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 estimated total volume of water required for cooling tower makeup, cycle makeup, and cooling for the CO_2 system is approximately 10,000 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 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

The base cost estimate for this technology case totals $4558/kW. Table 2-1 summarizes the cost components for this case. Cost associated with CO_2 sequestration have been excluded. 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. No special systems are needed to prevent freezing or to account for snow loads on structures.

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 and 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, ZLD equipment is added. Zero liquid discharge 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 STG equipment will be enclosed in all locations.

Table 2-1 — Case 2 Capital Cost Estimate

Case 2 EIA – Capital Cost Estimates – 2019 $s			
Configuration		650 MW Net, Ultra-Supercritical Coal w/ 30% Carbon Capture 1 x 769 MW Gross	
Combustion Emissions Controls		Low NOx Burners / OFA	
Post-Combustion Emissions Controls		SCR / Baghouse/ WFGD / WESP - AMINE Based CCS	
Fuel Type		High Sulfur Bituminous	
	Units		
Plant Characteristics			
Net Plant Capacity (60 deg F, 60% RH)	MW	650	
Heat Rate, HHV Basis	Btu/kWh	9751	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	10%	
Project Contingency	% of Project Costs	12%	
Owner's Services	% of Project Costs	7%	
Estimated Land Requirement (acres)	$	300	
Estimated Land Cost ($/acre)	$	30,000	
Interconnection Costs			
Electrical Transmission Line Costs	$/mile	2,520,000	
Miles	miles	1.00	
Substation Expansion	$	0	
Gas Interconnection Costs			
Pipeline Cost	$/mile	2,500,000	
Miles	miles	0.50	
Metering Station	$	3,600,000	
Typical Project Timelines			
Development, Permitting, Engineering	months	24	
Plant Construction Time	months	36	
Total Lead Time Before COD	months	60	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		263,200,000
Mechanical – Boiler Plant	$	935,766,667	
Mechanical – Turbine Plant	$	185,866,667	
Mechanical – Balance of Plant	$	49,966,667	
Mechanical Subtotal	$		1,171,600,000

Case 2 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**650 MW Net, Ultra-Supercritical Coal w/ 30% Carbon Capture** 1 x 769 MW Gross	
Combustion Emissions Controls		Low NOx Burners / OFA	
Post-Combustion Emissions Controls		SCR / Baghouse/ WFGD / WESP - AMINE Based CCS	
Fuel Type		High Sulfur Bituminous	
	Units		
Electrical – Main Power System	$	21,100,000	
Electrical – Aux Power System	$	25,800,000	
Electrical – BOP and I&C	$	107,900,000	
Electrical – Substation and Switchyard	$	18,100,000	
Electrical Subtotal	$		172,900,000
CCS Plant Subtotal	$		278,752,000
Project Indirects	$		347,200,000
EPC Total Before Fee	$		2,233,652,000
EPC Fee	$		223,365,200
EPC Subtotal	$		2,457,017,200
Owner's Cost Components (Note 2)			
Owner's Services	$		171,991,000
Land	$		9,000,000
Electrical Interconnection	$		2,520,000
Gas Interconnection	$		4,850,000
Owner's Cost Subtotal	$		188,361,000
Project Contingency	$		317,445,000
Total Capital Cost	**$**		2,962,823,200
	$/kW net		**4,558**
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, gas interconnection costs (if applicable), and land acquisition costs.			

2.3 O&M COST ESTIMATE

The O&M costs for the USC coal-fired power generation facility with 30% carbon capture are summarized in Table 2-2. The fixed costs cover the O&M labor, contracted maintenance services and materials, and 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, while shorter outages (e.g., change out 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 type of service agreement would be needed for the compressors, absorbers, strippers, and other specialized equipment.

Non-fuel variable costs for this technology case include FGD reagent costs, 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, FGD waste disposal costs, and solvent makeup. 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 combustion turbine [CT] blowdown treatment), and additional demineralized makeup water costs.

Table 2-2 — Case 2 O&M Cost Estimate

Case 2 EIA – Non-Fuel O&M Costs – 2019 $s		
650 MW Net, Ultra-Supercritical Coal w/ 30% Carbon Capture		
Fixed O&M – Plant (Note 1)		
Labor	$/year	18,177,000
Materials and Contract Services	$/year	10,959,000
Administrative and General	$/year	6,156,000
Subtotal Fixed O&M	$/year	35,292,000
$/kW-year	$/kW-year	**54.30 $/kW-year**
Variable O&M (Note 2)	$/MWh	**7.08 $/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, limestone, water, ash disposal, FGD waste disposal, and water discharge treatment cost.		

2.4 ENVIRONMENTAL & 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. The CO_2 emissions estimates are based on a 30% removal from the default CO_2 emissions factors listed in Table C-1 of 40 CFR 98, Subpart C.

Table 2-3 — Case 2 Emissions

Case 2 EIA – Emissions Rates		
650 MW Net, Ultra-Supercritical Coal w/ 30% Carbon Capture		
Predicted Emissions Rates (Note 1)		
NOx	lb/MMBtu	0.06 (Note 2)
SO_2	lb/MMBtu	0.09 (Note 3)
CO_2	lb/MMBtu	144 (Note 4)
Emissions Control Notes		
1. High sulfur Bituminous Coal, 4.3 lb/MMBtu SO2 Coal		
2. NOx Removal using LNBs with OFA, and SCR		
3. SO2 Removal by Forced Oxidation, Limestone Based, Wet FGD, 98% Reduction		
4. 30% reduction from baseline Per 40 CFR 98, Subpt. C, Table C-1		

CASE 3. ULTRA-SUPERCRITICAL COAL WITH 90% CO_2 CAPTURE, 650 MW

3.1 CASE DESCRIPTION

This case comprises a coal-fired power plant with a nominal net capacity of 650 MW with a single steam generator and ST with coal storage and handling systems, BOP systems, emissions control systems, and a 90% CO_2 capture system. This case is similar to the plant description provided in (Case 1) and (Case 2); however, this case employs 90% CO_2 capture system for the entire flue gas stream, which requires a larger boiler size and higher heat input to account for the low-pressure steam extraction and larger auxiliary loads needed for the CO_2 capture technology used. The steam cycle is generally similar to the UCS cases with carbon capture; however, the boiler feedwater pumps are steam driven as opposed to motor driven.

The CO_2 capture systems are commonly referred to as 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 compressed to supercritical conditions and injected into a pipeline at terminated at the fence line of the facility. For this report, the terms "CO_2 capture" and "carbon capture" are used interchangeably.

As with Case 1 and Case 2, the base configuration used for the cost estimate is a single-unit station constructed on a greenfield site of approximately 300 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 used for cycle cooling and steam cycle makeup is provided by an adjacent fresh water reservoir or river.

3.1.1 Mechanical Equipment & 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 CO_2 capture systems used as the basis for the capital and O&M cost estimates.

3.1.1.1 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 90% CO_2 capture in the absorption column. Please refer to Figure 2-1 for simplified process flow diagram of the CO_2 capture system.

3.1.1.2 CO_2 Capture Systems

It is assumed that this case will be built with full integration to the CO_2 capture facility. 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, which 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 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 compressor 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. Doing so requires a larger boiler or turbine to maintain the same net power output of the facility. Overall, CO_2 capture system integration can account for a net derate of approximately 30% in comparison with the base facility power output.

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 is not a minor flow rate. CO_2 capture systems can require similar circulating cooling water rates as condensers themselves. 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 is used to cool 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. This 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 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.

3.1.1.3 90% CO_2 Capture

For the case where a new USC coal-fired facility is required to provide 90% CO_2 reduction, the full flue gas path must be treated. As referenced previously, 90% 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 90% 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.

3.1.1.4 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 90% CO_2 capture. Approximately 2,370,000 lb/hr of low-pressure steam is required for the CO_2 system. While the boiler efficiency is assumed to be 87.5%, the estimated gross size of the steam generator is approximately 1,054 MW, which is approximately 40% larger than the case without carbon capture (Case 1). The estimated total auxiliary load for the plant is 181 MW, with 118 MW required for the for the CO_2 system. The net heat rate is estimated to be 12507 Btu/kWh based on the HHV of the fuel and the net electrical output.

3.1.2 Electrical & Control Systems

The electrical equipment includes the turbine generator, which is connected via generator circuit breakers to a 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 DCS.

3.1.3 Offsite Requirements

Coal is delivered to the facility by rail. The maximum daily coal rate for the facility is approximately 6700 tons per day. The number of rail cars to support this facility is estimated at approximately 470 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 17,000 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.

3.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $5876/kW. Table 3-1 summarizes the cost components for this case. Cost associated with CO_2 sequestration have been excluded. 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. No special systems are needed to prevent freezing or to account for snow loads on structures.

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 and 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, ZLD equipment is added. Zero liquid discharge 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 STG equipment will be enclosed in all locations.

Table 3-1 — Case 3 Capital Cost Estimate

Case 3 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**650 MW Net, Ultra-Supercritical Coal w/ 90% Carbon Capture** 1 x 831 MW Gross	
Combustion Emissions Controls		Low NOx Burners / OFA	
Post-Combustion Emissions Controls		SCR / Baghouse/ WFGD / WESP / AMINE Based CCS 90%	
Fuel Type		High Sulfur Bituminous	
	Units		
Plant Characteristics			
Net Plant Capacity (60 deg F, 60% RH)	MW	650	
Heat Rate, HHV Basis	Btu/kWh	12507	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	10%	
Project Contingency	% of Project Costs	15%	
Owner's Services	% of Project Costs	5%	
Estimated Land Requirement (acres)	$	300	
Estimated Land Cost ($/acre)	$	30,000	
Interconnection Costs			
Electrical Transmission Line Costs	$/mile	2,520,000	
Miles	miles	1.00	
Substation Expansion	$	0	
Gas Interconnection Costs			
Pipeline Cost	$/mile	2,500,000	
Miles	miles	0.50	
Metering Station	$	3,600,000	
Typical Project Timelines			
Development, Permitting, Engineering	months	24	
Plant Construction Time	months	36	
Total Lead Time Before COD	months	60	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		311,200,000
Mechanical – Boiler Plant	$	967,433,333	
Mechanical – Turbine Plant	$	242,533,333	
Mechanical – Balance of Plant	$	92,077,778	
Mechanical Subtotal	$		1,302,044,444
Electrical – Main Power System	$	26,350,000	
Electrical – Aux Power System	$	31,050,000	
Electrical – BOP and I&C	$	113,150,000	
Electrical – Substation and Switchyard	$	23,350,000	
Electrical Subtotal	$		193,900,000
CCS Plant Subtotal	$		663,846,000
Project Indirects	$		390,200,000
EPC Total Before Fee	$		2,861,190,000
EPC Fee	$		286,119,000
EPC Subtotal	$		3,147,309,000
Owner's Cost Components (Note 2)			
Owner's Services	$		157,365,000
Land	$		9,000,000
Electrical Interconnection	$		2,520,000
Gas Interconnection	$		4,850,000

Case 3 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**650 MW Net, Ultra-Supercritical Coal w/ 90% Carbon Capture** 1 x 831 MW Gross
Combustion Emissions Controls		Low NOx Burners / OFA
Post-Combustion Emissions Controls		SCR / Baghouse/ WFGD / WESP / AMINE Based CCS 90%
Fuel Type		High Sulfur Bituminous
	Units	
Owner's Cost Subtotal	$	173,735,000
Project Contingency	$	498,157,000
Total Capital Cost	**$**	3,819,201,000
	$/kW net	**5,876**
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, gas interconnection costs (if applicable), and land acquisition costs.		

3.3 O&M COST ESTIMATE

The O&M costs for the USC coal-fired power generation facility with 90% carbon capture are summarized in Table 3-2. The fixed costs cover the O&M labor, contracted maintenance services and materials, and 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, while shorter outages (e.g., change out 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 type of service agreement would be needed for the compressors, absorbers, strippers, and other specialized equipment.

Non-fuel Variable costs for this technology case include FGD reagent costs, 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, FGD waste disposal costs, and solvent makeup. 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 3-2 — Case 3 O&M Cost Estimate

Case 3 EIA – Non-Fuel O&M Costs – 2019 $s		
650 MW Net, Ultra-Supercritical Coal w/ 90% Carbon Capture		
Fixed O&M – Plant (Note 1)		
Labor	$/year	18,817,000
Materials and Contract Services	$/year	12,051,000
Administrative and General	$/year	7,836,000
Subtotal Fixed O&M	$/year	38,704,000
$/kW-year	$/kW-year	**59.54 $/kW-year**
Variable O&M (Note 2)	$/MWh	**10.98 $/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, limestone, water, ash disposal, FGD waste disposal, and water discharge treatment cost.		

3.4 ENVIRONMENTAL & EMISSIONS INFORMATION

The emissions for the major criteria pollutants are summarized in Table 3-3. 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. The CO_2 emissions estimates are based on a 90% removal from the default CO_2 emissions factors listed in Table C-1 of 40 CFR 98, Subpart C.

Table 3-3 — Case 3 Emissions

Case 3 EIA – Emissions Rates		
650 MW Net, Ultra-Supercritical Coal w/ 90% Carbon Capture		
Predicted Emissions Rates (Note 1)		
NOx	lb/MMBtu	0.06 (Note 2)
SO_2	lb/MMBtu	0.09 (Note 3)
CO_2	lb/MMBtu	20.6 (Note 4)
Emissions Control Notes		
1. High sulfur Bituminous Coal, 4.3 lb/MMBtu SO2 Coal		
2. NOx Removal using LNBs with OFA, and SCR		
3. SO2 Removal by Forced Oxidation, Limestone Based, Wet FGD, 98% Reduction		
4. 90% reduction from baseline Per 40 CFR 98, Subpt. C, Table C-1		

CASE 4. INTERNAL COMBUSTION ENGINES, 20 MW

4.1 CASE DESCRIPTION

This case is a reciprocating internal combustion engine (RICE) power plant based on four large-scale natural-gas-fired engines. Each engine is rated nominally at 5.6 MW with a net capacity of 21.4 MW. The configuration is selected to represent the installation of peaking or supplemental capacity for a municipality or small utility.

4.1.1 Mechanical Equipment & Systems

The RICE power plant comprises four gas-fired engines that are coupled to a generator. The power plant also includes the necessary engine auxiliary systems, which are fuel gas, lubricated oil, compressed air, cooling water, air intake, and exhaust gas.

Each engine is comprised of 10 cylinders in a V configuration. The engines are a four-stroke, spark-ignited, single fuel engine that operates on the Otto cycle. Each engine includes a turbocharger with an intercooler that uses the expansion of hot exhaust gases to drive a compressor that raises the pressure and density of the inlet air to each cylinder, leading to increased power output of the engine. Each engine is equipped with an SCR and carbon monoxide (CO) catalyst for emissions control.

The engines are cooled using a closed-loop cooling water system that circulates a water/glycol mixture through the engine block. Heat is rejected from the cooling water system by air-cooled radiators. A starting air system provides the high-pressure compressed air required to start the engine. An instrument air system is provided for standard instrumentation and plant air use.

4.1.2 Electrical & Control Systems

The electrical generator is coupled to the engine. The generator is a medium voltage, air-cooled, synchronous alternating current (AC) generator.

The engine original equipment manufacturer (OEM) provides a DCS that allows for a control interface, plant operating data, and historian functionality. The control system is in an onsite building. Programmable logic controllers are also provided throughout the plant for local operation.

4.1.3 Offsite Requirements

Natural gas is delivered to the facility through a gas connection at the site boundary. A natural gas line is routed from the nearest gas lateral to a gas metering station at the site boundary. The gas pressure is reduced as necessary to meet the requirements of the facility downstream of the metering station.

Since water consumption is minimal at the power plant, water is obtained from the municipal water supply. The power plant also includes minimal water treatment for onsite water usage. Wastewater is treated using an oil-water separator and then is directed to a municipal wastewater system. Used oil that is no longer filterable is stored in a waste oil tank and removed offsite with a vacuum truck.

The power plant's onsite switchyard is connected to the transmission system through a nearby substation.

4.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $1810/kW. Table 4-1 summarizes the cost components for this case.

Table 4-1 — Case 4 Capital Cost Estimate

Case 4 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Internal Combustion Engines** 4 x 5.6 MW
Combustion Emissions Controls		None
Post-Combustion Emissions Controls		SCR
Fuel Type		Natural Gas
	Units	
Plant Characteristics		
Net Plant Capacity (60 deg F, 60% RH)	MW	21.4
Net Plant Heat Rate, HHV Basis	Btu/kWh	8295
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct & Indirect Costs	10%
Project Contingency	% of Project Costs	8%
Owner's Services	% of Project Costs	7.5%
Estimated Land Requirement (acres)	$	10
Estimated Land Cost ($/acre)	$	30,000
Interconnection Costs		
Electrical Transmission Line Costs	$/mile	720,000
Miles	miles	1.00
Substation Expansion	$	0
Gas Interconnection Costs		
Pipeline Cost	$/mile	100,000
Miles	miles	0.50
Metering Station	$	75,000

Case 4 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**Internal Combustion Engines** 4 x 5.6 MW	
Combustion Emissions Controls		None	
Post-Combustion Emissions Controls		SCR	
Fuel Type		Natural Gas	
	Units		
Typical Project Timelines			
Development, Permitting, Engineering	months	12	
Plant Construction Time	months	18	
Total Lead Time Before COD	months	30	
Operating Life	years	30	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		6,861,000
Engines (Note 3)	$	11,974,000	
Mechanical BOP	$	5,521,000	
Mechanical Subtotal	$		17,495,000
Electrical Subtotal	$		6,668,000
Project Indirects	$		180,000
EPC Total Before Fee	$		19,230,000
EPC Fee	$		1,923,000
EPC Subtotal	$		21,153,000
Owner's Cost Components (Note 2)			
Owner's Services	$		1,586,000
Land	$		300,000
Owner Furnished Equipment (Note 3)	$		11,974,000
Electrical Interconnection	$		720,000
Gas Interconnection	$		125,000
Owner's Cost Subtotal	$		14,705,000
Project Contingency	$		2,869,000
Total Capital Cost	$		38,727,000
	$/kW net		**1,810**

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, gas interconnection costs (if applicable), and land acquisition costs.
3. Engines and associated auxiliaries procured by Owner from the engine OEM.

4.3 O&M COST ESTIMATE

The O&M cost estimate includes all tasks discussed in the O&M estimate description.

Table 4-2 — Case 4 O&M Cost Estimate

Case 4 EIA – Non-Fuel O&M Costs – 2019 $s		
Internal Combustion Engines		
Fixed O&M – Plant (Note 1)		
Subtotal Fixed O&M	$/kW-year	**35.16 $/kW-year**
Variable O&M (Note 2)	$/MWh	**5.69 $/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.		

4.4 ENVIRONMENTAL & EMISSIONS INFORMATION

NO_X and CO emissions are maintained through an SCR and CO catalyst installed in the exhaust system of each engine. SO_2 is uncontrolled but minimal and below emission limits because of the low amounts of SO_2 in the natural gas fuel. Water, wastewater, solid waste, and spent lubricating oil are disposed of through conventional means.

