this report, the terms "CO_2 capture" and "carbon capture" are used interchangeably.

The facility is designed to receive, store, and burn wood chips with moisture content between 20% and 50%. The technology used is a bubbling fluidized bed (BFB) boiler with bed material consisting of sand, crushed limestone, or ash. The facility does not include equipment to further process or dry the fuel prior to combustion. The fuel storage area is assumed to be uncovered. The facility does not have a connection to a natural gas supply and is designed to start up on diesel fuel only. The emission controls are used to limit NO_X and particulate matter, while SO_2 emissions are not controlled.

8.1.1. Mechanical Equipment and Systems

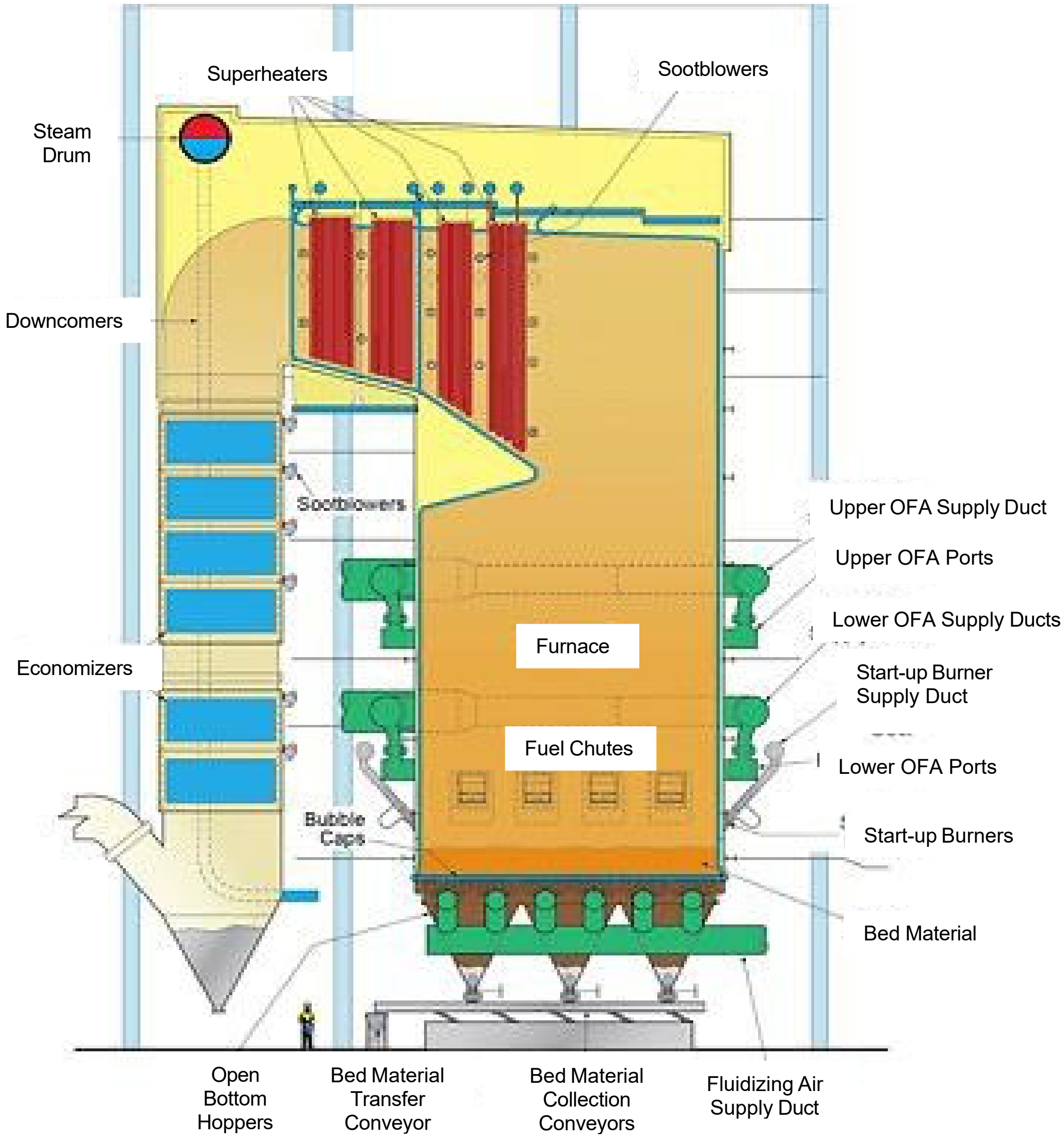
The core technology for this case is a BFB boiler designed to combust wood chips. The boiler is a natural circulation balanced-draft, non-reheat cycle. For this size range, the boiler is assumed to be a top-supported design arranged in a similar manner as shown in Figure 8-1. The BFB furnace consists of horizontally arranged air distribution nozzles in the lower portion of the furnace that introduces air or recirculated flue gas to a bed of sand, ash, or other non-combustible material such as crushed limestone. The balanced-draft boiler consists of water-wall tubes that are refractory lined in the bed area. Air flow is forced upward through the bed material at velocities just beyond the point of fluidization where voids or bubbles start to form within the bed. The bed material is maintained typically at a range of temperatures between 1400°F to 1600°F, depending on the moisture content of the fuel. Diesel oil-fired start-up burners are used to heat the bed material prior to the introduction of fuel. The biomass fuel is fed through chutes located in the lower furnace. Depending on the moisture content of the fuel, flue gases can be mixed with the fluidized air to control the bed heat release rate to levels that prevent the formation of agglomerated ash. Overfire air (OFA) is used to complete combustion of the fuel and to control the emissions of NO_X.

The steam cycle includes a condensing steam turbine and turbine auxiliaries, condensate pumps, low-pressure and high-pressure feedwater heaters, boiler feed pumps, economizers, furnace water walls, steam drum, and primary and secondary superheaters. Boiler feed pumps and condensate pumps are provided in a 2x100% sizing basis. The steam conditions at the turbine are assumed to be 1500 psig at 950°F. Cycle cooling is provided by a mechanical draft cooling tower.

The air and flue gas systems include primary and secondary air fans, flue gas recirculation fans, a single tubular air heater, induced draft fans and the associated duct work, and dampers. The fans are assumed to be provided on a 2x50% basis. A material handling is provided to convey the wood chips to the fuel surge bins that direct the fuel to multiple feeders. The BOP equipment includes sootblowers, a water treatment system and demineralized water storage tanks, a fire protection and detection system, a diesel oil storage and transfer system, a compressed air system, an aqueous ammonia storage system and feed pumps, an ash handling and storage system, and a continuous emissions monitoring system.

NO_X emissions are controlled in-furnace using OFA and with a high dust selective catalytic reduction (SCR) system, SO_2 emissions from wood firing are inherently low and therefore are uncontrolled. Particulate matter is controlled using a pulse jet fabric filter baghouse.

Figure 8-1 — Typical BFB Biomass Boiler Arrangement



Babcock & Wilcox Top-Supported BFB Boiler

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The plant performance estimates for woodchip fired BFB boilers are highly dependent on fuel moisture. Generally, BFB boiler efficiencies range from 75% to 80%. The estimated net heat rate firing wood chips is 19,965 Btu/kWh for this system based on the higher heating value (HHV) of the fuel.

8.1.2. 95% CO_2 Capture

For Case 8, to obtain 95% CO_2 removal from the flue gas generated from the biomass plant, the full flue gas path must be treated. The flue gas generated from biomass combustion results in a similar CO_2 concentration in the flue gas as compared to the flue gas from a coal-fired facility. As such, the CO_2 capture system would scale directly with the mass rate of CO_2 captured.

In this scenario, it is not practical to increase the biomass plant size to account for the steam extraction and added auxiliary power required by the CO_2 capture system.

100% of the gas is directed to the CO_2 capture system located downstream of the pulse jet fabric filter baghouse. Rather than exiting a stack, the flue gases would be ducted to a set of booster fans that would feed the CO_2 absorber column.

Steam for the CO_2 stripper is to be extracted from the intermediate-pressure turbine to low-pressure turbine crossover line; however, the steam must be attemperated to meet the requirements of the CO_2 capture system. The total process steam flow required for the carbon capture system is approximately 77 pounds per hour.

The total auxiliary power required by the plant is approximately 15.5 MW, of which 9 MW is used by the CO_2 capture system. This reduces the plant's 65.5 MW (gross) steam turbine generator to 50 MW of net output. The net plant heat rate for the 95% carbon capture case is 19,965 Btu/kWh, HHV basis.

8.1.3. Electrical and Control Systems

The electrical system for this case includes the turbine generator which is connected via generator circuit breakers to a generator step-up transformer (GSU). The GSU increases the voltage from the generator voltages level to the transmission system high-voltage level. The facility and most of the sub-systems are controlled using a central distributed control system (DCS). Some systems are controlled using programmable logic controllers, and these systems include the sootblower system, the fuel handling system, and the ash handling system.

8.1.4. Offsite Requirements

The facility is constructed on a greenfield site of approximately 100 acres. Wood chips are delivered to the facility by truck and rail. The maximum daily rate for wood chips for the facility is approximately 1750 tons per day.

Water for steam cycle makeup and cooling tower makeup is assumed to be sourced from onsite wells. Wastewater generated from the water treatment systems and the cooling tower blow down is sent to the adjacent waterway from one or more outfalls from a water treatment pond or wastewater treatment system.

The electrical interconnection costs are based on a one-mile distance from the facility switchyard to the terminal point on an existing utility substation. For the purposes of this estimate, the cost associated with the expansion of the substation is excluded.

8.2. CAPITAL COST ESTIMATE

Table 8-1 below summarizes the cost components for this case. The basis of the estimate assumes that the site is constructed in a United States region that has good access to lower cost construction labor and has reasonable access to either well water or water resources, locally sourced wood chips, and existing utility transmission substations or existing transmission lines. The geographic location is assumed to be characterized by seismic, wind, and other loading criteria that do not add significantly to the capital costs. An outdoor installation is assumed, meaning that the boiler building is not enclosed. No special systems are needed to prevent freezing or to account for snow loads on structures.

Table 8-1 — Case 8 Capital Cost Estimate

Case 8 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration	**50 MW Biomass Plant Bubbling Fluidized Bed 95% Carbon Capture System**	
Combustion Emissions Controls	OFA	
Post-Combustion Emissions Controls	SCR / Baghouse / Amine-Based CCS	
Fuel Type	Woodchips	
	Units	
Plant Characteristics		
Net Plant Capacity (60°F, 60% RH)	MW	50
Heat Rate, HHV Basis	Btu/kWh	19,965
Capital Cost Assumptions		
Engineering, Procurement, and Construction (EPC) Contracting Fee	% of Direct and Indirect Costs	10%
EPC Contingency	% of EPC Costs	12%
Owner's Services	% of EPC Costs	7%
Owner's Contingency	% of Owner's Costs	12%
Estimated Land Requirement	acres	100
Estimated Land Cost	$/acre	37,000
Interconnection Costs		
Electrical Transmission Interconnection Costs		

Case 8 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**50 MW Biomass Plant Bubbling Fluidized Bed 95% Carbon Capture System**
Combustion Emissions Controls		OFA
Post-Combustion Emissions Controls		SCR / Baghouse / Amine-Based CCS
Fuel Type		Woodchips
	Units	
Transmission Line Cost	$/mile	2,076,000
Miles	miles	1.00
Substation Expansion Cost	$	0
Typical Project Timelines		
Development, Permitting, Engineering	months	24
Plant Construction Time	months	40
Total Lead Time Before Commercial Operation Date (COD)	months	64
Operating Life	years	40
EPC Cost Components (Note 1)		
Civil/Structural/Architectural - Equipment and Materials	$	19,621,000
Boiler Plant - Equipment and Materials	$	44,217,000
Turbine Plant - Equipment and Materials	$	10,330,000
Main and Aux Power System - Equipment and Materials	$	3,801,000
Balance of Plant and I&C - Equipment and Materials	$	4,326,000
Substation and Switchyard Costs	$	29,405,000
Carbon Capture System Plant – Equipment and Materials	$	134,825,000
Construction Labor Costs	$	181,190,000
Indirect Costs	$	42,772,000
EPC Fee	$	47,049,000
EPC Contingency	$	62,104,000
EPC Subtotal	$	**579,640,000**
Owner's Cost Components (Note 2)		
Owner's Services	$	40,575,000
Land	$	3,700,000
Electrical Interconnection	$	2,076,000
Gas Interconnection	$	0
Owner's Contingency	$	5,562,000
Owner's Cost Subtotal	$	51,913,000
Total Capital Cost	**$**	**631,553,000**
	$/kW net	**12,631**
Capital Cost Notes		

Case 8 EIA – Capital Cost Estimates – 2023 $ USD	
Configuration	**50 MW Biomass Plant Bubbling Fluidized Bed 95% Carbon Capture System**
Combustion Emissions Controls	OFA
Post-Combustion Emissions Controls	SCR / Baghouse / Amine-Based CCS
Fuel Type	Woodchips
	Units
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include engineering, construction management, start-up, and commissioning. EPC fees are applied to the sum of direct and indirect costs.	
2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's start-up and commissioning costs. Other owner's costs include electrical interconnection costs, and land acquisition costs.	

8.3. OPERATIONS AND MAINTENANCE COST ESTIMATE

The operating and maintenance (O&M) costs for the 50 MW biomass wood-fired generation facility are summarized in Table 8-2. The fixed costs cover the O&M labor, contracted maintenance services and materials, and general and administrative (G&A). Major overhauls for the facility are generally based on a three-year basis for boiler equipment and firing equipment and a six-year basis for the steam turbine. Shorter outages (for example, change out SCR catalyst) are generally performed on a two-year cycle.

Non-fuel variable costs for this case include SCR catalyst replacement costs, SCR reagent costs, water treatment costs, wastewater treatment costs, fly ash and bottom ash disposal costs, bag replacement for the fabric filters, bed material makeup, and water and solvent costs for the CO_2 capture system.

Table 8-2 — Case 8 Operational Cost Estimate

Case 8 EIA – Non-Fuel O&M Costs – 2023 $ USD		
50 MW BFB Biomass Plant with 95% Carbon Capture		
Fixed O&M – Plant (Note 1)	**Units**	**Value**
Labor	$/year	7,957,000
Materials and Contract Services	$/year	3,266,000
Administrative and General	$/year	1,836,000
Subtotal Fixed O&M	$/year	**13,059,000**
	$/kW-year	**261.18 $/kW-year**
Variable O&M (Note 2)	$/MWh	**9.65 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. Variable O&M costs include catalyst replacement, ammonia, water, ash disposal, solvent and water costs for the CCS, and water discharge treatment cost.		

8.4. ENVIRONMENTAL AND EMISSIONS INFORMATION

The emissions for the major criteria pollutants are summarized below in Table 8-3. The NO_X emissions assume that the in-furnace controls such as low NOx burners (LNBs), OFA, and SCR systems are employed to control emissions to 0.08 lb/MMBtu. The SO_2 emissions from wood fired combustion are assumed to be negligible and are uncontrolled. The CO_2 emissions estimate is based on a 95% reduction in base emissions, through the implementation of the CO_2 capture system. The base CO_2 emission rate is derived from 40 CFR, Subpart C, Table C-1; as 206 lb/MMBtu; therefore, giving a net CO_2 emission rate of 10.3 lb/MMBtu.

Table 8-3 — Case 8 Emission Rates

Case 8 EIA – Emissions Rates		
50 MW, BFB Biomass Plant with 95% Carbon Capture		
Predicted Emissions Rates (Note 1)	**Units**	**Value**
NOx	lb/MMBtu	0.08 (Note 2)
SO_2	lb/MMBtu	<0.03 (Note 3)
PM	lb/MMBtu	0.03 (Note 4)
CO_2	lb/MMBtu	10.3 (Note 5)
Emissions Control Notes		
1. Wood fuel – 20% to 50% fuel moisture		
2. NOx removal using OFA, and SCR		
3. SO_2 is assumed negligible in wood fuel		
4. Controlled using pulse jet fabric filter		
5. Per 40 CFR 98, Subpart. C, Table C-1		

CASE 9. ADVANCED NUCLEAR PLANT (BROWNFIELD), 2 X AP1000 UNITS, 2156 MW NET

9.1. CASE DESCRIPTION

The case is based on the AP1000 ("AP" stands for "Advanced Passive"), which is an improvement of AP600. The AP1000 is a pressurized water reactor nuclear plant designed by Westinghouse. The first AP1000 unit came online in China's Sanmen Nuclear Power Station in June 2018. Two new AP1000 units have been constructed at the Vogtle Electric Generating Station in Burke County Georgia. Vogtle Unit 3 began commercial operation in July of 2023, and Vogtle Unit 4 began the process to load fuel into the reactor core in August of 2023. These represent the only newly constructed nuclear units in the United States in more than three decades. We assume the plant for this case is constructed on a brownfield site as it is likely for current U.S. operators to take advantage of their existing nuclear plant sites as in the case of Vogtle Units 3 and 4. This assumption considers several efficiencies in zoning, permitting, and regulatory activities, which would otherwise add to the cost and extend the development schedule if a new greenfield nuclear facility were being considered.

9.1.1. Mechanical Equipment and Systems

The AP1000 improves on previous nuclear designs by simplifying the design to decrease the number of components including piping, wiring, and valves. The AP1000 design is also standardized as much as possible to reduce engineering and procurement costs. The AP1000 component reductions from previous designs are approximately:

- 50% fewer valves
- 35% fewer pumps
- 80% less pipe
- 45% less seismic building volume
- 85% less cable

The AP1000 design uses an improved passive nuclear safety system that requires no operator intervention or external power to remove heat for up to 72 hours.

The AP1000 uses a traditional steam cycle similar to other generating facilities such as coal or combined-cycle (CC) units. The primary difference is that the AP1000 uses enriched uranium as fuel instead of coal or gas as the heat source to generate steam. The fission reaction of enriched uranium releases large amounts of energy in the form of heat and radiation inside the pressurized water reactor. The AP1000 uses a two-loop system in which the heat generated by the fuel is released into the surrounding pressurized reactor cooling water. The pressurization allows the cooling water to absorb the released heat without boiling. The reactor cooling water then flows through a steam generator where it rejects heat into the secondary loop, producing steam that turns a steam turbine for electrical generation.

9.1.2. Electrical and Control Systems

The advanced nuclear facility has one steam turbine electric generator for each reactor. Each generator is a 60-Hz machine rated at approximately 1,250 MVA with an output voltage of 24 kV. The steam turbine electric generator is connected through a generator circuit breaker to a generator step-up transformer (GSU). The GSU is connected between two circuit breakers in the high-voltage bus in the facility switchyard through a disconnect switch. The GSU increases the voltage from the electric generator from 24 kV to interconnected transmission system high voltage.

The advanced nuclear facility is controlled using a distributed control system (DCS). The DCS provides centralized control of the facility by integrating the control systems provided with the reactor, steam turbine, and associated electric generator and the control of balance-of-plant (BOP) systems and equipment.

9.1.3. Offsite Requirements

Water for the power plant is obtained from a nearby river or lake. The facility uses a water treatment system to produce the high-quality process water required as well as service water and potable water. The electrical interconnection from the power plant onsite switchyard is connected to the transmission line through a nearby substation.

9.2. CAPITAL COST ESTIMATE

Table 9-1 summarizes the cost components for this case. The overnight capital cost estimate was compared to actual construction costs documented for various reactor types in multiple countries found in Table 8.2 of the IEA 2020 Projected Costs of Generating Electricity Report. The capital cost breakdown for the various reactor types was not provided in the report, nor were the construction completion dates, but construction of all reference projects commenced ten or more years ago. Therefore, these values (escalated to 2023 $ USD), their mean and collective standard deviation were used as benchmarks to validate the capital cost estimate we determined.

Table 9-1 — Case 9 Capital Cost Estimate

Case 9 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Advanced Nuclear (Brownfield)** 2 x AP1000
	Units	
Plant Characteristics		
Net Plant Capacity (60°F, 60% RH)	MW	2156
Net Plant Heat Rate	Btu/kWh	10608
Capital Cost Assumptions		
Engineering, Procurement, and Construction (EPC) Contracting Fee	% of Direct and Indirect Costs	10%
EPC Contingency	% of EPC Costs	12%
Owner’s Services	% of EPC Costs	20%
Owner’s Contingency	% of Owner's Costs	12%
Estimated Land Requirement	acres	60
Estimated Land Cost	$/acre	44,000
Interconnection Costs		
Electrical Transmission Line Costs		
Transmission Line Cost	$/mile	3,040,000
Miles	miles	1.00
Substation Expansion	$	0
Gas Interconnection Costs		
Pipeline Cost	$/mile	0
Miles	miles	0.00
Metering Station	$	0
Typical Project Timelines		
Development, Permitting, Engineering	months	32
Plant Construction Time	months	52
Total Lead Time Before Commercial Operation Date (COD)	months	84
Operating Life	years	40
EPC Cost Components (Note 1)		
Civil/Structural/Architectural	$	2,098,819,000
Nuclear Island	$	3,086,499,000
Conventional Island	$	1,728,440,000
Balance of Plant	$	1,975,360,000
Indirect Costs	$	2,345,739,000
EPC Fee	$	1,123,486,000
EPC Contingency	$	1,483,001,000
EPC Subtotal	$	13,841,344,000
Owner's Cost Components (Note 2)		
Owner's Services	$	2,768,269,000
Land	$	2,640,000
Electrical Interconnection	$	3,040,000
Gas Interconnection	$	0
Owner’s Contingency	$	332,874,000
Owner's Cost Subtotal	$	3,106,823,000

Case 9 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		Advanced Nuclear (Brownfield) 2 x AP1000
	Units	
Total Capital Cost	**$**	16,948,167,000
	$/kW net	**7,861**
Capital Cost Notes		
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, start-up and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs. 2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's start-up and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.		

As a consideration for the interconnection costs, the transmission line for the nuclear facility is expected to operate at a high voltage to be capable of exporting the large capacity of baseload power.

9.3. OPERATIONS AND MAINTENANCE COST ESTIMATE

The operating and maintenance (O&M) cost estimates for nuclear power were informed by the Nuclear Energy Institute's (NEI) *Nuclear Costs in Context* (NEI 2022) which summarizes operating and maintenance data collected by the EUCG from operating nuclear power generation facilities. The NEI report is the most comprehensive source of cost data that is publicly available for both merchant and regulated nuclear power plants in the United States. Non-fuel reported costs were separated between fixed and variable components and escalated to 2023 dollars using Handy Whitman's Total Nuclear Production Plant index.

Table 9-2 — Case 9 Operational Cost Estimate

Case 9 EIA – Non-Fuel O&M Costs – 2023 $ USD		
Advanced Nuclear (Brownfield)		
Fixed O&M – Plant (Note 1)	**Units**	**Value**
Subtotal Fixed O&M	$/kW-year	**156.20 $/kW-year**
Variable O&M (Note 2)	$/MWh	**2.52 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. Variable O&M costs include water, water discharge treatment cost, chemicals, and consumables. Fuel is not included.		

9.4. ENVIRONMENTAL AND EMISSIONS INFORMATION

Nuclear power plants do not produce regulated environmental air emissions. While other environmental compliance requirements may apply, only air emissions were considered for this report. Therefore, the emissions of NO_X, SO_2, and CO_2 are 0.00 lb/MMBtu.

CASE 10. SMALL MODULAR REACTOR NUCLEAR POWER PLANT, 6 X 80 MW UNITS, 480 MW NET

10.1. CASE DESCRIPTION

Small modular reactors (SMRs) are a class of advanced nuclear reactors that are typically sized to deliver 300 MW(e) or less per unit. Besides this distinction in size which is about one third the capacity of traditional nuclear power stations, SMRs are designed with modular building blocks which allow key systems and components to be factory-assembled and shipped to site for improved quality control and a more streamlined installation.

This case is based on 6 small reactor modules. Each module has a net capacity of 80 MW for a net plant capacity of 480 MW. The SMR case is not based on a particular OEM but rather is a representative SMR plant.

10.1.1. Mechanical Equipment and Systems

The mechanical systems are similar to those of an advanced nuclear power plant. Each reactor module is comprised of a nuclear core and steam generator within a reactor vessel, which is enclosed within a containment vessel in a vertical orientation. The nuclear core is located at the base of the module with the steam generator located in the upper half of the module. Feedwater enters and steam exits through the top of the vessel towards the steam turbine. The entire containment vessel sits within a water-filled pool that provides cooling and passive protection in a loss of power event. All 6 reactor modules sit within the same water-filled pool housed within a common reactor building.

Each SMR module uses a pressurized water reactor design to achieve a high level of safety and reduce the number of components required. To improve on licensing and construction times, each reactor is prefabricated at the OEM's facility and shipped to site for assembly. The compact integral design allows each reactor to be shipped by rail, truck, or barge.

Each module has a dedicated balance-of-plant (BOP) system for power generation. Steam from the reactor module is pumped through a steam turbine connected to a generator for electrical generation. Each BOP system is fully independent, containing a steam turbine and all necessary pumps, tanks, heat exchangers, electrical equipment, and controls for operation. This allows for independent operation of each reactor module. The independent operation of each reactor module allows for greater efficiencies at lower operating loads when dispatched capacity is reduced.

Additionally, the modular design of the reactors allows for refueling and maintenance of the individual reactors without requiring an outage of the entire facility. An extra reactor bay is included in the pool housed within the reactor building. This extra bay allows for removal of individual reactors for maintenance without impacting the remaining reactors.

10.1.2. Electrical and Control Systems

Each SMR has its own generator, which is a 60-Hz machine rated at approximately 80 MVA with an output voltage of 13.8 kV. The steam turbine electric generator is connected through a generator circuit breaker to a generator step-up transformer (GSU) that is in turn connected between two circuit breakers in the high-voltage bus in the facility switchyard through a disconnect switch. The GSU increases the voltage from the electric generator from 13.8 kV to interconnected transmission system high voltage.

The SMR facility is controlled using a distributed control system (DCS). The DCS provides centralized control of the facility by integrating the control systems provided with the reactor, steam turbine, and associated electric generator and the control of BOP systems and equipment.

