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Capital Cost Estimates for Utility Scale Electricity Generating Plants

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Introduction

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

EIA commissioned an external consultant to develop up-to-date cost and performance estimates for utility-scale electric generating plants for AEO2013.[1] This information allowed EIA to compare the costs of different power plant technologies on a standardized basis and was a key input enhancement to the National Energy Model System (NEMS). For the AEO 2016 development, EIA commissioned the same consultant group to update the cost and performance estimates for a select set of the technologies evaluated in the original 2012 study. This paper summarizes the results of the findings and discusses how EIA used the updated information to analyze the development of new capacity in the electric power sector.

Developing updated estimates: key design considerations

The focus of the 2016 update was to gather current information on the "overnight" construction costs, operating costs, and performance characteristics for a wide range of generating technologies.[2] The estimates were developed through costing exercises, using a common methodology across technologies. Comparing cost estimates developed on a similar basis using the same methodology is of particular importance to ensure modeling consistency.

Each technology is represented by a generic facility of a specific size and configuration, in a location that does not have unusual constraints or infrastructure requirements. Where possible, costs estimates were based on information on system design, configuration, and construction derived from actual or planned projects known to the consultant, using generic assumptions for labor and materials rates. When this information was not available, the project costs were estimated using a more generic technology representation and costing models that account for the current labor and materials rates necessary to complete the construction of a generic facility as well as consistent assumptions for the contractual relationship between the project owner and the construction contractor.

The specific overnight costs for each type of facility were broken down to include:

- **Civil and structural costs:** allowance for site preparation, drainage, the installation of underground utilities, structural steel supply, and construction of buildings on the site
- **Mechanical equipment supply and installation:** major equipment, including but not limited to, boilers, flue gas desulfurization scrubbers, cooling towers, steam turbine generators,

[1] U.S. Energy Information Administration, Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants 2013

[2] The term “overnight” refers to the cost of the project as if no interest were incurred during its construction.

condensers, photovoltaic modules, combustion turbines, wind turbines, and other auxiliary equipment

- **Electrical and instrumentation and control:** electrical transformers, switchgear, motor control centers, switchyards, distributed control systems, and other electrical commodities
- **Project indirect costs**: engineering, distributable labor and materials, craft labor overtime and incentives, scaffolding costs, construction management start up and commissioning, and fees for contingency[3]
- **Owners costs:** development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction, and the electrical interconnection costs, including a tie-in to a nearby electrical transmission system

Non-fuel operations and maintenance (O&M) costs associated with each of the power plant technologies were evaluated as well. The O&M costs that do not vary significantly with a plant's electricity generation are classified as fixed, including salaries for facility staff and maintenance that is scheduled on a calendar basis. The costs incurred to generate electricity are classified as variable such as the cost of consumable materials and maintenance that may be scheduled based on the number of operating hours or start-stop cycles of the plant. The heat rates[4] were also evaluated for the appropriate technologies. It should be noted that all estimates provided in this report are broad in scope. A more in-depth cost assessment would require a more detailed level of engineering and design work, tailored to a specific site.

Findings

Table 1 summarizes updated cost estimates for generic utility-scale generating technologies, including four powered by coal, six by natural gas, three by solar energy, and one each by wind, biomass, uranium, and battery storage. EIA does not model all of these generating plant types, but included them in the study in order to present consistent cost and performance information for a broad range of generating technologies and to aid in the evaluation for potential inclusion of new or different technologies or technology configurations in future analyses.

The specific technologies represented in the NEMS model for*AEO2016* that use the cost data from this report are identified in the last column of Table 1.

Table 2 compares the updated overnight cost estimates to those developed for the 2013 report. To facilitate comparisons, the costs are expressed in 2016 dollars.[5] Notable changes include:

- **Ultra Supercritical Coal (USC) with and without carbon capture and storage (USC/CCS).** USC with carbon capture and storage was added for this study to help meet EPA's 111b new source performance standard for carbon emissions. While USC without carbon capture cannot be built under current regulations, inclusion of this technology maintains the capability to analyze policy alternatives that may exclude 111b requirements.