Table 4-3 — Case 4 Emissions

Case 4 EIA – Emissions Rates		
Internal Combustion Engines		
Predicted Emissions Rates – Natural Gas		
NOx	lb/MMBtu	0.02 (Note 1)
SO_2	lb/MMBtu	0.00
CO	lb/MMBtu	0.03
CO_2	lb/MMBtu	117 (Note 2)
Emissions Control Notes		
1. With SCR		
2. Per 40 CFR98 Sub Part C – Table C1		

CASE 5. COMBUSTION TURBINES AERODERIVATIVE, 100-MW SIMPLE CYCLE

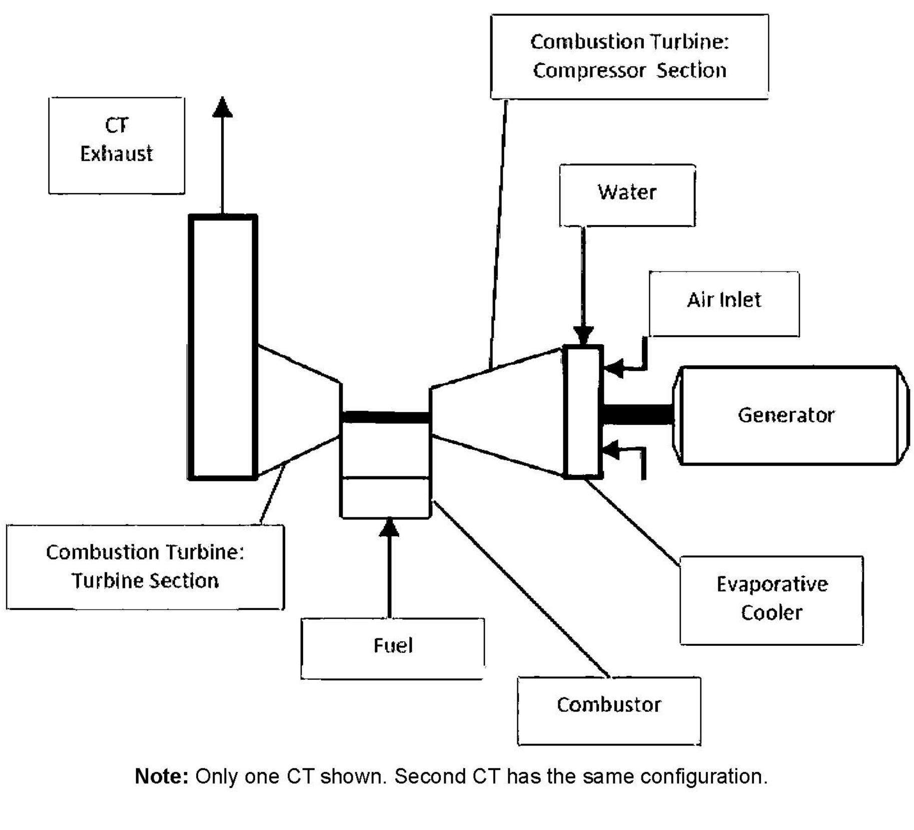
5.1 CASE DESCRIPTION

This case is comprised of two duplicate aeroderivative CTs in simple-cycle configuration. It is based on natural gas firing of the CTs, although dual fuel capability is provided. Output power voltage is stepped up for transmission to the external grid through an onsite switchyard.

5.1.1 Mechanical Equipment & Systems

Case 5 is comprised of a pair of aeroderivative dual fuel CTs in simple-cycle configuration, with a nominal output of 53.7 MW gross per turbine. After deducting internal auxiliary power demand, the net output of the plant is 105.1 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. Not included in the Case 5 configuration are SCR units for further reduction of NO_X emissions or CO catalysts for further reduction of CO emissions. Refer to Figure 5-1 for a diagram of the CT systems.

Figure 5-1 — Case 2 Configuration



Note: Only one CT shown. Second CT has the same configuration.

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 in general operate at higher pressure ratios, have faster start-up times and ramp rates, and higher efficiencies compared to industrial frame CTs.

5.1.2 Electrical & Control Systems

Case 5 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 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 BOP systems (e.g., water supply to evaporative coolers, fuel supply).

5.1.3 Offsite Requirements

Offsite provisions in Case 5 include:

- **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.

5.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $1175/kW. 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, which include project development, studies, permitting, and legal; owner's project management; owner's engineering; and owner's participation in startup and commissioning. The estimate is presented as an overnight cost in 2019 dollars and thus excludes Allowance for Funds Used During Construction or interest during construction. In addition to the cost of external systems noted above (e.g., 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 – 2019 $s			
Configuration		**Combustion Turbines – Simple Cycle** 2 x Aeroderivative Class	
Combustion Emissions Controls		Dry Low Emissions Combustor	
Post-Combustion Emissions Controls		None	
Fuel Type		Natural Gas / No. 2 Backup 2 x 54 MW rating	
	Units		
Plant Characteristics			
Net Plant Capacity (60 deg F, 60% RH)	MW	105	
Heat Rate, HHV Basis	Btu/kWh	9124	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	10%	
Project Contingency	% of Project Costs	10%	
Owner's Services	% of Project Costs	7%	
Estimated Land Requirement (acres)	$	20	
Estimated Land Cost ($/acre)	$	30,000	
Interconnection Costs			
Electrical Transmission Line Costs	$/mile	1,200,000	
Miles	miles	1.00	
Substation Expansion	$	0	
Gas Interconnection Costs			
Pipeline Cost	$/mile	2,800,000	
Miles	miles	0.50	
Metering Station	$	3,100,000	
Typical Project Timelines			
Development, Permitting, Engineering	months	18	
Plant Construction Time	months	22	
Total Lead Time Before COD	months	40	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		6,300,000
Mechanical – Major Equipment	$	43,400,000	
Mechanical – Balance of Plant	$	9,900,000	
Mechanical Subtotal	$		53,300,000
Electrical Subtotal	$		15,400,000
Project Indirects	$		15,000,000
EPC Total Before Fee	$		90,000,000
EPC Fee	$		9,000,000
EPC Subtotal	$		99,000,000
Owner's Cost Components (Note 2)			
Owner's Services	$		6,930,000
Land	$		600,000
Electrical Interconnection	$		1,200,000
Gas Interconnection	$		4,500,000

Case 5 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Combustion Turbines – Simple Cycle** 2 x Aeroderivative Class
Combustion Emissions Controls		Dry Low Emissions Combustor
Post-Combustion Emissions Controls		None
Fuel Type		Natural Gas / No. 2 Backup 2 x 54 MW rating
	Units	
Owner's Cost Subtotal	$	13,230,000
Project Contingency	$	11,223,000
Total Capital Cost	**$**	123,453,000
	$/kW net	**1,175**
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, gas interconnection costs (if applicable), and land acquisition costs.		

5.3 O&M COST ESTIMATE

Table 5-2 shows 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 25,000 EOH, and a major overhaul is performed every 50,000 EOH. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of EOH. The aeroderivative CTs in Case 5 always use an EOH-driven maintenance overhaul schedule regardless of the operating profile. Refer to Case 6 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 5-2 — Case 5 O&M Cost Estimate

Case 5 EIA – Non-Fuel O&M Costs – 2019 $s		
Combustion Turbine – Simple Cycle		
Fixed O&M – Plant (Note 1)		
Subtotal Fixed O&M	$/kW-year	**16.30 $/kW-year**
Variable O&M (Note 2)	$/MWh	**4.70 $/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 and water discharge treatment cost. They are based on a number operating hours-based regimen.		

5.4 ENVIRONMENTAL & EMISSIONS INFORMATION

For the Case 5 simple-cycle configuration, NO_X emissions from the CT stacks when firing gas are indicated in Table 5-3. Although some locations in the United States would require SCRs and CO catalysts to further reduce stack emissions, SCRs and CO catalysts have not been included for Case 5.

Table 5-3 — Case 5 Emissions

Case 5 EIA – Emissions Rates		
Combustion Turbine – Simple Cycle		
Predicted Emissions Rates (Note 1)		
NOx	lb/MMBtu	0.09
SO_2	lb/MMBtu	0.00
CO_2	lb/MMBtu	117
Emissions Control Notes		
1. Natural Gas, no water injection		

CASE 6. COMBUSTION TURBINE F CLASS, 240-MW SIMPLE CYCLE

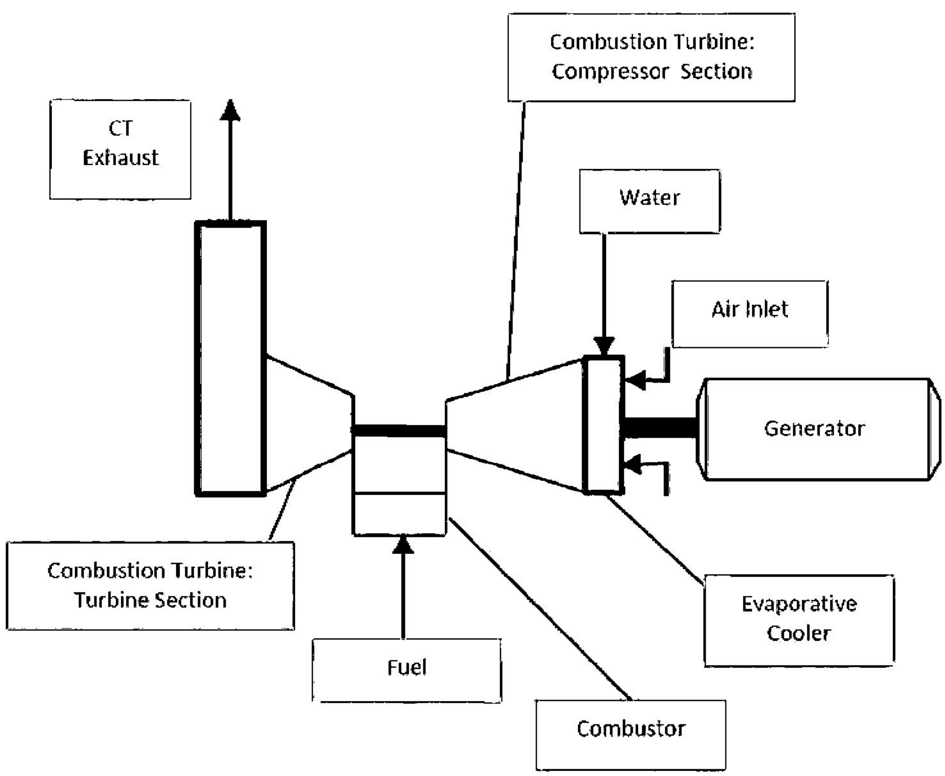
6.1 CASE DESCRIPTION

This case is comprised of one industrial frame Model F 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.

6.1.1 Mechanical Equipment & Systems

Case 6 is comprised of one industrial frame Model F dual fuel CT in simple-cycle configuration with a nominal output of 237.2 MW gross. After deducting internal auxiliary power demand, the net output of the plant is 232.6 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. Not included in the Case 6 configuration is an SCR unit for further reduction of NO_X emissions or a CO catalyst for further reduction of CO emissions. Figure 6-1 shows a diagram of the CT systems.

Figure 6-1 — Case 6 Configuration



Frame CTs differ from aeroderivative CTs in that the industrial frame CT's performance characteristics generally are more conducive to improved performance in 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.

6.1.2 Electrical & Control Systems

Case 6 includes one 60-Hz CT electric generator with an approximate rating of 240 MVA and output voltage of 13.8 kV. The generator output power is converted to a higher voltage by 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 BOP systems (e.g., water supply to evaporative coolers, fuel supply)

6.1.3 Offsite Requirements

Offsite provisions in Case 6 include:

- **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.

6.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $713/kW. Table 6-1 summarizes the cost components for this case. This estimate is based on an EPC contracting approach.

In addition to EPC contract costs, the capital cost estimate in Table 6-1 covers owner's costs, which include project development, studies, permitting, and legal; owner's project management; owner's engineering; and owner's participation in startup and commissioning. The estimate is presented as an overnight cost in 2019 dollars and thus excludes Allowance for Funds Used During Construction or interest during construction. In addition to the cost of external systems noted above (e.g., fuel gas supply), an estimated amount is included for the cost of land.

Table 6-1 — Case 6 Capital Cost Estimate

Case 6 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**Combustion Turbine – Simple Cycle** F-Class	
Combustion Emissions Controls		Dry Low Emissions Combustor	
Post-Combustion Emissions Controls		None	
Fuel Type		Natural Gas / No. 2 Backup 1 x 237 MW rating	
	Units		
Plant Characteristics			
Net Plant Capacity (60 deg F, 60% RH)	MW	233	
Heat Rate, HHV Basis	Btu/kWh	9905	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	10%	
Project Contingency	% of Project Costs	10%	
Owner's Services	% of Project Costs	7%	
Estimated Land Requirement (acres)	$	20	
Estimated Land Cost ($/acre)	$	30,000	
Interconnection Costs			
Electrical Transmission Line Costs	$/mile	1,200,000	
Miles	miles	1.00	
Substation Expansion	$	0	
Gas Interconnection Costs			
Pipeline Cost	$/mile	2,800,000	
Miles	miles	0.50	
Metering Station	$	3,100,000	
Typical Project Timelines			
Development, Permitting, Engineering	months	18	
Plant Construction Time	months	22	
Total Lead Time Before COD	months	40	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		12,300,000
Mechanical – Major Equipment	$	54,000,000	
Mechanical – Balance of Plant	$	17,200,000	
Mechanical Subtotal	$		71,200,000
Electrical Subtotal	$		20,200,000
Project Indirects	$		19,000,000
EPC Total Before Fee	$		122,700,000
EPC Fee	$		12,270,000
EPC Subtotal	$		134,970,000
Owner's Cost Components (Note 2)			
Owner's Services	$		9,448,000
Land	$		600,000
Electrical Interconnection	$		1,200,000
Gas Interconnection	$		4,500,000
Owner's Cost Subtotal	$		15,748,000
Project Contingency	$		15,072,000
Total Capital Cost	**$**		165,790,000
	$/kW net		**713**

Case 6 EIA – Capital Cost Estimates – 2019 $s	
Configuration	Combustion Turbine – Simple Cycle F-Class
Combustion Emissions Controls	Dry Low Emissions Combustor
Post-Combustion Emissions Controls	None
Fuel Type	Natural Gas / No. 2 Backup 1 x 237 MW rating
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, gas interconnection costs (if applicable), and land acquisition costs.	

6.3 O&M COST ESTIMATE

Operation and maintenance 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. 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 significant overhaul is performed for this type of CT every 900 equivalent starts, and a major overhaul is performed every 2,400 equivalent starts. (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 a starts-driven maintenance overhaul schedule. Refer to Case 5 for an EOH-based overhaul schedule.) In Table 6-2, the cost per start is broken out from the variable O&M costs that cover the consumables.

Table 6-2 — Case 6 O&M Cost Estimate

Case 6 EIA – Non-Fuel O&M Costs – 2019 $s		
Combustion Turbine – Simple Cycle		
Fixed O&M – Plant (Note 1)		
Subtotal Fixed O&M	$/kW-year	**7.00 $/kW-year**
Variable O&M		
Consumables, etc. (Note 2)	$/MWh	**0.60 $/MWh**
CT Major Maintenance (Note 2)	$/Start	**$18,500/Start**
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 consumables costs include water, water discharge treatment cost, etc. based on $/MWh. In addition to the Consumables VOM, add CT Major Maintenance VOM costs, which are based on a starts operating regime, with cost per start indicated.		

6.4 ENVIRONMENTAL & EMISSIONS INFORMATION

For the Case 6 simple-cycle configuration, NO_X emissions from the CT stack when firing gas are indicated in Table 6-3. Although some locations in the United States would require SCRs and CO catalysts to further reduce stack emissions, an SCR and a CO catalyst have not been included for Case 6.

Table 6-3 — Case 6 Emissions

Case 6 EIA – Emissions Rates		
Combustion Turbine – Simple Cycle		
Predicted Emissions Rates (Note 1)		
NOx	lb/MMBtu	0.030
SO_2	lb/MMBtu	0.00
CO_2	lb/MMBtu	117
Emissions Control Notes		
1. Natural Gas, no water injection		

CASE 7. COMBUSTION TURBINE H CLASS, 1100-MW COMBINED CYCLE

7.1 CASE DESCRIPTION

This case is comprised of one block of a CC power generation unit in a 2x2x1 configuration. The plant includes two industrial frame Model H "advanced technology" CTs and one STG. Case 7 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.

7.1.1 Mechanical Equipment & Systems

Case 7 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) with a nominal output for the CC plant of 1114.7-MW gross. Each CT generates 385.2 MW gross; the STG generates 344.3 MW gross. After deducting internal auxiliary power demand, the net output of the plant is 1083.3 MW. Refer to Figure 7-1 for a diagram of the Case 7 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 7 configuration are 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:

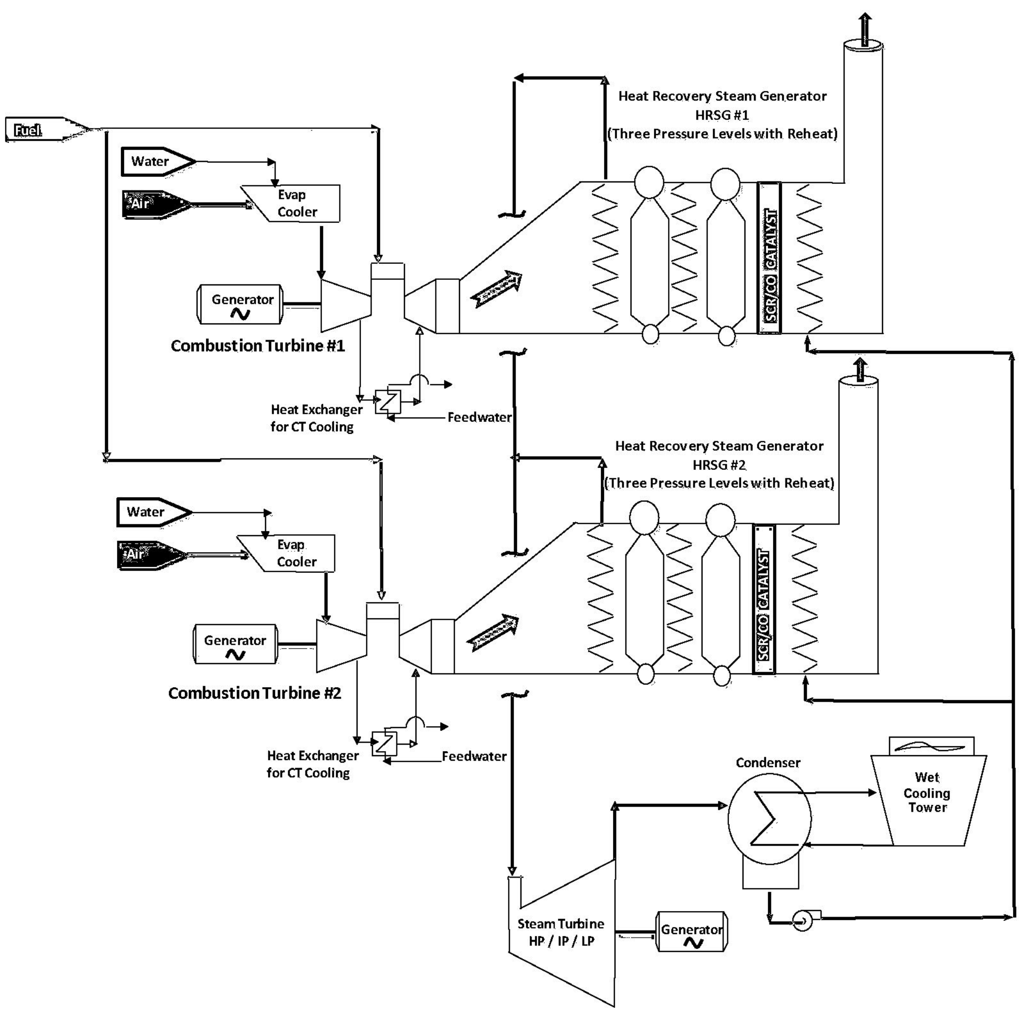
- High firing temperatures (~2900°F)
- Advanced materials of construction
- Advanced thermal barrier coatings
- Additional cooling of CT assemblies (depending on the CT model, additional cooling applies to the CT rotor, turbine section vanes, and the combustor). Refer to Figure 7-1, which depicts a dedicated additional cooler for the CT assemblies in Case 7.