10.1.3. Offsite Requirements

Water for all processes at the SMR nuclear power plant is obtained from a nearby river or lake. The SMR power plant uses a water treatment system to produce the high-quality process water required as well as service and potable water. The electrical interconnection from the SMR nuclear power plant onsite switchyard is connected to the transmission line through a nearby substation.

10.2. CAPITAL COST ESTIMATE

Table 10-1 summarizes the cost components for this case.

Table 10-1 — Case 10 Capital Cost Estimate

Case 10 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Small Modular Reactor Nuclear Power Plant** 6 x 80 MW Small Modular Reactor
	Units	
Plant Characteristics		
Net Plant Capacity (60°F, 60% RH)	MW	480
Net Plant Heat Rate	Btu/kWh	10046
Capital Cost Assumptions		
Engineering, Procurement, and Construction (EPC) Contracting Fee	% of Direct and Indirect Costs	10%

Case 10 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Small Modular Reactor Nuclear Power Plant** 6 x 80 MW Small Modular Reactor
	Units	
EPC Contingency	% of EPC Costs	12%
Owner's Services	% of EPC Costs	7.5%
Owner's Contingency	% of Owner's Costs	12%
Estimated Land Requirement	acres	35
Estimated Land Cost	$/acre	52,000
Interconnection Costs		
Electrical Transmission Line Costs		
Transmission Line Cost	$/mile	3,040,000
Miles	miles	1.00
Substation Expansion	$	0
Gas Interconnection Costs		
Pipeline Cost	$/mile	0
Miles	miles	0.00
Metering Station	$	0
Typical Project Timelines		
Development, Permitting, Engineering	months	24
Plant Construction Time	months	42
Total Lead Time Before Commercial Operation Date (COD)	months	66
Operating Life	years	40
EPC Cost Components (Note 1)		
Civil/Structural/Architectural	$	656,126,000
Nuclear Island	$	729,029,000
Conventional Island	$	473,869,000
Balance of Plant	$	729,029,000
Indirect Costs	$	619,555,000
EPC Fee	$	320,761,000
EPC Contingency	$	423,404,000
EPC Subtotal	$	3,951,773,000
Owner's Cost Components (Note 2)		
Owner's Services	$	296,383,000
Land	$	1,820,000
Electrical Interconnection	$	3,040,000
Gas Interconnection	$	0
Owner's Contingency	$	36,149,000
Owner's Cost Subtotal	$	337,392,000
Total Capital Cost	**$**	4,289,165,000
	$/kW net	**8,936**
Capital Cost Notes		
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, start-up and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs.		

Case 10 EIA – Capital Cost Estimates – 2023 $ USD	
Configuration	**Small Modular Reactor Nuclear Power Plant** 6 x 80 MW Small Modular Reactor
Units	
2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's start-up and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.	

Owner's costs include owner's services, land, and utility interconnection costs. Specifically, the transmission line for the SMR nuclear power plant is expected to operate at a high voltage to be capable of exporting the full plant output. The SMR costs also take into account cost efficiencies including industry learning that would be expected to be realized by a nth-of-a-kind facility. The indicated costs do not include the full burden of design, licensing, and manufacturing facility development required to bring a new SMR design to market. These costs are expected to make first-of-a-kind capital expenses greater than nth-of-a-kind capital expenses but may be somewhat offset by financial incentives such as tax credits or cost sharing arrangements through public-private partnerships.

10.3. OPERATIONS AND MAINTENANCE COST ESTIMATE

The operating and maintenance (O&M) cost estimates for SMR nuclear power were informed by the Nuclear Energy Institute's (NEI) *Nuclear Costs in Context* (NEI 2022) which summarizes operating and maintenance data collected by the EUCG from operating nuclear power generation facilities. Adjustments were made to reflect assumed differentials in fixed and variable O&M attributable to the nuances of SMR plant design and operation. Cost basis values were escalated to 2023 dollars using Handy Whitman's Total Nuclear Production Plant index.

Table 10-2 — Case 10 Operational Cost Estimate

Case 10 EIA – Non-Fuel O&M Costs – 2023 $ USD		
Small Modular Reactor Nuclear Power Plant		
Fixed O&M – Plant (Note 1)	**Units**	**Value**
Subtotal Fixed O&M	$/kW-year	**121.99 $/kW-year**
Variable O&M (Note 2)	$/MWh	**3.19 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. Variable O&M costs include water, water discharge treatment cost, chemicals, and consumables. Fuel is not included.		

10.4. ENVIRONMENTAL AND EMISSIONS INFORMATION

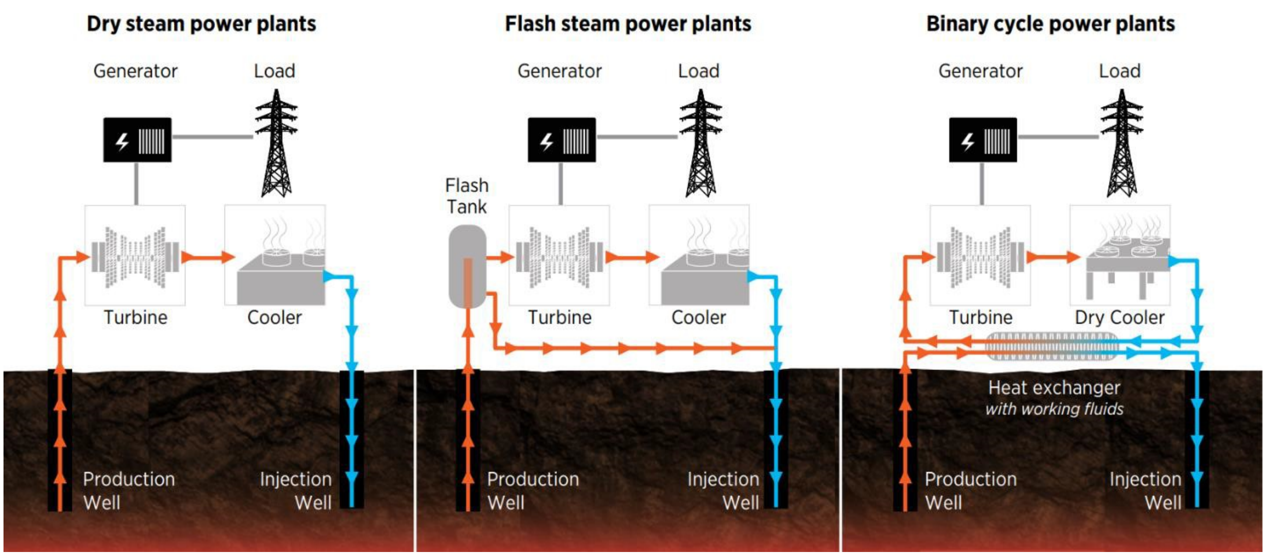
Small modular reactor nuclear power plants do not produce regulated environmental air emissions. While other environmental compliance requirements may apply, only air emissions were considered for this report. Therefore, the emissions of NO_X, SO_2, and CO_2 are 0.00 lb/MMBtu.

CASE 11. GEOTHERMAL PLANT, 50 MW NET

11.1. CASE DESCRIPTION

This case is a 50 MW (net) geothermal power plant accessing a hydrothermal reservoir to generate power via a binary cycle. Geothermal power can be generated either from hydrothermal reservoirs or an enhanced geothermal system (EGS). Hydrothermal reservoirs are underground reservoirs of high temperature, pressurized water. The hot water can be used to generate power through dry steam generators, flash steam generators, or binary cycles, as used in this case. Dry and flash steam generators convert the pumped water into steam to directly turn steam turbines. While these plants have lower capital costs per kW of capacity, they are restricted to very hot (>390°F) aquifers and the dissolved minerals and gases in the water lead to greater wear on the turbines and therefore higher maintenance costs.

Figure 11-1 — Geothermal Plant Configurations for Hydrothermal Reservoirs



Source: DOE, "GeoVision: Harnessing the Heat Beneath Our Feet", 2019

Binary cycle geothermal power plants use the hydrothermal reservoir to power an Organic Rankine Cycle (ORC) generator. ORC power generation uses an organic working fluid that is vaporized in a heat exchanger to power a conventional steam turbine. The low boiling-point of the working fluid allows power generation from lower temperature hydrothermal resources, typically 300–375°F. Binary cycle plants comprise the majority of new geothermal power plants built in the United States in the last five years. They are typically located near existing geothermal resources to utilize the aquifer's generation potential more fully. Additionally, binary cycle plants are often built to repower older power plants whose hydrothermal reservoirs have cooled down too much to be effective for steam power generation. Both of these scenarios significantly reduce the costs associated with resource exploration and well drilling, which can account for over 50% of the cost of a new geothermal plant. Likewise, this case presents a brownfield site, in which a hot aquifer (350°F) has been identified with production and injection wells already drilled. This analysis isolates the costs of building and maintaining the geothermal plant itself and is a realistic starting point for a new geothermal plant built in the United States today.

While hydrothermal reservoirs are naturally occurring geologic features, EGS reservoirs are human-made reservoirs where additional fluid has been injected into underground rock to increase permeability and fluid flow. They are less geographically restricted than conventional hydrothermal plants. EGS power plants are the subject of active research and development, but at this time there are no commercial examples in the United States on which to base a cost estimate.

11.1.1. Mechanical Equipment and Systems

A binary cycle geothermal power plant requires power generation equipment and a gathering system to convey geothermal fluid between the power plant and the reservoir wells.

The ORC power generation equipment for this case includes two 30 MW turbine generators, heat exchangers, and the associated fluid pumps. Each turbine generator requires three heat exchangers. Two of the heat exchangers are used to preheat and vaporize the organic working fluid by contacting it with the hot geothermal fluid, and the remaining heat exchanger uses an air blower to cool and condense the organic working fluid after expansion in the turbine. Unlike steam geothermal plants, the geothermal fluid never contacts air, as it cycles from the production wells through the heat exchangers and back into the reservoirs at injection wells.

The field gathering equipment includes pumps associated with production and injection wells, which are assumed to be already drilled to the depth of the hydrothermal reservoir. The number of wells required depends strongly on the characteristics of the hydrothermal reservoir, and this modeled case assumes 8 production and 8 injection wells. Pipes to transfer the fluid from the wells to the power plant equipment are also include in the field gathering system.

Operating the pumps and cooling equipment requires electricity that reduces the net output of the power plant. To obtain 50 MW of net output, the turbine generators require a gross output of about 58 MW.

11.1.2. Electrical and Control Systems

Each generator has its own step-up transformer and circuit breaker. After the circuit breaker, each electrical connection is combined via a high-voltage bus into a high-voltage circuit breaker before being fed into the grid.

11.1.3. Offsite Requirements

Geothermal plants must be located near drilled wells that tap into reservoirs of hot geothermal fluid. This case also assumes a one-mile transmission line.

11.2. CAPITAL COST ESTIMATE

Table 11-1 summarizes the cost components for this case.

Table 11-1 — Case 11 Capital Cost Estimate

Case 11 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Geothermal** 50 MW **Binary Cycle**
	Units	
Plant Characteristics		
Net Plant Capacity	MW	50
Capital Cost Assumptions (Note 1)		
Engineering, Procurement, and Construction (EPC) Contracting Fee	% of Direct and Indirect Costs	10%
EPC Contingency	% of EPC Costs	4%
Owner's Services	% of EPC Costs	12%
Owner's Contingency	% of Owner's Costs	4%
Estimated Land Requirements (Support buildings only)	acres	200
Estimated Land Cost	$/acre	30,000
Electric Interconnection Costs		
Transmission Line Cost	$/mile	2,076,000
Miles	miles	1.00
Typical Project Timelines		
Development, Permitting, Engineering	months	18
Plant Construction Time	months	18
Total Lead Time Before Commercial Operation Date (COD)	months	36
Operating Life	years	40
EPC Cost Components		
Civil Structural Material and Installation	$	39,670,000
Mechanical – Power generating Equipment	$	56,672,000
Mechanical – Field Gathering, Production / Injection Pumps		20,654,000
Electrical – Balance of Plant (BOP) and I&C	$	8,213,000

Case 11 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Geothermal** 50 MW **Binary Cycle**
	Units	
Electrical – Substation and Switchyard		6,453,000
Indirect Costs	$	15,799,000
EPC Fee	$	14,746,000
EPC Contingency	$	6,488,000
EPC Subtotal	$	168,695,000
Owner's Cost Components (Note 2)		
Owner's Services	$	20,243,000
Land	$	6,000,000
Electrical Interconnection	$	2,076,000
Owner's Contingency	$	1,133,000
Owner's Cost Subtotal	$	29,452,000
Total Capital Cost	**$**	**198,147,000**
	$/kW net	**3,963**
Capital Cost Notes		

1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, start-up and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs.
2. Owner’s costs include project development, studies, permitting, legal, owner’s project management, owner’s engineering, and owner’s start-up and commissioning costs. Other owner’s costs include electrical interconnection costs and land acquisition costs.

11.3. OPERATIONS AND MAINTENANCE COST ESTIMATE

Table 11-2 — Case 11 Operating and Maintenance (O&M) Cost Estimates

Case 11 EIA – Non-Fuel O&M Costs – 2023 $ USD		
Geothermal		
Fixed O&M – Plant (Note 1)	**Units**	**Value**
Labor	$/year	2,019,000
Plant Maintenance	$/year	2,994,000
Field Maintenance	$/year	1,258,000
Geothermal Pump Maintenance	$/year	1,259,000
Subtotal Fixed O&M	$/year	7,530,000
$/kW-year	$/kW-year	**150.60 $/kW-year**
Variable O&M	$/MWh	**0.00 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and general and administrative (G&A) costs. O&M costs exclude property taxes and insurance.		

11.4. ENVIRONMENTAL AND EMISSIONS INFORMATION

Binary geothermal power plants do not burn fuel, and the geothermal fluid extracted from the ground does not contact the air, so there is no release of dissolved gases from the hydrothermal reservoir. However, a small amount of the organic working fluid used in the ORC generator, typically isobutane or n-pentane, leaks through valves and seals during normal operation. For a 50 MW plant, this is expected to be limited to 125 tons of isobutane or n-pentane per year (0.167 lbs / MMBtu).

CASE 12. HYDROELECTRIC PLANT, 100 MW NET

12.1. CASE DESCRIPTION

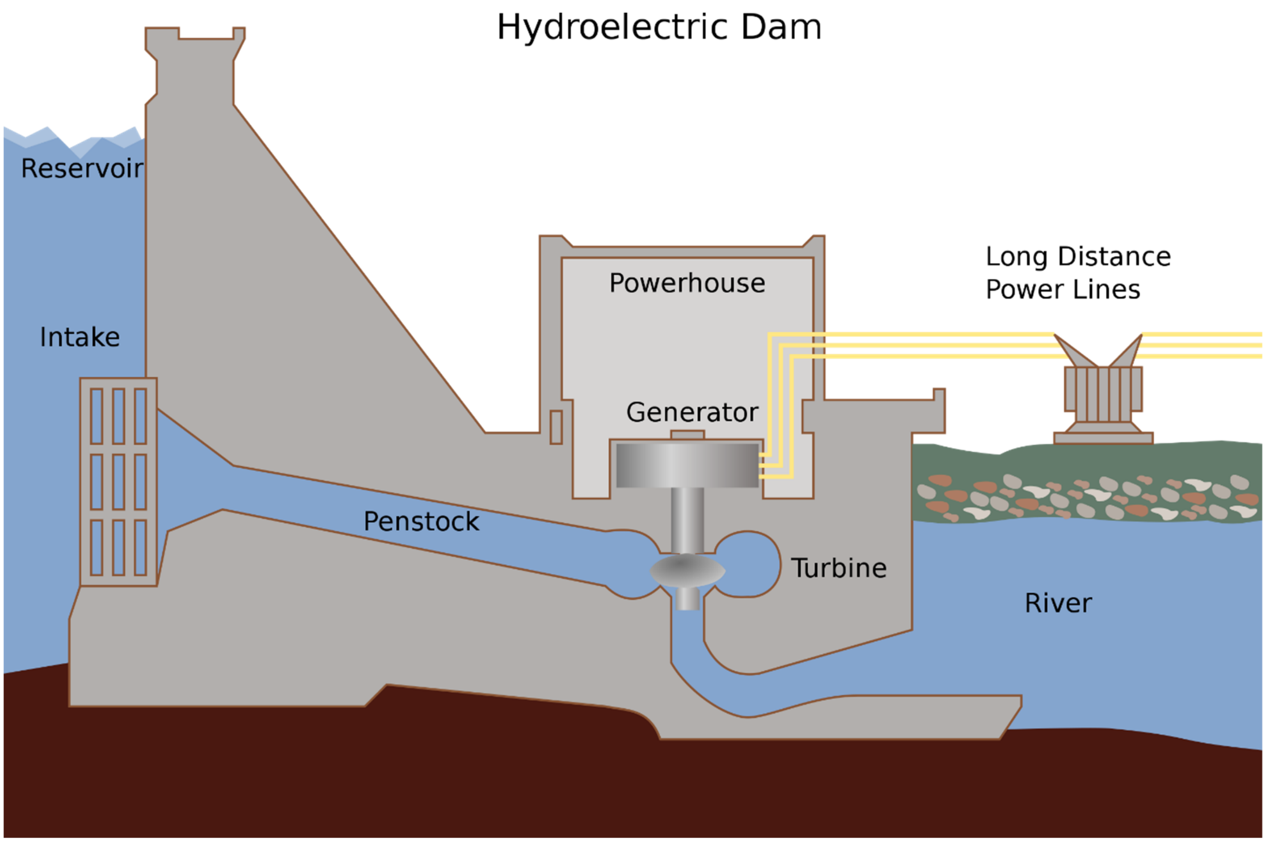
This case is based on a "New Stream Reach Development" 100 MW hydroelectric power plant with 30 feet of available head. There are several types of hydroelectric power plants including run-of-river, storage, and pumped storage. This case is based on a storage type hydropower plant that includes a dam to store water in a reservoir where water is released through tunnels to a powerhouse to spin a turbine.

Figure 12-1 — Dam of a Hydroelectric Power Plant

Source: Alan Cressler, *Marshall County*, AL. Digital Image.
Retrieved from Guntersville Dam - Encyclopedia of Alabama (accessed Aug 1, 2023)

Figure 12-2 show a diagram of the major components of a storage-type hydroelectric power plant. The dam structure holds water in a reservoir. Water passes through an intake in the reservoir through the penstock. The penstock consists of concrete 'power tunnels' that direct water to a turbine that spins a generator that distributes electric power to the grid.

Figure 12-2 — Storage-Type Hydroelectric Power Plant



Source: Tennessee Valley Authority, Licensed by GFDL and CC-BY-2.6, [Wikimedia Commons](#) (Accessed Aug 2 2023)

The costs for this case include a concrete dam with a spillway and diversion tunnel to control the water level in the reservoir. There are four identical penstocks, approximately 4.5 meters in diameter. Each penstock leads to a Kaplan-type hydro-turbine, which is suitable for modeled stream head. Each of the four turbine-generators is rated for 25 MW. Power is stepped up from 13.8 kV to 154 kV for distribution.

Figure 12-3 — Typical Hydroelectric Power Turbine Hall

Source: Sargent & Lundy project site photo archive.

12.2. CAPITAL COST ESTIMATE

Table 12-1 summarizes the cost components for this case.

Table 12-1 — Case 12 Capital Cost Estimates

Case 12 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Hydroelectric Power Plant** **New Stream Reach Development**
	Units	
Plant Characteristics		
Net Plant Capacity	MW	100

Case 12 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Hydroelectric Power Plant** **New Stream Reach Development**
	Units	
Head	ft	30
Capital Cost Assumptions (Note 1)		
Engineering, Procurement, and Construction (EPC) Contracting Fee	% of Direct and Indirect Costs	10%
EPC Contingency	% of EPC Costs	5%
Owner's Services	% of EPC Costs	7%
Owner's Contingency	% of Owner's Costs	5%
Estimated Land Requirements (Support buildings only)	acres	2
Estimated Land Cost	$/acre	128,000
Electric Interconnection Costs		
Transmission Line Cost	$/mile	2,412,000
Miles	miles	1.00
Substation Expansion	$	0
Typical Project Timelines		
Development, Permitting, Engineering	months	36
Plant Construction Time	months	36
Total Lead Time Before COD	months	72
Operating Life	years	50
EPC Cost Components		
Civil Structural Material and Installation	$	371,101,000
Mechanical Equipment Supply and Installation	$	93,933,000
Electrical / I&C Supply and Installation	$	42,248,000
Indirect Costs	$	60,874,000
EPC Fee	$	56,816,000
EPC Contingency	$	31,249,000
EPC Subtotal	$	656,221,000
Owner's Cost Components (Note 2)		
Owner's Services	$	45,935,000
Land	$	256,000
Electrical Interconnection	$	2,412,000
Owner's Contingency	$	2,430,000
Owner's Cost Subtotal	$	51,033,000
Total Capital Cost	**$**	**707,254,000**

Case 12 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Hydroelectric Power Plant** **New Stream Reach Development**
	Units	
	$/kW net	**7,073**
Capital Cost Notes		
1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs. 2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's start-up and commissioning costs. Other owner's costs include electrical interconnection costs and land acquisition costs.		

12.3. OPERATIONS AND MAINTENANCE COST ESTIMATE

Table 12-2 summarizes the operating and maintenance cost components for this case.

Table 12-2 — Case 12 Operating and Maintenance (O&M) Cost Estimates

Case 12 EIA – Non-Fuel O&M Costs – 2023 $ USD		
Hydroelectric Power Plant		
Fixed O&M – Plant (Note 1)	**Units**	**Value**
Subtotal Fixed O&M	$/year	3,354,000
$/kW-year	$/kW-year	**33.54 $/kW-year**
Variable O&M	$/MWh	**0.00 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials, and contracted services, and general and administrative (G&A) costs. O&M costs exclude property taxes and insurance.		

12.4. ENVIRONMENTAL AND EMISSIONS INFORMATION

Hydroelectric power does not produce regulated environmental air emissions. While other environmental compliance requirements apply, only air emissions were considered for this report. Therefore, the emissions of NO_X, SO_2, and CO_2 are 0.00 lb/MMBtu. Academic research on the impact of dams on the carbon cycle of their local waterways is ongoing.

CASE 13. ONSHORE WIND, LARGE PLANT FOOTPRINT,200 MW NET

13.1. CASE DESCRIPTION

This case is an onshore wind project in the Great Plains region that is based on a total project capacity of 200 MW. The region has an abundance of land that is suitable for onshore wind turbine siting and is not subject to land constraints that would constraint project size. Parameters that affect project costs and performance include turbine nameplate capacity, rotor diameter, and hub height. The case configuration assumes wind turbines rated at 2.8 MW and 125-meter rotor diameters and 90-meter hub height. These features reflect modern wind turbines which employ larger rotor diameter and greater hub heights. The main advantage to taller hub heights and increased rotor diameters include access to better wind profiles at higher altitudes and increased turbine swept area, allowing the turbine unit to capture more energy.

13.1.1. Mechanical Equipment and Systems

Wind turbine generators (WTGs) convert kinetic wind energy into electrical power. The most ubiquitous type of wind turbine utilized for electric power generation are those of the horizontal-axis three-bladed design. Lift is generated when wind flows around the turbine blades, resulting in rotation. The blades are connected to a central hub and drivetrain which turns a generator located inside of the nacelle, the housing positioned atop the wind turbine tower.

13.1.2 Electrical and Control Systems

Each WTG consists of a doubly fed induction generator. The low-voltage output from the generator is stepped up to medium voltage through a transformer located either in the nacelle or at the tower base. A medium-voltage collection system conveys the generated energy to an onsite substation, which further steps up the voltage for interconnection with the transmission system with a voltage of 230 kV.

A supervisory control and data acquisition (SCADA) system is provided for communications and control of the wind turbines and substation. The SCADA system allows the operations staff to remotely control and monitor each wind turbine and the wind farm as a whole.

13.1.3 Offsite Requirements

Wind farms harness power from wind and thus, require no fuel or fuel infrastructure. The offsite requirements are limited to construction of site and access roads to each wind turbine, operating and maintenance (O&M) building and electrical interconnection to the transmission system.

13.2. CAPITAL COST ESTIMATE

Table 13-1 summarizes the cost components for this case. The capital cost estimate is based on an engineering, procurement, and construction (EPC) contracting approach.

In addition to EPC contract costs, the capital cost estimate in Table 13-1 covers owner's costs. Owner's costs include owner's services which include project development, studies, permitting, legal, owner's project management, owner's engineering, owner's start-up and commissioning costs, project feasibility analyses, wind resource assessments, geotechnical studies, contracting for land access, transmission access, permitting, and electrical interconnection costs. The estimate is presented as an overnight cost in 2023 dollars and thus excludes allowance for funds used during construction or interest during construction. Leasing costs are provided in the O&M.

Table 13-1 — Case 13 Capital Cost Estimate

Case 13 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Onshore Wind – Large Plant Footprint: Great Plains Region** 200 MW | 2.8 MW WTG
Hub Height (m)		90
Rotor Diameter (m)		125
	Units	
Plant Characteristics		
Net Plant Capacity	MW	200
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct and Indirect Costs	8%
EPC Contingency	% of EPC Costs	5%
Owner's Services	% of EPC	7%
Owner's Contingency	% of Owners Costs	5%
Electric Interconnection Costs		
Transmission Line Cost	$/mile	2,412,000
Miles	miles	1.00
Typical Project Timelines		
Development, Permitting, Engineering	months	12
Plant Construction Time	months	9
Total Lead Time Before Commercial Operation Date (COD)	months	21
Operating Life	years	25
EPC Cost Components (Note 1)		
WTG Procurement and Supply	$	160,168,000

Case 13 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Onshore Wind – Large Plant Footprint: Great Plains Region** 200 MW | 2.8 MW WTG
Hub Height (m)		90
Rotor Diameter (m)		125
	Units	
WTG Civil Work	$	62,130,000
Electrical - Collection System	$	12,100,000
Indirect Costs	$	8,112,000
EPC Fee	$	19,401,000
EPC Contingency	$	13,096,000
EPC Subtotal	$	275,007,000
Owner's Cost Components (Note 2)		
Owner's Services	$	19,250,000
Electrical Interconnection	$	2,412,000
Owner's Contingency	$	1,083,000
Owner's Cost Subtotal	$	22,745,000
Total Capital Cost	**$**	297,752,000
	$/kW net	1,489
Capital Cost Notes		

1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs.
2. Owner’s costs include project development, studies, permitting, legal, owner’s project management, owner’s engineering, and owner’s startup and commissioning costs. Other owner’s costs include electrical interconnection costs.