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 7. (Supplemental HRSG firing, while increasing the MW output of the STG, reduces plant efficiency.)

A wet cooling tower system provides plant cooling for Case 7. A wet cooling tower is preferred over the alternative ACC approach since plant performance is better (i.e., 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 7-1 — Case 7 Configuration



7.1.2 Electrical & Control Systems

Case 7 includes one 60-Hz electric generator per CT with an approximate rating of 390 megavolt amperes (MVA) and output voltage of 13.8 kV. The STG includes one 60-Hz electric generator with an approximate 350-MVA rating. The output power from the three generators is converted to a higher voltage by GSUs for transmission to the external grid, transmitted through an onsite facility switchyard.

The CC facility is controlled by a central 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 BOP systems and equipment (e.g., water systems, fuel systems, main cooling systems).

7.1.3 Offsite Requirements

Offsite provisions in Case 7 include:

- **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.

7.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $958/kW. Table 7-1 summarizes the cost components for this case. This estimate is based on an EPC contracting approach.

In addition to EPC contract costs, the capital cost estimate in Table 7-1 covers owner's costs, which include project development, studies, permitting, and legal; owner's project management; owner's engineering; and owner's participation in startup and commissioning. The estimate is presented as an overnight cost in 2019 dollars and thus excludes Allowance for Funds Used During Construction or interest during construction. In addition to the cost of external systems noted above (e.g., 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 – 2019 $s			
Configuration		**Combined Cycle 2x2x1** H-Class	
Combustion Emissions Controls		Dry Low NOx combustor with axial fuel staging	
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 deg F, 60% RH)	MW	1083	
Net Plant Heat Rate, HHV Basis	Btu/kWh	6370	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	10%	
Project Contingency	% of Project Costs	10%	
Owner's Services	% of Project Costs	7%	
Estimated Land Requirement (acres)	$	60	
Estimated Land Cost ($/acre)	$	30,000	
Interconnection Costs			
Electrical Transmission Line Costs	$/mile	2,520,000	
Miles	miles	1.00	
Substation Expansion	$	0	
Gas Interconnection Costs			
Pipeline Cost	$/mile	2,800,000	
Miles	miles	0.50	
Metering Station	$	4,500,000	
Typical Project Timelines			
Development, Permitting, Engineering	months	18	
Plant Construction Time	months	24	
Total Lead Time Before COD	months	42	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		60,000,000
Mechanical – Major Equipment	$	294,000,000	
Mechanical – Balance of Plant	$	196,000,000	
Mechanical Subtotal	$		490,000,000
Electrical Subtotal	$		93,000,000
Project Indirects	$		150,000,000
EPC Total Before Fee	$		793,000,000
EPC Fee	$		79,300,000
EPC Subtotal	$		872,300,000
Owner's Cost Components (Note 2)			
Owner's Services	$		61,061,000
Land	$		1,800,000
Electrical Interconnection	$		2,520,000
Gas Interconnection	$		5,900,000
Owner's Cost Subtotal	$		71,281,000
Project Contingency	$		94,358,000
Total Capital Cost	**$**		1,037,939,000
	$/kW net		**958**

Case 7 EIA – Capital Cost Estimates – 2019 $s	
Configuration	**Combined Cycle 2x2x1** H-Class
Combustion Emissions Controls	Dry Low NOx combustor with axial fuel staging
Post-Combustion Emissions Controls	SCR Catalyst, CO Catalyst
Fuel Type	Natural gas / No. 2 Backup
Post Firing	No Post Firing
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, gas interconnection costs (if applicable), and land acquisition costs.	

7.3 O&M COST ESTIMATE

Table 7-2 indicates 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 EOH the CT has run. Typically, a significant overhaul is performed for this type of CT every 25,000 EOH, and a major overhaul is performed every 50,000 EOH. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of EOH. Case 7 assumes the operating profile results in an EOH-driven maintenance overhaul schedule. Refer to Case 6 for a starts-based overhaul schedule.) Planned major outage work on the STG is scheduled less frequently than the CTs, typically planned for every six to eight years.

Table 7-2 — Case 7 O&M Cost Estimate

Case 7 EIA – Non-Fuel O&M Costs – 2019 $s		
Combined Cycle 2x2x1		
Fixed O&M – Plant (Note 1)		
Subtotal Fixed O&M	$/kW-year	**12.20 $/kW-year**
Variable O&M (Note 2)	$/MWh	**1.87 $/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, and water discharge treatment cost.		

7.4 ENVIRONMENTAL & EMISSIONS INFORMATION

For the Case 7 CC configuration, NO_X emissions from the HRSG stacks when firing gas are indicated in Table 7-3. 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 7-3 — Case 7 Emissions

Case 7 EIA – Emissions Rates		
Combined Cycle 2x2x1		
Predicted Emissions Rates (Note 1)		
NOx	lb/MMBtu	0.0075
SO_2	lb/MMBtu	0.001
CO_2	lb/MMBtu	117
Emissions Control Notes		
1. Natural Gas, no water injection		

CASE 8. COMBUSTION TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT, 430 MW

8.1 CASE DESCRIPTION

This case is comprised of one block of a combined-cycle power generation unit. The plant includes one industrial frame Model H "advanced technology" CT, one STG, and one electric generator that is common to the CT and the STG. Case 8 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.

8.1.1 Mechanical Equipment & Systems

Case 8 is comprised of one Model H dual fuel CT in a 1x1x1 single-shaft CC configuration with a nominal output for the CC plant of 430.4 MW gross. The CT generates 297.2 MW gross and the STG generates 133.2 MW gross. After deducting internal auxiliary power demand, the net output of the plant is 418.3 MW. Refer to Figure 8-1 for a diagram of the Case 8 process, which is similar to Case 7.

The Case 8 layout differs from Case 7 in that Case 8 is a single-shaft CC plant. That is, the Case 8 CT, STG, and electric generator all share one horizontal shaft. Therefore, it has a more compact footprint than a plant like Case 7, where the CTs and STG have separate shafts and generators. Refer to Figure 8-2 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, the single-shaft unit will have only one electric generator whereas a multiple shaft 1x1x1 CC will have two generators. Also, the smaller footprint of the single-shaft unit will lessen 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 8 configuration is an SCR unit for further reduction of NO_X emissions and a CO catalyst for further reduction of CO emissions.

The CT is categorized as Model H 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

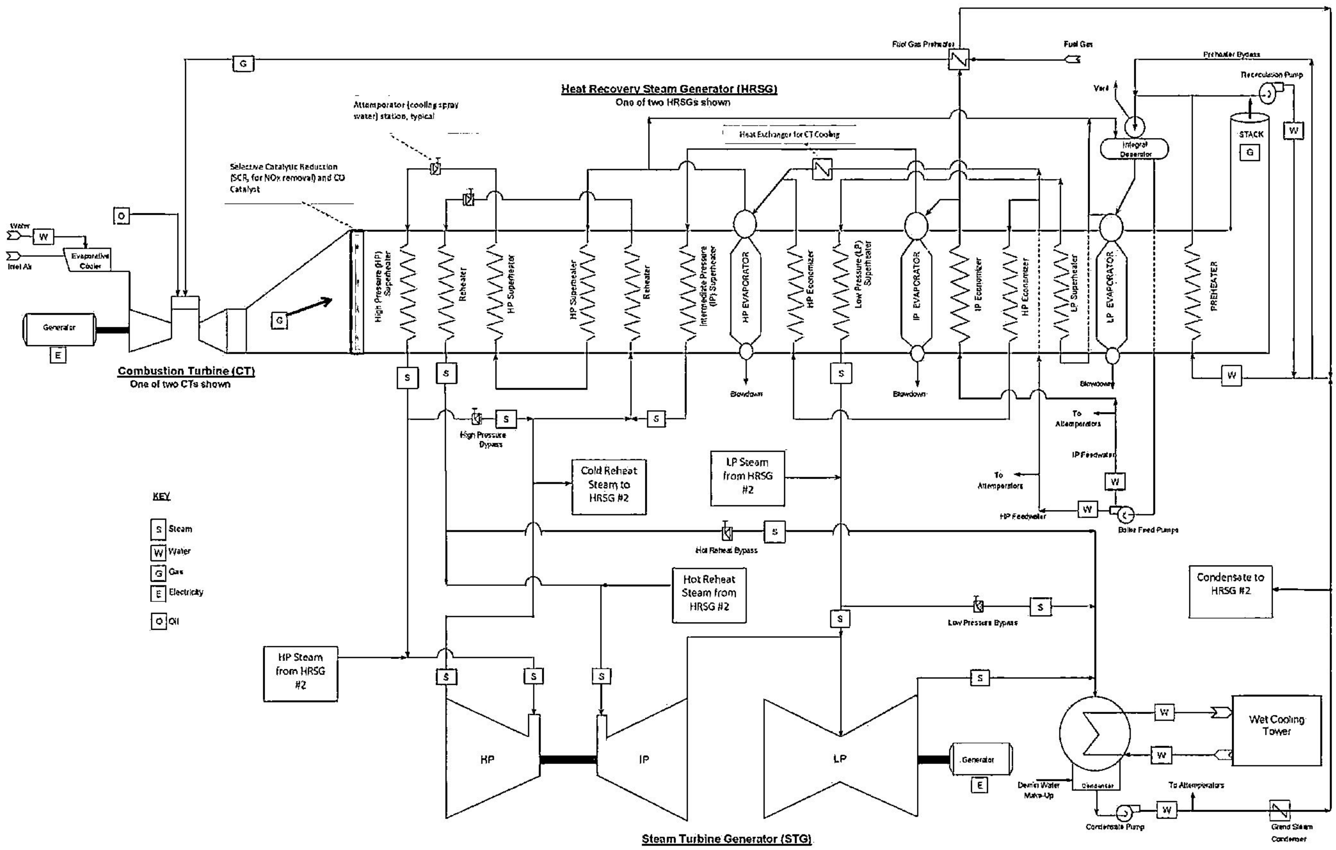
- Advanced thermal barrier coatings
- Additional cooling of CT assemblies (depending on the CT model, additional cooling applies to the CT rotor, turbine section vanes, and the combustor). Refer to Figure 8-1, which depicts a dedicated additional cooler for the CT assemblies in Case 8.

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.

Hot exhaust gas from the CT is directed to a HRSG. Steam generated in the HRSG is directed to the STG. An HRSG may be optionally equipped with additional supplemental firing, but this feature is not included in Case 8. (Supplemental HRSG firing, while increasing the MW output of the STG, reduces plant efficiency.)

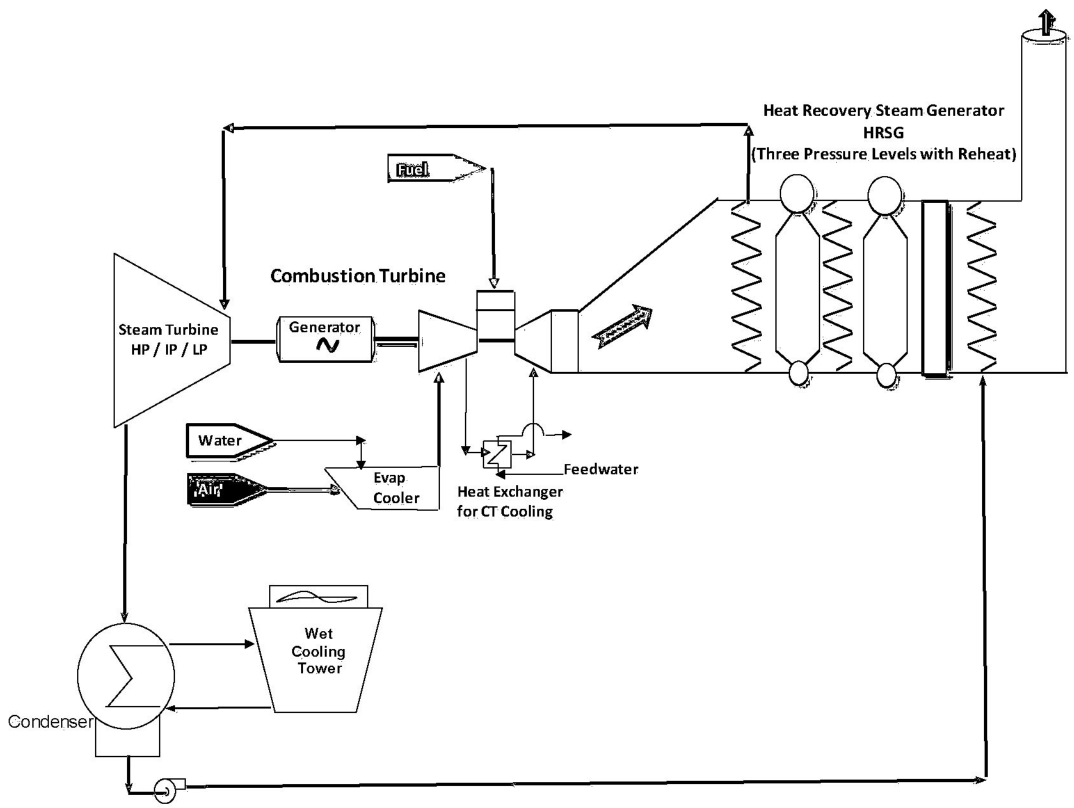
Plant cooling for Case 8 is provided by a wet cooling tower system. Generally, a wet cooling tower is preferred over the alternative ACC approach since plant performance is better (i.e., greater MW output and higher efficiency) with a wet tower and capital cost is generally lower. However, ACCs are often selected in areas where the supply of makeup water needed for a wet cooling tower is scarce or expensive, such as in desert areas in the southwestern United States.

Figure 8-1 — Case 8 Configuration – Process Diagram



Note: Only one CT and one HRSG shown. Second CT and HRSG have the same configurations.

Figure 8-2 — Case 8 Configuration – Simplified Sketch



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

8.1.2 Electrical & Control Systems

Case 8 includes one 60-Hz electric generator for both the CT and steam turbine, with an approximate rating of 435 MVA and output voltage of 13.8 kV. The output power from the generator is converted to a higher voltage by a GSU for transmission to the external grid, transmitted through an onsite facility switchyard.

The CC facility is controlled by a central 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 (e.g., water systems, fuel systems, main cooling systems).

8.1.3 Offsite Requirements

Offsite provisions in Case 8 include:

- **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.

8.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $1084/kW. Table 8-1 summarizes the cost components for this case. The capital cost estimate is based on an EPC contracting approach.

In addition to EPC contract costs, the capital cost estimate in Table 8-1 covers owner's costs, which include project development, studies, permitting, and legal; owner's project management; owner's engineering; and owner's participation in startup and commissioning. The estimate is presented as an overnight cost in 2019 dollars and thus excludes Allowance for Funds Used During Construction or interest during construction. In addition to the cost of external systems noted above (e.g., fuel gas supply and transmission line), an estimated amount is included for the cost of land.

Table 8-1 — Case 8 Capital Cost Estimate

Case 8 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Combined Cycle 1x1x1, Single Shaft** H Class
Combustion Emissions Controls		Dry Low NOx combustor with axial fuel staging
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 deg F, 60% RH)	MW	418
Heat Rate, HHV Basis	Btu/kWh	6431
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct & Indirect Costs	10%
Project Contingency	% of Project Costs	10%
Owner's Services	% of Project Costs	7%
Estimated Land Requirement (acres)	$	60
Estimated Land Cost ($/acre)	$	30,000
Interconnection Costs		
Electrical Transmission Line Costs	$/mile	1,800,000
Miles	miles	1.00
Substation Expansion	$	0

Case 8 EIA – Capital Cost Estimates – 2019 $s			
Configuration		Combined Cycle 1x1x1, Single Shaft H Class	
Combustion Emissions Controls		Dry Low NOx combustor with axial fuel staging	
Post-Combustion Emissions Controls		SCR Catalyst, CO Catalyst	
Fuel Type		Natural Gas / No. 2 Backup	
Post Firing		No Post Firing	
	Units		
Gas Interconnection Costs			
Pipeline Cost	$/mile	2,800,000	
Miles	miles	0.50	
Metering Station	$	4,500,000	
Typical Project Timelines			
Development, Permitting, Engineering	months	18	
Plant Construction Time	months	22	
Total Lead Time Before COD	months	40	
Operating Life	years	25	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		31,000,000
Mechanical – Major Equipment	$	130,000,000	
Mechanical – Balance of Plant	$	73,000,000	
Mechanical Subtotal	$		203,000,000
Electrical Subtotal	$		28,000,000
Project Indirects	$		80,000,000
EPC Total Before Fee	$		342,000,000
EPC Fee	$		34,200,000
EPC Subtotal	$		376,200,000
Owner's Cost Components (Note 2)			
Owner's Services	$		26,334,000
Land	$		1,800,000
Electrical Interconnection	$		1,800,000
Gas Interconnection	$		5,900,000
Owner's Cost Subtotal	$		35,834,000
Project Contingency	$		41,203,000
Total Capital Cost	$		453,237,000
	$/kW net		**1,084**
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, gas interconnection costs (if applicable), and land acquisition costs.			

8.3 O&M COST ESTIMATE

Operation and maintenance costs are indicated in Table 8-2. 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 EOH the CT has run. A significant overhaul is typically performed for this type of CT every 25,000 EOH, and a major overhaul is performed every 50,000 EOH. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of EOH. In Case 8, it is assumed the operating profile results in an EOH-driven maintenance overhaul schedule. Refer to Case 6 for a starts-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.

Table 8-2 — Case 8 O&M Cost Estimate

Case 8 EIA – Non-Fuel O&M Costs – 2019 $s		
Combined Cycle 1x1x1, Single Shaft		
Fixed O&M – Plant (Note 1)		
Subtotal Fixed O&M	$kW-/year	**14.10 $/kW-year**
Variable O&M (Note 2)	$/MWh	**2.55 $/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, and water discharge treatment cost.		

8.4 ENVIRONMENTAL & EMISSIONS INFORMATION

For the Case 8 CC configuration, NO_X emissions from the HRSG stack when firing gas are indicated in Table 8-3. 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 8-3 — Case 8 Emissions

Case 8 EIA – Emissions Rates		
Combined Cycle 1x1x1, Single Shaft		
Predicted Emissions Rates (Note 1)		
NOx	lb/MMBtu	0.0075 (Note 2)
SO_2	lb/MMBtu	0.00
CO_2	lb/MMBtu	117
Emissions Control Notes		
1. Natural Gas, no water injection		

CASE 9. COMBUSTION TURBINE H CLASS, COMBINED-CYCLE SINGLE SHAFT WITH 90% CO_2 CAPTURE, 430 MW

9.1 CASE DESCRIPTION

This case includes one block of a combined-cycle power generation unit in a 1x1x1 single-shaft configuration. The plant includes one industrial frame Model H "advanced technology" CT, one STG, and one electric generator that is common to the CT and the STG. Case 9 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 90% of the CO_2 in the CT exhaust gas.

Refer to Case 8 for a description the power generation systems, since Case 9 is the same in this regard.

9.1.1 Mechanical Equipment & Systems

This technology case adds a 90% CO_2 capture system to an industrial frame GE Model H 7HA.01 dual fuel CTs in a 1x1x1 single-shaft CC configuration. The nominal output of the CC plant unit without carbon capture is 430.4 MW gross. The major power cycle equipment and configurations are described in Case 8. The CO_2 capture systems are commonly referred to as 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. For a brief description of the post-combustion, amine-based CO_2 capture system, please refer to Case 5.

As with the technology of Case 8, the base configuration used for the cost estimate is a single CC unit power generation plant station constructed on a greenfield site of approximately 60 acres. 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.

For Case 9, to obtain 90% CO_2 removal from the flue gas generated from the CT, he full flue gas path must be treated. The flue gas generated from natural gas-fired CT combustions 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 8.