13.3. OPERATIONS AND MAINTENANCE COST ESTIMATE

O&M cost estimates reflect a full-service agreement arrangement, under which an O&M contractor provides labor, management, and parts replacement (including unscheduled parts replacement) for the WTGs, collection system, and substation. Our cost estimates exclude site specific owner's costs such royalties, property taxes and insurance. Table 13-2 summarizes the average annual O&M expenses projected for an assumed 25-year project life.

Table 13-2 — Case 13 O&M Cost Estimate

Case 13 EIA – Non-Fuel O&M Costs – 2023 $ USD		
Onshore Wind – Large Plant Footprint: Great Plains Region		
Fixed O&M – Plant (Note 1)	**Units**	**Value**
WTG Scheduled Maintenance	$/year	2,240,000
WTG Unscheduled Maintenance	$/year	2,800,000
Leasing Costs	$/year	996,000
Balance of Plant Maintenance	$/year	575,200
Subtotal Fixed O&M	$/year	6,611,200
$/kW-year	$/kW-year	**33.06 $/kW-year**
Variable O&M (Note 2)	$/MWh	**0.00 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and general and administrative (G&A) costs.		
2. O&M costs estimates reflect the Full Service Agreement, unscheduled maintenance, land lease, and BOP maintenance, and exclude certain site-specific owner's costs such as royalties, property taxes, and insurance.		
3. Average Full Service Agreement term considered: 25 years		

13.4. ENVIRONMENTAL AND EMISSIONS INFORMATION

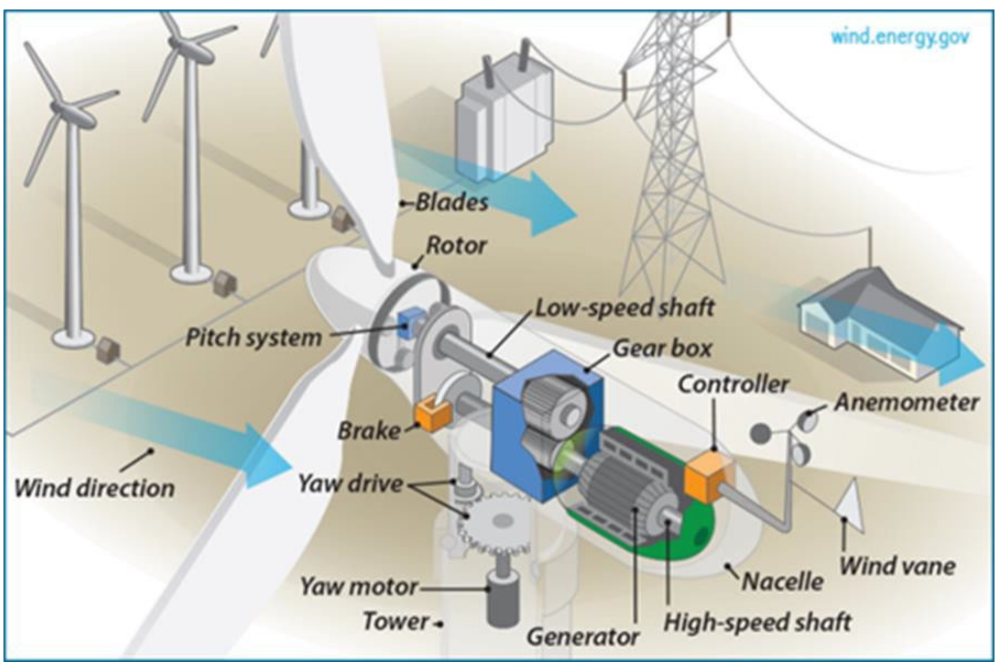
Wind power projects do not produce regulated environmental air emissions. While other environmental compliance requirements may apply, only air emissions were considered for this report. Therefore, the emissions of NO_X, SO_2, and CO_2 are 0.00 lb/MMBtu.

CASE 14. ONSHORE WIND, REPOWERING/RETROFIT, 150 MW NET

14.1. CASE DESCRIPTION

The onshore wind repower case is based on a total project capacity of 150 MW. The region is reflective of the Midwest/Great Plains area in the center of the United States, which has an abundance of wind turbines suitable for potential repower scenarios. Parameters that affect project cost and performance include turbine nameplate capacity, rotor diameter and hub height. The case configuration assumes a partial repower of wind turbines rated at 1.5 MW to wind turbines rated at 1.6 MW with 125-m rotor diameter and 90-m hub height. This will consist of the repowering of 94 wind turbine generators (WTGs) for a 150 MW capacity. These features reflect modern wind turbine repowers which employ larger rotor diameter. The primary advantage of larger rotor diameters is the increased turbine swept area, enabling the unit to capture more energy. Wind project repowering can be categorized as either a partial repowering or a full repowering. This case is assumed to be a partial repowering, which entails the replacement of certain high use WTG components with upgraded equipment while other components of the initial WTG are reused. The partial repower includes the replacement of blades, hub, nacelle components, main shaft, main bearing assembly, gearbox, and flex coupling.

Figure 14-1 — Wind Repower Component Layout



Source: Office of Energy Efficiency & Renewable Energy, Wind Energy Technologies Office – U.S. Department of Retrieved from Energy.gov, https://www.energy.gov/eere/wind/inside-wind-turbine (accessed May 31, 2019).

14.1.1. Mechanical Equipment and Systems

WTGs convert kinetic wind energy into electrical power. The most ubiquitous type of wind turbine utilized for electric power generation are those of the horizontal-axis three-bladed design. Lift is generated when wind flows around the turbine blades, resulting in rotation. The blades are connected to a central hub and drivetrain which turns a generator located inside of the nacelle, the housing positioned atop the wind turbine tower.

14.1.2. Electrical and Control Systems

Each WTG consists of a doubly fed induction generator. The low-voltage output from the generator is stepped up to medium voltage through a transformer located either in the nacelle or at the tower base. A medium-voltage collection system conveys the generated energy to an onsite substation, which further steps up the voltage for interconnection with the transmission system with a voltage of 230 kV.

A supervisory control and data acquisition (SCADA) system is provided for communications and control of the wind turbines and substation. The SCADA system allows the operations staff to remotely control and monitor each wind turbine and the wind farm as a whole.

14.1.3. Offsite Requirements

Wind farms harness power from wind and thus, require no fuel or fuel infrastructure. The offsite requirements are limited to construction of site and access roads to each wind turbine, operating and maintenance (O&M) building and electrical interconnection to the transmission system.

14.2. CAPITAL COST ESTIMATE

Table 14-1 summarizes the cost components for this case. The capital cost estimate is based on an engineering, procurement, and construction (EPC) contracting approach.

In addition to EPC contract costs, the capital cost estimate in Table 14-1 covers owner's costs. Owner's costs include owner's services which include project development, studies, permitting, legal, owner's project management, owner's engineering, owner's start-up and commissioning costs, project feasibility analyses, wind resource assessments, geotechnical studies, contracting for land access, transmission access, permitting, and electrical interconnection costs. The estimate is presented as an overnight cost in 2023 dollars and thus excludes allowance for funds used during construction or interest during construction. Leasing Costs are provided in the O&M.

Table 14-1 — Case 14 Capital Cost Estimate

Case 14 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Onshore Wind – Repower** 150 MW | 1.5-1.62 MW WTG
Hub Height (m)		90
Rotor Diameter (m)		125
	Units	
Plant Characteristics		
Net Plant Capacity	MW	150
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct and Indirect Costs	8%
EPC Contingency	% of EPC Costs	5%
Owner's Services	% of EPC Costs	10%
Owner's Contingency	% of Owner's Costs	5%
Electric Interconnection Costs		
Transmission Line Cost	$/mile	0
Miles	miles	0
Typical Project Timelines		
Development, Permitting, Engineering	months	12
Plant Construction Time	months	6
Total Lead Time Before Commercial Operation Date (COD)	months	18
Operating Life	years	20
EPC Cost Components (Notes 1)		
WTG Components -Turbine Kit and Blade Kit	$	136,323,000
Component Removal	$	4,928,000
Installation/Repowering	$	12,017,000
Mobilization/Demobilization	$	4,739,000
Indirect Costs	$	7,900,000
EPC Fee	$	13,273,000
EPC Contingency	$	8,959,000
EPC Subtotal	$	188,139,000
Owner's Cost Components (Notes 2)		
Owner's Services	$	18,814,000
Owner's Contingency	$	941,000
Owner's Costs Subtotal	$	19,755,000
Total Capital Cost	**$**	**207,894,000**
	$/kW net	**1,386**
Capital Cost Notes		
1. Costs based on EPC contracting approach. This is an estimate of a repower replacing the blades, hub, nacelle, main shaft, main bearing assembly, gearbox, and flex coupling. WTG component costs consist of 1.62 MW components to replace 1.5 MW WTGs. Indirect costs include distributable material and labor		

Case 14 EIA – Capital Cost Estimates – 2023 $ USD	
Configuration	**Onshore Wind – Repower** 150 MW | 1.5-1.62 MW WTG
Hub Height (m)	90
Rotor Diameter (m)	125
	Units

costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. Component removal costs include dismantling of WTG, loading to vehicles, grounding checks, and (gearbox) oil disposal. Installation/Repowering costs include road work, civil work, and WTG installation.

2. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Owner's contingency is applied to owner's services costs only. Interconnection costs are not included as existing interconnection equipment is assumed to be reused for the repowered facility.

14.3. OPERATIONS AND MAINTENANCE COST ESTIMATE

O&M cost estimates reflect a full-service agreement arrangement, under which an O&M contractor provides labor, management, and parts replacement (including unscheduled parts replacement) for the WTGs, collection system, and substation. Our cost estimates exclude site specific owner's costs such as property taxes and insurance. Table 14-2 summarizes the average annual O&M expenses projected for an assumed additional 20-year project life.

Table 14-2 — Case 14 O&M Cost Estimate

Case 14 EIA – Non-Fuel O&M Costs – 2023 $ USD		
Onshore Wind – Large Plant Footprint: Great Plains Region		
Fixed O&M – Plant (Note 1)	**Units**	**Value**
WTG Scheduled Maintenance	$/year	1,808,000
WTG Unscheduled Maintenance	$/year	2,260,000
Balance of Plant Maintenance	$/year	452,000
Leasing Costs	$/year	1,262,000
Subtotal Fixed O&M	$/year	5,782,000
$/kW-year	$/kW-year	**38.55 $/kW-year**
Variable O&M (Note 2)	$/MWh	**0.00 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and general and administrative (G&A) costs. 2. O&M costs estimates reflect the Full Service Agreement and exclude site-specific owner's costs, such as royalties, property taxes, and insurance. 3. Average FSA term considered: 20 years		

14.4. ENVIRONMENTAL AND EMISSIONS INFORMATION

Wind power projects do not produce regulated environmental air emissions. While other environmental compliance requirements may apply, only air emissions were considered for this report. Therefore, the emissions of NO_X, SO_2, and CO_2 are 0.00 lb/MMBtu.

CASE 15. OFFSHORE WIND: FIXED-BOTTOM MONOPILE FOUNDATIONS, 900 MW NET

15.1. CASE DESCRIPTION

The offshore wind project is based on a total project capacity of 900 MW. Parameters that affect project cost and performance include project size, turbine nameplate capacity, water depth and distance to shore. The case configuration assumes wind turbines rated at 15 MW each, located 30 miles offshore in waters with a depth of 100 feet. An onshore cable run of 5 miles is also assumed.

For the purposes of this study, it has been assumed that wind turbines installed employ fixed-type foundation structures. Generally, these are installed in relatively shallow waters, not exceeding 150 feet, consistent with our assumption. Water depth and distance to shore has a significant impact on the cost of fixed foundation structure due to the expenses being related to cable lengths and installation costs.

15.1.1. Mechanical Equipment and Systems

Wind turbine generators (WTGs) convert kinetic wind energy into electrical power. The most ubiquitous type of wind turbine utilized for electric power generation are those of the horizontal-axis three-bladed design. Lift is generated when wind flows around the turbine blades, resulting in rotation. The blades are connected to a central hub and drivetrain which turns a generator located inside of the nacelle, the housing positioned atop the wind turbine tower.

15.1.2 Electrical and Control Systems

Each wind turbine consists of a doubly fed induction generator with high-speed electrical slip rings, which produces electricity from the rotational energy of wind. The converter converts DC to AC. The power collection system collects energy from all the wind turbines and increases the voltage to 66 kV through a dedicated transformer at the WTG. The electricity is transmitted via array cables, buried in the sea floor to the offshore substation, where the voltage is increased to 138kV. It is then transmitted to an onshore substation via export cables. The power from this substation is supplied for interconnection with the transmission system.

A supervisory control and data acquisition (SCADA) system is provided for communications and control of the wind turbines and substation. The SCADA system allows the operations staff to remotely control and monitor each wind turbine and the wind farm as a whole.

15.1.3 Offsite Requirements

Since wind is a clean source of energy, the offsite requirements are very limited. These include construction of offshore-to-shore submarine cables, port infrastructures, installation vessels (construction and cable laying) and electrical interconnection to the transmission system.

15.2. CAPITAL COST ESTIMATE

Table 15-1 summarizes the cost components for this case. The capital cost estimate is based on an engineering, procurement, and construction (EPC) contracting approach.

In addition to EPC contract costs, the capital cost estimate in Table 15-1 covers owner's costs. Owner's costs include owner's services which include project development, studies, permitting, legal, owner's project management, owner's engineering, owner's start-up and commissioning costs, project feasibility analyses, wind resource assessments, geotechnical studies, contracting for land access, transmission access, permitting, and electrical interconnection costs. The estimate is presented as an overnight cost in 2023 dollars and thus excludes allowance for funds used during construction or interest during construction. Leasing Costs are provided in the operating and maintenance (O&M).

Table 15-1 — Case 15 Capital Cost Estimate

Case 15 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Offshore Wind: Fixed-Bottom Monopile Foundations** 900 MW | 15 MW WTG
Offshore Cable Length (mi)		30
Onshore Cable Length (mi)		5
Water Depth (ft)		100
Plant Characteristics		
Net Plant Capacity	MW	900
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct and Indirect Costs	10%
EPC Contingency	% of EPC Costs	6%
Owner's Services	% of EPC Costs	10%
Owner's Contingency	% of Owner's Costs	7%
Typical Project Timelines		
Development, Permitting, Engineering	months	24
Plant Construction Time	months	12
Total Lead Time Before Commercial Operation Date (COD)	months	36
Operating Life	years	25
EPC Cost Components (Note 1-2)		

Case 15 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Offshore Wind: Fixed-Bottom Monopile Foundations** 900 MW | 15 MW WTG
Offshore Cable Length (mi)		30
Onshore Cable Length (mi)		5
Water Depth (ft)		100
WTG Procurement and Supply	$	1,172,322,000
WTG Fabrication/Assembly/Installation	$	688,635,000
Electrical Interconnection	$	385,623,000
Onshore Transmission	$	49,832,000
Offshore Transmission and Electrical Balance of Plant (BOP)	$	152,010,000
Indirect Costs	$	123,678,000
EPC Fee	$	257,210,000
EPC Contingency	$	169,759,000
EPC Subtotal	$	2,999,069,000
Owner's Cost Components (Note 3)	$	
Owner's Services	$	299,907,000
Owner's Contingency	$	20,993,000
Owner's Costs Subtotal	$	320,900,000
Total Capital Cost	**$**	**3,319,969,000**
	$/kW net	**3,689**
Capital Cost Notes		
1. Costs based on EPC contracting approach. WTG assembly and installation costs include port staging, WTG and offshore substation foundations, and installation costs of WTGs. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, startup and commissioning, and contractor overhead. EPC fees are applied to the sum of direct and indirect costs. 2. Interconnection costs include interconnection surveys, application fees, and construction materials/contracting costs with the necessary equipment. Onshore/Offshore transmission costs include onshore/offshore substation costs and transmission line costs. 3. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs include electrical interconnection costs.		

15.3. OPERATIONS AND MAINTENANCE COST ESTIMATE

Operating expenditures cover all maintenance expenses during operations, including leasing, management, labor, equipment and vessel rentals, parts, and consumables for both scheduled and unscheduled maintenance of the WTGs and balance of plant systems, as well as operations monitoring. Table 15-2 summarizes the average annual O&M expenses projected for an assumed 25-year project life.

Table 15-2 — Case 15 O&M Cost Estimate

Case 15 EIA – Non-Fuel O&M Costs – 2023 $ USD		
Fixed-bottom Offshore Wind: Monopile Foundations		
Fixed O&M – Plant (Notes 1-2)	**Units**	**Value**
Maintenance Costs	$/year	109,800,000
Leasing Costs	$/year	28,800,000
Subtotal Fixed O&M	$/year	138,600,000
$/kW-year	$/kW-year	**154.00 $/kW-year**
Variable O&M	$/MWh	0.00 $/MWh
O&M Notes		
1. Leasing numbers are based on projects on the east coast (New York, North Carolina, and South Carolina). Leasing will fluctuate based on location.		
2. Fixed O&M costs include labor, materials, and contracted services.		

15.4. ENVIRONMENTAL AND EMISSIONS INFORMATION

Wind power projects do not produce regulated environmental air emissions. While other environmental compliance requirements may apply, only air emissions were considered for this report. Therefore, the emissions of NO_X, SO_2, and CO_2 are 0.00 lb/MMBtu.

CASE 16. SOLAR PHOTOVOLTAIC WITH SINGLE AXIS TRACKING, 150 MWAC

16.1. CASE DESCRIPTION

This case is a nominal 150 MW_{AC} solar photovoltaic (PV) facility with single-axis tracking. While continued advances in technical efficiency have resulted in lower module prices over the past decade, solar PV costs have increased somewhat relative to 2019 pricing. This case uses 195 MW_{DC} of monocrystalline passive emitter and rear contact (PERC) bifacial modules connected in 1500-V strings with independent single-axis tracker rows that are placed in a north-south orientation with east-west tracking. The case also uses 150 MW_{AC} of central power conversion stations (inverters with integrated medium-voltage transformers), resulting in a DC/AC ratio of 1.3 at the inverter. Solar PV projects are relatively simple since there is no fuel or waste and limited moving parts; however, single-axis tracking systems require considerable land commitments due to a low ground coverage ratio intended to limit self-shading as well as create room for both tracking rotation and easy access for maintenance purposes. Many tracking companies offer advanced backtracking software that help to optimize yield and ground coverage ratio, though this was not considered in this estimate.

Figure 16-1 — Solar PV Project

Bifacial PV panels (left) and tracking systems (right).

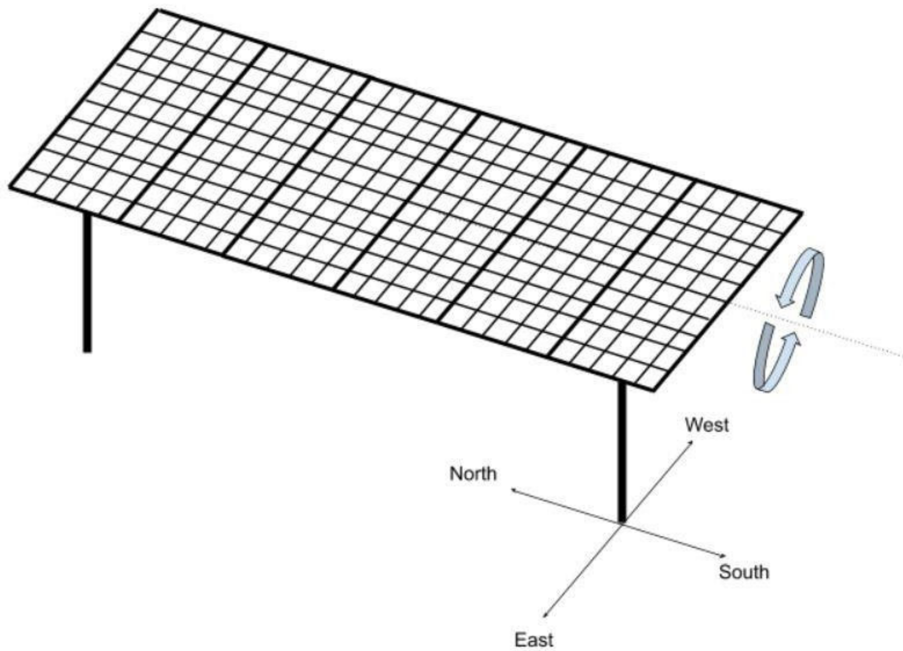
Source: Sargent & Lundy project site photo archive.

16.1.1. Mechanical Equipment and Systems

Solar PV systems convert sunlight into electrical power. Solar PV modules convert incident solar radiation into a potential difference within individual solar cells that produces DC electricity. The solar PV facility assumed for this study is comprised of 390,000 individual 500-watt, 1500-V monocrystalline solar modules with PERC architecture for increased efficiency. These modules are connected in series to each other in strings. The exact number of modules in each string varies across the United States depending on site specific conditions and module characteristics but typically range from 26 up to 32 modules per string. The strings connect to each other in parallel to form large solar arrays, which make up the bulk of the facility. Arrays are often grouped together into distinct blocks throughout the plant with each block having a single designated inverter pad. Mechanical components of these arrays include the racking and solar tracking equipment. This estimate assumes the racking uses a driven pile foundation; however, depending on the site's geotechnical characteristics, ground screws and concrete foundations can also be used.

The tracking system's exact mechanics depend on the manufacturer. This system, and nearly all single-axis tracking systems currently being manufactured, use a north-south oriented tracking axis that is horizontally parallel with respect to the ground. This orientation allows the panels to track the sun as it crosses the sky from east to west. One variation in tracking mechanics that can impact the overall cost is linked versus unlinked row tracking. Linked row tracking connects multiple rows to a single tracker mechanism, thereby requiring them all to rotate at the same angle throughout the day but significantly reducing the number of tracker motors that need to be procured for the system. Unlinked row tracking allows individual rows to track the sun at different angles but require a solar tracker mechanism on each row. This case assumes an unlinked single-axis tracker technology.

Figure 16-2 — Single-Axis Tracking



16.1.2. Electrical and Control Systems

Each block within a PV is typically made up of identical components and functionality. Electrical components include:

- DC and AC wiring
- Combiner boxes
- Inverters
- Step-up transformers
- Control system
- Switchyard with electrical interconnection to the grid

As previously explained, modules are combined in series to form series strings. These strings are combined in parallel to form solar arrays. Arrays are then connected via combiner boxes to combine the current from each string of each array before feeding the DC power into an inverter. The number of arrays combined into each combiner box is dependent on the site layout, the current of each string, and the size of the combiner box. This estimate assumes one combiner box for every thirty strings. After DC cables from the combiner boxes are fed into the inverter, the inverter then converts the DC electricity from the combiner boxes into AC electricity. Inverters are generally grouped into two different categories defined by their capacity with smaller inverters that are spread around the array being referred to as string inverters and larger inverters skidded at select central locations in the facility are referred to as central inverters. Central inverters currently used in new projects are typically rated between 1,500 kW and 4000 kW. This system uses one 2500-kW central inverter with one integrated 2.5 MVA medium-voltage transformer within each PV block. Inverters that are skidded with a medium-voltage transformer (either via internal or external integration) are referred to as power conversion stations and are typically sold as a cohesive unit from the inverter manufacturer.

A solar facility's nominal capacity is typically defined by either the net AC capacity of the inverters across all blocks or the maximum allowable injection capacity into the electric grid as defined by the project's interconnection agreement. In general, there will always be more installed DC capacity from the modules than AC capacity from the inverters. The ratio of DC to AC capacity (DC/AC ratio) is typically between 1.2 and 1.4; however, some projects increase the DC/AC ratio with the intention of harnessing the DC power that is clipped by the inverter's maximum capacity into battery storage energy. On the other side of the spectrum, some projects will decrease the DC/AC ratio to allow for additional reactive compensation. This estimate assumes a DC/AC ratio of 1.3.

16.1.3. Offsite Requirements

Solar PV facilities require no fuel and produce no waste. The offsite requirements are limited to an interconnection between the PV facility and the transmission system. In the event the facility plans to have the modules cleaned, offsite requirements will also include water for the purpose of cleaning the solar modules. Water is not always a requirement because the necessity of cleaning is regionally dependent. In regions with significant rainfall and limited dust accumulation, cleaning is often unnecessary because it occurs naturally. In dust heavy and dry regions (which often have higher solar irradiance), cleaning occurs proportionally to the dust accumulation from once or twice a year up to bi-monthly and typically uses offsite water that is brought in on trucks. This analysis assumes one cleaning per year.

16.2. CAPITAL COST ESTIMATE

Table 16-1 summarizes the cost components for this case. Solar prices have been increasing due to rising commodity pricing, delivery and manufacturing costs, and labor costs. As the solar PV industry has been subject to volatile pricing, labor challenges, and being restricted to difficult land, the engineering, procurement, and construction (EPC) contractors and developers have also been bearing more contingency and overhead, further increasing a solar project's overall cost.

Despite these cost increases, advancements in solar PV technology and construction continue to provide downward pressure on the $/kW cost. As solar modeling and engineering software advances, projects are able to optimize layouts and ground coverage for the lowest levelized cost of energy; however, in recent years, this only serves to limit the cost increases rather than to cause a material decrease in total project costs. Solar modules that are arriving on the market are rated to have a net string potential of 1500 V rather than the previous 1000 V string that was common in the early and mid-2010s. This increased net potential allows for lower wiring losses, which increases the net energy yield and lowers wiring material costs in the electrical balance-of-plant.