The flue gas path differs from the base case (Case 8) in that 100% of the gas is directed to the carbon capture system located downstream of the preheater section of the HRSG. The 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 8 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 steam required for the carbon capture system is approximately 306,000 pounds per hour. As a result of the steam extraction, the gross STG generation outlet decreases from 133 MW to 112 MW.

The total auxiliary power required by the plant is 31.7 MW, of which 20 MW is used by the carbon capture system. The net output decreases from the base case (Case 8) from 418 MW to 377 MW. The net plant heat rate for the 90% carbon capture case is 7124 Btu/kWh, HHV basis (compared to 6431 Btu/kWh, HHV basis, for Case 8).

9.1.2 Electrical & Control Systems

The electrical and controls systems for this case is essentially similar is scope to Case 8's electrical system; however, the auxiliary power system supplies a much larger amount of medium voltage load for the 90% carbon capture case.

The CC facility and the CO_2 capture plant are controlled by a central 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 BOP systems and equipment (e.g., water systems, fuel systems, main cooling systems).

9.1.3 Offsite Requirements

Offsite provisions in Case 9 include:

- **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 90% carbon capture case is significantly higher than for the base CC case (Case 8. The estimated increase in cooling water makeup is approximately 1,500 gallons per minute. 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.

9.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $2481/kW. Table 9-1 summarizes the cost components for this case. The capital cost estimate is based on an EPC contracting approach.

In addition to EPC contract costs, the capital cost estimate in Table 9-1 covers owner's costs, which include project development, studies, permitting, and legal; owner's project management; owner's engineering; and owner's participation in startup and commissioning. The estimate is presented as an overnight cost in 2019 dollars and thus excludes Allowance for Funds Used During Construction or interest during construction. In addition to the cost of external systems noted above (e.g., fuel gas supply and transmission line), an estimated amount is included for the cost of land.

Table 9-1 — Case 9 Capital Cost Estimate

Case 9 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**Combined Cycle 1x1x1, Single Shaft, w/ 90% Carbon Capture** H-Class	
Combustion Emissions Controls		Dry Low NOx combustor with axial fuel staging	
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 deg F, 60% RH)	MW	377	
Heat Rate, HHV Basis	Btu/kWh	7124	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	10%	
Project Contingency	% of Project Costs	10%	
Owner's Services	% of Project Costs	7%	
Estimated Land Requirement (acres)	$	60	
Estimated Land Cost ($/acre)	$	30,000	
Interconnection Costs			
Electrical Transmission Line Costs	$/mile	1,800,000	
Miles	miles	1.00	
Substation Expansion	$	0	
Gas Interconnection Costs			
Pipeline Cost	$/mile	2,800,000	
Miles	miles	0.50	
Metering Station	$	4,500,000	
Typical Project Timelines			
Development, Permitting, Engineering	months	24	
Plant Construction Time	months	30	
Total Lead Time Before COD	months	54	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		31,000,000
Mechanical – Major Equipment	$	130,000,000	
Mechanical – Balance of Plant	$	73,000,000	
Mechanical Subtotal	$		203,000,000
Electrical Subtotal	$		28,000,000
CCS Plant Subtotal	$		362,306,000
Project Indirects	$		90,000,000
EPC Total Before Fee	$		714,306,000
EPC Fee	$		71,430,600
EPC Subtotal	$		785,736,600
Owner's Cost Components (Note 2)			
Owner's Services	$		55,002,000
Land	$		1,800,000
Electrical Interconnection	$		1,800,000
Gas Interconnection	$		5,900,000
Owner's Cost Subtotal	$		64,502,000
Project Contingency	$		85,024,000
Total Capital Cost	$		935,262,600
	$/kW net		**2,481**

Case 9 EIA – Capital Cost Estimates – 2019 $s	
Configuration	**Combined Cycle 1x1x1, Single Shaft, w/ 90% Carbon Capture** H-Class
Combustion Emissions Controls	Dry Low NOx combustor with axial fuel staging
Post-Combustion Emissions Controls	SCR Catalyst, CO Catalyst
Fuel Type	Natural gas / No. 2 Backup
Post Firing	No Post Firing
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, gas interconnection costs (if applicable), and land acquisition costs.	

9.3 O&M COST ESTIMATE

Operation and maintenance costs are indicated in Table 9-2. 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 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 EOH the CT has run. A significant overhaul is typically performed for this type of CT every 25,000 EOH, and a major overhaul is performed every 50,000 EOH. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of EOH. In Case 9, it is assumed the operating profile results in an EOH-driven maintenance overhaul schedule. Refer to Case 6 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 9-2 — Case 9 O&M Cost Estimate

Case 9 EIA – O&M Costs – 2019 $s		
Combined Cycle 1x1x1, Single Shaft, w/ 90% Carbon Capture		
Fixed O&M – Plant (Note 1)		
Subtotal Fixed O&M	$/kW-year	**27.60 $/kW-year**
Variable O&M (Note 2)	$/MWh	**5.84 $/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, and water discharge treatment cost.		

9.4 ENVIRONMENTAL & EMISSIONS INFORMATION

For the Case 9 CC configuration with 90% carbon capture, NO_X emissions from the plant when firing gas are indicated in Table 9-3. 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 90% for Case 9.

Table 9-3 — Case 9 Emissions

Case 9 EIA – Emissions Rates		
Combined Cycle 1x1x1, Single Shaft, w/ 90% Carbon Capture		
Predicted Emissions Rates (Note 1)		
NOx	lb/MMBtu	0.0075 (Note 2)
SO_2	lb/MMBtu	0.00
CO_2	lb/MMBtu	12
Emissions Control Notes		
1. Natural Gas, no water injection		

CASE 10. FUEL CELL, 10 MW

10.1 CASE DESCRIPTION

This case is based on a 10-MW fuel cell power generation facility using a series of identical modular fuel cells. Fuel cells use a potential difference between a cathode and an anode. There is a chemical reaction between oxygen from the air and the fuel within the anode that releases an electron to generate a current. There are many types of fuel cells, but only two technologies have demonstrated capability for utility-sized projects: molten carbonate fuel cell and solid oxide fuel cells. These types of fuel cells operate at high temperatures, (greater than 1,000°F) providing the unique ability to use multiple types of fuel and allows for more design options such as combined heat and power production. This study is based on solid oxide fuel cells oriented in multiple 300-kW stacks. Solid oxide fuel cell stacks are intended to act as modular components that can be combined in various geometries to generate whatever capacity is required for the project. The 10-MW solid oxide fuel cell plant used in this estimate comprises 36 fuel cell stacks operating at 92% capacity. These stacks would be grouped together in 3 groups of 12 stacks, and each group would have its own inverter.

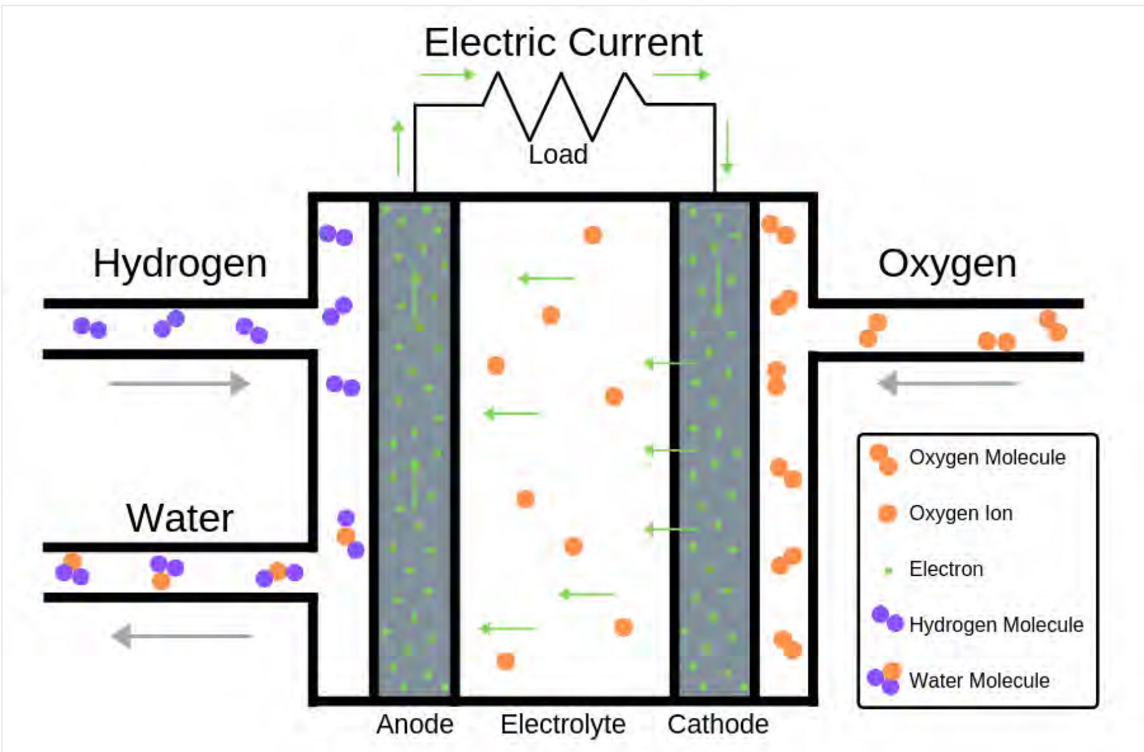
10.1.1 Chemical Operation

A solid oxide fuel cell stack is comprised of thousands of individual fuel cells made of a ceramic electrolyte (typically yttria stabilized zirconia) with a thin anode coating on one side and cathode coating on the other. Solid oxide fuel cells operate by generating steam to reform natural gas methane into hydrogen and carbon monoxide at the anode. At the same time, hot air passes over the cathode which absorbs oxygen molecules. The oxygen molecules react with the electrons in the cathode to form oxygen ions that pass through an electrolyte to combine with the hydrogen and carbon monoxide in the anode to form carbon dioxide, water, a free electron, and heat. The free electron is harnessed and used to generate an electrical current that can be converted into power, the water and heat are recycled to continually generate steam to reform the fuel, and the carbon dioxide is a waste byproduct that is released outside of the fuel cell.

Table 10-1 — Fuel Cell Chemical Reactions

Reaction	Equation
Steam Reforming	$CH_4 + H_2O\ (g) \xrightarrow{yields} 3H_2 + CO$
Electrolyte Reaction	$3H_2 + CO + 2O_2 \xrightarrow{yields} CO_2 + 2H_2O + e^- + Heat$
Net Solid Oxide Fuel Cell	$CH_4 + H_2O\ (g) + 2O_2 \xrightarrow{yields} CO_2 + H_2O + e^- + Heat$

Figure 10-1 — Simplified Solid Oxide Fuel Cell



Adapted from Battery Japan,
https://www.batteryjapan.jp/en-gb/visit/feature10-tokyo.html (accessed June 12, 2019)

10.1.2 Mechanical Equipment & Systems

Due to the small physical size and relative simplicity in design of these modular fuel cell stacks, minimal additional equipment is required. The heating of air and water, fuel reforming, and current generation all occur within the fuel stack itself. Their only external mechanical requirement is a foundation and the gas interconnection for the fuel. For this cost breakdown, however, the stack itself will refer only to the fuel cells within it. The mechanical BOP includes heat recovery components; the fuel processor components; and the supply components for the fuel, water, and air. The electrical equipment includes the power electric equipment such as the inverter and step-up transformer as well as the control and instrumentation equipment. The most expensive single component of the facility is the electric inverters. Fuel cells use a hybrid inverter. Hybrid inverters eliminate the need for a direct current (DC)/DC converter to match the battery voltage and are relatively new on the market. The recent development of these inverters makes them more expensive than other inverters.

Figure 10-2 — Typical Solid Oxide Fuel Cell Project

Source: Office of Fossil Energy – U.S. Department of Energy, ND. Digital Image.
Retrieved from Energy.gov, https://www.energy.gov/fe/science-innovation/clean-coal-research/solid-oxide-fuel-cells (accessed July 8, 2019).

10.1.3 Offsite Requirements

Fuel cells require a water supply and natural fuel supply as well as water discharge. They are typically designed near existing transmission lines and typically have minimal offsite electrical interconnection and transmission costs.

10.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $6700/kW. Table 10-2 summarizes the cost components for this case. Although the costs shown are based on an EPC contracting basis, the utility-sized fuel cell projects have been structured as build, own, operate, and maintain by the fuel cell manufacturers with electricity purchase agreements with the client or end user at a set $/kilowatt hour (kWh) basis. With that in mind, most of the solid oxide fuel cell applications are for individual entities, not microgrid or utility operations. These individual entities can range from small-scale businesses to large data centers that need 10+ MW of constant, uninterruptible power because they are unable to be offline for more than a few minutes.

Table 10-2 — Case 10 Capital Cost Estimate

Case 10 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**Fuel Cell** 34 x 300 kW Gross	
Fuel Cell Type		Solid Oxide	
Fuel Type		Natural Gas	
	Units		
Plant Characteristics			
Net Plant Capacity	MW	10	
Heat Rate	Btu/kWh	6469	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	5%	
Project Contingency	% of Project Costs	4%	
Owner's Services	% of Project Costs	8%	
Estimated Land Requirement (acres)	$	2	
Estimated Land Cost ($/acre)	$	30,000	
Interconnection Costs			
Gas Interconnection Costs			
Pipeline Cost	$/mile	2,500,000	
Miles	miles	0.25	
Metering Station	$	1,200,000	
Typical Project Timelines			
Development, Permitting, Engineering	months	21	
Plant Construction Time	months	3	
Total Lead Time Before COD	months	24	
Operating Life	years	20	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		3,764,000
Mechanical – Fuel Cell Stacks	$	11,601,000	
Mechanical – Balance of Plant	$	16,033,000	
Mechanical Subtotal	$		27,634,000
Electrical Subtotal	$		21,809,000
Project Indirects	$		3,075,000
EPC Total Before Fee	$		56,282,000
EPC Fee	$		2,814,000
EPC Subtotal	$		59,096,000
Owner's Cost Components (Note 2)			
Owner's Services	$		4,728,000
Land	$		60,000
Gas Interconnection	$		1,825,000
Owner's Cost Subtotal	$		6,613,000
Project Contingency	$		2,628,000
Total Capital Cost	**$**		68,337,000
	$/kW net		**6,700**

Case 10 EIA – Capital Cost Estimates – 2019 $s	
Configuration	**Fuel Cell** 34 x 300 kW Gross
Fuel Cell Type	Solid Oxide
Fuel Type	Natural Gas
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, gas interconnection costs (if applicable), and land acquisition costs.	

10.3 O&M COST ESTIMATE

Common practice for solid oxide fuel cell vendors is to build, operate, and maintain the fuel cell plant while charging a fixed monthly O&M to the owner of the project (i.e., the utility or corporation to which they are selling the energy). This leads to a large amount of fixed O&M costs. The only exception being the water supply and discharge, which is left to the owner. These costs are shown as variable O&M within this estimate.

Table 10-3 — Case 10 O&M Cost Estimate

Case 10 EIA – Non-Fuel O&M Costs – 2019 $s		
Fuel Cell		
Fixed O&M – Plant (Note 1)		
Routine Maintenance & Management	$/year	34,000
Fuel Cell Maintenance Reserve	$/year	280,000
Subtotal Fixed O&M	$/year	314,000
$/kW-year	$/kW-year	**30.78 $/kW-year**
Variable O&M (Note 2)	$/MWh	**0.59 $/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 includes costs of water supply and water discharge.		

10.4 ENVIRONMENTAL & EMISSIONS INFORMATION

Solid oxide fuel cell emissions are dependent on the fuel that is used: biofuel or natural gas. Biofuel allows for a reduction in emissions but carries a higher associated heat rate and operating cost. Therefore, in the interest of being economically competitive, most fuel cells today use natural gas. Even when using natural gas as the fuel source, fuel cells are considered a clean energy source. One important distinction between a natural gas-powered combustion turbine and a fuel cell that uses natural gas is that the fuel cell does not burn the gas. Within the fuel cell, natural gas is reformed with steam, which still releases CO_2 but reduces the other emissions, allowing fuel cells to maintain their "green" status.

Table 10-4 — Case 10 Emissions

Case 10 EIA – Emissions Rates		
Fuel Cell		
Predicted Emissions Rates (Note 1)		
NOx	lb/MMBtu	0.0002
SO_2	lb/MMBtu	0.00
CO	lb/MMBtu	0.005
CO_2	lb/MMBtu	117
Emissions Control Notes		
1. Natural Gas		

CASE 11. ADVANCED NUCLEAR, 2156 MW

11.1 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 June 2018.

11.1.1 Mechanical Equipment & 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 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 enriched uranium is contained 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 cooling water then flows through a steam generator that provide steam to the steam turbine for electrical generation.

11.1.2 Electrical & 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 GSU. The GSI 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 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.

11.1.3 Offsite Requirements

Water for all processes at the power plant is obtained from a nearby river or lake. The 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 power plant onsite switchyard is typically connected to the transmission line through a nearby substation.

11.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $6041/kW. Table 11-1 summarizes the cost components for this case.

Table 11-1 — Case 11 Capital Cost Estimate

Case 11 EIA – Capital Cost Estimates – 2019 $s		
Configuration		Advanced Nuclear (Brownfield) 2 x AP1000
	Units	
Plant Characteristics		
Net Plant Capacity (60 deg F, 60% RH)	MW	2156
Net Plant Heat Rate, HHV Basis	Btu/kWh	10608
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct & Indirect Costs	10%
Project Contingency	% of Project Costs	10%
Owner's Services	% of Project Costs	20.0%
Estimated Land Requirement (acres)	$	60
Estimated Land Cost ($/acre)	$	30,000
Interconnection Costs		
Electrical Transmission Line Costs	$/mile	2,520,000
Miles	miles	1.00
Substation Expansion	$	0
Gas Interconnection Costs		
Pipeline Cost	$/mile	0
Miles	miles	0.00
Metering Station	$	0

Case 11 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**Advanced Nuclear (Brownfield)** 2 x AP1000	
	Units		
Typical Project Timelines			
Development, Permitting, Engineering	months	24	
Plant Construction Time	months	48	
Total Lead Time Before COD	months	72	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		1,675,180,000
Nuclear Island	$	2,463,500,000	
Conventional Island	$	1,379,560,000	
Balance of Plant	$	788,320,000	
Mechanical Subtotal	$		4,631,380,000
Electrical Subtotal	$		788,320,000
Project Indirects	$		1,872,260,000
EPC Total Before Fee	$		8,967,140,000
EPC Fee	$		896,714,000
EPC Subtotal	$		9,863,854,000
Owner's Cost Components (Note 2)			
Owner's Services	$		1,972,771,000
Land	$		1,800,000
Electrical Interconnection	$		2,520,000
Gas Interconnection	$		0
Owner's Cost Subtotal	$		1,977,091,000
Project Contingency	$		1,184,095,000
Total Capital Cost	**$**		13,025,040,000
	$/kW net		**6,041**
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, gas interconnection costs (if applicable), and land acquisition costs.			

Owner's costs were reviewed to ensure that utility interconnection costs were accounted for appropriately. Specifically, 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.

11.3 O&M COST ESTIMATE

The O&M cost estimate includes all tasks discussed in the O&M estimate description.

Table 11-2 — Case 11 O&M Cost Estimate

Case 11 EIA – Non-Fuel O&M Costs – 2019 $s		
Advanced Nuclear (Brownfield)		
Fixed O&M – Plant ($/year) (Note 1)		
Subtotal Fixed O&M	$/kW-year	**121.64 $/kW-year**
Variable O&M ($/MWh) (Note 2)	$/MWh	**2.37 $/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.		