Table 16-1 — Case 16 Capital Cost Estimate

Case 16 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Solar PV with Single-Axis Tracking** 150 MW AC
DC / AC Ratio		1.3
Module Type		Bifacial Monocrystalline
	Units	
Plant Characteristics		
Net Plant Capacity	MW_AC	150
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct and Indirect Costs	5%
EPC Contingency	% of EPC Costs	5%
Owner's Services	% of EPC Costs	5%
Owner's Contingency	% of Owner's Costs	10%
Estimated Land Requirement (Note 1)	acres	1000
Interconnection Costs		
Electrical Transmission Interconnection Costs		
Transmission Line Cost	$/mile	2,412,000
Miles	miles	1.00
Typical Project Timelines		
Development, Permitting, Engineering	months	24
Plant Construction Time	months	12
Total Lead Time Before Commercial Operation Date (COD)	months	36
Operating Life	years	35
EPC Cost Components (Note 2)		
Module Supply	$	72,150,000
Inverter Supply	$	10,395,000
Racking, Tracker and Balance-of-Plant (BOP) Equipment Supply	$	44,850,000
Main Power Transformer and Substation	$	10,500,000
Construction / Installation Labor	$	26,325,000
Supervisory, Control, and Data Acquisition Subcontract	$	915,000
Civil/Structural/Architectural Subcontract	$	13,650,000
Indirect Costs	$	12,675,000
EPC Contracting Fee	$	9,573,000

Case 16 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Solar PV with Single-Axis Tracking** 150 MW AC
DC / AC Ratio		1.3
Module Type		Bifacial Monocrystalline
	Units	
EPC Contingency	$	10,052,000
EPC Subtotal	$	211,085,000
Owner's Cost Components (Note 3)		
Owner's Services	$	10,554,000
Electrical Interconnection	$	2,412,000
Owner's Contingency	$	1,297,000
Owner's Costs Subtotal	$	14,263,000
Total Capital Cost	**$**	**225,348,000**
	$/kW net	**1,502**

Capital Cost Notes

1. Land for this resource type is typically leased and not purchased. Minor costs for land acquisition and lease during development and construction period is included in the owner's services costs. Annual lease costs are also accounted for in the fixed operating and maintenance (O&M).
2. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, start-up and commissioning, contractor overhead, freight, and duties/sales taxes. EPC fees are applied to the sum of direct and indirect costs.
3. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's start-up and commissioning costs. Other owner's costs include electrical interconnection costs.

16.3. OPERATIONS AND MAINTENANCE COST ESTIMATE

Operations and maintenance costs associated with 150-MW_{AC}, single-axis tracking solar PV project have increased slightly overall with a range of specific factors increasing and decreasing individually. There are five main factors to solar PV O&M: preventative maintenance, unscheduled maintenance, module cleaning, inverter maintenance reserve, and the land lease. As technological reliability increases and designs become more focused on decreasing O&M costs, preventative maintenance gets less costly and unscheduled maintenance occurs less frequently. Examples of O&M-focused designs are DC harnesses for optimal wiring configurations, wireless communication and control systems, and central inverter locations for ease of access. These increases in design and reliability savings are more than offset by the increases in equipment and maintenance labor costs leading to an overall increase in both preventative and unscheduled maintenance. Similarly, the inverter maintenance reserve is another factor that increased overall in cost but is subject to competing impacts between higher inverter pricing but increasing inverter reliability that drives the reserve down.

Module cleaning is the only cost component that decreased overall. Cleaning is typically less expensive for PV fields with trackers using independent rows because a single truck can clean two rows at a time instead of one. New coatings and design of PV modules have also resulted in slight decreases in the amount of "typical" module cleanings in the United States from two on average down to one. The final annual expense is the land lease. Solar PV projects typically rent, rather than purchase, the land for the project; therefore, it is an operating expense and not a capital cost. As the increased demand for solar PV projects continues throughout the country, there has been a material drop in ideal sites that are available and PV developers have been forced to locate facilities on more expensive and unideal land. Additionally, landowners have become more aware of the economic value of these facilities and have begun to charge more for leasing their land.

Table 16-2 — Case 16 O&M Cost Estimate

Case 16 EIA – Non-Fuel O&M Costs – 2023 $ USD		
Solar PV with Single-Axis Tracking		
Fixed O&M – Plant (Note 1)	**Units**	**Value**
Preventative Maintenance	$/year	1,500,000
Module Cleaning (Note 2)	$/year	136,000
Unscheduled Maintenance	$/year	225,000
Inverter Maintenance Reserve	$/year	374,000
Land Lease (Note 3)	$/year	800,000
Subtotal Fixed O&M	$/year	3,035,000
$/kW-year	$/kW-year	**20.23 $/kW-yr**
Variable O&M	$/MWh	**0.00 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and general and administrative (G&A) costs. O&M costs exclude property taxes and insurance. 2. Assume one module cleaning per year. 3. Land for solar PV projects is typically leased rather than owned, this is considered to be a representative annual expense but varies across projects.		

16.4. ENVIRONMENTAL AND EMISSIONS INFORMATION

Solar PV does not produce regulated environmental air emissions. While other environmental compliance requirements may apply, only air emissions were considered for this report. Therefore, the emissions of NO_X, SO_2, and CO_2 are 0.00 lb/MMBtu.

CASE 17. SOLAR PHOTOVOLTAIC WITH SINGLE AXIS TRACKING, AC-COUPLED BATTERY ENERGY STORAGE, 150 MWAC | 200 MWH

17.1. CASE DESCRIPTION

This case is based on a nominal 150 MW_{AC} solar photovoltaic (PV) plant with 200 MWh of lithium-ion battery storage that is AC-coupled. Solar PV has increasingly been coupled with battery storage in recent years due to price reductions in lithium-ion batteries. The AC-coupling architecture refers to a design in which the PV and battery components are coupled on AC side (grid side) of the inverter. The AC-coupled system assumes a DC/AC ratio of 1.4, resulting in a DC size of 210 MW. AC-coupled systems are typically built at a higher DC/AC ratio than standalone PV to maximize the amount of available energy to charge the battery energy storage system (BESS) without sacrificing PV output while the BESS is charging or idle. The factors driving cost increases of solar PV projects are shared with systems coupled with battery storage. Cost increases are partially offset by modeling technology used to optimize design and reduce civil costs per kW, higher power modules, lower priced inverters, and lower risk. Batteries can be either AC- or DC-coupled to the solar array. AC-coupled systems have a simpler architecture that is easier to install and can be retrofit to an existing solar plant with the batteries interconnected directly at the substation. AC-coupled systems offer higher efficiency when used in power AC applications, but they also have slightly lower efficiencies when charging the battery. The most common application for AC-coupled systems is peak shaving, or energy arbitrage, where there is a limit on the power allowed into the grid and the peak of the solar generation is stored in a battery to be sold during the highest demand peaks for optimal profit.

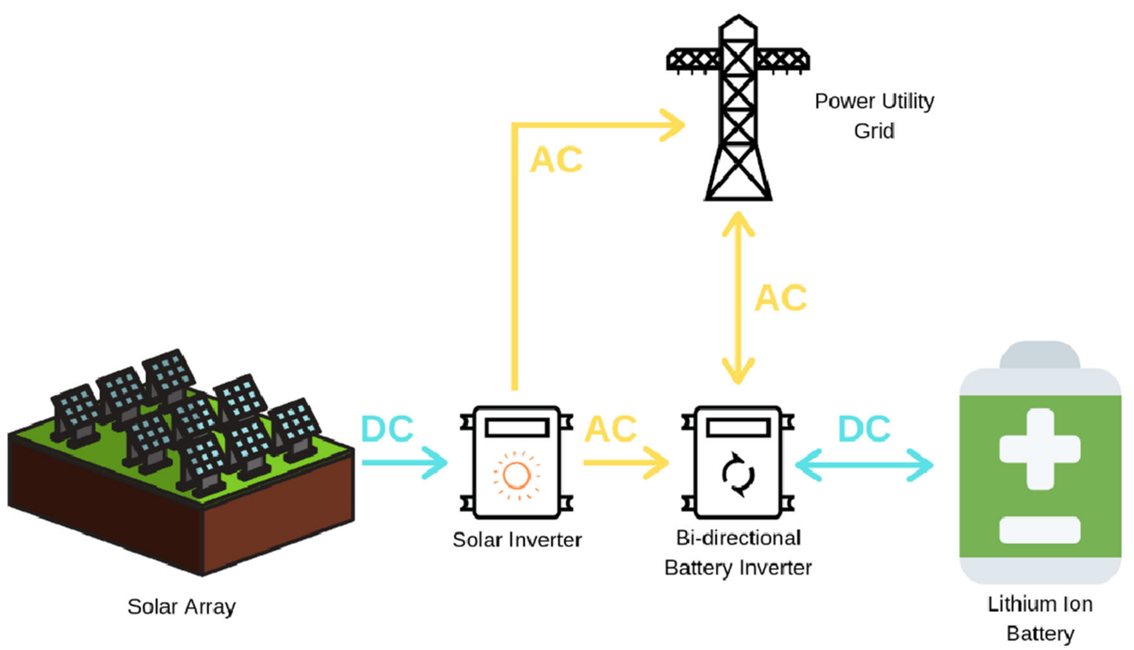
17.1.1. Mechanical Equipment and Systems

This case assumes a nominal 150 MW_{AC} solar PV plant with 200 MWh of lithium-ion battery storage. Batteries are typically sized by their output in kWh and not by their capacity in MW, which is defined by the AC capacity of the battery's inverters. The 200 MWh battery system in this estimate is comprised of four hours of 50 MW output. The mechanical equipment for the solar portion is the same as a stand-alone solar PV facility: 500-watt 1500-V monocrystalline modules, ground mounted racking with driven pile foundations, and independent single-axis tracking equipment. The mechanical equipment associated with the battery storage is the batteries themselves, the containers they are placed in, the fire suppression system, and the concrete foundations for the battery containers. This estimate assumes the use of 80 containers, each 40 feet in length and containing 2.5 MWh of battery storage. Smaller 20-foot containers are sometimes used depending on constraints with site availability and project size. Containers are often provided with unpopulated racks to allow for periodic additions of more batteries ("augmentation") to compensate for energy capacity lost to battery degradation. Alternatively, battery augmentation may be performed by adding entirely new battery containers to vacant footprints on a project site.

17.1.2. Electrical and Control Systems

When incorporating AC-coupled battery storage into a solar PV site, there is no change in the electrical components of the solar array and solar inverters. The solar modules are connected in series with DC wiring into solar strings. The solar strings are connected in parallel to combiner boxes that output the current into the solar inverters. The output of the solar inverter then enters a switchgear that feeds the AC current into either the grid or the battery inverter. It is also important to note that battery storage inverters are different from solar inverters in that they are typically bi-directional inverters that can alternate between inverting AC to DC and inverting DC to AC. Battery storage inverters also allow the batteries to be charged by either the solar array or the grid. This facility uses 150 MW of solar inverters plus 50 MW of battery inverters. Battery inverters are typically more expensive than solar inverters.

Figure 17-1 — AC-Coupled Solar PV and Battery Storage



Adapted from Clean Energy Reviews, https://www.cleanenergyreviews.info/blog/ac-coupling-vs-dc-coupling-solar-battery-storage (accessed June 12, 2019).

Whether power is being used from the battery storage or the solar array, it passes through a switchyard that contains the circuit breaker, step-up transformer, and electrical interconnection with the grid. A supervisory control and data acquisition (SCADA) system is provided for communications and control of the inverters and substation. The SCADA system allows the operations staff to remotely control and monitor the solar PV farm as a whole.

17.1.3. Offsite Requirements

Solar PV and battery storage facilities require no fuel and produce no waste. The offsite requirements are limited to an interconnection between the facility and the transmission system as well as water for the purpose of cleaning the solar modules—if applicable since cleaning is regionally dependent. In regions with significant rainfall and limited dust accumulation, cleaning is often unnecessary and occurs naturally. In dust heavy and dry regions, cleaning typically occurs once or twice a year and uses offsite water that is brought in on trucks. This analysis assumes two cleanings per year.

17.2. CAPITAL COST ESTIMATE

Table 17-1 summarizes the cost components for this case. It should be noted that the DC/AC ratio for this paired technology is higher than that of a standalone PV system. This requires more panels, racking, etc., so the cost for these components will be higher than those of a standalone PV system with the same net AC output. Solar prices have been increasing due to rising commodity pricing, delivery and manufacturing costs, and labor costs. Facing volatile pricing, labor challenges, and being restricted to difficult land, EPC contractors and developers have also been bearing more contingency and overhead, further increasing the solar portion of the project's overall price. The battery cost estimate also increased relative to the 2019 pricing due to inflation and the inclusion of substation costs.

Table 17-1 — Case 17 Capital Cost Estimate

Case 17 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Solar PV with Single-Axis Tracking and Battery Storage**
Battery Configuration		AC Coupled
DC / AC Ratio		1.4
Module Type		Bifacial Monocrystalline
Battery Type		Lithium Ion
	Units	
Plant Characteristics		
Net Solar Capacity	MW_AC	150
Net Battery Capacity	MW_AC	50
Battery Duration	hour	4
Capital Cost Assumptions		

Case 17 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Solar PV with Single-Axis Tracking and Battery Storage**
Battery Configuration		AC Coupled
DC / AC Ratio		1.4
Module Type		Bifacial Monocrystalline
Battery Type		Lithium Ion
	Units	
EPC Contracting Fee	% of Direct and Indirect Costs	5%
EPC Contingency	% of Project Costs	5%
Owner's Services	% of Project Costs	5%
Owner's Contingency	% of Project Costs	10%
Estimated Land Requirement (Note 1)	acres	1150
Interconnection Costs		
Electrical Transmission Interconnection Costs		
Transmission Line Cost	$/mile	2,412,000
Miles	miles	1.00
Typical Project Timelines		
Development, Permitting, Engineering	months	24
Plant Construction Time	months	12
Total Lead Time Before Commercial Operation Date (COD)	months	36
Operating Life	years	35-Year PV; 20-Year BESS
EPC Cost Components (Note 2)		
PV Module Supply	$	77,700,000
PV Inverter Supply	$	10,395,000
PV Racking, Tracker and Balance-of-Plant (BOP) Equipment Supply	$	48,300,000
BESS Container Supply	$	50,560,000
BESS BOP Equipment Supply (Note 3)	$	12,280,000
Main Power Transformer and Substation	$	10,500,000
PV Construction / Installation Labor	$	28,350,000
BESS Construction / Installation Labor	$	2,900,000
SCADA Subcontract	$	915,000
Civil/Structural/Architectural Subcontract	$	14,700,000
Indirect Costs	$	21,650,000
EPC Contracting Fee	$	13,913,000
EPC Contingency	$	14,608,000
EPC Subtotal	$	306,771,000

Case 17 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Solar PV with Single-Axis Tracking and Battery Storage**
Battery Configuration		AC Coupled
DC / AC Ratio		1.4
Module Type		Bifacial Monocrystalline
Battery Type		Lithium Ion
	Units	
Owner's Cost Components (Note 4)		
Owner's Services	$	15,339,000
Electrical Interconnection	$	2,412,000
Owner's Contingency	$	1,775,000
Owner's Cost Subtotal	$	19,526,000
Total Capital Cost	**$**	**326,297,000**
	$/kW net	**2,175**
Capital Cost Notes		

1. Land for this resource type is typically leased and not purchased. Minor costs for land acquisition and lease during development and construction period is included in the owner's services costs. Annual lease costs are also accounted for in the fixed operating and maintenance (O&M).
2. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, start-up and commissioning, contractor overhead, freight, and duties/sales taxes. EPC fees are applied to the sum of direct and indirect costs.
3. BESS BOP equipment supply is inclusive of all equipment and materials except for BESS units to provide medium-voltage feeders to the substation. Including but not limited to auxiliary power equipment and transfer switches; inverters; medium-voltage transformers; cabling and conduit; equipment foundations; and supervisory control and data acquisition (SCADA).
4. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's start-up and commissioning costs. Other owner's costs include electrical interconnection costs.

17.3. OPERATIONS AND MAINTENANCE COST ESTIMATE

For this case, Sargent & Lundy grouped the O&M costs into the following categories: preventative maintenance, unscheduled maintenance, module cleaning, inverter maintenance reserve, battery augmentation, and the land lease. Descriptions of all the factors except the battery augmentation can be found in Section 16.3. The typical lifetime of a battery is 7300 cycles, which yields a lifetime of roughly 20 years (based on approximately one cycle per day). Sargent & Lundy assumes periodic augmentation to compensate for energy capacity lost to battery degradation for the first 20 years. More extensive decommissioning of the original BESS equipment and rebuilding with entirely new batteries, may be necessary in order to have storage of PV generation for the 35-year expected life of the PV technology.

Sargent & Lundy has modeled only augmentation through year 20, not any decommissioning or extensive rebuild afterwards.

Table 17-2 — Case 17 O&M Cost Estimate

Case 17 EIA – Non-Fuel O&M Costs – 2023 $ USD		
Solar PV with Single-Axis Tracking and Battery Storage		
Fixed O&M – Plant (Note 1)	**Units**	**Value**
Preventative Maintenance	$/year	2,700,000
Module Cleaning (Note 2)	$/year	146,000
Unscheduled Maintenance	$/year	525,000
Inverter Maintenance Reserve	$/year	374,000
Battery Augmentation	$/year	1,200,000
Land Lease (Note 3)	$/year	814,200
Subtotal Fixed O&M	$/year	5,759,200
$/kW-year	$/kW-year	**38.39 $/kW-year**
Variable O&M	$/MWh	**0.00 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and general and administrative (G&A) costs. O&M costs exclude property taxes and insurance.		
2. Assume two module cleanings per year.		
3. Solar PV projects typically rent land rather than purchase it, this is considered to be a representative annual expense but varies across projects.		

17.4. ENVIRONMENTAL AND EMISSIONS INFORMATION

Neither solar PV nor battery storage produce regulated environmental air emissions. While other environmental compliance requirements may apply, only air emissions were considered for this report. Therefore, the emissions of NO_X, SO_2, and CO_2 are 0.00 lb/MMBtu.

CASE 18. SOLAR PHOTOVOLTAIC WITH SINGLE AXIS TRACKING, DC-COUPLED BATTERY ENERGY STORAGE, 150 MWAC | 200 MWH

18.1. CASE DESCRIPTION

This case is based on a nominal 150 MW_{AC} solar photovoltaic (PV) plant with 200 MWh of lithium-ion battery storage that is DC-coupled. The DC-coupling architecture refers to a design in which the PV and battery components are coupled on DC side (plant side) of the inverter. The DC-coupled system assumes a DC/AC ratio of 1.6, resulting in a DC size of 240 MW. DC-coupled systems often have the highest DC/AC ratio because unlike most systems that experience increased clipping losses as the DC/AC ratio increases, DC-coupled systems can capture energy that would have otherwise been clipped and use it to charge the battery energy storage system (BESS). DC-coupled systems require no inversion of solar electricity from DC to AC and back again before the electricity is stored in the battery and can thus achieve higher BESS roundtrip efficiency than AC-coupled systems. But DC-coupled systems also have a more complex arrangement and control architecture, are more difficult to install and retrofit with an existing solar system, and require additional equipment such as DC to DC converters. DC-coupled systems may be used for the same applications as AC-coupled systems such as peak shaving, or energy arbitrage, but they tend to be more costly to install than AC-coupled designs and are less common in the industry.

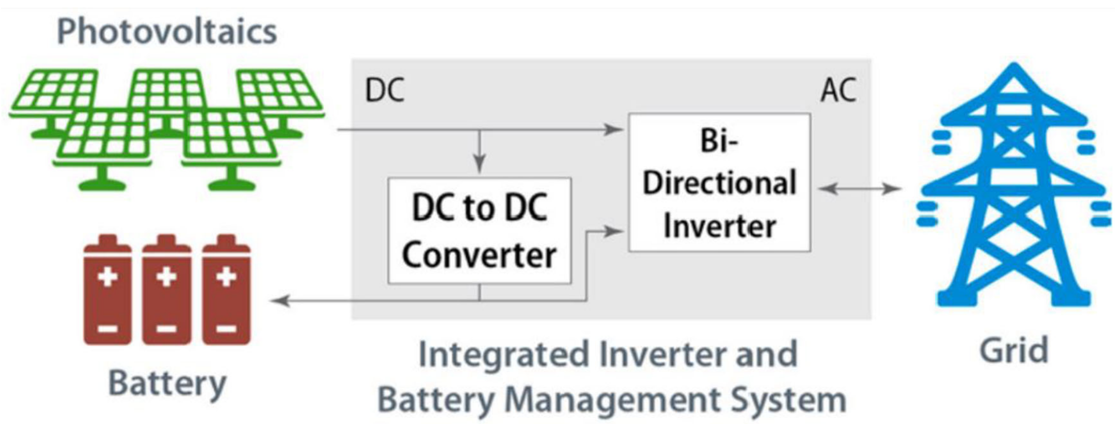
18.1.1. Mechanical Equipment and Systems

This case assumes a nominal 150 MW_{AC} solar PV plant with 200 MWh of lithium-ion battery storage. Batteries are typically sized by their output in kWh and not by their capacity in MW, which is defined by the AC capacity of the battery's inverters. The 200 MWh battery system in this estimate is comprised of four hours of 50 MW output. The mechanical equipment for the solar portion is the same as a stand-alone solar PV facility: 500-watt 1500-V monocrystalline modules, ground mounted racking with driven pile foundations, and independent single-axis tracking equipment. The mechanical equipment associated with the battery storage is the batteries themselves, the containers they are placed in, the fire suppression system, and the concrete foundations for the battery containers. This estimate assumes the use of 80 containers, each 40 feet in length and containing 2.5 MWh of battery storage. Smaller 20-foot containers are sometimes used depending on constraints with site availability and project size. Containers are often provided with unpopulated racks to allow for periodic battery augmentations to compensate for energy capacity lost to battery degradation. Alternatively, battery augmentation may be performed by adding entirely new battery containers to vacant footprints on a project site. For DC-coupled PV and BESS facilities, the former augmentation strategy (using spare racks in original containers) has historically been preferred to allow for more gradual augmentations at the distributed BESS locations on the site; but many modern suppliers offer stand-alone modular options in smaller kWh increments to serve the same purpose.

18.1.2. Electrical and Control Systems

In a DC-coupled system, the PV and battery components share the same bidirectional inverters, and energy used to charge the battery passes through a DC-to-DC converter. In such an architecture, the hardware and controls allow charging the battery from the grid or directly from the PV without conversion to AC. In this case, excess PV generation that exceeds the inverter capacity limit and would normally be clipped by the inverter is instead used to charge the batteries. Like most PV arrangements, the PV modules are connected in series with DC wiring to form strings which are in turn connected in parallel at combiner boxes. In the DC-coupled architecture, the DC output from the PV combiner boxes may be sent through the DC/AC inverters to the grid or directly to the BESS through the DC-to-DC converters. This facility uses 150 MW of bidirectional inverters which covers both the PV and BESS capacities. Bidirectional inverters (sometimes referred to as battery inverters) are typically more expensive than solar inverters.

Figure 18-1 — DC-Coupled Solar PV and Battery Storage



NREL
Source: (https://www.nrel.gov/docs/fy21osti/77917.pdf)

Whether power is being used from the battery storage or the solar array, it passes through a switchyard that contains the circuit breaker, step-up transformer, and electrical interconnection with the grid.

18.1.3. Offsite Requirements

Solar PV and battery storage facilities require no fuel and produce no waste. The offsite requirements are limited to an interconnection between the facility and the transmission system as well as water for the purpose of cleaning the solar modules. Cleaning is regionally dependent. In regions with significant rainfall and limited dust accumulation, cleaning is often unnecessary and occurs naturally. In dust heavy and dry regions, cleaning typically occurs once or twice a year and uses offsite water that is brought in on trucks. This analysis assumes two cleanings per year.

18.2. CAPITAL COST ESTIMATE

Table 18-1 summarizes the cost components for this case. It should be noted that the DC/AC ratio for this paired technology is higher than that of the AC-coupled and standalone PV systems. This requires more panels, racking, etc., so the cost for these components will be higher than those of the AC-coupled and standalone PV cases with the same net AC capacity ratings. Facing volatile pricing, labor challenges, and being restricted to difficult land, EPC contractors and developers have also been bearing more contingency and overhead, further increasing the solar portion of the project's overall price. The battery cost estimate also increased relative to the 2019 pricing due to inflation and the inclusion of substation costs in this iteration of the estimate.

Table 18-1 — Case 18 Capital Cost Estimate

Case 18 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Solar PV with Single-Axis Tracking and Battery Storage**
Battery Configuration		DC Coupled
DC / AC Ratio		1.6
Module Type		Bifacial Monocrystalline
Battery Type		Lithium Ion
	Units	
Plant Characteristics		
Net Solar Capacity	MW_AC	150
Net Battery Capacity	MW_AC	50
Battery Duration	hour	4
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct and Indirect Costs	5%
EPC Contingency	% of Project Costs	5%
Owner's Services	% of Project Costs	5%
Owner's Contingency	% of Project Costs	10%
Estimated Land Requirement (Note 1)	acres	1300
Interconnection Costs		
Electrical Transmission Interconnection Costs		
Transmission Line Cost	$/mile	2,412,000
Miles	miles	1.00

Case 18 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Solar PV with Single-Axis Tracking and Battery Storage**
Battery Configuration		DC Coupled
DC / AC Ratio		1.6
Module Type		Bifacial Monocrystalline
Battery Type		Lithium Ion
	Units	
Typical Project Timelines		
Development, Permitting, Engineering	months	24
Plant Construction Time	months	12
Total Lead Time Before Commercial Operation Date (COD)	months	36
Operating Life	years	35-Year PV; 20-Year BESS
EPC Cost Components (Note 2)		
PV Module Supply	$	88,800,000
Bidirectional Inverter Supply	$	11,205,000
PV Racking, Tracker and Balance-of-Plant (BOP) Equipment Supply	$	55,200,000
BESS Container Supply	$	50,560,000
BESS BOP Equipment Supply (Note 3)	$	30,700,000
Main Power Transformer & Substation	$	10,500,000
PV Construction / Installation Labor	$	32,400,000
BESS Construction / Installation Labor	$	7,250,000
Supervisory, Control, and Data Acquisition Subcontract	$	915,000
Civil/Structural/Architectural Subcontractor	$	16,800,000
Indirect Costs	$	23,600,000
EPC Contracting Fee	$	16,397,000
EPC Contingency	$	17,216,000
EPC Subtotal	$	361,543,000
Owner's Cost Components (Note 4)		
Owner's Services	$	18,077,000
Electrical Interconnection		2,412,000
Owner's Contingency	$	2,049,000
Owner's Cost Subtotal	$	22,538,000
Total Capital Cost	**$**	**384,081,000**
	$/kW net	**2,561**
Capital Cost Notes		

Case 18 EIA – Capital Cost Estimates – 2023 $ USD	
Configuration	**Solar PV with Single-Axis Tracking and Battery Storage**
Battery Configuration	DC Coupled
DC / AC Ratio	1.6
Module Type	Bifacial Monocrystalline
Battery Type	Lithium Ion
	Units

1. Land for this resource type is typically leased and not purchased. Minor costs for land acquisition and lease during development and construction period is included in the owner's services costs. Annual lease costs are also accounted for in the fixed operating and maintenance (O&M).
2. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, start-up and commissioning, contractor overhead, freight, and duties/sales taxes. EPC fees are applied to the sum of direct and indirect costs.
3. BESS BOP equipment supply is inclusive of all equipment and materials except for BESS units to provide medium-voltage feeders to the substation, including, but not limited to, auxiliary power equipment and transfer switches; DC-to-DC converters; medium-voltage transformers; cabling and conduit; equipment foundations; and supervisory control and data acquisition (SCADA).
4. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's start-up and commissioning costs. Other owner's costs include electrical interconnection costs.

18.3. OPERATIONS AND MAINTENANCE COST ESTIMATE

For this case, Sargent & Lundy grouped the O&M costs into the following categories: preventative maintenance, unscheduled maintenance, module cleaning, inverter maintenance reserve, battery augmentation, and the land lease. Descriptions of all the factors except the battery augmentation can be found in Section 16.3. The typical lifetime of a battery is 7300 cycles, which yields a lifetime of roughly 20 years (based on approximately one cycle per day). Sargent & Lundy assumes periodic augmentation to compensate for energy capacity lost to battery degradation for the first 20 years. More extensive decommissioning of the original BESS equipment and rebuilding with entirely new batteries, may be necessary in order to have storage of PV generation for the 35-year expected life of the PV technology. Sargent & Lundy has modeled only augmentation through year 20, not any decommissioning or extensive rebuild afterwards.

Table 18-2 — Case 18 O&M Cost Estimate

Case 18 EIA – Non-Fuel O&M Costs – 2023 $ USD
Solar PV with Single-Axis Tracking and Battery Storage

Fixed O&M – Plant (Note 1)	Units	Value
Preventative Maintenance	$/year	2,700,000
Module Cleaning (Note 2)	$/year	167,000
Unscheduled Maintenance	$/year	525,000
Inverter Maintenance Reserve	$/year	374,000
Battery Augmentation	$/year	1,200,000
Land Lease (Note 3)	$/year	920,400
Subtotal Fixed O&M	$/year	5,886,400
$/kW-year	$/kW-year	**39.24 $/kW-year**
Variable O&M	$/MWh	**0.00 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and general and administrative (G&A) costs. O&M costs exclude property taxes and insurance. 2. Assume one module cleaning per year. 3. Land for solar PV projects is typically leased rather than owned, this is considered to be a representative annual expense but varies across projects.		

18.4. ENVIRONMENTAL AND EMISSIONS INFORMATION

Solar PV does not produce regulated environmental air emissions. While other environmental compliance requirements may apply, only air emissions were considered for this report. Therefore, the emissions of NO_X, SO_2, and CO_2 are 0.00 lb/MMBtu.

CASE 19. BATTERY ENERGY STORAGE SYSTEM, 150 MW | 600 MWH

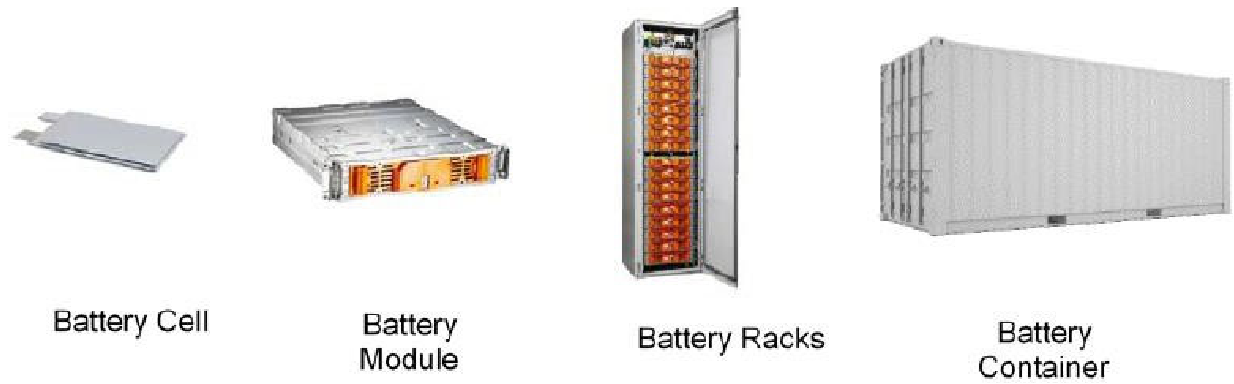
19.1. CASE DESCRIPTION

This case consists of a utility-scale, lithium-ion, battery energy storage system (BESS) with a 150 MW power rating and 600 MWh energy rating; the system can provide 150 MW of power for a four-hour duration. The cost estimate includes a substation consisting of a transformer to increase voltage from the BESS system to the interconnection voltage (modeled as 138 kV), as well as associated switchgear.

The BESS consists of 240 modular, factory-integrated battery storage containers that house the batteries and supporting systems (for example, battery management system, electrical protections, thermal management system, fire protection, etc.). The battery containers modeled in Case 19 are of representative size, 20 feet long x 10 feet wide x 8 feet high, however, industry offerings vary in size and modularity but offer roughly the same energy density per acre and total cost. The BESS uses utility-scale lithium-ion batteries. Approximately 1.5% of the initial battery capacity is assumed to degrade each year and require augmentation by the addition of new batteries. (The augmentation cost is included with the annual O&M, as discussed in Section 19.3). Battery containers are grouped together and connected with an associated inverter-transformer skid, which is approximately 15 feet long x 10 feet wide x 8 feet high and is commonly referred to as a Power Conditioning System (PCS). The PCS houses the inverters, transformer, and associated electrical equipment (for example, fuses and breakers). There is one control building with approximate dimension of 20 feet long x 10 feet wide x 8 feet high to support O&M activities. Each building is set on a concrete slab foundation.

Figure 19-1 shows a typical utility-scale lithium-ion battery. Several battery cells make up a battery module, also commonly referred to as a “battery pack”, which is independently monitored and controlled. Several battery modules are contained within a battery rack, and there are several battery racks in a battery container.

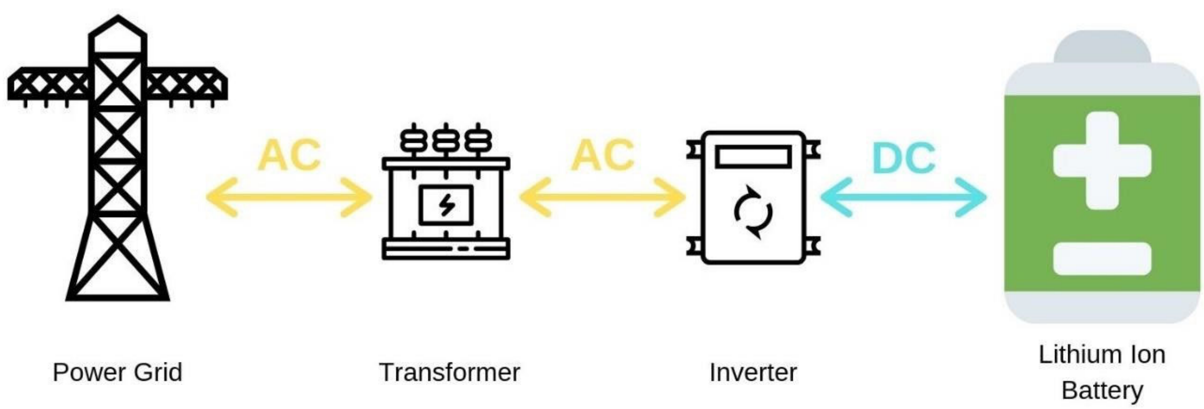
Figure 19-1 — Utility-Scale Lithium-Ion Batteries



Source: National Renewable Energy Laboratory (NREL) "2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark, Technical Report NREL/TP-6A20-71714, November 2018. (https://www.nrel.gov/docs/fy19osti/71714.pdf) (accessed July 23, 2019)

The BESS is equipped with 600 MWh of lithium-ion batteries connected in strings and one hundred 1.5 MW inverters. Batteries operate on DC power; however, most electric power generation on the grid is produced and distributed as AC power. Standalone BESS are equipped with inverters to convert between AC power from the grid to DC power for storage within the batteries. Sequentially, the grid or substation AC power is converted by the main power transformer from high-voltage (138+ kV) to medium-voltage (34.5 kV), medium-voltage power is converted to the operational voltage range of the inverters (480–700 V_{AC}, depending on design) by medium-voltage transformers, and inverters convert AC power to DC power (1000–1500 V_{DC}) for connection with the battery containers. AC-coupled and DC-coupled BESS are discussed in Case 17 and Case 18, respectively, however it is noteworthy that the majority of existing and near-term planned installations of BESS are either standalone or AC-coupled configurations.

Figure 19-2 — Standalone BESS Flow Diagram



Adapted from Clean Energy Reviews, https://www.cleanenergyreviews.info/blog/ac-coupling-vs-dc-coupling-solar-battery-storage (accessed June 12, 2019).

19.2. CAPITAL COST ESTIMATE

Table 19-1 summarizes the cost components for this case. Both the $/kW and $/kWh are provided to clearly describe the system estimate. The capital cost estimate is based on a BESS with a power rating of 150 MW and energy rating of 600 MWh (equivalent to a four-hour duration system). The cost estimate includes civil works, foundations, buildings, electrical equipment and related equipment, substation, switchyard, transformers, transmission lines, cabling, controls, and instrumentation. The cost estimate increased relative to the 2019 pricing due to inflation and the inclusion of substation costs in this iteration of the estimate.

Table 19-1 — Case 19 Capital Cost Estimate

Case 19 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Battery Energy Storage System 150 MW | 600 MWh Greenfield**
Battery Type		Lithium-Ion
Service Life		20 years
Total Charging Cycles in Service Life		7,300
	Units	
Plant Characteristics		
Power Rating	MW	150
Energy Rating	MWh	600
Duration	hour	4
Capital Cost Assumptions		
Engineering, Procurement, and Construction (EPC) Contracting Fee	% of Direct & Indirect Costs	5%
EPC Contingency	% of EPC Costs	5%
Owner's Services	% of EPC Costs	4%
Owner's Contingency	% of Owner's Costs	5%
Estimated Land Requirement	acres	6
Estimated Land Cost	$/acre	90,000
Interconnection Costs		
Electrical Transmission Interconnection Costs		
Transmission Line Cost	$/mile	2,412,000
Miles	miles	1.00
Typical Project Timelines		
Development, Permitting, Engineering	months	
Plant Construction Time	months	12
Total Lead Time Before Commercial Operation Date (COD)	months	18
Operating Life	years	20
EPC Cost Components (Note 1)		
BESS Unit Supply	$	151,700,000

Case 19 EIA – Capital Cost Estimates – 2023 $ USD		
Configuration		**Battery Energy Storage System 150 MW | 600 MWh Greenfield**
Battery Type		Lithium-Ion
Service Life		20 years
Total Charging Cycles in Service Life		7,300
	Units	
BESS Balance-of-Plant (BOP) Equipment Supply (Note 2)	$	36,857,000
BESS Installation	$	8,672,000
Main Power Transformer & Substation	$	10,500,000
Indirect Costs	$	17,345,000
EPC Contracting Fee	$	11,254,000
EPC Contingency	$	11,816,000
EPC Subtotal	$	248,144,000
Owner's Cost Components (Note 2)		
Owner's Services	$	9,926,000
Land	$	540,000
Electrical Interconnection	$	2,412,000
Owner's Contingency	$	644,000
Owner's Cost Subtotal	$	13,522,000
Total Capital Cost	**$**	**261,666,000**
	$/kW net	**1,744**
	$/kWh	**436**
Capital Cost Notes		

1. Costs based on EPC contracting approach. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, and electrical/I&C components of the facility. Indirect costs include distributable material and labor costs, cranes, scaffolding, engineering, construction management, start-up and commissioning, contractor overhead, freight, and duties/sales taxes. EPC fees are applied to the sum of direct and indirect costs.
2. BESS BOP equipment supply is inclusive of all equipment and materials except for BESS units to provide medium-voltage feeders to the substation, including, but not limited to, auxiliary power equipment and transfer switches; inverters; medium-voltage transformers; cabling and conduit; equipment foundations; and supervisory control and data acquisition (SCADA).
3. Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's start-up and commissioning costs. Other owner's costs include electrical interconnection costs, gas interconnection costs (if applicable), and land acquisition costs.

19.3. OPERATIONS AND MAINTENANCE COST ESTIMATE

The O&M cost estimate considers the ongoing O&M cost through the life of a BESS project. The service life of a BESS depends on how it is used. This case assumes that the BESS will have a service life of 7300 equivalent cycles, which yields a lifetime of roughly 20 years (based on approximately one cycle per day) representing a typical use case basis in the industry. A full charge-discharge cycle occurs when a battery is at 0% usable state of charge, is then charged fully to 100% state of charge, and finally is discharged fully back to 0% state of charge. An “equivalent cycle” can be understood as the sum of partial charges and discharges equating to the same net energy throughput as a full charge-discharge cycle. BESS projects that serve ancillary markets may not experience a full charge and discharge cycle every day or may experience partial charge cycles, which is why the concept of “equivalent cycles” is useful. The 7300 equivalent-cycle service life is a typical industry basis to determine the cost and technical specifications for an energy storage system. Capacity degradation of lithium-ion batteries is an inherent performance characteristic of lithium-ion battery technology, occurring both due to age-alone and proportional to their usage. Battery performance guarantees in the industry suggest approximately 1.5% average annual capacity degradation associated with a one full-cycle per day use case for a four-hour duration lithium-ion BESS. Battery degradation guarantees are tailored to the specific use case expected for the individual BESS.

Many BESS projects engage a third-party contractor to conduct regular O&M activities. This cost estimate considers the cost of such contracted services, which include remote monitoring of the system, periodic onsite inspection of equipment conditions and cable connections, replacement of regular consumables (air filters, coolant, etc.), and grounds maintenance. This O&M cost estimate uses the 1.5% battery degradation factor and incorporates the equipment and labor cost of subsequent augmentations in the annual fixed O&M cost. The O&M cost include an annual allowance for general and administrative (G&A) costs. The fixed O&M costs are $40.00/kW-year or $10.00/kWh-year. Augmentation is included with fixed cost in this case since the use case assumes the same number of charging cycles each year during the service life of the project. Divergence from the use case could cause greater than expected degradation and voiding of battery performance guarantees. The variable costs are $0.00/MWh, since there are no consumables linked to energy output within the expected use case.

The O&M costs do not include the cost of energy to charge the system. No costs are included for decommissioning.

Table 19-2 — Case 19 O&M Cost Estimate

Case 19 EIA – Non-Fuel O&M Costs – 2023 $ USD		
BESS - 150 MW | 600 MWh - Greenfield		
Fixed O&M – Plant (Note 1)	**Units**	**Value**
Battery Maintenance (Preventative & Corrective)	$/year	2,400,000
Battery Augmentation	$/year	3,600,000
Subtotal Fixed O&M	$/year	6,000,000
$/kW-year	$/kW-year	**40.00 $/kW-year**
Variable O&M (Note 2)	$/MWh	**0.00 $/MWh**
O&M Cost Notes		
1. Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.		
2. All costs tied to energy produced are covered in fixed cost.		

19.4. ENVIRONMENTAL AND EMISSIONS INFORMATION

BESSs do not produce regulated environmental emission. While other environmental compliance requirements may apply, only air emissions were considered for this report. Therefore, the emissions of NO_X, SO_2, and CO_2 are 0.00 lb/MMBtu.

APPENDIX A. LABOR LOCATION-BASED COST ADJUSTMENTS

Table 1-1 — Location Adjustment for Ultra-Supercritical Coal w/o Carbon Capture – Greenfield
(2023 USD)
Case Configuration: 650 MW Net, 1 x 735 MW Gross

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	4,103	0.97	(132)	3971
Arizona	Phoenix	4,103	1.09	383	4486
Arkansas	Little Rock	4,103	0.97	(137)	3966
California	Bakersfield	4,103	1.31	1,262	5365
California	Los Angeles	4,103	1.33	1,366	5469
California	Modesto	4,103	1.35	1,418	5521
California	Sacramento	4,103	1.37	1,501	5604
California	San Francisco	4,103	1.48	1,951	6054
Colorado	Denver	4,103	1.03	141	4244
Connecticut	Hartford	4,103	1.27	1,103	5206
Delaware	Dover	4,103	1.24	991	5094
District of Columbia	Washington	4,103	1.09	381	4484
Florida	Tallahassee	4,103	0.94	(255)	3848
Florida	Tampa	4,103	0.96	(184)	3919
Georgia	Atlanta	4,103	1.02	84	4187
Idaho	Boise	4,103	1.03	114	4217
Illinois	Chicago	4,103	1.36	1,466	5569
Indiana	Indianapolis	4,103	1.01	25	4128
Iowa	Davenport	4,103	1.05	203	4306
Iowa	Waterloo	4,103	0.99	(52)	4051
Kansas	Wichita	4,103	0.99	(59)	4044
Kentucky	Louisville	4,103	1.01	32	4135
Louisiana	New Orleans	4,103	1.00	4	4107
Maine	Portland	4,103	1.03	137	4240
Maryland	Baltimore	4,103	1.03	111	4214
Massachusetts	Boston	4,103	1.36	1,489	5592
Michigan	Detroit	4,103	1.11	461	4564
Michigan	Grand Rapids	4,103	1.02	62	4165
Minnesota	Saint Paul	4,103	1.13	531	4634
Mississippi	Biloxi	4,103	0.95	(209)	3894
Missouri	St. Louis	4,103	1.13	525	4628
Missouri	Kansas City	4,103	1.07	306	4409
Montana	Great Falls	4,103	0.98	(76)	4027
Nebraska	Omaha	4,103	0.99	(56)	4047
New Hampshire	Manchester	4,103	1.11	466	4569
New Jersey	Newark	4,103	1.30	1,249	5352
New Mexico	Albuquerque	4,103	1.03	141	4244
New York	New York	4,103	1.70	2,852	6955
New York	Syracuse	4,103	1.14	573	4676
Nevada	Las Vegas	4,103	1.17	681	4784
North Carolina	Charlotte	4,103	0.98	(71)	4032
North Dakota	Bismarck	4,103	1.04	183	4286
Ohio	Cincinnati	4,103	0.98	(97)	4006
Oklahoma	Oklahoma City	4,103	0.95	(217)	3886
Oregon	Portland	4,103	1.21	866	4969
Pennsylvania	Philadelphia	4,103	1.35	1,422	5525
Pennsylvania	Scranton	4,103	1.13	538	4641
Rhode Island	Providence	4,103	1.23	927	5030
South Carolina	Charleston	4,103	0.95	(207)	3896
South Dakota	Rapid City	4,103	1.00	(6)	4097
Tennessee	Nashville	4,103	0.99	(54)	4049
Texas	Houston	4,103	0.90	(406)	3697
Utah	Salt Lake City	4,103	0.99	(30)	4073
Vermont	Burlington	4,103	1.08	315	4418
Virginia	Alexandria	4,103	1.07	304	4407
Virginia	Roanoke	4,103	1.04	161	4264
Washington	Seattle	4,103	1.21	843	4946
Washington	Spokane	4,103	1.07	284	4387
West Virginia	Charleston	4,103	1.02	100	4203
Wisconsin	Green Bay	4,103	1.10	408	4511
Wyoming	Cheyenne	4,103	1.00	(21)	4082

Table 1-2 — Location Adjustment for Ultra-Supercritical Coal 95% Carbon Capture
(2023 USD)
Case Configuration: 650 MW Net, 1 x 819 MW Gross

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	7,346	0.97	(246)	7100
Arizona	Phoenix	7,346	1.03	210	7556
Arkansas	Little Rock	7,346	0.97	(224)	7122
California	Bakersfield	7,346	1.24	1,799	9145
California	Los Angeles	7,346	1.27	1,977	9323
California	Modesto	7,346	1.28	2,067	9413
California	Sacramento	7,346	1.30	2,205	9551
California	San Francisco	7,346	1.40	2,962	10308
Colorado	Denver	7,346	0.98	(151)	7195
Connecticut	Hartford	7,346	1.20	1,492	8838
Delaware	Dover	7,346	1.17	1,260	8606
District of Columbia	Washington	7,346	1.04	269	7615
Florida	Tallahassee	7,346	0.93	(486)	6860
Florida	Tampa	7,346	0.95	(354)	6992
Georgia	Atlanta	7,346	1.02	136	7482
Idaho	Boise	7,346	1.03	221	7567
Illinois	Chicago	7,346	1.35	2,600	9946
Indiana	Indianapolis	7,346	1.01	73	7419
Iowa	Davenport	7,346	1.05	359	7705
Iowa	Waterloo	7,346	0.99	(92)	7254
Kansas	Wichita	7,346	0.99	(105)	7241
Kentucky	Louisville	7,346	1.01	86	7432
Louisiana	New Orleans	7,346	1.00	15	7361
Maine	Portland	7,346	1.03	253	7599
Maryland	Baltimore	7,346	1.03	204	7550
Massachusetts	Boston	7,346	1.29	2,149	9495
Michigan	Detroit	7,346	1.11	817	8163
Michigan	Grand Rapids	7,346	1.01	109	7455
Minnesota	Saint Paul	7,346	1.12	911	8257
Mississippi	Biloxi	7,346	0.94	(408)	6938
Missouri	St. Louis	7,346	1.14	1,002	8348
Missouri	Kansas City	7,346	1.07	543	7889
Montana	Great Falls	7,346	0.98	(141)	7205
Nebraska	Omaha	7,346	0.99	(98)	7248
New Hampshire	Manchester	7,346	1.06	451	7797
New Jersey	Newark	7,346	1.30	2,228	9574
New Mexico	Albuquerque	7,346	1.04	260	7606
New York	New York	7,346	1.60	4,431	11777
New York	Syracuse	7,346	1.08	584	7930
Nevada	Las Vegas	7,346	1.17	1,263	8609
North Carolina	Charlotte	7,346	0.98	(125)	7221
North Dakota	Bismarck	7,346	1.04	293	7639
Ohio	Cincinnati	7,346	0.98	(178)	7168
Oklahoma	Oklahoma City	7,346	0.95	(387)	6959
Oregon	Portland	7,346	1.15	1,132	8478
Pennsylvania	Philadelphia	7,346	1.28	2,023	9369
Pennsylvania	Scranton	7,346	1.07	530	7876
Rhode Island	Providence	7,346	1.16	1,208	8554
South Carolina	Charleston	7,346	0.96	(296)	7050
South Dakota	Rapid City	7,346	0.99	(41)	7305
Tennessee	Nashville	7,346	0.99	(38)	7308
Texas	Houston	7,346	0.90	(715)	6631
Utah	Salt Lake City	7,346	1.00	2	7348
Vermont	Burlington	7,346	1.09	674	8020
Virginia	Alexandria	7,346	1.02	140	7486
Virginia	Roanoke	7,346	0.99	(109)	7237
Washington	Seattle	7,346	1.21	1,560	8906
Washington	Spokane	7,346	1.07	530	7876
West Virginia	Charleston	7,346	1.02	174	7520
Wisconsin	Green Bay	7,346	1.09	683	8029
Wyoming	Cheyenne	7,346	0.99	(49)	7297

Table 1-3 — Location Adjustment for Combustion Turbine – Simple Cycle (Aeroderivative)
(2023 USD)
Case Configuration: 211 MW Net, 4 x 54 MW Gross Aeroderivative Simple Cycle

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	1,606	0.98	(31)	1575
Arizona	Phoenix	1,606	1.01	10	1616
Arkansas	Little Rock	1,606	0.99	(22)	1584
California	Bakersfield	1,606	1.11	179	1785
California	Los Angeles	1,606	1.13	208	1814
California	Modesto	1,606	1.13	206	1812
California	Sacramento	1,606	1.14	223	1829
California	San Francisco	1,606	1.22	362	1968
Colorado	Denver	1,606	0.98	(26)	1580
Connecticut	Hartford	1,606	1.09	147	1753
Delaware	Dover	1,606	1.08	136	1742
District of Columbia	Washington	1,606	1.02	32	1638
Florida	Tallahassee	1,606	0.97	(55)	1551
Florida	Tampa	1,606	0.97	(41)	1565
Georgia	Atlanta	1,606	1.00	8	1614
Idaho	Boise	1,606	1.01	19	1625
Illinois	Chicago	1,606	1.16	258	1864
Indiana	Indianapolis	1,606	1.00	(1)	1605
Iowa	Davenport	1,606	1.01	22	1628
Iowa	Waterloo	1,606	0.99	(23)	1583
Kansas	Wichita	1,606	0.98	(25)	1581
Kentucky	Louisville	1,606	1.00	(0)	1606
Louisiana	New Orleans	1,606	1.00	(3)	1603
Maine	Portland	1,606	1.01	15	1621
Maryland	Baltimore	1,606	1.01	15	1621
Massachusetts	Boston	1,606	1.14	232	1838
Michigan	Detroit	1,606	1.05	88	1694
Michigan	Grand Rapids	1,606	1.00	3	1609
Minnesota	Saint Paul	1,606	1.06	98	1704
Mississippi	Biloxi	1,606	0.97	(47)	1559
Missouri	St. Louis	1,606	1.07	105	1711
Missouri	Kansas City	1,606	1.03	54	1660
Montana	Great Falls	1,606	0.99	(20)	1586
Nebraska	Omaha	1,606	0.99	(23)	1583
New Hampshire	Manchester	1,606	1.02	35	1641
New Jersey	Newark	1,606	1.15	246	1852
New Mexico	Albuquerque	1,606	1.01	19	1625
New York	New York	1,606	1.28	454	2060
New York	Syracuse	1,606	1.04	57	1663
Nevada	Las Vegas	1,606	1.08	135	1741
North Carolina	Charlotte	1,606	0.99	(18)	1588
North Dakota	Bismarck	1,606	1.01	19	1625
Ohio	Cincinnati	1,606	0.98	(26)	1580
Oklahoma	Oklahoma City	1,606	0.97	(45)	1561
Oregon	Portland	1,606	1.08	126	1732
Pennsylvania	Philadelphia	1,606	1.14	233	1839
Pennsylvania	Scranton	1,606	1.03	41	1647
Rhode Island	Providence	1,606	1.07	117	1723
South Carolina	Charleston	1,606	0.98	(29)	1577
South Dakota	Rapid City	1,606	0.99	(10)	1596
Tennessee	Nashville	1,606	1.00	1	1607
Texas	Houston	1,606	0.95	(80)	1526
Utah	Salt Lake City	1,606	1.00	(5)	1601
Vermont	Burlington	1,606	1.04	62	1668
Virginia	Alexandria	1,606	1.01	15	1621
Virginia	Roanoke	1,606	0.99	(20)	1586
Washington	Seattle	1,606	1.12	189	1795
Washington	Spokane	1,606	1.03	44	1650
West Virginia	Charleston	1,606	1.01	14	1620
Wisconsin	Green Bay	1,606	1.04	71	1677
Wyoming	Cheyenne	1,606	0.99	(12)	1594