11.4 ENVIRONMENTAL & 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 12. SMALL MODULAR REACTOR NUCLEAR POWER PLANT, 600 MW

12.1 CASE DESCRIPTION

This case is based on 12 small reactor modules. Each module has a net capacity of 50 MW for a net plant capacity of 600 MW. The small modular reactor (SMR) case is not based on a particular OEM but rather is a representative SMR plant.

12.1.1 Mechanical Equipment and Systems

The mechanical systems of an SMR are much smaller than those of a traditional nuclear plant. The mechanical systems are similar to that 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 12 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 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 including the pool housed with the reactor building. This extra bay allows for removal of individual reactors for maintenance without impacting the remaining reactors.

12.1.2 Electrical and Control Systems

Each SMR has its own generator, which is a 60-Hz machine rated at approximately 45 MVA with an output voltage of 13.8 kV. The steam turbine electric generator is connected through a generator circuit breaker to a 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 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.

12.1.3 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 typically connected to the transmission line through a nearby substation.

12.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $6191/kW. Table 12-1 summarizes the cost components for this case.

Table 12-1 — Case 12 Capital Cost Estimate

Case 12 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Small Modular Reactor Nuclear Power Plant** 12 x 50-MW Small Modular Reactor
	Units	
Plant Characteristics		
Net Plant Capacity	MW	600
Net Plant Heat Rate, HHV Basis	Btu/kWh	10046
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct & Indirect Costs	10%
Project Contingency	% of Project Costs	10%
Owner's Services	% of Project Costs	7.5%
Estimated Land Requirement (acres)	acres	35
Estimated Land Cost ($/acre)	$	30,000
Interconnection Costs		
Electrical Transmission Line Costs	$/mile	2,520,000
Miles	miles	1.00
Substation Expansion	$	0

Case 12 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**Small Modular Reactor Nuclear Power Plant** 12 x 50-MW Small Modular Reactor	
	Units		
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	48	
Total Lead Time Before COD	months	72	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		583,524,000
Nuclear Island	$	648,360,000	
Conventional Island	$	421,434,000	
Balance of Plant	$	389,016,000	
Mechanical Subtotal	$		1,458,810,000
Electrical Subtotal	$		259,344,000
Project Indirects	$		551,000,000
EPC Total Before Fee	$		2,852,678,000
EPC Fee	$		285,267,800
EPC Subtotal	$		3,137,945,800
Owner's Cost Components (Note 2)			
Owner's Services	$		235,346,000
Land	$		1,050,000
Electrical Interconnection	$		2,520,000
Gas Interconnection	$		0
Owner's Cost Subtotal	$		238,916,000
Project Contingency	$		337,686,000
Total Capital Cost	$		3,714,547,800
	$/kW net		**6,191**
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, gas interconnection costs (if applicable), and land acquisition costs.			

Owner's costs include 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 that any SMR built at this time would be a first-of-a-kind facility. The indicated costs do not include financial incentives such as tax credits or cost sharing arrangements through public-private partnerships that may support first-of-a-kind facilities.

12.3 O&M COST ESTIMATE

The O&M cost estimate includes all tasks discussed in the O&M estimate description.

Table 12-2 — Case 12 O&M Cost Estimate

Case 12 EIA – Non-Fuel O&M Costs – 2019 $s		
Small Modular Reactor Nuclear Power Plant		
Fixed O&M – Plant (Note 1)		
Subtotal Fixed O&M	$/kW-year	**95.00 $/kW-year**
Variable O&M (Note 2)	$/MWh	**3.00 $/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. Variable O&M costs include water, water discharge treatment cost, chemicals, and consumables. Fuel is not included.		

12.4 ENVIRONMENTAL & 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 13. BIOMASS PLANT, 50 MW

13.1 CASE DESCRIPTION

This case comprises a greenfield biomass-fired power generation facility with a nominal net capacity of 50 MW with a single steam generator and condensing steam turbine with biomass storage and handling systems, BOP systems, in-furnace, and post-combustion emissions control systems. 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 and CO_2 are not controlled.

13.1.1 Mechanical Equipment & Systems

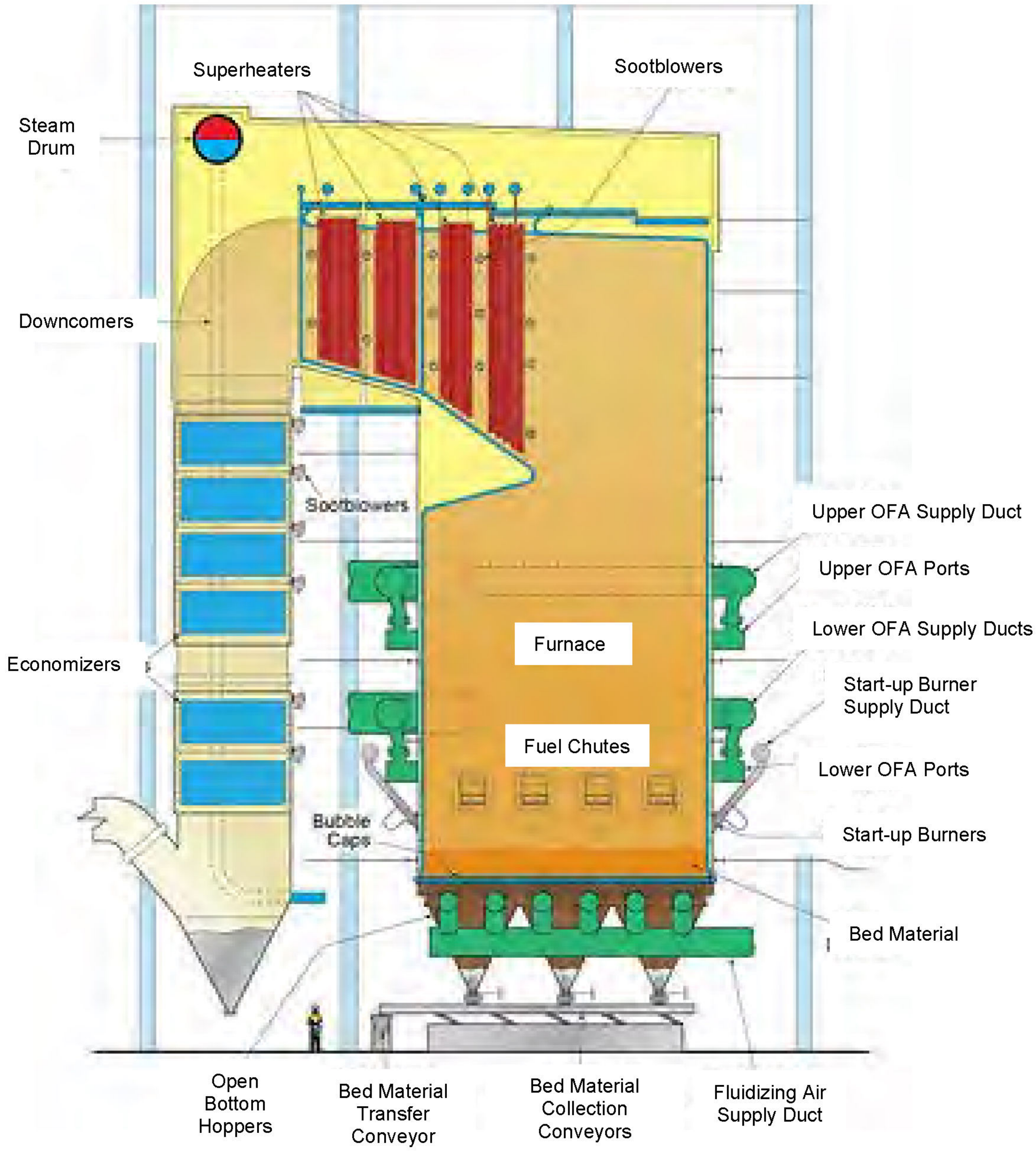
The core technology for this case is a BFB boiler designed to fire wood chips. The boiler is a natural circulation balanced-draft, non-reheat cycle. For this size range, the boiler is assumed to be a top-supported design arranged in a similar manner as shown in Figure 13-1. The BFB furnace consists of 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 1,400°F to 1,600°F, depending on the moisture content of the fuel. Diesel oil-fired startup 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 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, water treatment system and demineralized water storage tanks, a fire protection and detection system, diesel oil storage and transfer system, compressed air system, 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 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 13-1 — Typical BFB Biomass Boiler Arrangement



Babcock & Wilcox Top-Supported BFB Boiler

Source: Babcock & Wilcox, *BFB-boiler-top-supported*, ND. Digital Image. Reprinted with permission from Babcock & Wilcox. Retrieved from Babcock.com, https://www.babcock.com/products/bubbling-fluidized-bed-boilers (accessed June 5, 2019).

The plant performance estimates for BFB boilers firing wood chips is highly dependent on fuel moisture. Generally, BFB boiler efficiencies range from 75% to 80%. The estimated net heat rate firing wood chips is 13,300 Btu/kWh based on the HHV of the fuel.

13.1.2 Electrical & Control Systems

The electrical system for this case includes the turbine generator which is connected via generator circuit breakers to a GSU. The GSU increases the voltage from the generator voltages level to the transmission system high voltage level. The facility and most of the subsystems are controlled using a central 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

13.1.3 Offsite Requirements

The facility is constructed on a greenfield site of approximately 50 acres. Wood chips are delivered to the facility by truck and rail. The maximum daily rate for wood chips for the facility is approximately 1500 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.

13.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $4097/kW. Table 13-1 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 well water and/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 13-1 — Case 13 Capital Cost Estimate

Case 13 EIA – Capital Cost Estimates – 2019 $s			
Configuration		50-MW Biomass Plant Bubbling Fluidized Bed	
Combustion Emissions Controls		OFA	
Post-Combustion Emissions Controls		SCR / Baghouse	
Fuel Type		Woodchips	
	Units		
Plant Characteristics			
Net Plant Capacity (60 deg F, 60% RH)	MW	50	
Heat Rate, HHV Basis	Btu/kWh	13300	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	10%	
Project Contingency	% of Project Costs	12%	
Owner's Services	% of Project Costs	7%	
Estimated Land Requirement (acres)	$	50	
Estimated Land Cost ($/acre)	$	30,000	
Interconnection Costs			
Electrical Transmission Line Costs	$/mile	1,200,000	
Miles	miles	1.00	
Substation Expansion	$	0	
Gas Interconnection Costs			
Pipeline Cost	$/mile	N/A	
Miles	miles	N/A	
Metering Station	$	N/A	
Typical Project Timelines			
Development, Permitting, Engineering	months	24	
Plant Construction Time	months	36	
Total Lead Time Before COD	months	60	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		22,266,000
Mechanical – Boiler Plant	$	60,477,000	
Mechanical – Turbine Plant	$	8,230,000	
Mechanical – Balance of Plant	$	20,111,000	
Mechanical Subtotal	$		88,818,000
Electrical – Main and Auxiliary Power Systems	$	3,543,000	
Electrical – BOP and I&C	$	17,657,000	
Electrical – Substation and Switchyard	$	5,408,000	
Electrical Subtotal	$		26,608,000
Project Indirects	$		15,418,000
EPC Total Before Fee	$		153,110,000
EPC Fee	$		15,311,000
EPC Subtotal	$		168,421,000
Owner's Cost Components (Note 2)			
Owner's Services	$		11,789,000
Land	$		1,500,000
Electrical Interconnection	$		1,200,000
Gas Interconnection	$		0
Owner's Cost Subtotal	$		14,489,000
Project Contingency	$		21,949,000
Total Capital Cost	$		204,859,000
	$/kW net		**4,097**

Case 13 EIA – Capital Cost Estimates – 2019 $s	
Configuration	**50-MW Biomass Plant** Bubbling Fluidized Bed
Combustion Emissions Controls	OFA
Post-Combustion Emissions Controls	SCR / Baghouse
Fuel Type	Woodchips
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, gas interconnection costs (if applicable), and land acquisition costs.	

13.3 O&M COST ESTIMATE

The O&M costs for 50-MW biomass wood-fired generation facility are summarized in Table 13-2. The fixed costs cover the O&M labor, contracted maintenance services and materials, and 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 (e.g., 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, and bed material makeup.

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

Case 13 EIA – Non-Fuel O&M Costs – 2019 $s		
50-MW Biomass Plant		
Fixed O&M – Plant (Note 1)		
Labor	$/year	3,510,000
Materials and Contract Services	$/year	1,250,000
Administrative and General	$/year	1,526,000
Subtotal Fixed O&M	$/year	6,286,000
$/kW-year	$/kW-year	**125.72 $/kW-year**
Variable O&M (Note 2)	$/MWh	**4.83 $/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, and water discharge treatment cost.		

13.4 ENVIRONMENTAL & EMISSIONS INFORMATION

The emissions for the major criteria pollutants are summarized in Table 13-3. The NO_X emissions assume that the in-furnace controls such as LNB, OFA, and SCR systems are employed to control emissions to 0.08 lb/MMBtu. The SO_2 emissions from wood fired combustion are assumed to be negligible and are uncontrolled. The CO_2 emissions estimates are based on emissions factors listed in Table C-1 of 40 CFR 98, Subpart C.

Table 13-3 — Case 13 Emissions

Case 13 EIA – Emissions Rates		
50-MW Biomass Plant		
Predicted Emissions Rates (Note 1)		
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	206 (Note 5)
Emissions Control Notes		
1. Wood Fuel – 20% to 50% Fuel Moisture		
2. NOx Removal using OFA, and SCR		
3. SO2 is assumed negligible in for wood fuel		
4. Controlled using pulse jet fabric filter		
5. Per 40 CFR 98, Subpt. C, Table C-1		

CASE 14. 10% BIOMASS CO-FIRE RETROFIT

14.1 CASE DESCRIPTION

This case is a retrofit of an existing 300-MW pulverized coal power facility to cofire wood biomass at a rate corresponding to 10% of the equivalent output in MW. In this scenario, the biomass fuel displaces coal to generate approximately 30 MW of the net output with the balance from coal. The type of boiler assumed for the retrofit is a balanced draft, radiant reheat type boiler that fires a high to medium sulfur bituminous coal through pulverizers. The firing system is either tangential or wall-fired and is assumed to have low-NO_X features such as LNBs and OFA. The biomass is a pelletized wood-based material formed from sawdust or paper. The biomass is not mixed with the coal and is not fed through the pulverizers but is introduced into the boiler through separate burners in new water-wall openings. The heat input from the biomass displaces the equivalent heat input from coal.

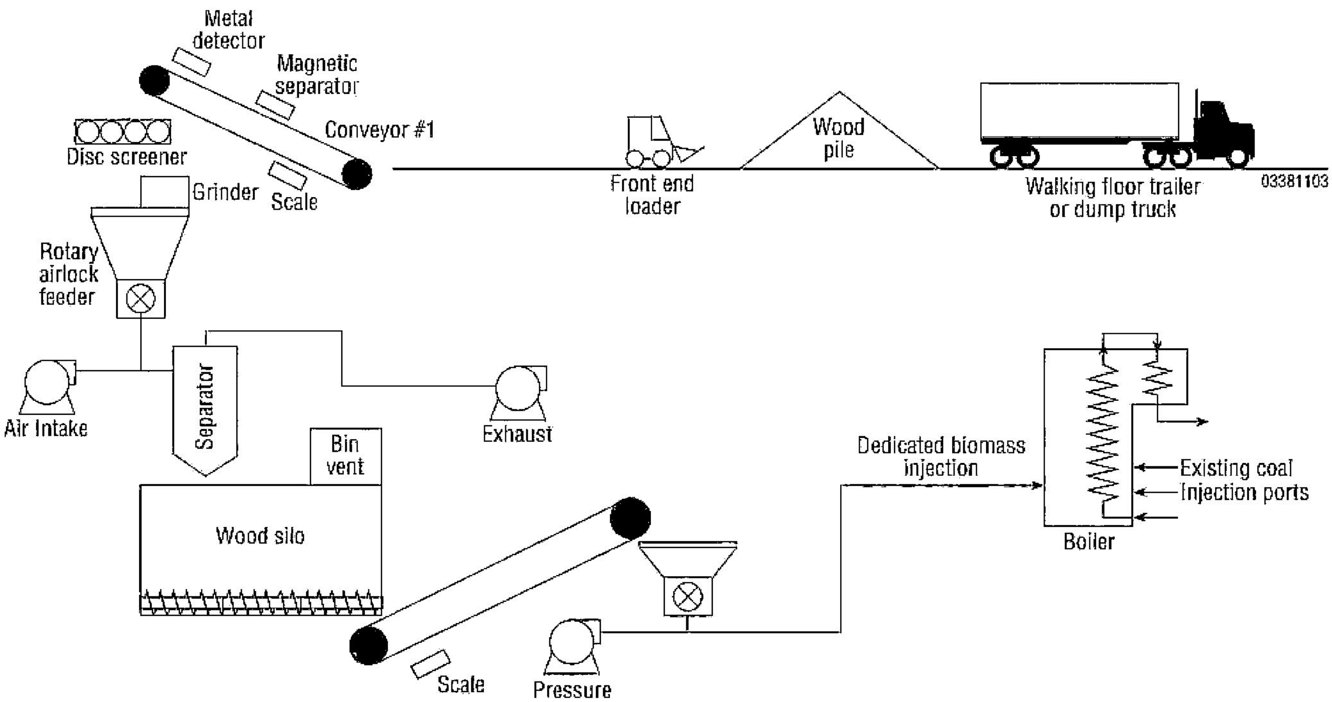
14.1.1 Mechanical Equipment & Systems

Figure 14-1 summarizes schematically the equipment required for the retrofit of biomass cofiring equipment to an existing 300-MW coal-fired facility. A portion of the facility is modified to receive and store the biomass fuel. The biomass fuel storage area is constructed on a concrete pad and a roof to minimize exposure to rain and snow. A reclaim system will convey the fuel to a grinder and feeder system located near the boiler. The biomass is then fed into surge bins feeding four individual burners. The biomass is conveyed to the boiler with heated primary air. The biomass burners have windboxes for secondary air distribution. The boiler water walls are modified to account for the new biomass firing equipment.

The BOP equipment modifications include additional fire detection and protection equipment. Additional duct control equipment is provided to minimize dangerous accumulation of fines. Additional automated and manual wash water systems are provided to remove any dust accumulation along the material handling path. Additional sootblowers are included in areas of the upper furnace and convective passes to address increases in fouling and slagging by the cofiring of the wood biomass. No modifications to the boiler post-combustion emissions controls are necessary; however, the boiler controls are modified to account for the redistribution of combustion air.

The introduction of biomass into the boiler will decrease the boiler efficacy. The estimated increase in heat rate for the 100% coal-fired base case is approximately 1.5%.

Figure 14-1 — Biomass Cofiring in Coal-Fired Boilers, Separate Feed Arrangement



Source: NREL, *DOE/EE-0288 Biomass Cofiring in Coal-Fired Boilers*, 2004. PDF.
Retrieved from NREL.gov, https://www.nrel.gov/docs/fy04osti/33811.pdf (accessed June 13, 2019).

14.1.2 Electrical & Control Systems

No major modifications to the electrical system are needed for this retrofit; however, new power feeds to the biomass fuel handling equipment and biomass conveying fans will be required. The plant DCS system will be upgraded to accommodate the additional input/output and control systems for the biomass handling and combustions systems.

14.1.3 Offsite Requirements

The pelletized wood biomass is delivered to the facility by truck. The maximum daily biomass fuel rate for the facility is approximately 500 tons per day, which corresponds to 20 to 24 trucks per day. New roads and additional site access are provided to accommodate the increase in daily truck traffic.

There are no substantial increases in the demands of cycle makeup water or cooling tower makeup. The service water demands increase due to the additional washdown systems needed for dust control, but the current water resources are sufficient to meet these demands.