Table 1-4 — Location Adjustment for Combustion Turbine – Simple Cycle
(2023 USD)
Case Configuration: 419 MW Net, 1 x H Class Simple Cycle

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	836	0.97	(22)	814
Arizona	Phoenix	836	1.01	6	842
Arkansas	Little Rock	836	0.98	(18)	818
California	Bakersfield	836	1.14	115	951
California	Los Angeles	836	1.16	133	969
California	Modesto	836	1.16	132	968
California	Sacramento	836	1.17	144	980
California	San Francisco	836	1.28	234	1070
Colorado	Denver	836	0.98	(17)	819
Connecticut	Hartford	836	1.11	95	931
Delaware	Dover	836	1.11	90	926
District of Columbia	Washington	836	1.02	20	856
Florida	Tallahassee	836	0.96	(37)	799
Florida	Tampa	836	0.97	(28)	808
Georgia	Atlanta	836	1.00	3	839
Idaho	Boise	836	1.01	11	847
Illinois	Chicago	836	1.20	169	1005
Indiana	Indianapolis	836	1.00	(3)	833
Iowa	Davenport	836	1.02	14	850
Iowa	Waterloo	836	0.98	(16)	820
Kansas	Wichita	836	0.98	(17)	819
Kentucky	Louisville	836	1.00	(2)	834
Louisiana	New Orleans	836	0.99	(5)	831
Maine	Portland	836	1.01	9	845
Maryland	Baltimore	836	1.01	8	844
Massachusetts	Boston	836	1.18	151	987
Michigan	Detroit	836	1.07	57	893
Michigan	Grand Rapids	836	1.00	1	837
Minnesota	Saint Paul	836	1.08	65	901
Mississippi	Biloxi	836	0.96	(32)	804
Missouri	St. Louis	836	1.08	65	901
Missouri	Kansas City	836	1.04	35	871
Montana	Great Falls	836	0.98	(13)	823
Nebraska	Omaha	836	0.98	(16)	820
New Hampshire	Manchester	836	1.02	20	856
New Jersey	Newark	836	1.19	160	996
New Mexico	Albuquerque	836	1.01	9	845
New York	New York	836	1.36	297	1133
New York	Syracuse	836	1.04	37	873
Nevada	Las Vegas	836	1.10	86	922
North Carolina	Charlotte	836	0.99	(12)	824
North Dakota	Bismarck	836	1.02	13	849
Ohio	Cincinnati	836	0.98	(17)	819
Oklahoma	Oklahoma City	836	0.96	(30)	806
Oregon	Portland	836	1.10	79	915
Pennsylvania	Philadelphia	836	1.18	152	988
Pennsylvania	Scranton	836	1.03	26	862
Rhode Island	Providence	836	1.09	75	911
South Carolina	Charleston	836	0.97	(25)	811
South Dakota	Rapid City	836	0.99	(6)	830
Tennessee	Nashville	836	1.00	(3)	833
Texas	Houston	836	0.94	(53)	783
Utah	Salt Lake City	836	0.99	(7)	829
Vermont	Burlington	836	1.04	35	871
Virginia	Alexandria	836	1.01	9	845
Virginia	Roanoke	836	0.98	(14)	822
Washington	Seattle	836	1.15	121	957
Washington	Spokane	836	1.03	27	863
West Virginia	Charleston	836	1.01	9	845
Wisconsin	Green Bay	836	1.06	48	884
Wyoming	Cheyenne	836	0.99	(8)	828

Table 1-5 — Location Adjustment for Combined-Cycle 2x2x1
(2023 USD)
Case Configuration: 1227 MW Net, 2 x 1 H Class Combined Cycle

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	868	0.97	(26)	842
Arizona	Phoenix	868	1.01	8	876
Arkansas	Little Rock	868	0.97	(22)	846
California	Bakersfield	868	1.15	131	999
California	Los Angeles	868	1.18	152	1020
California	Modesto	868	1.17	151	1019
California	Sacramento	868	1.19	164	1032
California	San Francisco	868	1.31	268	1136
Colorado	Denver	868	0.98	(20)	848
Connecticut	Hartford	868	1.13	109	977
Delaware	Dover	868	1.12	104	972
District of Columbia	Washington	868	1.03	23	891
Florida	Tallahassee	868	0.95	(42)	826
Florida	Tampa	868	0.96	(32)	836
Georgia	Atlanta	868	1.00	3	871
Idaho	Boise	868	1.01	12	880
Illinois	Chicago	868	1.22	194	1062
Indiana	Indianapolis	868	1.00	(4)	864
Iowa	Davenport	868	1.02	16	884
Iowa	Waterloo	868	0.98	(18)	850
Kansas	Wichita	868	0.98	(19)	849
Kentucky	Louisville	868	1.00	(3)	865
Louisiana	New Orleans	868	0.99	(7)	861
Maine	Portland	868	1.01	10	878
Maryland	Baltimore	868	1.01	10	878
Massachusetts	Boston	868	1.20	173	1041
Michigan	Detroit	868	1.08	66	934
Michigan	Grand Rapids	868	1.00	2	870
Minnesota	Saint Paul	868	1.09	76	944
Mississippi	Biloxi	868	0.96	(36)	832
Missouri	St. Louis	868	1.08	73	941
Missouri	Kansas City	868	1.05	40	908
Montana	Great Falls	868	0.98	(15)	853
Nebraska	Omaha	868	0.98	(18)	850
New Hampshire	Manchester	868	1.03	22	890
New Jersey	Newark	868	1.21	184	1052
New Mexico	Albuquerque	868	1.01	10	878
New York	New York	868	1.39	341	1209
New York	Syracuse	868	1.05	42	910
Nevada	Las Vegas	868	1.11	97	965
North Carolina	Charlotte	868	0.98	(14)	854
North Dakota	Bismarck	868	1.02	16	884
Ohio	Cincinnati	868	0.98	(20)	848
Oklahoma	Oklahoma City	868	0.96	(34)	834
Oregon	Portland	868	1.10	90	958
Pennsylvania	Philadelphia	868	1.20	174	1042
Pennsylvania	Scranton	868	1.04	30	898
Rhode Island	Providence	868	1.10	85	953
South Carolina	Charleston	868	0.96	(32)	836
South Dakota	Rapid City	868	0.99	(6)	862
Tennessee	Nashville	868	0.99	(5)	863
Texas	Houston	868	0.93	(61)	807
Utah	Salt Lake City	868	0.99	(9)	859
Vermont	Burlington	868	1.04	37	905
Virginia	Alexandria	868	1.01	10	878
Virginia	Roanoke	868	0.98	(16)	852
Washington	Seattle	868	1.16	138	1006
Washington	Spokane	868	1.04	31	899
West Virginia	Charleston	868	1.01	10	878
Wisconsin	Green Bay	868	1.07	56	924
Wyoming	Cheyenne	868	0.99	(9)	859

Table 1-6 — Location Adjustment for Combined-Cycle 1x1x1, Single Shaft
(2023 USD)
Case Configuration: 627 MW Net, 1 x 1 H Class Combined Cycle

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	921	0.97	(29)	892
Arizona	Phoenix	921	1.01	10	931
Arkansas	Little Rock	921	0.97	(27)	894
California	Bakersfield	921	1.14	133	1054
California	Los Angeles	921	1.17	156	1077
California	Modesto	921	1.17	154	1075
California	Sacramento	921	1.18	168	1089
California	San Francisco	921	1.30	277	1198
Colorado	Denver	921	0.98	(20)	901
Connecticut	Hartford	921	1.12	113	1034
Delaware	Dover	921	1.12	111	1032
District of Columbia	Washington	921	1.03	24	945
Florida	Tallahassee	921	0.95	(44)	877
Florida	Tampa	921	0.96	(34)	887
Georgia	Atlanta	921	1.00	1	922
Idaho	Boise	921	1.01	12	933
Illinois	Chicago	921	1.22	204	1125
Indiana	Indianapolis	921	0.99	(6)	915
Iowa	Davenport	921	1.02	18	939
Iowa	Waterloo	921	0.98	(19)	902
Kansas	Wichita	921	0.98	(20)	901
Kentucky	Louisville	921	1.00	(5)	916
Louisiana	New Orleans	921	0.99	(10)	911
Maine	Portland	921	1.01	10	931
Maryland	Baltimore	921	1.01	10	931
Massachusetts	Boston	921	1.20	180	1101
Michigan	Detroit	921	1.08	69	990
Michigan	Grand Rapids	921	1.00	2	923
Minnesota	Saint Paul	921	1.09	82	1003
Mississippi	Biloxi	921	0.96	(37)	884
Missouri	St. Louis	921	1.08	72	993
Missouri	Kansas City	921	1.05	42	963
Montana	Great Falls	921	0.98	(15)	906
Nebraska	Omaha	921	0.98	(19)	902
New Hampshire	Manchester	921	1.02	20	941
New Jersey	Newark	921	1.21	193	1114
New Mexico	Albuquerque	921	1.01	7	928
New York	New York	921	1.39	356	1277
New York	Syracuse	921	1.05	44	965
Nevada	Las Vegas	921	1.11	98	1019
North Carolina	Charlotte	921	0.98	(14)	907
North Dakota	Bismarck	921	1.02	20	941
Ohio	Cincinnati	921	0.98	(20)	901
Oklahoma	Oklahoma City	921	0.96	(35)	886
Oregon	Portland	921	1.10	91	1012
Pennsylvania	Philadelphia	921	1.20	182	1103
Pennsylvania	Scranton	921	1.03	32	953
Rhode Island	Providence	921	1.10	88	1009
South Carolina	Charleston	921	0.96	(41)	880
South Dakota	Rapid City	921	1.00	(4)	917
Tennessee	Nashville	921	0.99	(9)	912
Texas	Houston	921	0.93	(64)	857
Utah	Salt Lake City	921	0.99	(13)	908
Vermont	Burlington	921	1.03	31	952
Virginia	Alexandria	921	1.01	10	931
Virginia	Roanoke	921	0.98	(16)	905
Washington	Seattle	921	1.15	140	1061
Washington	Spokane	921	1.03	31	952
West Virginia	Charleston	921	1.01	11	932
Wisconsin	Green Bay	921	1.07	62	983
Wyoming	Cheyenne	921	0.99	(8)	913

Table 1-7 — Location Adjustment for Combined Cycle 1x1x1, Single Shaft 95% Carbon Capture (2023 USD)
Case Configuration: 543 MW Net, 1 x 1 H Class Combined Cycle

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	2,365	0.96	(92)	2273
Arizona	Phoenix	2,365	1.01	32	2397
Arkansas	Little Rock	2,365	0.96	(90)	2275
California	Bakersfield	2,365	1.18	417	2782
California	Los Angeles	2,365	1.21	488	2853
California	Modesto	2,365	1.20	481	2846
California	Sacramento	2,365	1.22	526	2891
California	San Francisco	2,365	1.37	870	3235
Colorado	Denver	2,365	0.97	(60)	2305
Connecticut	Hartford	2,365	1.15	357	2722
Delaware	Dover	2,365	1.15	352	2717
District of Columbia	Washington	2,365	1.03	75	2440
Florida	Tallahassee	2,365	0.94	(138)	2227
Florida	Tampa	2,365	0.95	(107)	2258
Georgia	Atlanta	2,365	1.00	3	2368
Idaho	Boise	2,365	1.02	37	2402
Illinois	Chicago	2,365	1.27	643	3008
Indiana	Indianapolis	2,365	0.99	(20)	2345
Iowa	Davenport	2,365	1.02	56	2421
Iowa	Waterloo	2,365	0.98	(58)	2307
Kansas	Wichita	2,365	0.97	(61)	2304
Kentucky	Louisville	2,365	0.99	(16)	2349
Louisiana	New Orleans	2,365	0.99	(35)	2330
Maine	Portland	2,365	1.01	32	2397
Maryland	Baltimore	2,365	1.01	32	2397
Massachusetts	Boston	2,365	1.24	566	2931
Michigan	Detroit	2,365	1.09	219	2584
Michigan	Grand Rapids	2,365	1.00	8	2373
Minnesota	Saint Paul	2,365	1.11	262	2627
Mississippi	Biloxi	2,365	0.95	(117)	2248
Missouri	St. Louis	2,365	1.09	222	2587
Missouri	Kansas City	2,365	1.06	135	2500
Montana	Great Falls	2,365	0.98	(46)	2319
Nebraska	Omaha	2,365	0.97	(60)	2305
New Hampshire	Manchester	2,365	1.03	60	2425
New Jersey	Newark	2,365	1.26	607	2972
New Mexico	Albuquerque	2,365	1.01	18	2383
New York	New York	2,365	1.47	1,123	3488
New York	Syracuse	2,365	1.06	141	2506
Nevada	Las Vegas	2,365	1.13	307	2672
North Carolina	Charlotte	2,365	0.98	(45)	2320
North Dakota	Bismarck	2,365	1.03	65	2430
Ohio	Cincinnati	2,365	0.97	(61)	2304
Oklahoma	Oklahoma City	2,365	0.95	(109)	2256
Oregon	Portland	2,365	1.12	283	2648
Pennsylvania	Philadelphia	2,365	1.24	573	2938
Pennsylvania	Scranton	2,365	1.04	100	2465
Rhode Island	Providence	2,365	1.12	275	2640
South Carolina	Charleston	2,365	0.94	(140)	2225
South Dakota	Rapid City	2,365	1.00	(8)	2357
Tennessee	Nashville	2,365	0.99	(34)	2331
Texas	Houston	2,365	0.91	(202)	2163
Utah	Salt Lake City	2,365	0.98	(45)	2320
Vermont	Burlington	2,365	1.04	89	2454
Virginia	Alexandria	2,365	1.01	32	2397
Virginia	Roanoke	2,365	0.98	(51)	2314
Washington	Seattle	2,365	1.18	437	2802
Washington	Spokane	2,365	1.04	95	2460
West Virginia	Charleston	2,365	1.02	37	2402
Wisconsin	Green Bay	2,365	1.08	199	2564
Wyoming	Cheyenne	2,365	0.99	(22)	2343

Table 1-8 — Location Adjustment for Bio Energy 95% Carbon Capture
(2023 USD)
Case Configuration: 50 MW Net, 1 x 65.5 MW Gross Woody Biomass Bubbling Fluidized Bed

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	12,631	0.96	(527)	12104
Arizona	Phoenix	12,631	1.01	161	12792
Arkansas	Little Rock	12,631	0.96	(492)	12139
California	Bakersfield	12,631	1.19	2,375	15006
California	Los Angeles	12,631	1.23	2,903	15534
California	Modesto	12,631	1.21	2,639	15270
California	Sacramento	12,631	1.24	2,986	15617
California	San Francisco	12,631	1.40	5,046	17677
Colorado	Denver	12,631	0.98	(294)	12337
Connecticut	Hartford	12,631	1.17	2,165	14796
Delaware	Dover	12,631	1.16	1,961	14592
District of Columbia	Washington	12,631	1.05	588	13219
Florida	Tallahassee	12,631	0.94	(814)	11817
Florida	Tampa	12,631	0.95	(686)	11945
Georgia	Atlanta	12,631	1.00	(32)	12599
Idaho	Boise	12,631	1.02	293	12924
Illinois	Chicago	12,631	1.29	3,679	16310
Indiana	Indianapolis	12,631	1.00	41	12672
Iowa	Davenport	12,631	1.03	354	12985
Iowa	Waterloo	12,631	0.99	(167)	12464
Kansas	Wichita	12,631	0.99	(148)	12483
Kentucky	Louisville	12,631	1.00	(50)	12581
Louisiana	New Orleans	12,631	0.99	(152)	12479
Maine	Portland	12,631	1.01	165	12796
Maryland	Baltimore	12,631	1.03	386	13017
Massachusetts	Boston	12,631	1.26	3,259	15890
Michigan	Detroit	12,631	1.10	1,203	13834
Michigan	Grand Rapids	12,631	1.01	93	12724
Minnesota	Saint Paul	12,631	1.11	1,433	14064
Mississippi	Biloxi	12,631	0.94	(725)	11906
Missouri	St. Louis	12,631	1.11	1,450	14081
Missouri	Kansas City	12,631	1.06	801	13432
Montana	Great Falls	12,631	0.98	(256)	12375
Nebraska	Omaha	12,631	0.99	(170)	12461
New Hampshire	Manchester	12,631	1.04	471	13102
New Jersey	Newark	12,631	1.27	3,456	16087
New Mexico	Albuquerque	12,631	1.01	164	12795
New York	New York	12,631	1.52	6,576	19207
New York	Syracuse	12,631	1.07	858	13489
Nevada	Las Vegas	12,631	1.13	1,695	14326
North Carolina	Charlotte	12,631	0.98	(306)	12325
North Dakota	Bismarck	12,631	1.03	365	12996
Ohio	Cincinnati	12,631	0.97	(357)	12274
Oklahoma	Oklahoma City	12,631	0.95	(664)	11967
Oregon	Portland	12,631	1.13	1,700	14331
Pennsylvania	Philadelphia	12,631	1.27	3,356	15987
Pennsylvania	Scranton	12,631	1.06	776	13407
Rhode Island	Providence	12,631	1.13	1,589	14220
South Carolina	Charleston	12,631	0.94	(747)	11884
South Dakota	Rapid City	12,631	0.99	(74)	12557
Tennessee	Nashville	12,631	0.99	(178)	12453
Texas	Houston	12,631	0.90	(1,202)	11429
Utah	Salt Lake City	12,631	0.99	(184)	12447
Vermont	Burlington	12,631	1.06	757	13388
Virginia	Alexandria	12,631	1.02	310	12941
Virginia	Roanoke	12,631	0.98	(262)	12369
Washington	Seattle	12,631	1.20	2,499	15130
Washington	Spokane	12,631	1.05	575	13206
West Virginia	Charleston	12,631	1.01	171	12802
Wisconsin	Green Bay	12,631	1.09	1,090	13721
Wyoming	Cheyenne	12,631	0.99	(153)	12478

Table 1-9 — Location Adjustment for Advanced Nuclear (Brownfield)
(2023 USD)
Case Configuration: 2156 MW Net, 2 x AP1000

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	7,861	1.01	68	7929
Arizona	Phoenix	7,861	1.00	(18)	7843
Arkansas	Little Rock	7,861	1.04	328	8189
California	Bakersfield	7,861	1.18	1,384	9245
California	Los Angeles	7,861	1.19	1,499	9360
California	Modesto	7,861	1.20	1,567	9428
California	Sacramento	7,861	1.21	1,628	9489
California	San Francisco	7,861	1.26	2,053	9914
Colorado	Denver	7,861	0.98	(191)	7670
Connecticut	Hartford	7,861	1.12	926	8787
Delaware	Dover	7,861	1.06	488	8349
District of Columbia	Washington	7,861	1.02	179	8040
Florida	Tallahassee	7,861	0.97	(253)	7608
Florida	Tampa	7,861	0.98	(129)	7732
Georgia	Atlanta	7,861	1.04	287	8148
Idaho	Boise	7,861	1.03	272	8133
Illinois	Chicago	7,861	1.19	1,464	9325
Indiana	Indianapolis	7,861	1.03	265	8126
Iowa	Davenport	7,861	1.02	189	8050
Iowa	Waterloo	7,861	0.99	(48)	7813
Kansas	Wichita	7,861	0.99	(74)	7787
Kentucky	Louisville	7,861	1.03	271	8132
Louisiana	New Orleans	7,861	1.05	376	8237
Maine	Portland	7,861	1.03	219	8080
Maryland	Baltimore	7,861	1.02	169	8030
Massachusetts	Boston	7,861	1.17	1,352	9213
Michigan	Detroit	7,861	1.06	452	8313
Michigan	Grand Rapids	7,861	1.01	49	7910
Minnesota	Saint Paul	7,861	1.04	279	8140
Mississippi	Biloxi	7,861	0.97	(241)	7620
Missouri	St. Louis	7,861	1.14	1,099	8960
Missouri	Kansas City	7,861	1.04	310	8171
Montana	Great Falls	7,861	0.98	(134)	7727
Nebraska	Omaha	7,861	0.99	(44)	7817
New Hampshire	Manchester	7,861	1.07	581	8442
New Jersey	Newark	7,861	1.17	1,344	9205
New Mexico	Albuquerque	7,861	1.07	546	8407
New York	New York	7,861	1.33	2,567	10428
New York	Syracuse	7,861	1.04	304	8165
Nevada	Las Vegas	7,861	1.14	1,118	8979
North Carolina	Charlotte	7,861	0.99	(72)	7789
North Dakota	Bismarck	7,861	0.99	(83)	7778
Ohio	Cincinnati	7,861	0.98	(152)	7709
Oklahoma	Oklahoma City	7,861	0.97	(248)	7613
Oregon	Portland	7,861	1.13	1,013	8874
Pennsylvania	Philadelphia	7,861	1.15	1,193	9054
Pennsylvania	Scranton	7,861	1.04	300	8161
Rhode Island	Providence	7,861	1.11	861	8722
South Carolina	Charleston	7,861	1.09	728	8589
South Dakota	Rapid City	7,861	0.97	(271)	7590
Tennessee	Nashville	7,861	1.06	444	8305
Texas	Houston	7,861	0.95	(371)	7490
Utah	Salt Lake City	7,861	1.06	435	8296
Vermont	Burlington	7,861	1.16	1,262	9123
Virginia	Alexandria	7,861	1.01	105	7966
Virginia	Roanoke	7,861	0.99	(97)	7764
Washington	Seattle	7,861	1.17	1,344	9205
Washington	Spokane	7,861	1.06	501	8362
West Virginia	Charleston	7,861	1.01	76	7937
Wisconsin	Green Bay	7,861	1.01	86	7947
Wyoming	Cheyenne	7,861	0.98	(132)	7729

Table 1-10 — Location Adjustment for Small Modular Reactor Nuclear Power Plant
(2023 USD)
Case Configuration: 480 MW Net, 6 x 80 MW Small Modular Reactor

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	8,936	0.99	(76)	8860
Arizona	Phoenix	8,936	1.01	60	8996
Arkansas	Little Rock	8,936	1.00	26	8962
California	Bakersfield	8,936	1.13	1,193	10129
California	Los Angeles	8,936	1.15	1,305	10241
California	Modesto	8,936	1.15	1,364	10300
California	Sacramento	8,936	1.16	1,442	10378
California	San Francisco	8,936	1.21	1,897	10833
Colorado	Denver	8,936	0.98	(148)	8788
Connecticut	Hartford	8,936	1.10	912	9848
Delaware	Dover	8,936	1.07	668	9604
District of Columbia	Washington	8,936	1.02	153	9089
Florida	Tallahassee	8,936	0.97	(288)	8648
Florida	Tampa	8,936	0.98	(190)	8746
Georgia	Atlanta	8,936	1.02	157	9093
Idaho	Boise	8,936	1.02	186	9122
Illinois	Chicago	8,936	1.18	1,579	10515
Indiana	Indianapolis	8,936	1.01	123	9059
Iowa	Davenport	8,936	1.02	213	9149
Iowa	Waterloo	8,936	0.99	(55)	8881
Kansas	Wichita	8,936	0.99	(69)	8867
Kentucky	Louisville	8,936	1.01	130	9066
Louisiana	New Orleans	8,936	1.02	139	9075
Maine	Portland	8,936	1.02	180	9116
Maryland	Baltimore	8,936	1.02	143	9079
Massachusetts	Boston	8,936	1.15	1,327	10263
Michigan	Detroit	8,936	1.06	493	9429
Michigan	Grand Rapids	8,936	1.01	62	8998
Minnesota	Saint Paul	8,936	1.05	474	9410
Mississippi	Biloxi	8,936	0.97	(252)	8684
Missouri	St. Louis	8,936	1.09	792	9728
Missouri	Kansas City	8,936	1.04	331	9267
Montana	Great Falls	8,936	0.99	(105)	8831
Nebraska	Omaha	8,936	0.99	(56)	8880
New Hampshire	Manchester	8,936	1.04	368	9304
New Jersey	Newark	8,936	1.15	1,383	10319
New Mexico	Albuquerque	8,936	1.03	298	9234
New York	New York	8,936	1.30	2,683	11619
New York	Syracuse	8,936	1.04	326	9262
Nevada	Las Vegas	8,936	1.10	905	9841
North Carolina	Charlotte	8,936	0.99	(76)	8860
North Dakota	Bismarck	8,936	1.01	92	9028
Ohio	Cincinnati	8,936	0.99	(126)	8810
Oklahoma	Oklahoma City	8,936	0.97	(246)	8690
Oregon	Portland	8,936	1.09	794	9730
Pennsylvania	Philadelphia	8,936	1.14	1,222	10158
Pennsylvania	Scranton	8,936	1.03	302	9238
Rhode Island	Providence	8,936	1.09	773	9709
South Carolina	Charleston	8,936	1.02	143	9079
South Dakota	Rapid City	8,936	0.99	(112)	8824
Tennessee	Nashville	8,936	1.02	142	9078
Texas	Houston	8,936	0.95	(423)	8513
Utah	Salt Lake City	8,936	1.02	155	9091
Vermont	Burlington	8,936	1.08	717	9653
Virginia	Alexandria	8,936	1.01	75	9011
Virginia	Roanoke	8,936	0.99	(98)	8838
Washington	Seattle	8,936	1.12	1,104	10040
Washington	Spokane	8,936	1.04	392	9328
West Virginia	Charleston	8,936	1.01	98	9034
Wisconsin	Green Bay	8,936	1.03	312	9248
Wyoming	Cheyenne	8,936	0.99	(67)	8869

Table 1-11 — Location Adjustment for Geothermal
(2023 USD)
Case Configuration: 50 MW Net, Binary Cycle

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	N/A	N/A	N/A	N/A
Arizona	Phoenix	N/A	N/A	N/A	N/A
Arkansas	Little Rock	N/A	N/A	N/A	N/A
California	Bakersfield	3,963	1.14	535	4,498
California	Los Angeles	3,963	1.16	625	4,588
California	Modesto	3,963	1.15	606	4,569
California	Sacramento	3,963	1.17	656	4,619
California	San Francisco	3,963	1.24	934	4,897
Colorado	Denver	N/A	N/A	N/A	N/A
Connecticut	Hartford	N/A	N/A	N/A	N/A
Delaware	Dover	N/A	N/A	N/A	N/A
District of Columbia	Washington	N/A	N/A	N/A	N/A
Florida	Tallahassee	N/A	N/A	N/A	N/A
Florida	Tampa	N/A	N/A	N/A	N/A
Georgia	Atlanta	N/A	N/A	N/A	N/A
Idaho	Boise	3,963	1.02	82	4,045
Illinois	Chicago	N/A	N/A	N/A	N/A
Indiana	Indianapolis	N/A	N/A	N/A	N/A
Iowa	Davenport	N/A	N/A	N/A	N/A
Iowa	Waterloo	N/A	N/A	N/A	N/A
Kansas	Wichita	N/A	N/A	N/A	N/A
Kentucky	Louisville	N/A	N/A	N/A	N/A
Louisiana	New Orleans	N/A	N/A	N/A	N/A
Maine	Portland	N/A	N/A	N/A	N/A
Maryland	Baltimore	N/A	N/A	N/A	N/A
Massachusetts	Boston	N/A	N/A	N/A	N/A
Michigan	Detroit	N/A	N/A	N/A	N/A
Michigan	Grand Rapids	N/A	N/A	N/A	N/A
Minnesota	Saint Paul	N/A	N/A	N/A	N/A
Mississippi	Biloxi	N/A	N/A	N/A	N/A
Missouri	St. Louis	N/A	N/A	N/A	N/A
Missouri	Kansas City	N/A	N/A	N/A	N/A
Montana	Great Falls	N/A	N/A	N/A	N/A
Nebraska	Omaha	N/A	N/A	N/A	N/A
New Hampshire	Manchester	N/A	N/A	N/A	N/A
New Jersey	Newark	N/A	N/A	N/A	N/A
New Mexico	Albuquerque	N/A	N/A	N/A	N/A
New York	New York	N/A	N/A	N/A	N/A
New York	Syracuse	N/A	N/A	N/A	N/A
Nevada	Las Vegas	3,963	1.10	395	4,358
North Carolina	Charlotte	N/A	N/A	N/A	N/A
North Dakota	Bismarck	N/A	N/A	N/A	N/A
Ohio	Cincinnati	N/A	N/A	N/A	N/A
Oklahoma	Oklahoma City	N/A	N/A	N/A	N/A
Oregon	Portland	3,963	1.09	353	4,316
Pennsylvania	Philadelphia	N/A	N/A	N/A	N/A
Pennsylvania	Scranton	N/A	N/A	N/A	N/A
Rhode Island	Providence	N/A	N/A	N/A	N/A
South Carolina	Charleston	N/A	N/A	N/A	N/A
South Dakota	Rapid City	N/A	N/A	N/A	N/A
Tennessee	Nashville	N/A	N/A	N/A	N/A
Texas	Houston	N/A	N/A	N/A	N/A
Utah	Salt Lake City	N/A	N/A	N/A	N/A
Vermont	Burlington	N/A	N/A	N/A	N/A
Virginia	Alexandria	N/A	N/A	N/A	N/A
Virginia	Roanoke	N/A	N/A	N/A	N/A
Washington	Seattle	3,963	1.13	512	4,475
Washington	Spokane	3,963	1.03	138	4,101
West Virginia	Charleston	N/A	N/A	N/A	N/A
Wisconsin	Green Bay	N/A	N/A	N/A	N/A
Wyoming	Cheyenne	N/A	N/A	N/A	N/A

Table 1-12 — Location Adjustment for Hydroelectric Power Plant
(2023 USD)
Case Configuration: 100 MW Net, New Stream Reach Development

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	N/A	N/A	N/A	N/A
Arizona	Phoenix	N/A	N/A	N/A	N/A
Arkansas	Little Rock	N/A	N/A	N/A	N/A
California	Bakersfield	7,073	1.18	1,254	8327
California	Los Angeles	7,073	1.19	1,366	8439
California	Modesto	7,073	1.20	1,428	8501
California	Sacramento	7,073	1.21	1,498	8571
California	San Francisco	7,073	1.27	1,937	9010
Colorado	Denver	7,073	0.98	(162)	6911
Connecticut	Hartford	7,073	1.13	904	7977
Delaware	Dover	N/A	N/A	N/A	N/A
District of Columbia	Washington	N/A	N/A	N/A	N/A
Florida	Tallahassee	N/A	N/A	N/A	N/A
Florida	Tampa	N/A	N/A	N/A	N/A
Georgia	Atlanta	N/A	N/A	N/A	N/A
Idaho	Boise	7,073	1.03	216	7289
Illinois	Chicago	N/A	N/A	N/A	N/A
Indiana	Indianapolis	N/A	N/A	N/A	N/A
Iowa	Davenport	N/A	N/A	N/A	N/A
Iowa	Waterloo	N/A	N/A	N/A	N/A
Kansas	Wichita	N/A	N/A	N/A	N/A
Kentucky	Louisville	N/A	N/A	N/A	N/A
Louisiana	New Orleans	N/A	N/A	N/A	N/A
Maine	Portland	7,073	1.03	192	7265
Maryland	Baltimore	N/A	N/A	N/A	N/A
Massachusetts	Boston	N/A	N/A	N/A	N/A
Michigan	Detroit	N/A	N/A	N/A	N/A
Michigan	Grand Rapids	N/A	N/A	N/A	N/A
Minnesota	Saint Paul	N/A	N/A	N/A	N/A
Mississippi	Biloxi	N/A	N/A	N/A	N/A
Missouri	St. Louis	7,073	1.13	903	7976
Missouri	Kansas City	7,073	1.04	318	7391
Montana	Great Falls	7,073	0.98	(115)	6958
Nebraska	Omaha	N/A	N/A	N/A	N/A
New Hampshire	Manchester	N/A	N/A	N/A	N/A
New Jersey	Newark	N/A	N/A	N/A	N/A
New Mexico	Albuquerque	N/A	N/A	N/A	N/A
New York	New York	N/A	N/A	N/A	N/A
New York	Syracuse	N/A	N/A	N/A	N/A
Nevada	Las Vegas	7,073	1.14	978	8051
North Carolina	Charlotte	N/A	N/A	N/A	N/A
North Dakota	Bismarck	N/A	N/A	N/A	N/A
Ohio	Cincinnati	7,073	0.98	(134)	6939
Oklahoma	Oklahoma City	N/A	N/A	N/A	N/A
Oregon	Portland	7,073	1.12	870	7943
Pennsylvania	Philadelphia	N/A	N/A	N/A	N/A
Pennsylvania	Scranton	N/A	N/A	N/A	N/A
Rhode Island	Providence	N/A	N/A	N/A	N/A
South Carolina	Charleston	N/A	N/A	N/A	N/A
South Dakota	Rapid City	7,073	0.98	(173)	6900
Tennessee	Nashville	N/A	N/A	N/A	N/A
Texas	Houston	N/A	N/A	N/A	N/A
Utah	Salt Lake City	N/A	N/A	N/A	N/A
Vermont	Burlington	N/A	N/A	N/A	N/A
Virginia	Alexandria	N/A	N/A	N/A	N/A
Virginia	Roanoke	N/A	N/A	N/A	N/A
Washington	Seattle	7,073	1.17	1,186	8259
Washington	Spokane	7,073	1.06	429	7502
West Virginia	Charleston	N/A	N/A	N/A	N/A
Wisconsin	Green Bay	N/A	N/A	N/A	N/A
Wyoming	Cheyenne	N/A	N/A	N/A	N/A

Table 1-13 — Location Adjustment for Onshore Wind – Large Plant Footprint: Great Plains Region (2023 USD)
Case Configuration: 200 MW Net, 200 MW | 2.82 MW WTG

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	1,489	0.99	(18)	1471
Arizona	Phoenix	1,489	1.00	(8)	1481
Arkansas	Little Rock	1,489	1.00	5	1494
California	Bakersfield	1,489	1.15	218	1707
California	Los Angeles	1,489	1.18	274	1763
California	Modesto	1,489	1.16	244	1733
California	Sacramento	1,489	1.18	268	1757
California	San Francisco	1,489	1.28	420	1909
Colorado	Denver	1,489	0.98	(31)	1458
Connecticut	Hartford	1,489	1.11	167	1656
Delaware	Dover	1,489	1.07	102	1591
District of Columbia	Washington	1,489	1.03	38	1527
Florida	Tallahassee	1,489	0.96	(54)	1435
Florida	Tampa	1,489	0.97	(38)	1451
Georgia	Atlanta	1,489	1.01	16	1505
Idaho	Boise	1,489	1.02	34	1523
Illinois	Chicago	1,489	1.20	304	1793
Indiana	Indianapolis	1,489	1.02	26	1515
Iowa	Davenport	1,489	1.02	24	1513
Iowa	Waterloo	1,489	0.98	(24)	1465
Kansas	Wichita	1,489	0.98	(27)	1462
Kentucky	Louisville	1,489	1.01	12	1501
Louisiana	New Orleans	1,489	1.02	23	1512
Maine	Portland	1,489	1.01	17	1506
Maryland	Baltimore	1,489	1.01	15	1504
Massachusetts	Boston	1,489	1.18	273	1762
Michigan	Detroit	1,489	1.06	92	1581
Michigan	Grand Rapids	1,489	1.00	1	1490
Minnesota	Saint Paul	1,489	1.07	104	1593
Mississippi	Biloxi	1,489	0.97	(51)	1438
Missouri	St. Louis	1,489	1.10	152	1641
Missouri	Kansas City	1,489	1.04	60	1549
Montana	Great Falls	1,489	0.98	(25)	1464
Nebraska	Omaha	1,489	0.98	(26)	1463
New Hampshire	Manchester	1,489	1.04	54	1543
New Jersey	Newark	1,489	1.19	284	1773
New Mexico	Albuquerque	1,489	1.02	33	1522
New York	New York	1,489	1.34	501	1990
New York	Syracuse	1,489	1.05	78	1567
Nevada	Las Vegas	1,489	1.12	181	1670
North Carolina	Charlotte	1,489	0.99	(21)	1468
North Dakota	Bismarck	1,489	1.00	2	1491
Ohio	Cincinnati	1,489	0.98	(34)	1455
Oklahoma	Oklahoma City	1,489	0.97	(47)	1442
Oregon	Portland	1,489	1.11	161	1650
Pennsylvania	Philadelphia	1,489	1.18	265	1754
Pennsylvania	Scranton	1,489	1.03	41	1530
Rhode Island	Providence	1,489	1.09	140	1629
South Carolina	Charleston	1,489	1.01	20	1509
South Dakota	Rapid City	1,489	0.99	(21)	1468
Tennessee	Nashville	1,489	1.02	23	1512
Texas	Houston	1,489	0.95	(81)	1408
Utah	Salt Lake City	1,489	1.01	14	1503
Vermont	Burlington	1,489	1.07	105	1594
Virginia	Alexandria	1,489	1.02	25	1514
Virginia	Roanoke	1,489	0.98	(24)	1465
Washington	Seattle	1,489	1.16	238	1727
Washington	Spokane	1,489	1.04	56	1545
West Virginia	Charleston	1,489	1.00	6	1495
Wisconsin	Green Bay	1,489	1.05	76	1565
Wyoming	Cheyenne	1,489	0.98	(26)	1463

Table 1-14 — Location Adjustment for Onshore Wind Repowering/Retrofit
(2023 USD)
Case Configuration: 150 MW Net, 150 MW | 1.5-1.62 MW WTG

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	1,386	1.00	(3)	1383
Arizona	Phoenix	1,386	0.99	(9)	1377
Arkansas	Little Rock	1,386	1.01	21	1407
California	Bakersfield	1,386	1.11	148	1534
California	Los Angeles	1,386	1.13	182	1568
California	Modesto	1,386	1.12	165	1551
California	Sacramento	1,386	1.13	179	1565
California	San Francisco	1,386	1.20	271	1657
Colorado	Denver	1,386	0.98	(22)	1364
Connecticut	Hartford	1,386	1.08	106	1492
Delaware	Dover	1,386	1.04	56	1442
District of Columbia	Washington	1,386	1.02	25	1411
Florida	Tallahassee	1,386	0.98	(32)	1354
Florida	Tampa	1,386	0.99	(20)	1366
Georgia	Atlanta	1,386	1.01	18	1404
Idaho	Boise	1,386	1.02	27	1413
Illinois	Chicago	1,386	1.13	186	1572
Indiana	Indianapolis	1,386	1.02	24	1410
Iowa	Davenport	1,386	1.01	15	1401
Iowa	Waterloo	1,386	0.99	(15)	1371
Kansas	Wichita	1,386	0.99	(17)	1369
Kentucky	Louisville	1,386	1.01	16	1402
Louisiana	New Orleans	1,386	1.02	28	1414
Maine	Portland	1,386	1.01	13	1399
Maryland	Baltimore	1,386	1.01	11	1397
Massachusetts	Boston	1,386	1.12	173	1559
Michigan	Detroit	1,386	1.04	56	1442
Michigan	Grand Rapids	1,386	1.00	0	1386
Minnesota	Saint Paul	1,386	1.04	55	1441
Mississippi	Biloxi	1,386	0.98	(32)	1354
Missouri	St. Louis	1,386	1.08	113	1499
Missouri	Kansas City	1,386	1.03	37	1423
Montana	Great Falls	1,386	0.99	(17)	1369
Nebraska	Omaha	1,386	0.99	(16)	1370
New Hampshire	Manchester	1,386	1.03	46	1432
New Jersey	Newark	1,386	1.13	177	1563
New Mexico	Albuquerque	1,386	1.03	35	1421
New York	New York	1,386	1.22	310	1696
New York	Syracuse	1,386	1.03	48	1434
Nevada	Las Vegas	1,386	1.09	125	1511
North Carolina	Charlotte	1,386	0.99	(13)	1373
North Dakota	Bismarck	1,386	0.99	(8)	1378
Ohio	Cincinnati	1,386	0.98	(22)	1364
Oklahoma	Oklahoma City	1,386	0.98	(30)	1356
Oregon	Portland	1,386	1.08	114	1500
Pennsylvania	Philadelphia	1,386	1.12	165	1551
Pennsylvania	Scranton	1,386	1.02	26	1412
Rhode Island	Providence	1,386	1.07	93	1479
South Carolina	Charleston	1,386	1.03	48	1434
South Dakota	Rapid City	1,386	0.98	(22)	1364
Tennessee	Nashville	1,386	1.02	32	1418
Texas	Houston	1,386	0.97	(48)	1338
Utah	Salt Lake City	1,386	1.02	25	1411
Vermont	Burlington	1,386	1.07	97	1483
Virginia	Alexandria	1,386	1.01	18	1404
Virginia	Roanoke	1,386	0.99	(15)	1371
Washington	Seattle	1,386	1.12	162	1548
Washington	Spokane	1,386	1.03	42	1428
West Virginia	Charleston	1,386	1.00	3	1389
Wisconsin	Green Bay	1,386	1.03	36	1422
Wyoming	Cheyenne	1,386	0.99	(20)	1366

Table 1-15 — Location Adjustment for Fixed-bottom Offshore Wind: Monopile Foundations
Case Configuration: 900 MW Net, 900 MW | 15 MW WTG

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	N/A	N/A	N/A	N/A
Arizona	Phoenix	N/A	N/A	N/A	N/A
Arkansas	Little Rock	N/A	N/A	N/A	N/A
California	Bakersfield	3,689	1.15	542	4231
California	Los Angeles	3,689	1.18	674	4363
California	Modesto	3,689	1.16	606	4295
California	Sacramento	3,689	1.18	660	4349
California	San Francisco	3,689	1.27	1,012	4701
Colorado	Denver	N/A	N/A	N/A	N/A
Connecticut	Hartford	3,689	1.11	397	4086
Delaware	Dover	3,689	1.06	218	3907
District of Columbia	Washington	N/A	N/A	N/A	N/A
Florida	Tallahassee	N/A	N/A	N/A	N/A
Florida	Tampa	N/A	N/A	N/A	N/A
Georgia	Atlanta	3,689	1.02	57	3746
Idaho	Boise	N/A	N/A	N/A	N/A
Illinois	Chicago	3,689	1.19	703	4392
Indiana	Indianapolis	N/A	N/A	N/A	N/A
Iowa	Davenport	N/A	N/A	N/A	N/A
Iowa	Waterloo	N/A	N/A	N/A	N/A
Kansas	Wichita	N/A	N/A	N/A	N/A
Kentucky	Louisville	N/A	N/A	N/A	N/A
Louisiana	New Orleans	N/A	N/A	N/A	N/A
Maine	Portland	3,689	1.01	47	3736
Maryland	Baltimore	3,689	1.01	41	3730
Massachusetts	Boston	3,689	1.18	647	4336
Michigan	Detroit	3,689	1.06	212	3901
Michigan	Grand Rapids	3,689	1.00	1	3690
Minnesota	Saint Paul	3,689	1.06	218	3907
Mississippi	Biloxi	N/A	N/A	N/A	N/A
Missouri	St. Louis	N/A	N/A	N/A	N/A
Missouri	Kansas City	N/A	N/A	N/A	N/A
Montana	Great Falls	N/A	N/A	N/A	N/A
Nebraska	Omaha	N/A	N/A	N/A	N/A
New Hampshire	Manchester	N/A	N/A	N/A	N/A
New Jersey	Newark	3,689	1.18	664	4353
New Mexico	Albuquerque	N/A	N/A	N/A	N/A
New York	New York	3,689	1.32	1,168	4857
New York	Syracuse	3,689	1.05	181	3870
Nevada	Las Vegas	N/A	N/A	N/A	N/A
North Carolina	Charlotte	3,689	0.99	(48)	3641
North Dakota	Bismarck	N/A	N/A	N/A	N/A
Ohio	Cincinnati	N/A	N/A	N/A	N/A
Oklahoma	Oklahoma City	N/A	N/A	N/A	N/A
Oregon	Portland	3,689	1.11	412	4101
Pennsylvania	Philadelphia	N/A	N/A	N/A	N/A
Pennsylvania	Scranton	N/A	N/A	N/A	N/A
Rhode Island	Providence	3,689	1.09	344	4033
South Carolina	Charleston	3,689	1.04	134	3823
South Dakota	Rapid City	N/A	N/A	N/A	N/A
Tennessee	Nashville	N/A	N/A	N/A	N/A
Texas	Houston	3,689	0.95	(185)	3504
Utah	Salt Lake City	N/A	N/A	N/A	N/A
Vermont	Burlington	N/A	N/A	N/A	N/A
Virginia	Alexandria	3,689	1.02	64	3753
Virginia	Roanoke	3,689	0.98	(56)	3633
Washington	Seattle	3,689	1.16	595	4284
Washington	Spokane	3,689	1.04	150	3839
West Virginia	Charleston	N/A	N/A	N/A	N/A
Wisconsin	Green Bay	3,689	1.04	147	3836
Wyoming	Cheyenne	N/A	N/A	N/A	N/A

Table 1-16 — Location Adjustment for Solar PV w/ Single Axis Tracking
(2023 USD)
Case Configuration: 150 MW Net, 150 MWAC

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	1,502	0.98	(22)	1480
Arizona	Phoenix	1,502	1.01	11	1513
Arkansas	Little Rock	1,502	0.99	(20)	1482
California	Bakersfield	1,502	1.09	136	1638
California	Los Angeles	1,502	1.10	150	1652
California	Modesto	1,502	1.10	155	1657
California	Sacramento	1,502	1.11	165	1667
California	San Francisco	1,502	1.16	247	1749
Colorado	Denver	1,502	0.99	(18)	1484
Connecticut	Hartford	1,502	1.07	112	1614
Delaware	Dover	1,502	1.07	104	1606
District of Columbia	Washington	1,502	1.01	19	1521
Florida	Tallahassee	1,502	0.97	(40)	1462
Florida	Tampa	1,502	0.98	(29)	1473
Georgia	Atlanta	1,502	1.00	7	1509
Idaho	Boise	1,502	1.01	14	1516
Illinois	Chicago	1,502	1.13	201	1703
Indiana	Indianapolis	1,502	1.00	(2)	1500
Iowa	Davenport	1,502	1.01	23	1525
Iowa	Waterloo	1,502	0.99	(15)	1487
Kansas	Wichita	1,502	0.99	(15)	1487
Kentucky	Louisville	1,502	1.00	2	1504
Louisiana	New Orleans	1,502	1.00	(3)	1499
Maine	Portland	1,502	1.01	14	1516
Maryland	Baltimore	1,502	1.01	11	1513
Massachusetts	Boston	1,502	1.11	171	1673
Michigan	Detroit	1,502	1.04	65	1567
Michigan	Grand Rapids	1,502	1.00	4	1506
Minnesota	Saint Paul	1,502	1.05	77	1579
Mississippi	Biloxi	1,502	0.98	(33)	1469
Missouri	St. Louis	1,502	1.05	74	1576
Missouri	Kansas City	1,502	1.03	42	1544
Montana	Great Falls	1,502	0.99	(12)	1490
Nebraska	Omaha	1,502	0.99	(15)	1487
New Hampshire	Manchester	1,502	1.02	24	1526
New Jersey	Newark	1,502	1.12	181	1683
New Mexico	Albuquerque	1,502	1.01	14	1516
New York	New York	1,502	1.23	341	1843
New York	Syracuse	1,502	1.03	42	1544
Nevada	Las Vegas	1,502	1.07	101	1603
North Carolina	Charlotte	1,502	0.99	(12)	1490
North Dakota	Bismarck	1,502	1.01	21	1523
Ohio	Cincinnati	1,502	0.99	(16)	1486
Oklahoma	Oklahoma City	1,502	0.98	(32)	1470
Oregon	Portland	1,502	1.06	87	1589
Pennsylvania	Philadelphia	1,502	1.11	165	1667
Pennsylvania	Scranton	1,502	1.02	32	1534
Rhode Island	Providence	1,502	1.06	89	1591
South Carolina	Charleston	1,502	0.98	(28)	1474
South Dakota	Rapid City	1,502	1.00	(4)	1498
Tennessee	Nashville	1,502	1.00	(3)	1499
Texas	Houston	1,502	0.96	(58)	1444
Utah	Salt Lake City	1,502	1.00	(5)	1497
Vermont	Burlington	1,502	1.03	41	1543
Virginia	Alexandria	1,502	1.00	7	1509
Virginia	Roanoke	1,502	0.99	(14)	1488
Washington	Seattle	1,502	1.09	132	1634
Washington	Spokane	1,502	1.02	35	1537
West Virginia	Charleston	1,502	1.01	13	1515
Wisconsin	Green Bay	1,502	1.04	55	1557
Wyoming	Cheyenne	1,502	1.00	(6)	1496

Table 1-17 — Location Adjustment for Solar PV w/ Single Axis Tracking + AC Coupled Battery Storage (2023 USD)