14.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $705/kW based on the net output from the biomass; in this case, it is 30 MW. Table 14-1 summarizes the cost components for this case. The basis of the estimate assumes that the site has sufficient space for the biomass fuel storage and sufficient auxiliary power capacity for the new electrical loads.

Table 14-1 — Case 14 Capital Cost Estimate

Case 14 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**10% Biomass Co-Fire Retrofit** 300-MW PC Boiler
Combustion Emissions Controls		LNB / OFA / SCR
Post-Combustion Emissions Controls		ESP
Fuel Type		Wood Pellets, up to 10%
	Units	
Plant Characteristics		
Equivalent Biomass Plant Capacity	MW	30
Heat Rate, HHV Basis	% Change from Baseline	+ 1.5%
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct & Indirect Costs	10%
Project Contingency	% of Project Costs	20%
Owner's Services	% of Project Costs	7%
Estimated Land Requirement (acres)	$	0
Estimated Land Cost ($/acre)	$	30,000
Interconnection Costs		
Electrical Transmission Line Costs	$/mile	1,200,000
Miles	miles	1.00
Substation Expansion	$	N/A
Gas Interconnection Costs		
Pipeline Cost	$/mile	N/A
Miles	miles	N/A
Metering Station	$	N/A
Typical Project Timelines		
Development, Permitting, Engineering	months	18
Plant Construction Time	months	8
Total Lead Time Before COD	months	26
Operating Life	years	20
Cost Components (Note 1)		**Total**
Civil/Structural/Architectural Subtotal	$	1,572,000
Mechanical Subtotal	$	9,880,000
Electrical Subtotal	$	2,769,000
Project Indirects	$	749,000
EPC Total Before Fee	$	14,970,000
EPC Fee	$	1,497,000
EPC Subtotal	$	16,467,000

Case 14 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**10% Biomass Co-Fire Retrofit** 300-MW PC Boiler
Combustion Emissions Controls		LNB / OFA / SCR
Post-Combustion Emissions Controls		ESP
Fuel Type		Wood Pellets, up to 10%
	Units	
Owner's Cost Components (Note 2)		
Owner's Services	$	1,153,000
Land	$	0
Electrical Interconnection	$	0
Gas Interconnection	$	0
Owner's Cost Subtotal	$	1,153,000
Project Contingency	$	3,524,000
Total Capital Cost	**$**	21,144,000
	$/kW net	**705**
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, gas interconnection costs (if applicable), and land acquisition costs.		

14.3 O&M COST ESTIMATE

The O&M costs for biomass cofiring are summarized in Table 14-2. Costs are normalized by the equivalent electrical output from biomass. The fixed costs cover the O&M labor, contracted maintenance services and materials, and G&A for the cofiring systems only.

Non-fuel variable costs for this technology case include increased water treatment costs and increased fly ash and bottom ash disposal costs.

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

Case 14 EIA – Non-Fuel O&M Costs – 2019 $s		
10% Biomass Co-Fire Retrofit		
Fixed O&M – Plant (Note 1)		
Labor	$/year	267,000
Materials and Contract Services	$/year	350,000
Administrative and General	$/year	150,000
Subtotal Fixed O&M	$/year	767,000
$/kW-year	$/kW-year	**25.57 $/kW-year**
Variable O&M (Note 2)	$/MWh	**1.90 $/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, ash disposal, and water discharge treatment cost.		

14.4 ENVIRONMENTAL & EMISSIONS INFORMATION

The emissions for the major criteria pollutants are summarized in Table 14-3. No major modifications to the emissions controls system are required; however, the combustion air and OFA distribution within the furnace need to be tuned and adjusted to optimize the performance on the biomass fuel. The NO_X emissions as measured at the outlet of the economizer are expected to decrease by up to 20% from baseline levels depending on the type of boiler and the coal fired. The SO_2 emissions are expected to decrease by approximately 8%. and the CO_2 emissions derived from coal reduce by approximately 8% from baseline levels.

Table 14-3 — Case 14 Emissions

Case 14 EIA – Emissions Offsets		
10% Biomass Co-Fire Retrofit		
Predicted Emissions Rates (Note 1)		
NOx	% change at Economizer Outlet	- 0 to -20% (Note 2)
SO_2	% change at Economizer Outlet	-8%
PM	% change at Economizer Outlet	0%
CO_2 (Derived from Coal)	% change at Economizer Outlet	-8% (Note 3)
Emissions Control Notes		
1. Emissions are presented as differentials to the baseline, uncontrolled emissions rates		
2. In-furnace NOx reduction systems in place; LNBs and OFA		
3. Based on a reduction of the coal derived CO2		

CASE 15. GEOTHERMAL PLANT, 50 MW

15.1 CASE DESCRIPTION

This case is a hydrothermal-based net 50-MW geothermal power plant using a binary cycle. Capital costs for geothermal power are highly site specific and technology specific. There are two distinct types of geothermal systems: Enhanced Geothermal System (EGS) and Hydrothermal. EGS technology uses fractures, or porous characteristics, in dry, hot rock to create a geothermal reservoir by injecting the water into the hot rock before commercial operation. Hydrothermal systems use naturally occurring geothermal aquifers that already have hot liquid water and/or steam within fractured or porous reservoirs.

Either type of geothermal system can use one of three general technologies for the generation of electricity: dry, flash, and binary cycle. The choice of technology is usually based on the temperature of the water (liquid, steam, or both) found within the geothermal reservoir (or the temperature of the EGS-developed reservoir). In some cases, these technologies may be combined, such as a flash plant with a bottoming binary cycle. Dry steam technology is used with geothermal reservoirs that produce superheated, dry steam that self-discharges from the production well. These systems are typically reserved for the upper range of reservoir temperatures. Flash technology is used with geothermal reservoirs that produce steam and water. The steam and water are separated at the surface with the steam being routed to a steam generator and the liquid either being reinjected into the well or being flashed into steam by a pressure reduction before being routed to a steam generator. This case assumes the use of the third technology: binary cycle.

The use of a binary cycle rather than flash would typically be considered for geothermal production temperatures of 350°F or less, although there is no firm temperature demarcation point as to when binary versus flash technologies should be used. Reservoirs with lower temperatures (approximately 350°F or less) will typically be produced via wells that will not self-discharge and require a means of pumping the fluid from the reservoir up to the surface. This pumping is usually accomplished using individual pumps installed into each production well. The binary cycle is also commonly referred to as Organic Rankine Cycle.

When using a binary cycle, the produced reservoir fluid is maintained as a pressurized liquid (i.e., at a pressure above the saturation pressure corresponding to the fluid's temperature) within the production well, the surface piping and plant equipment, all the way to the injection wells where it is readmitted to the reservoir. This pressurized state keeps the hot geothermal fluid from boiling (flashing), and the geothermal fluid is never in contact with ambient air. A portion of the heat content of the pressurized geothermal fluid is transferred into a working fluid via one or more heat exchanger(s). The working fluid is typically vaporized within the heat exchanger(s) and is then sent to a turboexpander where it expands and produces mechanical power. The turboexpander drives an electrical generator. Binary cycle power plants may use either air-cooling or water-cooling for condensing the turbo-expander exhaust back into a liquid. Currently, most geothermal plants operating within the United States use flash steam technology; however, this case assumes the use of binary cycle technology due to the lower temperatures of remaining unused geothermal resources.

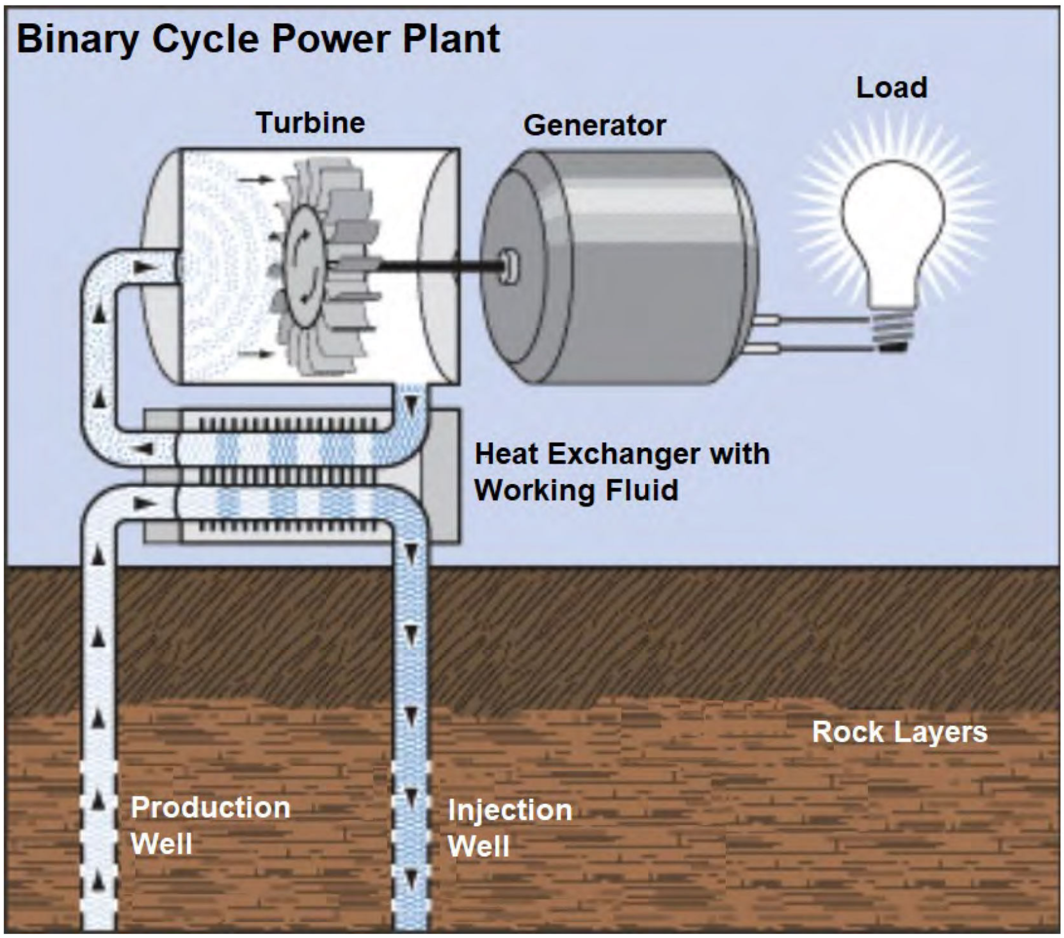
Utility-scale geothermal power requires high-temperature aquifers to be cost effective. Locating aquifers with a sufficiently high temperature and sustainable flow rate is a significant task. The costs associated with exploration and drilling of the wells often accounts for over 50% of the total overnight capital expenditures for a geothermal project. To isolate the costs of building and maintaining the geothermal plant itself, this study has assumed that the geothermal plant was built on a brownfield site. This means that a sufficiently hot aquifer has already been identified with production and injection wells already developed. While this is rare, it does occasionally occur within the industry. As the geothermal well gets hotter, lower flow rates are required to maintain the same output thus reducing capital costs and operation costs. This analysis assumes that the geothermal reservoir has a temperature of 300°F.

15.1.1 Mechanical Equipment & Systems

A binary cycle power plant has three independent fluid loops: (1) the geothermal fluid loop, (2) the closed working fluid loop, and (3) the open cooling water loop. A simplified image of binary cycle including loops (1) and (2) can be seen in Figure 15-1. The open geothermal loop is comprised of the production well(s), downhole well pump(s), piping to the power plant, heat exchanger(s) coupled with the working fluid, piping to the injection well field, and the injection well(s). The temperature and flow rate of the geothermal loop is dependent upon the properties of the reservoir, but it is always kept at a pressure above its flash point. A single geothermal production well typically has the potential to convert the well's thermal power into around 3 MW of electric power. A geothermal plant typically has between a 2:1 ratio and a 1:1 ratio of production wells to injection wells. This system is assumed to have 17 production wells and 10 injections wells.

The closed working fluid loop is comprised of a pump for pumping the working fluid in the liquid phase, a turboexpander that is connected to a generator, and heat exchanger(s). Heat exchangers transfer heat from the hot geothermal fluid to the working fluid, essentially boiling the working fluid and the resulting vapor is sent through the turboexpander. After the turboexpander, another heat exchanger (condenser) transfers heat from the working vapor, condensing it back into a liquid to be pumped back through the cycle. The working fluid typically has a low boiling point, which allows for reliable operation, and has a high conversion efficiency for good utilization of the geothermal heat. The 50-MW geothermal plant uses two working fluid loops, each with its own 25-MW steam turbine and generator.

Figure 15-1 — Geothermal Binary Cycle Power Plant



Source: Office of Energy Efficiency & Renewable Energy,
Geothermal Technologies Office – U.S. Department of Energy, *binaryplant*, ND. Digital Image
Retrieved from Energy.gov, https://www.energy.gov/eere/geothermal/electricity-generation (accessed July 9, 2019)

The final loop, which is not shown in the diagram above, is an open loop of cooling water which is comprised of a cooling water pump, heat exchanger (condenser), and the cooling tower. The cooling system used for this case is a wet cooling tower. Water vapor from the cooling tower is the only emission of binary cycle power plants, with the exception of a cooling water blowdown stream from the cooling tower. Air-cooled condensers can also be used, but risk declines in power output during periods of high ambient temperature.

15.1.2 Electrical & Control Systems

This 50-MW geothermal plant uses two 25-MW turboexpanders with independent generators. 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.

15.1.3 Offsite Requirements

Geothermal plants use renewable heat from within the earth and naturally occurring water sources. This allows geothermal facilities to be free from requiring offsite fuel or materials. Water for the cooling system is either sourced from offsite or uses nearby natural sources such as a lake, freshwater well, or river. Unlike dry steam and flash power plants, binary cycle plants continually reinject all of the produced geothermal fluid back into the reservoir, thereby removing the need for brine processing and disposal. This reinjection of all produced mass also helps in maintaining reservoir pressure since there is no net mass removal from the reservoir.

15.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $2521/kW. Table 15-1 summarizes the cost components for this case. This price is dependent on the technology used, reservoir temperature, and location of the power plant. This analysis assumes that due to geological constraints, only the west coast of the United States should be considered for this cost estimate (i.e., California, Oregon, Washington, Nevada, and Idaho).

Table 15-1 — Case 15 Capital Cost Estimate

Case 15 EIA – Capital Cost Estimates – 2019 $s			
Configuration		Geothermal 50 MW	
Plant Configuration		Binary Cycle	
	Units		
Plant Characteristics			
Net Plant Capacity	MW	50	
Capital Cost Assumptions			
EPC Contracting Fee	% of Direct & Indirect Costs	15%	
Project Contingency	% of Project Costs	8%	
Owner's Services	% of Project Costs	12%	
Estimated Land Requirement (acres)	$	200	
Estimated Land Cost ($/acre)	$	10,000	
Electric Interconnection Costs			
Transmission Line Cost	$/mile	1,200,000	
Miles	miles	1.00	
Substation Expansion	$	0	
Typical Project Timelines			
Development, Permitting, Engineering	months	24	
Plant Construction Time	months	36	
Total Lead Time Before COD	months	60	
Operating Life	years	40	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		8,463,000
Mechanical – Steam Turbine	$	18,750,000	
Mechanical – Production / Injection System	$	21,644,000	
Mechanical – Balance of Plant	$	19,663,000	
Mechanical Subtotal	$		60,057,000
Electrical – BOP and I&C	$	5,475,000	
Electrical – Substation and Switchyard	$	4,302,000	
Electrical Subtotal	$		9,777,000
Project Indirects	$		9,838,000
EPC Total Before Fee	$		88,135,000
EPC Fee	$		13,220,000
EPC Subtotal	$		101,355,000
Owner's Cost Components (Note 2)			
Owner's Services	$		12,163,000
Land	$		2,000,000
Electrical Interconnection	$		1,200,000
Owner's Cost Subtotal	$		15,363,000
Project Contingency	$		9,337,000
Total Capital Cost	$		126,055,000
	$/kW net		**2,521**
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, gas interconnection costs (if applicable), and land acquisition costs.

15.3 O&M COST ESTIMATE

Different geothermal technologies have different O&M costs. Binary cycle geothermal plants are able to maintain the turbine (turboexpander) at a lower cost than other geothermal technologies due to the increased quality of the working fluid compared to the geothermal steam that passes through the turbine in dry steam and flash plant designs. What binary cycle plants save in turbine maintenance is lost in the additional pump maintenance since the other technologies do not require downhole pumps. Additionally, for binary cycle plants to produce equivalent net power outputs, they require higher flow rates from the production wells and have more overall pumps and piping compared to the other geothermal technologies.

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

Case 15 EIA – Non-Fuel O&M Costs – 2019 $s		
Geothermal		
Fixed O&M – Plant (Note 1)		
Labor	$/year	1,470,000
Steam Turbine Maintenance	$/year	3,750,000
Materials and Contract Services	$/year	661,800
Administrative and General	$/year	545,400
Subtotal Fixed O&M	$/year	6,427,200
$/kW-year	$kW-year	**128.54 $/kW-year**
Variable O&M (Note 2)	$/MWh	**1.16 $/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, limestone, water, ash disposal, FGD waste disposal, and water discharge treatment cost.		

15.4 ENVIRONMENTAL & EMISSIONS INFORMATION

While flash and dry geothermal power plants produce small emissions, binary cycle geothermal plants produce no regulated environmental emissions. The only emission is water vapor and small amounts of blowdown tower water from the cooling tower because the working fluid is kept in a closed loop and the geothermal loop is only open to the underground reservoir. Therefore, the emissions of NOx, SO_2, and CO_2 are 0.00 lb/MMBtu.

CASE 16. INTERNAL COMBUSTION ENGINES, LANDFILL GAS, 30 MW

16.1 CASE DESCRIPTION

This case is a landfill gas-fired power plant that is powered by four reciprocating internal combustion engines. Each engine is nominally rated at 9.1 MW for a net capacity of 35.6 MW. The case only includes the power block and does not include any of the landfill gas gathering or filtering systems.

16.1.1 Mechanical Equipment and Systems

The RICE power plant comprises four large-scale gas-fired engines that are coupled to a generator. The power plant also includes the necessary engine auxiliary systems, which are fuel gas, lubricated oil, compressed air, cooling water, air intake, and exhaust gas.

Each engine is comprised of 10 cylinders in a V configuration. The engines are a four-stroke, spark-ignited engine that operates on the Otto cycle. Each engine includes a turbocharger with an intercooler that uses the expansion of hot exhaust gases to drive a compressor that raises the pressure and density of the inlet air to each cylinder. The turbocharger is an axial turbine/compressor with the turbine and the centrifugal compressor mounted on the same shaft. Heat generated by compressing the inlet air is removed by a water-cooled "intercooler." Turbocharging increases the engine output due to the denser air/fuel mixture.

The engines are cooled using a water/glycol mixture that circulates through the engine block, cylinder heads, and the charge air coolers. The cooling system is a closed-loop system and is divided into a high-temperature and a low-temperature circuit. The high-temperature circuit cools the engine block, cylinder heads, and the first stage of the charge air cooler. The low-temperature cooler cools the second stage of the charge air cooler. Heat is rejected from the cooling water system by air-cooled radiators.

16.1.2 Electrical and Control Systems

The electrical generator is coupled to the engine. The generator is a medium voltage, air-cooled, synchronous AC generator.

The engine OEM provides a DCS that allows for a control interface, plant operating data, and historian functionality. The control system is in an onsite building. Programmable logic controllers are also provided throughout the plant for local operation.

16.1.3 Offsite Requirements

Fuel for combustion is delivered through the landfill gas gathering system. As water consumption is minimal at the power plant, water is obtained from the municipal water supply. The power plant also includes minimal water treatment for onsite water usage. Wastewater is treated using an oil-water separator and then is directed to a municipal wastewater system. Used oil that is no longer filterable is stored in a waste oil tank and removed offsite with a vacuum truck.