Case Configuration: 150 MW Net, 150 MWAC Solar
50 MW | 200 MWh Storage

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	2,175	0.99	(18)	2157
Arizona	Phoenix	2,175	1.00	8	2183
Arkansas	Little Rock	2,175	1.00	(2)	2173
California	Bakersfield	2,175	1.09	191	2366
California	Los Angeles	2,175	1.10	209	2384
California	Modesto	2,175	1.10	216	2391
California	Sacramento	2,175	1.10	227	2402
California	San Francisco	2,175	1.15	331	2506
Colorado	Denver	2,175	0.99	(27)	2148
Connecticut	Hartford	2,175	1.07	146	2321
Delaware	Dover	2,175	1.06	120	2295
District of Columbia	Washington	2,175	1.01	27	2202
Florida	Tallahassee	2,175	0.98	(49)	2126
Florida	Tampa	2,175	0.98	(33)	2142
Georgia	Atlanta	2,175	1.01	19	2194
Idaho	Boise	2,175	1.01	26	2201
Illinois	Chicago	2,175	1.12	251	2426
Indiana	Indianapolis	2,175	1.00	9	2184
Iowa	Davenport	2,175	1.01	27	2202
Iowa	Waterloo	2,175	0.99	(19)	2156
Kansas	Wichita	2,175	0.99	(20)	2155
Kentucky	Louisville	2,175	1.01	13	2188
Louisiana	New Orleans	2,175	1.01	15	2190
Maine	Portland	2,175	1.01	21	2196
Maryland	Baltimore	2,175	1.01	17	2192
Massachusetts	Boston	2,175	1.10	222	2397
Michigan	Detroit	2,175	1.04	82	2257
Michigan	Grand Rapids	2,175	1.00	4	2179
Minnesota	Saint Paul	2,175	1.04	84	2259
Mississippi	Biloxi	2,175	0.98	(42)	2133
Missouri	St. Louis	2,175	1.06	120	2295
Missouri	Kansas City	2,175	1.02	53	2228
Montana	Great Falls	2,175	0.99	(19)	2156
Nebraska	Omaha	2,175	0.99	(18)	2157
New Hampshire	Manchester	2,175	1.02	48	2223
New Jersey	Newark	2,175	1.11	231	2406
New Mexico	Albuquerque	2,175	1.02	37	2212
New York	New York	2,175	1.20	433	2608
New York	Syracuse	2,175	1.02	53	2228
Nevada	Las Vegas	2,175	1.07	147	2322
North Carolina	Charlotte	2,175	0.99	(15)	2160
North Dakota	Bismarck	2,175	1.01	13	2188
Ohio	Cincinnati	2,175	0.99	(23)	2152
Oklahoma	Oklahoma City	2,175	0.98	(41)	2134
Oregon	Portland	2,175	1.06	130	2305
Pennsylvania	Philadelphia	2,175	1.10	211	2386
Pennsylvania	Scranton	2,175	1.02	42	2217
Rhode Island	Providence	2,175	1.06	122	2297
South Carolina	Charleston	2,175	1.01	11	2186
South Dakota	Rapid City	2,175	0.99	(18)	2157
Tennessee	Nashville	2,175	1.01	20	2195
Texas	Houston	2,175	0.97	(71)	2104
Utah	Salt Lake City	2,175	1.01	15	2190
Vermont	Burlington	2,175	1.04	97	2272
Virginia	Alexandria	2,175	1.01	12	2187
Virginia	Roanoke	2,175	0.99	(18)	2157
Washington	Seattle	2,175	1.09	188	2363
Washington	Spokane	2,175	1.02	54	2229
West Virginia	Charleston	2,175	1.01	15	2190
Wisconsin	Green Bay	2,175	1.02	54	2229
Wyoming	Cheyenne	2,175	0.99	(13)	2162

Table 1-18 — Location Adjustment for Solar Photovoltaic, Single-Axis Tracking (with 1.6 Inverter Loading Ratio) with Battery Hybrid (2023 USD)

Case Configuration: 150 MW PV DC Coupled to 50 MW/200 MWh BESS

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	2,561	0.99	(23)	2538
Arizona	Phoenix	2,561	1.00	9	2570
Arkansas	Little Rock	2,561	1.00	(4)	2557
California	Bakersfield	2,561	1.09	230	2791
California	Los Angeles	2,561	1.10	252	2813
California	Modesto	2,561	1.10	261	2822
California	Sacramento	2,561	1.11	274	2835
California	San Francisco	2,561	1.16	400	2961
Colorado	Denver	2,561	0.99	(34)	2527
Connecticut	Hartford	2,561	1.07	177	2738
Delaware	Dover	2,561	1.06	146	2707
District of Columbia	Washington	2,561	1.01	31	2592
Florida	Tallahassee	2,561	0.98	(60)	2501
Florida	Tampa	2,561	0.98	(41)	2520
Georgia	Atlanta	2,561	1.01	22	2583
Idaho	Boise	2,561	1.01	30	2591
Illinois	Chicago	2,561	1.12	305	2866
Indiana	Indianapolis	2,561	1.00	9	2570
Iowa	Davenport	2,561	1.01	33	2594
Iowa	Waterloo	2,561	0.99	(23)	2538
Kansas	Wichita	2,561	0.99	(25)	2536
Kentucky	Louisville	2,561	1.01	15	2576
Louisiana	New Orleans	2,561	1.01	16	2577
Maine	Portland	2,561	1.01	25	2586
Maryland	Baltimore	2,561	1.01	19	2580
Massachusetts	Boston	2,561	1.11	269	2830
Michigan	Detroit	2,561	1.04	98	2659
Michigan	Grand Rapids	2,561	1.00	4	2565
Minnesota	Saint Paul	2,561	1.04	102	2663
Mississippi	Biloxi	2,561	0.98	(52)	2509
Missouri	St. Louis	2,561	1.06	144	2705
Missouri	Kansas City	2,561	1.02	63	2624
Montana	Great Falls	2,561	0.99	(23)	2538
Nebraska	Omaha	2,561	0.99	(23)	2538
New Hampshire	Manchester	2,561	1.02	57	2618
New Jersey	Newark	2,561	1.11	280	2841
New Mexico	Albuquerque	2,561	1.02	43	2604
New York	New York	2,561	1.21	526	3087
New York	Syracuse	2,561	1.03	64	2625
Nevada	Las Vegas	2,561	1.07	177	2738
North Carolina	Charlotte	2,561	0.99	(19)	2542
North Dakota	Bismarck	2,561	1.01	16	2577
Ohio	Cincinnati	2,561	0.99	(29)	2532
Oklahoma	Oklahoma City	2,561	0.98	(51)	2510
Oregon	Portland	2,561	1.06	156	2717
Pennsylvania	Philadelphia	2,561	1.10	256	2817
Pennsylvania	Scranton	2,561	1.02	50	2611
Rhode Island	Providence	2,561	1.06	147	2708
South Carolina	Charleston	2,561	1.00	10	2571
South Dakota	Rapid City	2,561	0.99	(22)	2539
Tennessee	Nashville	2,561	1.01	22	2583
Texas	Houston	2,561	0.97	(87)	2474
Utah	Salt Lake City	2,561	1.01	17	2578
Vermont	Burlington	2,561	1.04	114	2675
Virginia	Alexandria	2,561	1.01	13	2574
Virginia	Roanoke	2,561	0.99	(23)	2538
Washington	Seattle	2,561	1.09	227	2788
Washington	Spokane	2,561	1.03	65	2626
West Virginia	Charleston	2,561	1.01	18	2579
Wisconsin	Green Bay	2,561	1.03	65	2626
Wyoming	Cheyenne	2,561	0.99	(16)	2545

Table 1-19 — Location Adjustment for Battery Storage: 4 hours
(2023 USD)
Case Configuration: 150 MW / 600 MWh

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alabama	Huntsville	1,744	1.01	21	1765
Arizona	Phoenix	1,744	0.99	(17)	1727
Arkansas	Little Rock	1,744	1.03	58	1802
California	Bakersfield	1,744	1.07	126	1870
California	Los Angeles	1,744	1.09	149	1893
California	Modesto	1,744	1.07	130	1874
California	Sacramento	1,744	1.08	136	1880
California	San Francisco	1,744	1.11	187	1931
Colorado	Denver	1,744	0.99	(18)	1726
Connecticut	Hartford	1,744	1.05	83	1827
Delaware	Dover	1,744	1.01	22	1766
District of Columbia	Washington	1,744	1.01	24	1768
Florida	Tallahassee	1,744	0.99	(15)	1729
Florida	Tampa	1,744	1.00	(4)	1740
Georgia	Atlanta	1,744	1.02	34	1778
Idaho	Boise	1,744	1.02	31	1775
Illinois	Chicago	1,744	1.07	121	1865
Indiana	Indianapolis	1,744	1.02	37	1781
Iowa	Davenport	1,744	1.01	13	1757
Iowa	Waterloo	1,744	1.00	(5)	1739
Kansas	Wichita	1,744	1.00	(4)	1740
Kentucky	Louisville	1,744	1.02	35	1779
Louisiana	New Orleans	1,744	1.03	56	1800
Maine	Portland	1,744	1.01	19	1763
Maryland	Baltimore	1,744	1.01	19	1763
Massachusetts	Boston	1,744	1.07	123	1867
Michigan	Detroit	1,744	1.02	32	1776
Michigan	Grand Rapids	1,744	1.00	1	1745
Minnesota	Saint Paul	1,744	1.01	15	1759
Mississippi	Biloxi	1,744	0.99	(17)	1727
Missouri	St. Louis	1,744	1.07	121	1865
Missouri	Kansas City	1,744	1.01	25	1769
Montana	Great Falls	1,744	0.99	(13)	1731
Nebraska	Omaha	1,744	1.00	(4)	1740
New Hampshire	Manchester	1,744	1.03	60	1804
New Jersey	Newark	1,744	1.06	112	1856
New Mexico	Albuquerque	1,744	1.03	61	1805
New York	New York	1,744	1.12	204	1948
New York	Syracuse	1,744	1.02	34	1778
Nevada	Las Vegas	1,744	1.07	116	1860
North Carolina	Charlotte	1,744	1.00	(5)	1739
North Dakota	Bismarck	1,744	0.99	(22)	1722
Ohio	Cincinnati	1,744	0.99	(17)	1727
Oklahoma	Oklahoma City	1,744	0.99	(19)	1725
Oregon	Portland	1,744	1.06	107	1851
Pennsylvania	Philadelphia	1,744	1.06	105	1849
Pennsylvania	Scranton	1,744	1.01	23	1767
Rhode Island	Providence	1,744	1.04	75	1819
South Carolina	Charleston	1,744	1.07	119	1863
South Dakota	Rapid City	1,744	0.98	(35)	1709
Tennessee	Nashville	1,744	1.04	66	1810
Texas	Houston	1,744	0.99	(23)	1721
Utah	Salt Lake City	1,744	1.03	60	1804
Vermont	Burlington	1,744	1.08	143	1887
Virginia	Alexandria	1,744	1.01	21	1765
Virginia	Roanoke	1,744	1.00	(8)	1736
Washington	Seattle	1,744	1.08	138	1882
Washington	Spokane	1,744	1.03	44	1788
West Virginia	Charleston	1,744	1.00	(1)	1743
Wisconsin	Green Bay	1,744	0.99	(8)	1736
Wyoming	Cheyenne	1,744	0.99	(22)	1722

APPENDIX B. COMBUSTION TURBINE CAPACITY ADJUSTMENTS

									Gas Turbine Based Capacity and Heat Rate Adjustments											
LOCATION		Adjustment Basis			Simple Cycle		Combined Cyle		4 x LM6000PF+		1 x 7HA.03		2 x 7HA.03 WCT		2 x 7HA.03 ACC		1 x 9000HL WCT		1 x 9000HL ACC	
State	City	ASHRAE Station	Alt (ft)	Ave T (F)	MW adj SC	HR adj SC	MW adj CC	HR adj CC	MW net	HR net	MW net	HR net	MW net	HR net	MW net	HR net	MW net	HR net	MW net	HR net
ISO	**ISO**	**-**	**0**	**59.0**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**210.7**	**8,511**	**419.4**	**8,236**	**1,227.3**	**5,660**	**1,211.5**	**5,734**	**626.7**	**5,645**	**616.2**	**5,742**
Alabama	Huntsville	723230	624	62.2	96.6%	100.3%	97.0%	100.3%	203.5	8,538	405.0	8,262	1,190.9	5,676	1,175.6	5,750	608.2	5,661	597.9	5,758
Arizona	Phoenix	722780	1,107	75.5	89.8%	101.7%	92.2%	101.0%	189.2	8,651	376.6	8,372	1,131.1	5,719	1,116.6	5,794	577.6	5,705	567.9	5,802
Arkansas	Little Rock	723400	563	61.7	97.0%	100.3%	97.4%	100.2%	204.3	8,534	406.7	8,258	1,195.0	5,674	1,179.7	5,748	610.2	5,659	600.0	5,756
California	Los Angeles	722950	97	63.4	97.9%	100.4%	98.6%	100.2%	206.3	8,548	410.6	8,272	1,209.7	5,673	1,194.1	5,747	617.7	5,659	607.4	5,756
California	Bakersfield	723840	489	66.2	95.5%	100.7%	96.5%	100.5%	201.2	8,572	400.4	8,295	1,184.6	5,686	1,169.4	5,760	604.9	5,671	594.8	5,768
California	Sacramento	724839	23	61.9	98.8%	100.3%	99.2%	100.1%	208.1	8,536	414.2	8,260	1,217.4	5,668	1,201.8	5,742	621.7	5,654	611.2	5,750
California	Modesto	724926	73	63.4	98.0%	100.4%	98.6%	100.2%	206.5	8,548	411.0	8,272	1,210.7	5,673	1,195.2	5,747	618.3	5,659	607.9	5,755
California	San Francisco	724940	8	58.3	100.3%	99.9%	100.1%	100.0%	211.3	8,505	420.5	8,230	1,229.1	5,658	1,213.3	5,732	627.7	5,643	617.1	5,740
California	Redding	725920	497	63.2	96.6%	100.4%	97.2%	100.3%	203.6	8,547	405.2	8,271	1,193.3	5,677	1,178.0	5,751	609.4	5,663	599.1	5,760
Colorado	Denver	725650	5,414	51.2	83.6%	99.2%	82.6%	100.7%	176.1	8,444	350.5	8,172	1,014.1	5,699	1,001.1	5,773	517.9	5,684	509.2	5,781
Connecticut	Hartford	725087	19	52.5	102.5%	99.4%	101.6%	99.7%	216.1	8,456	430.0	8,182	1,246.4	5,642	1,230.4	5,715	636.5	5,627	625.8	5,723
DC	Washington	745940	282	56.7	99.9%	99.8%	99.6%	99.9%	210.6	8,491	419.1	8,217	1,222.2	5,657	1,206.5	5,730	624.1	5,642	613.6	5,739
Delaware	Dover	724088	28	56.3	101.0%	99.7%	100.6%	99.9%	212.8	8,488	423.5	8,214	1,234.4	5,653	1,218.5	5,726	630.4	5,638	619.8	5,734
Florida	Tampa	722110	19	73.9	94.0%	101.5%	96.2%	100.7%	198.0	8,638	394.2	8,359	1,180.8	5,702	1,165.6	5,776	603.0	5,688	592.9	5,785
Florida	Tallahassee	722140	55	68.6	96.0%	101.0%	97.4%	100.5%	202.2	8,593	402.5	8,315	1,195.5	5,688	1,180.2	5,762	610.5	5,673	600.3	5,770
Georgia	Atlanta	722190	1,027	63.3	94.7%	100.4%	95.4%	100.4%	199.7	8,547	397.4	8,271	1,170.5	5,684	1,155.4	5,758	597.7	5,669	587.7	5,766
Idaho	Boise	726810	2,814	53.4	92.2%	99.4%	91.4%	100.3%	194.2	8,463	386.6	8,190	1,121.9	5,676	1,107.5	5,750	572.9	5,661	563.3	5,758
Illinois	Chicago	997338	663	50.1	101.2%	99.1%	99.9%	99.7%	213.2	8,435	424.3	8,163	1,225.5	5,642	1,209.8	5,716	625.8	5,628	615.3	5,724
Indiana	Indianapolis	724380	790	53.9	99.2%	99.5%	98.5%	99.9%	209.1	8,467	416.1	8,194	1,208.6	5,654	1,193.1	5,728	617.2	5,640	606.8	5,736
Iowa	Davenport	725349	753	49.7	101.0%	99.1%	99.6%	99.7%	212.8	8,432	423.5	8,159	1,222.7	5,642	1,207.0	5,715	624.4	5,628	613.9	5,724
Iowa	Waterloo	725480	686	48.0	101.9%	98.9%	100.3%	99.6%	214.7	8,417	427.4	8,145	1,230.8	5,637	1,215.0	5,710	628.5	5,622	617.9	5,718
Kansas	Wichita	724500	1,321	57.9	95.8%	99.9%	95.6%	100.2%	201.9	8,501	401.8	8,227	1,173.8	5,672	1,158.7	5,746	599.4	5,657	589.3	5,754
Kentucky	Louisville	724230	488	58.6	98.4%	100.0%	98.4%	100.1%	207.5	8,507	412.9	8,233	1,207.5	5,664	1,192.0	5,738	616.7	5,650	606.3	5,746
Louisiana	New Orleans	722316	2	69.1	96.0%	101.0%	97.5%	100.5%	202.2	8,597	402.4	8,319	1,196.2	5,689	1,180.9	5,763	610.9	5,674	600.6	5,771
Maine	Portland	726060	45	47.2	104.6%	98.8%	102.8%	99.4%	220.3	8,410	438.5	8,139	1,261.5	5,627	1,245.3	5,700	644.2	5,613	633.4	5,709
Maryland	Baltimore	724060	56	56.3	100.9%	99.7%	100.5%	99.9%	212.6	8,488	423.1	8,214	1,233.2	5,653	1,217.3	5,726	629.7	5,638	619.1	5,735
Massachusetts	Boston	725090	12	52.2	102.7%	99.3%	101.7%	99.7%	216.4	8,453	430.6	8,180	1,247.6	5,641	1,231.6	5,714	637.1	5,626	626.4	5,722
Michigan	Detroit	725375	626	51.1	100.9%	99.2%	99.7%	99.7%	212.6	8,444	423.2	8,171	1,224.1	5,645	1,208.4	5,718	625.1	5,630	614.6	5,726
Michigan	Grand Rapids	726350	803	49.1	101.0%	99.0%	99.6%	99.7%	212.9	8,427	423.8	8,154	1,222.3	5,641	1,206.6	5,714	624.2	5,626	613.7	5,723
Minnesota	Saint Paul	726584	700	46.9	102.3%	98.8%	100.5%	99.5%	215.5	8,408	428.9	8,136	1,233.4	5,634	1,217.6	5,707	629.9	5,619	619.3	5,715
Mississippi	Jackson	722350	330	65.5	96.3%	100.7%	97.2%	100.4%	202.9	8,566	403.8	8,290	1,193.4	5,682	1,178.1	5,756	609.4	5,667	599.2	5,764
Missouri	St. Louis	724340	531	57.8	98.6%	99.9%	98.4%	100.0%	207.8	8,501	413.6	8,226	1,208.1	5,663	1,192.6	5,736	616.9	5,648	606.6	5,745
Missouri	Kansas City	724463	742	57.4	98.0%	99.8%	97.8%	100.1%	206.6	8,497	411.1	8,223	1,200.2	5,664	1,184.8	5,737	612.9	5,649	602.6	5,746
Montana	Great Falls	727750	3,364	45.2	93.1%	98.6%	91.3%	100.0%	196.2	8,393	390.5	8,122	1,120.2	5,659	1,105.8	5,732	572.0	5,644	562.4	5,741
Nebraska	Omaha	725530	1,332	51.6	98.2%	99.3%	97.1%	99.9%	206.8	8,448	411.7	8,175	1,191.7	5,654	1,176.4	5,728	608.6	5,639	598.3	5,736
Nevada	Las Vegas	724846	2,203	69.4	88.5%	101.0%	89.9%	101.0%	186.4	8,599	371.0	8,322	1,103.2	5,714	1,089.1	5,789	563.4	5,700	553.9	5,797
New Hampshire	Concord	726050	346	47.2	103.5%	98.8%	101.7%	99.5%	218.0	8,410	433.9	8,139	1,248.2	5,630	1,232.2	5,704	637.4	5,616	626.7	5,712
New Jersey	Newark	725020	7	55.8	101.3%	99.7%	100.8%	99.8%	213.4	8,484	424.7	8,210	1,236.8	5,651	1,220.9	5,724	631.6	5,636	621.0	5,733
New Mexico	Albuquerque	723650	5,310	58.5	81.6%	100.0%	81.5%	101.0%	171.9	8,507	342.1	8,232	1,000.5	5,719	987.6	5,793	510.9	5,704	502.3	5,801
New York	New York	725053	130	55.3	101.0%	99.6%	100.5%	99.8%	212.9	8,479	423.7	8,206	1,233.0	5,651	1,217.2	5,724	629.7	5,636	619.1	5,733
New York	Syracuse	725190	413	48.9	102.5%	99.0%	101.0%	99.6%	216.1	8,425	430.0	8,153	1,240.1	5,636	1,224.2	5,709	633.3	5,621	622.6	5,718
North Carolina	Charlotte	723140	728	61.5	96.5%	100.3%	96.8%	100.3%	203.3	8,532	404.6	8,257	1,188.6	5,675	1,173.3	5,749	607.0	5,661	596.8	5,757
North Carolina	Asheville	723150	2,117	56.5	93.5%	99.8%	93.2%	100.3%	197.1	8,490	392.2	8,215	1,143.5	5,677	1,128.8	5,751	583.9	5,662	574.1	5,759
North Dakota	Bismarck	727640	1,651	43.5	100.1%	98.5%	97.9%	99.6%	210.9	8,379	419.7	8,108	1,201.2	5,635	1,185.8	5,708	613.4	5,620	603.1	5,716
Ohio	Cincinnati	724297	490	55.0	99.9%	99.6%	99.3%	99.9%	210.4	8,477	418.8	8,203	1,218.3	5,654	1,202.7	5,728	622.2	5,640	611.7	5,736

									Gas Turbine Based Capacity and Heat Rate Adjustments											
LOCATION		Adjustment Basis			Simple Cycle		Combined Cyle		4 x LM6000PF+		1 x 7HA.03		2 x 7HA.03 WCT		2 x 7HA.03 ACC		1 x 9000HL WCT		1 x 9000HL ACC	
State	City	ASHRAE Station	Alt (ft)	Ave T (F)	MW adj SC	HR adj SC	MW adj CC	HR adj CC	MW net	HR net	MW net	HR net	MW net	HR net	MW net	HR net	MW net	HR net	MW net	HR net
ISO	**ISO**	**-**	**0**	**59.0**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**210.7**	**8,511**	**419.4**	**8,236**	**1,227.3**	**5,660**	**1,211.5**	**5,734**	**626.7**	**5,645**	**616.2**	**5,742**
Oklahoma	Oklahoma City	723530	1,285	61.3	94.6%	100.2%	95.0%	100.4%	199.4	8,530	396.9	8,255	1,165.4	5,681	1,150.4	5,755	595.1	5,666	585.1	5,763
Oklahoma	Tulsa	723560	650	61.6	96.7%	100.3%	97.1%	100.3%	203.8	8,533	405.6	8,257	1,191.6	5,675	1,176.3	5,748	608.5	5,660	598.3	5,757
Oregon	Portland	726980	19	54.9	101.6%	99.6%	101.0%	99.8%	214.0	8,476	426.0	8,202	1,239.1	5,649	1,223.1	5,722	632.7	5,634	622.1	5,730
Pennsylvania	Philadelphia	724080	10	56.8	100.8%	99.8%	100.5%	99.9%	212.5	8,492	423.0	8,218	1,233.6	5,654	1,217.8	5,727	630.0	5,639	619.4	5,736
Pennsylvania	Wilkes-Barre	725130	930	50.5	100.0%	99.2%	98.8%	99.8%	210.8	8,439	419.6	8,166	1,212.6	5,646	1,197.0	5,720	619.2	5,632	608.8	5,728
Rhode Island	Providence	997278	33	53.0	102.3%	99.4%	101.4%	99.7%	215.5	8,460	429.0	8,187	1,244.3	5,643	1,228.3	5,717	635.4	5,629	624.7	5,725
South Carolina	Charleston	722080	40	66.7	96.8%	100.8%	97.9%	100.4%	203.9	8,576	405.9	8,299	1,202.0	5,682	1,186.6	5,756	613.8	5,668	603.5	5,764
South Carolina	Spartanburg	723120	943	61.6	95.7%	100.3%	96.1%	100.3%	201.6	8,533	401.4	8,257	1,179.1	5,678	1,163.9	5,752	602.1	5,663	592.0	5,760
South Dakota	Rapid City	726620	3,160	47.3	93.1%	98.8%	91.5%	100.0%	196.2	8,411	390.5	8,140	1,123.5	5,662	1,109.1	5,736	573.7	5,648	564.1	5,744
Tennessee	Knoxville	723260	962	59.8	96.3%	100.1%	96.4%	100.2%	203.0	8,518	404.0	8,243	1,183.6	5,673	1,168.4	5,747	604.4	5,658	594.3	5,755
Tennessee	Nashville	723270	600	60.5	97.3%	100.2%	97.5%	100.2%	205.1	8,524	408.1	8,248	1,197.0	5,671	1,181.7	5,745	611.3	5,656	601.0	5,753
Texas	Houston	722436	32	70.7	95.2%	101.2%	97.0%	100.6%	200.6	8,610	399.3	8,332	1,190.1	5,693	1,174.8	5,767	607.7	5,679	597.5	5,776
Utah	Salt Lake City	725720	4,225	54.1	86.9%	99.5%	86.3%	100.6%	183.1	8,469	364.4	8,196	1,058.6	5,694	1,045.0	5,768	540.6	5,679	531.5	5,776
Vermont	Burlington	726170	330	47.0	103.6%	98.8%	101.8%	99.5%	218.3	8,409	434.5	8,137	1,249.5	5,630	1,233.5	5,703	638.1	5,615	627.4	5,711
Virginia	Alexandria	724050	10	59.0	100.0%	100.0%	100.0%	100.0%	210.6	8,511	419.3	8,236	1,226.9	5,660	1,211.1	5,734	626.5	5,645	616.0	5,742
Virginia	Lynchburg	724100	940	56.5	97.7%	99.8%	97.3%	100.1%	205.8	8,490	409.7	8,215	1,194.3	5,663	1,179.0	5,737	609.9	5,649	599.7	5,745
Washington	Spokane	727850	2,353	48.5	95.6%	99.0%	94.2%	99.9%	201.5	8,421	401.0	8,150	1,155.8	5,657	1,140.9	5,730	590.2	5,642	580.3	5,739
Washington	Seattle	994014	7	53.5	102.2%	99.5%	101.4%	99.7%	215.3	8,464	428.5	8,191	1,243.9	5,644	1,227.9	5,718	635.2	5,630	624.5	5,726
West Virginia	Charleston	724140	910	56.0	98.0%	99.7%	97.5%	100.0%	206.5	8,485	410.9	8,211	1,197.1	5,662	1,181.8	5,735	611.3	5,647	601.1	5,744
Wisconsin	Green Bay	726450	687	45.8	102.7%	98.7%	100.8%	99.5%	216.5	8,399	430.9	8,127	1,237.3	5,630	1,221.4	5,704	631.9	5,616	621.2	5,712
Wyoming	Cheyenne	725640	6,130	47.0	82.3%	98.8%	80.9%	100.6%	173.5	8,409	345.2	8,137	992.9	5,695	980.2	5,769	507.0	5,680	498.5	5,777