The power plant's onsite switchyard is connected to the transmission system through a nearby substation.

16.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $1563/kW. Table 19-1 summarizes the cost components for this case.

Table 16-1 — Case 16 Capital Cost Estimate

Case 16 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Internal Combustion Engines** 4 x 9.1 MW
Fuel Type		Landfill Gas
	Units	
Plant Characteristics		
Net Plant Capacity (60 deg F, 60% RH)	MW	35.6
Net Plant Heat Rate, HHV Basis	Btu/kWh	8513
Capital Cost Assumptions		
EPC Contracting Fee	% of Direct & Indirect Costs	10%
Project Contingency	% of Project Costs	8%
Owner's Services	% of Project Costs	7.5%
Estimated Land Requirement (acres)	$	10
Estimated Land Cost ($/acre)	$	30,000
Interconnection Costs		
Electrical Transmission Line Costs	$/mile	720,000
Miles	miles	1.00
Substation Expansion	$	0
Gas Interconnection Costs		
Pipeline Cost	$/mile	0
Miles	miles	0.00
Metering Station	$	0
Typical Project Timelines		

Case 16 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**Internal Combustion Engines** 4 x 9.1 MW	
Fuel Type		Landfill Gas	
	Units		
Development, Permitting, Engineering	months	12	
Plant Construction Time	months	18	
Total Lead Time Before COD	months	30	
Operating Life	years	30	
Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		12,464,000
Engines (Note 3)	$	13,637,000	
Mechanical BOP	$	8,735,000	
Mechanical Subtotal	$		22,372,000
Electrical Subtotal	$		9,803,000
Project Indirects	$		180,000
EPC Total Before Fee	$		31,182,000
EPC Fee	$		3,118,000
EPC Subtotal	$		34,300,000
Owner's Cost Components (Note 2)			
Owner's Services	$		2,573,000
Land	$		300,000
Owner Furnished Equipment (Note 3)	$		13,637,000
Electrical Interconnection	$		720,000
Gas Interconnection	$		0
Owner's Cost Subtotal	$		17,230,000
Project Contingency	$		4,122,000
Total Capital Cost	**$**		55,652,000
	$/kW net		**1,563**
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, gas interconnection costs (if applicable), and land acquisition costs.			
3. Engines and associated auxiliary procured from the engine OEM.			

Owner’s costs were reviewed to ensure that utility interconnection costs were accounted for appropriately. Specific to the landfill gas case, a natural gas interconnection for engine fuel is not required. Additionally, it is expected that some electrical and water utilities will already be available at the existing landfill site.

16.3 O&M COST ESTIMATE

The O&M cost estimate includes all tasks discussed in the O&M estimate description.

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

Case 16 EIA – Non-Fuel O&M Costs – 2019 $s		
Internal Combustion Engines		
Fixed O&M – Plant (Note 1)		
Subtotal Fixed O&M	$/kW-year	**20.10 $/kW-year**
Variable O&M (Note 2)	$/MWh	**6.20 $/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.		

16.4 ENVIRONMENTAL & EMISSIONS INFORMATION

NOx and CO emissions are maintained through an SCR and CO catalyst installed in the exhaust system of each engine. SO_2 is uncontrolled but minimal and below emission limits because of the low amounts of SO_2 in the natural gas fuel. Water, wastewater, solid waste, and spent lubricating oil are disposed of through conventional means.

Table 16-3 — Case 16 Emissions

Case 16 EIA – Emissions Rates		
Internal Combustion Engines		
Predicted Emissions Rates – Natural Gas		
NOx	lb/MMBtu	0.02 (Note 1)
SO_2	lb/MMBtu	0.00
CO	lb/MMBtu	0.03
CO_2	lb/MMBtu	115 (Note 2)
Emissions Control Notes		
1. With SCR		
2. Per 40 CFR98 Sub Part C – Table C1		

CASE 17. HYDROELECTRIC PLANT, 100 MW

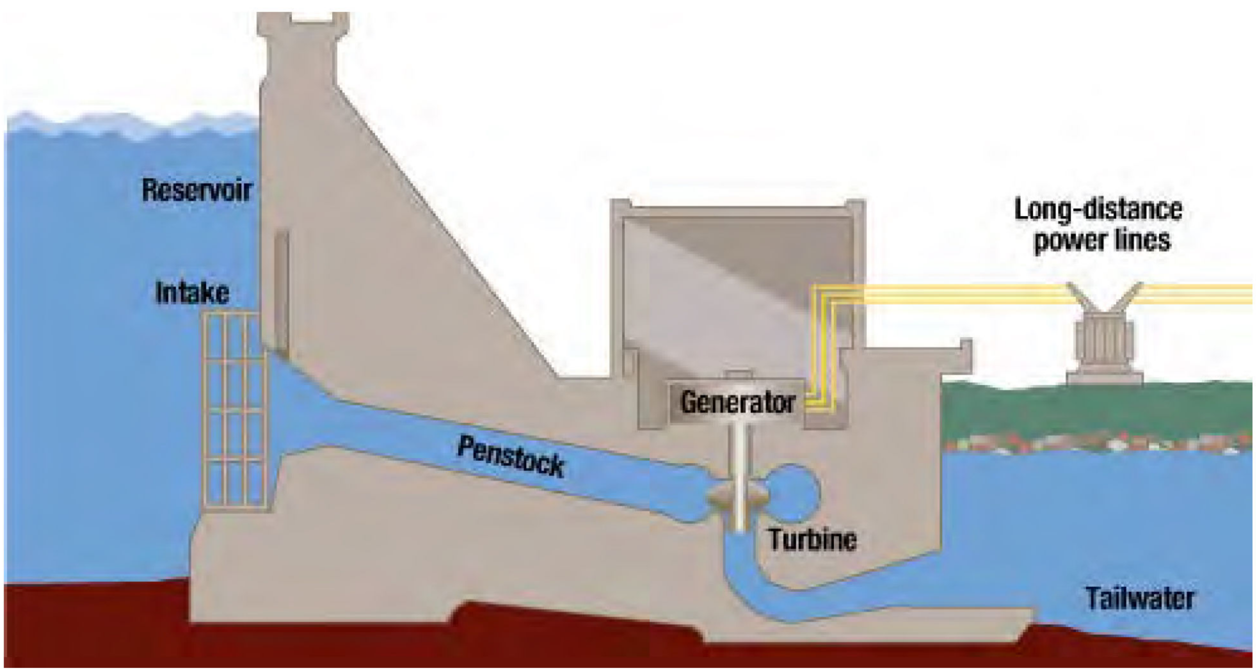
17.1 CASE DESCRIPTION

This case is based on a "New Stream Reach Development" 100-MW hydroelectric power plant with 75 feet of available head. 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 17-1 shows 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.

Case 17 is based on a concrete dam with a spillway and diversion tunnel to control the water level in the reservoir. There are two identical penstocks approximately 4.5 meters in diameter. Each penstock leads to a Francis-type hydro-turbine. Each of the two turbine-generators is rated for 50 MW. Power is stepped up from 13.8 kV to 154 kV for distribution.

Figure 17-1 — Storage-Type Hydroelectric Power Plant



Source: Tennessee Valley Authority, How Hydroelectric Power Works, ND. Digital Image.
Retrieved from TVA.gov, https://www.tva.gov/Energy/Our-Power-System/Hydroelectric/How-Hydroelectric-Power-Works (accessed June 13, 2019).

Figure 17-2 shows the dam and spill way of a storage-type hydroelectric power plant.

Figure 17-2 — Dam and Spillway of Hydroelectric Power Plant

Source: Tennessee Valley Authority, Cherokee, ND. Digital Image.
Retrieved from TVA.gov, https://www.tva.gov/Energy/Our-Power-System/Hydroelectric/Cherokee-Reservoir (accessed June 13, 2019).

Figure 17-3 shows a typical turbine hall for a Francis-type hydropower turbine. The generator is located above the turbine and it connected to the same shaft.

Figure 17-3 — Typical Hydroelectric Power Turbine Hall

Source: Tennessee Valley Authority, Raccoon Mountain, ND. Digital Image.
Retrieved from TVA.gov, https://www.tva.gov/Energy/Our-Power-System/Hydroelectric/Raccoon-Mountain (accessed July 8, 2019).

17.1.1 Offsite Requirements

The cost estimate assumes an allowance for a one-mile transmission line.

17.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $5316/kW. Table 17-1 summarizes the cost components for this case. The capital cost estimate is based on an EPC contracting approach. In addition to EPC contract costs, the estimate includes owner's costs that cover owner's services, project development costs, studies, permitting, legal, project management, owner's engineering, and start-up and commissioning.

Table 17-1 — Case 17 Capital Cost Estimate

Case 17 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**Hydroelectric Power Plant** New Stream Reach Development	
	Units		
Plant Characteristics			
Net Power Rating	MW	100	
Head	ft	75	
Capital Cost Assumptions			
EPC Fee	% of Project Costs	10%	
Project Contingency	% of Project Costs	10%	
Owner's Services	% of Project Costs	7%	
Estimated Land Requirement (Support buildings only)	acres	2	
Estimated Land Cost	$/acres	10,000	
Electric Interconnection Costs			
Transmission Line Cost	$/mile	1,200,000	
Miles	miles	1.00	
Typical Project Timelines			
Development, Permitting, Engineering	months	36	
Plant Construction Time	months	36	
Total Lead Time Before COD	months	72	
Operating Life	years	50	
Cost Components		**Breakout**	**Total**
Direct Costs			
Civil Structural Material and Installation	$	247,865,000	
Mechanical Equipment Supply and Installation	$	73,759,000	
Electrical / I&C Supply and Installation	$	25,094,000	
Direct Cost Subtotal	$		346,718,000
Project Indirects (Note 1)	$		56,686,000
EPC Total Before Fee	$		403,404,000
EPC Fee	$		40,340,400
EPC Subtotal	$		443,744,400

Case 17 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**Hydroelectric Power Plant** New Stream Reach Development	
	Units		
Owner's Cost Components			
Owner's Services	$	38,351,000	
Land	$	20,000	
Electrical Interconnection	$	1,200,000	
Owner's Cost Subtotal	$		39,571,000
Project Contingency	$	48,332,000	48,332,000
Total Capital Cost	**$**		**531,647,400**
	$/kW net		**5,316**
Capital Cost Notes			
1. Engineering, procurement, scaffolding, project services, construction management, field engineering, and startup and commissioning using EPC contracting.			
2. Project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's participation in startup and commissioning. Excluded: Allowance for Funds Used During Construction, escalation excluded.			

17.3 O&M COST ESTIMATE

The O&M cost estimate incorporates the annual cost of the onsite O&M staff as well as contracted services for grounds keeping and computer maintenance. The estimate also covers the maintenance of the dam, spillway, penstock, turbine, generator, and BOP. The need for various consumables and replacement parts are also considered. The annual cost of consumables, such as lubricants, filters, chemicals, etc., is estimated as a fixed amount, so the variable cost component is considered to be zero. Total annual O&M costs for the New Stream Reach Development 100-MW hydroelectric power plant are summarized in Table 17-2.

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

Case 17 EIA – Non-Fuel O&M Costs – 2019 $s		
Hydroelectric Power Plant		
Fixed O&M – Plant (Note 1)		
Subtotal Fixed O&M	$/kW-year	**29.86 $/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 G&A costs. O&M costs exclude property taxes and insurance.		

17.4 ENVIRONMENTAL & EMISSIONS INFORMATION

Hydroelectric plants 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.

CASE 18. BATTERY ENERGY STORAGE SYSTEM, 50 MW / 200 MWH

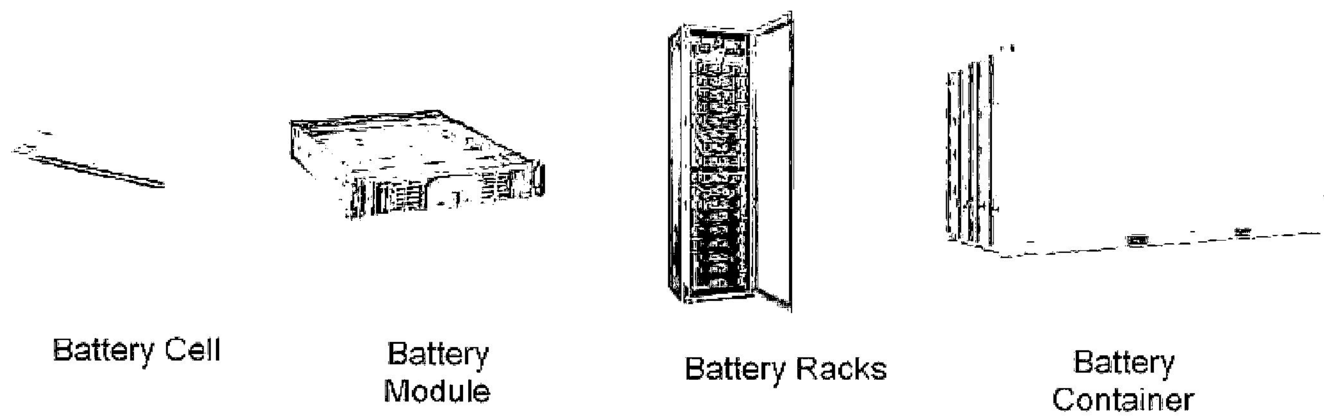
18.1 CASE DESCRIPTION

This case consists of a utility-scale, lithium-ion, battery energy storage system (BESS) with a 50-MW power rating and 200-MWh energy rating; the system can provide 50 MW of power for a four-hour duration. Case 18 assumes that the BESS will be constructed close to an existing potential interconnection point such as grid or generator substation. The cost estimate includes a substation consisting of a transformer to step up from the BESS system to the interconnection voltage (480 V to 13.8 kV) and associated switchgear.

The BESS consists of 25 modular, pre-fabricated battery storage container buildings that contain the racks and appurtenances to store the initial set of batteries and accommodate battery augmentation for the life of the project. The BESS uses utility-scale lithium-ion batteries. Approximately 3% 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 18.3.) Each battery container is equipped with fire detection and suppression systems and HVAC monitoring and control systems. The pre-fabricated battery containers are approximately 40 feet long x 10 feet wide x 8 feet high. Each battery container has an associated inverter-transformer building, which is approximately 20 feet long x 10 feet wide x 8 feet high. The inverter-transformer building houses the inverters, transformers, and associated electrical equipment for each battery container. 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 18-1 shows a typical utility-scale lithium-ion battery. Several battery cells make a battery module, which is independently monitored and controlled. Several battery modules are contained in a battery rack, and there are several battery racks in a battery container.

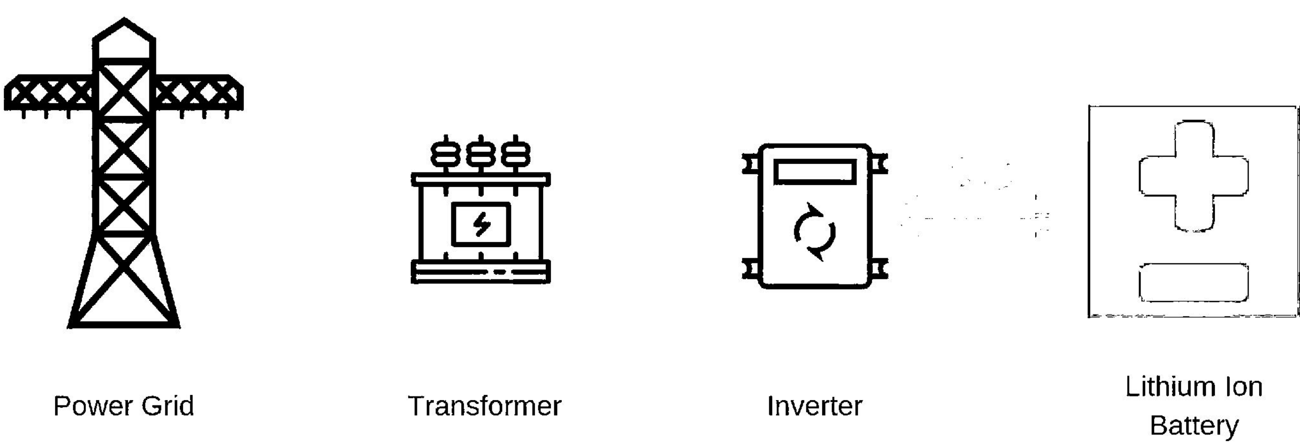
Figure 18-1 — Utility-Scale Lithium-Ion Batteries



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 200 MWh of lithium-ion batteries connected in strings and twenty-five 2-MW inverters. Battery energy storage systems are DC systems; however, most electric power generation is produced and distributed as AC power. The BESS is equipped with a power conversion system to convert between AC power for charging and distribution and DC power for storage. The power conversion system includes transformers and associated switchgear that supports battery charging and discharging by converting power between 13.8 kV and 480 V-direct-current. Power is provided by the BESS at a three-phase output voltage of 480 AC. The output voltage is stepped up by a transformer to 34.5 kV and connects to the grid at a substation. This interconnecting substation is not part of the project.

Figure 18-2 — BESS Flow Diagram

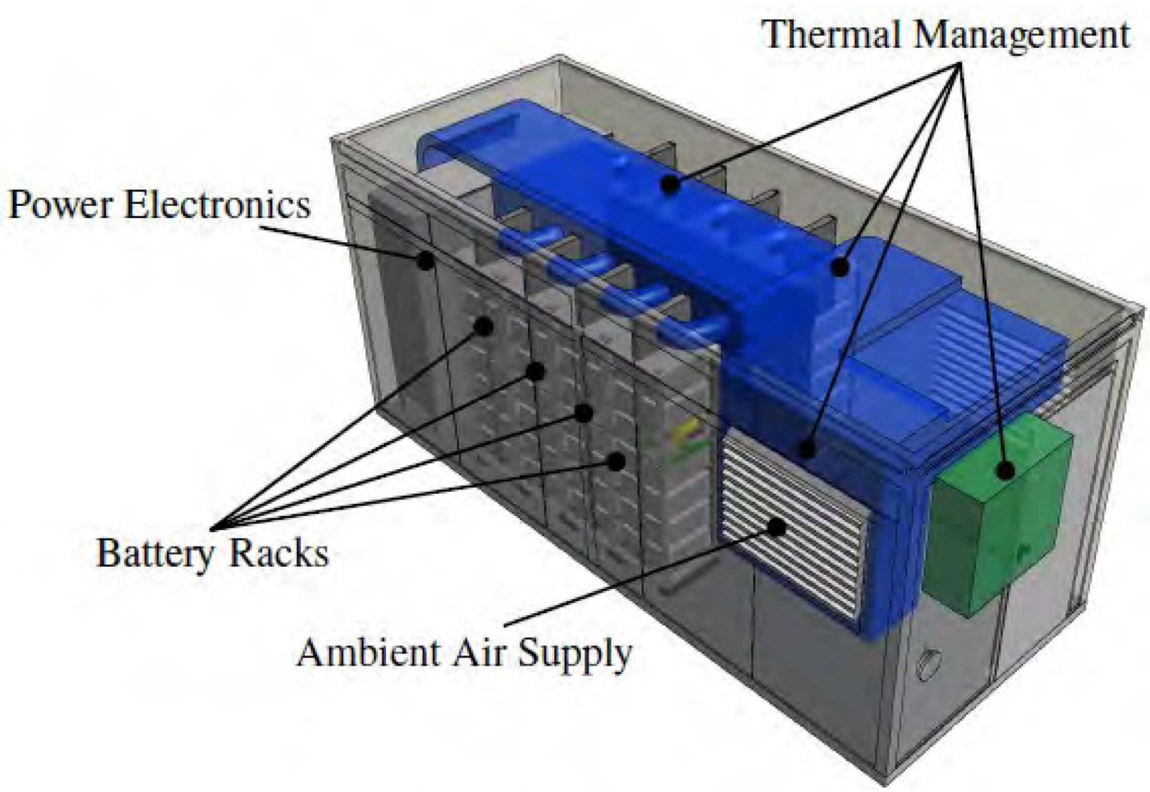


Each battery container is equipped with electronic protection such as current limiters, sensors, and disconnect switches to isolate strings of batteries. The BESS is equipped with multiple levels of monitoring and controls. Each battery module and battery string are monitored and can be controlled by its Battery Management Unit and Battery String Management Unit, respectively. The power conversion system is also monitored and controlled.

The BESS site is equipped with a Supervisory Control and Data Acquisition (SCADA) system that collects performance data from the Battery Management Units, Battery String Management Units, and power conversion system. The BESS can be monitored and controlled remotely through the SCADA system. Some BESS site may be programmed to respond to conditions in the grid through the SCADA system.

Figure 18-3 shows a cut-away view of a typical battery storage container.

Figure 18-3 — Typical Battery Storage Container



Source: Office of Scientific and Technical Information – U.S. Department of Energy, ND. Digital Image. Retrieved from OSTI.gov, https://www.osti.gov/biblio/1409737 (accessed July 15, 2019).

18.1.1 Offsite Requirements

Typically, BESS projects are built at the site of existing generators or near substations where the system can easily tie into a grid for charging and discharging power. This cost estimate includes an allowance for a substation consisting of a transformer to step up to the distribution voltage (480 V to 13.8 kV), associated switchgear, and transmission line to nearby tie-in so that the BESS can receive and distribute 13.8 kV-alternating current power.

The capital cost estimate assumes that road access is available and does not include the cost to build roads. Our cost estimate does not include an allowance for onsite storage of tools, chemicals, or other O&M necessities. The O&M cost estimate assumes the O&M contractor will bring all necessities to the BESS site.

18.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $1389/kW or $347/kWh. Both the $/kW and $/kWh are provided to clearly describe the system estimate. Table 18-1 summarizes the cost components for this case. The capital cost estimate is based on a BESS with a power rating of 50 MW and energy rating of 200 MWh (equivalent to a four-hour rating). The cost estimate includes civil works, foundations, buildings, electrical equipment and related equipment, substation, switchyard, transformers, transmission lines, cabling, controls, and instrumentation.

Table 18-1 — Case 18 Capital Cost Estimate

Case 18 EIA – Capital Cost Estimates – 2019 $s		
Configuration		**Battery Energy Storage System** 50 MW | 200 MWh Greenfield
Battery Type		Lithium-ion
Service Life		10 years
Total Charging Cycles in Service Life		3,000
	Units	
Plant Characteristics		
Power Rating	MW	50
Energy Rating	MWh	200
Duration	hour	4
Capital Cost Assumptions		
EPC Contracting Fee	% of Project Costs	5%
Project Contingency	% of Project Costs	5%
Owner's Services	% of Project Costs	4%
Estimated Land Requirement	acre	2
Estimated Land Cost	$/acre	30,000

Case 18 EIA – Capital Cost Estimates – 2019 $s			
Configuration		**Battery Energy Storage System** 50 MW | 200 MWh Greenfield	
Battery Type		Lithium-ion	
Service Life		10 years	
Total Charging Cycles in Service Life		3,000	
	Units		
Electric Interconnection Costs			
Transmission Line Cost	$/mile	1,200,000	
Miles	miles	0.00	
Typical Project Timelines			
Development, Permitting, Engineering	months	4	
Plant Construction Time	months	6	
Total Lead Time Before COD	months	10	
EPC Cost Components (Note 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		8,314,000
Batteries	$	40,037,000	
Inverters	$	5,237,000	
Grounding Wiring, Lighting, Etc.	$	254,000	
Transformers	$	533,000	
Cable	$	618,000	
Electrical Subtotal	$		46,679,000
Raceway, Cable tray & Conduit	$	258,000	
Control & Instrumentation	$	22,000	
Transformer Switchgear, Circuit Breaker & Transmission Line	$	305,000	
Other Equipment & Material Subtotal	$		585,000
Project Indirects	$		4,595,000
EPC Total Before Fee	$		60,173,000
EPC Fee	$		3,009,000
EPC Subtotal	$		63,182,000
Owner's Cost Components (Note 2)			
Owner's Services	$		2,906,000
Land	$		60,000
Electrical Interconnections (Note 3)	$		0
Owner's Cost Subtotal	$		2,966,000
Project Contingency	$		3,308,000
Total Capital Cost	**$**		**69,456,000**
	$/kW net		**1,389**
	$/kWh		**347**
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, gas interconnection costs (if applicable), and land acquisition costs.
3. The BESS is assumed to be located sufficient close to an existing substation, such that any transmission costs are covered in the project electrical equipment cost. A separate electric transmission cost is not necessary.

18.3 O&M 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 3000 full charge-discharge cycles, which is a relatively typical basis in the industry. A full charge-discharge cycle occurs when a battery is fully charged, demand requires the full discharge of the energy, and then the battery is fully charged again. A service life of 3000 full cycles in a 10-year period equates to slightly fewer than 1 cycle per day. BESS projects that serve ancillary markets may not experience full charge and discharge cycle every day or may experience partial charge cycles. and The BESS service life depends on the charge and discharge pattern; therefore, a system that experiences partial charge cycles or multiple full cycles each day will have a different service life than described. The 3000 full-cycle service life is a typical industry basis to determine the cost and technical specifications for an energy storage system.

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 review of equipment conditions and cable connections, grounds maintenance, and labor involved in battery augmentation. During the service life of a BESS, a percentage of the batteries are expected to significantly decrease in efficiency or stop functioning. Instead of removing and replacing those batteries, BESS are designed with excess racking to accommodate additional batteries to augment the lost capacity. The entire BESS will be removed when it is decommissioned at the end of its service life. This approach reduces the costs associated with removing and transporting failed batteries each year. Typically, BESS designs estimate that approximately 3% of the battery capacity will be needed to be augmented each year. This O&M cost estimate uses the 3% battery augmentation factor and incorporates that cost in the annual fixed O&M cost. The O&M cost include an annual allowance for G&A costs. The fixed O&M costs are $24.80/kW-year. The variable costs are $0.00/MWh, since there are no consumables linked to energy output. Augmentation is included with fixed cost in this case since the case assumes the same number of charging cycles each year during the service life of the project.

The O&M costs do not include the cost of energy to charge the system.

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

Case 18 EIA – Non-Fuel O&M Costs – 2019 $s		
Battery Energy Storage System - 50 MW | 200 MWh - Greenfield		
Fixed O&M – Plant (Note 1)		
General & Administrative and Contract Services (Remote monitoring, on-site O&M, battery augmentation labor, grounds keeping, etc.)	$/year	70,000
Battery Augmentation	$/year	1,170,000
Subtotal Fixed O&M	$/year	1,240,000
$/kW-year	$/kW-year	**24.80 $/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.		

18.4 ENVIRONMENTAL & EMISSIONS INFORMATION

Battery energy storage systems 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.

CASE 19. BATTERY ENERGY STORAGE SYSTEM, 50 MW / 100 MWH

19.1 CASE DESCRIPTION

This case is nearly identical to Case 18 with the exception that this is a BESS system with half the energy rating (100 MWh) and therefore half the duration (two hours). Since the energy rating for this case is half of Case 18, there will be half as many batteries. Therefore, this case will also have half as many battery containers. Case 19 assumes lithium-ion batteries are used, and the cost of civil works, foundations, buildings, electrical equipment and related equipment, substation, switchyard, transformers, transmission lines, cabling, and controls and instrumentation are included in the cost estimate. Case 19 assumes 3% of the initial set of batteries will require augmentation each year.

Refer to Case 18 for a more in-depth description of BESSs.

19.1.1 Offsite Requirements

Typically, BESS projects are built at the site of existing generators or near substations where the system can easily tie into a grid for charging and discharging power. This cost estimate includes an allowance for a substation consisting of a transformer to step up to the distribution voltage (480 V to 13.8 kV), associated switchgear, and transmission line to nearby tie-in so that the BESS can receive and distribute 13.8 kV-alternating current power.

19.2 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $845/kW or $423/kWh. Both the $/kW and $/kWh are provided to clearly describe the system estimate. Table 19-1 summarizes the cost components for this case. The capital cost estimate is based on a BESS with a power rating of 50 MW and energy rating of 100 MWh. Therefore, the BESS provides 50 MW of power for a duration of two hours. The capital cost estimate is based on an EPC contracting approach.

Typical project-related costs are included, such as owner's services, project development costs, studies, permitting, legal, project management, owner's engineering, and start-up and commissioning.

Table 19-1 — Case 19 Capital Cost Estimate

Case 19 EIA – Capital Cost Estimates – 2019 $s			
Configuration		Battery Energy Storage System 50 MW | 100 MWh Greenfield	
Battery Type		Lithium-ion	
Service Life		10 years	
Total Charging Cycles in Service Life		3,000	
	Units		
Plant Characteristics			
Power Rating	MW	50	
Energy Rating	MWh	100	
Duration	hour	2	
Capital Cost Assumptions			
EPC Contracting Fee	% of Project Costs	5%	
Project Contingency	% of Project Costs	5%	
Owner's Services	% of Project Costs	4%	
Estimated Land Requirement	acre	1.2	
Estimated Land Cost	$/acre	30,000	
Electric Interconnection Costs (Note 1)			
Transmission Line Cost	$/mile	1,200,000	
Miles	miles	0.00	
Typical Project Timelines			
Development, Permitting, Engineering	months	4	
Plant Construction Time	months	5	
Total Lead Time Before COD	months	9	
Cost Components (Notes 1)		**Breakout**	**Total**
Civil/Structural/Architectural Subtotal	$		6,071,000
Batteries	$	20,019,00	
Inverters	$	5,237,000	
Grounding Wiring, Lighting, Etc.	$	143,000	
Transformers	$	533,000	
Cable	$	370,000	
Electrical Equipment Subtotal	$		26,302,000
Raceway, Cable tray & Conduit	$	155,000	
Control & Instrumentation	$	22,000	
Transformer Switchgear, Circuit Breaker & Transmission Line	$	305,000	
Other Equipment & Material Subtotal	$		482,000
Project Indirects	$		3,679,000
EPC Total Before Fee	$		36,534,000
EPC Fee	$		1,827,000
EPC Subtotal	$		38,361,000
Owner's Cost Components (Note 2)			
Owner's Services	$		1,850,000
Land	$		36,000
Electrical Interconnection Cost (Note 3)	$		0
Owner's Cost Subtotal	$		1,886,000
Project Contingency	$		2,013,000
Total Capital Cost	**$**		**42,260,000**
	$/kW net		**845**
	$/kWh		**423**

Case 19 EIA – Capital Cost Estimates – 2019 $s	
Configuration	**Battery Energy Storage System** 50 MW | 100 MWh Greenfield
Battery Type	Lithium-ion
Service Life	10 years
Total Charging Cycles in Service Life	3,000
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, gas interconnection costs (if applicable), and land acquisition costs.	
3. The BESS is assumed to be located sufficient close to an existing substation, such that any transmission costs are covered in the project electrical equipment cost. A separate electric transmission cost is not necessary.	

19.3 O&M COST ESTIMATE

The O&M cost estimate considers the ongoing O&M cost through the life of a BESS project. As mentioned in Case 18, the service life of a BESS depends on how it is used. This case assumes that the BESS will have a service life of 3000 full charge-discharge cycles, which is a relatively typical basis in the industry. A full charge-discharge cycle occurs when a battery is fully charged, demand requires the full discharge of the energy, and then the battery is fully charged again. A service life of 3000 full cycles in a 10-year period equates to slightly fewer than 1 cycle per day. BESS projects that serve ancillary markets may not experience a full charge and discharge cycle every day or may experience partial charge cycles. The BESS service life depends on the charge and discharge pattern; therefore, a system that experience partial charge cycles or multiple cull cycles each day will have a different service life than described. The service life of 3000 full cycles is a typical industry basis to determine the cost and technical specifications for an energy storage system.

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 review of equipment conditions and cable connections, grounds maintenance, and labor involved in battery augmentation. During the service life of a BESS, a percentage of the batteries are expected to significantly decrease in efficiency or stop functioning. Instead of removing and replacing those batteries, BESS are designed with excess racking to accommodate additional batteries to augment the lost capacity. This approach reduces the costs associated with removing and transporting failed batteries each year. Typically, BESS designs estimate that approximately 3% of the total number of batteries installed will need to be augmented each year. The entire BESS will be removed when it is decommissioned at the end of its service life. This O&M cost estimate uses the 3% battery augmentation factor and incorporates that cost in the annual fixed O&M cost. The O&M cost includes an annual allowance for G&A costs. The fixed costs are $12.90/kW-year. The variable costs are $0.00/MWh, since there are no consumables linked to energy output. Augmentation is included with fixed cost in this case since the case assumes the same number of charging cycles each year during the service life of the project.

The O&M costs do not include the cost of energy to charge the system.

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

Case 19 EIA – Non-Fuel O&M Costs – 2019 $s		
Battery Energy Storage System - 50 MW | 100 MWh – Greenfield		
Fixed O&M – Plant (Note 1)		
General & Administrative and Contract Services (Remote monitoring, on-site O&M, battery augmentation labor, grounds keeping, etc.)	$/year	60,000
Battery Augmentation	$/year	585,000
Subtotal Fixed O&M	$/year	645,000
$/kW-year	$/kW-year	**12.90 $/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 & EMISSIONS INFORMATION

Battery energy storage systems 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.

CASE 20. ONSHORE WIND, LARGE PLANT FOOTPRINT, 200 MW

20.1 CASE DESCRIPTION

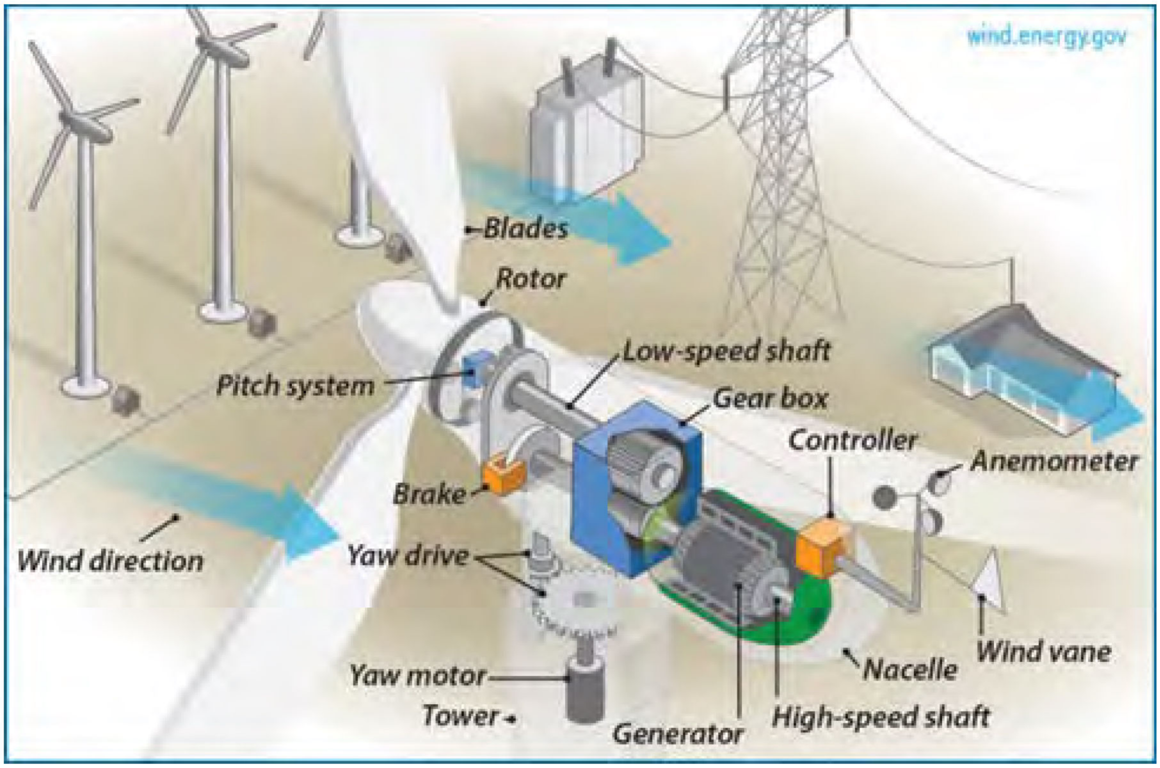
This case is an onshore wind power project located in the Great Plains region of the United States with a total project capacity of 200 MW. The Great Plains region, reflective of the central United States, has an abundance of land that is suitable for wind turbine siting and is generally not subject to land constraints that would otherwise limit project size.

20.2 MECHANICAL EQUIPMENT & SYSTEMS

This Great Plains region onshore wind project is based on a 200 MW total project capacity. Parameters that affect project cost and performance include turbine nameplate capacity, rotor diameter, and hub height. The case configuration assumes 71 wind turbines with a nominal rating of 2.8 MW with a 125-meter rotor diameter, and a 90-meter hub height. These features reflect modern wind turbines that employ larger rotor diameter and greater hub heights. The primary advantage of taller hub heights and larger rotor diameters include access to better wind profiles at higher altitudes and increased turbine swept area, enabling the unit to capture more energy.

Wind turbine generators convert kinetic wind energy into electrical power. The most ubiquitous type of wind turbine used 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 that turns a generator located inside of the nacelle, which is the housing positioned atop the wind turbine tower.

Figure 20-1 — Wind Turbine Generator Drivetrain



Source: Office of Energy Efficiency & Renewable Energy, Wind Energy Technologies Office – U.S. Department of Energy, *windTurbineLabels*, ND. Digital Image (Image 1 of 17).
Retrieved from Energy.gov, https://www.energy.gov/eere/wind/inside-wind-turbine (accessed May 31, 2019).

20.2.1 Electrical & Control Systems

Each wind turbine generator (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 that further steps up the voltage for interconnection with the transmission system with a voltage of 230 kV.

A 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 project as a whole.

20.2.2 Offsite Requirements

Wind projects harness power from wind and therefore do not require fuel or fuel infrastructure. The offsite requirements are limited to construction of site and wind turbine access roads, the O&M building, and electrical interconnection to the transmission system.

20.3 CAPITAL COST ESTIMATE

The base cost estimate for this technology case totals $1265/kW. Table 20-1 summarizes the cost components for this case.

Capital cost were broken down into the following categories:

- **Civil/Structural Costs:** These costs include the WTG spread footing and substation foundations, access roads, crane pads, road improvements, and O&M building.
- **Mechanical Costs:** These costs include the purchase price for the WTGs from the OEM (i.e., blades, hub, drivetrain, generator, tower, and electronics), transportation and delivery to the project site, and assembly and erection on site.
- **Electrical Costs:** These costs include pad-mounted transformers, underground collection system, and the project substation.
- **Project Indirect Costs:** These costs include construction management, engineering, and G&A costs.
- **EPC Fee:** The EPC fee is a markup charged by the construction contractor.
- **Project Contingency Costs:** Contingency is an allowance considered to cover the cost of undefined or uncertain scope of work, including EPC change orders or costs associated with schedule delays.
- **Owner Costs:** These costs include Project development costs that cover project feasibility analyses, wind resource assessments, geotechnical studies, contracting for land access, transmission access and permitting. However, estimates exclude project financing costs.

Table 20-1 — Case 20 Capital Cost Estimate

Case 20 EIA – Capital Cost Estimates – 2019 $s		
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 & Indirect Costs	8%
Project Contingency	% of Project Costs	4%
Owner's Services	% of Project Costs	7%
Electric Interconnection Costs		
Transmission Line Cost	$/mile	1,200,000
Miles	miles	1.00