[3] Fees for contingency include contractor overhead costs, fees, profit, and construction.

[4] Heat Rate is a measure of generating station thermal efficiency commonly stated as Btu per kilowatthour.

[5] U.S. Energy Information Administration, Annual Energy Outlook 2016, Table 20, GDP chain-type price index

- **Conventional Natural Gas Combined Cycle (NGCC) and Advanced Natural Gas Combined Cycle (ANGCC):** The updated overnight capital cost for conventional and advanced NGCC plants remained level relative to the cost in the 2013 study. The capacity of the NGCC unit increased from 400 MW in the 2013 study to 429 MW, while the capacity of the ANGCC unit increased from 620 MW to 702 MW for ANGCC to reflect trends toward larger installations for this technology.
- **Onshore Wind**: Overnight costs for onshore wind decreased by approximately 25 percent relative to the 2013 study, primarily due to lower wind turbine prices. EIA adjusted regional cost factors for wind plants from those reported in this report for inclusion in AEO 2016[hyper link to Table 8.2]. The regional factors in this report primarily account for regional variation in labor and materials costs, but subsequent evaluation of the regional variation in wind plant costs found that other factors, such as typical plant size, may account for a larger share of the observed regional differences in cost for the wind plants.
- **Solar Photovoltaic:** The overnight capital costs for solar photovoltaic technologies decreased by 67 percent for the 20 MW fixed tilt photovoltaic systems from the costs presented in the 2013 study. Solar photovoltaic single-axis tracking systems were introduced in this report (including both a 20 MW and 150 MW system configurations). There is not a significant difference in Capital costs between fixed-tilt and single-axis-tracking systems. The overall decreases in costs can be attributed to a decline in the component costs and the construction cost savings for the balance of plant systems.

  As previously noted, costs are developed using a consistent methodology that includes a broad project scope and includes indirect and owners costs. The cost figures will not necessarily match those derived in other studies that employ different approaches to cost estimation.

EIA's analysis of technology choice in the electric power sector

EIA's modeling employs a net present value (NPV) capital budgeting methodology to evaluate different investment options for new power plants. Estimates of the overnight capital cost, fixed and variable operations and maintenance costs, and plant heat rates for generic generating technologies serve as a starting point for developing the total cost of new generating capacity. However, other parameters also play a key role in determining the total capital costs. Because several of these factors are dynamic, the realized overall capital cost for given technologies can vary based on a variety of circumstances. Five of the most notable parameters are:

- **Financing:** EIA determines the cost of capital required to build new power plants by calculating a weighted average cost of capital using a mix of macro-economic parameters determined through EIA's modeling and an assumed capital structure for the electric power industry.
- **Lead Time:** The amount of time needed to build a given type of power plant varies by technology. Projects with longer lead times increase financing costs. Each year of construction represents a year of additional interest charges before the plant is placed in service and starts generating revenue. Furthermore, plants with front-weighted construction and development profiles will incur higher interest charges during construction than plants where most of the construction expenditures occur at the end of the development cycle.

- **Inflation of material and construction costs:** The projected relationship between the rate of inflation for the overall economy and key drivers of plant costs, such as materials and construction, are important elements impacting overall plant costs. A projected economy-wide inflation rate that exceeds the projected inflation rate for materials and construction costs results in a projected decline in real (inflation-adjusted) capital costs and vice versa.
- **Resource Supply:** Technologies such as wind, geothermal, or hydroelectric must be sited in suitable locations to take advantage of the particular resource. In order to capture the site specific costs associated with these technologies, EIA develops upward sloping supply curves for each of these technologies. These curves assume that the lowest-cost, most-favorable resources will be developed first, and when only higher-cost, less-favorable sites remain, development costs will increase and/or project performance will decrease.
- **Learning by doing:** The overnight capital costs developed for the report serve as an input to EIA's long term modeling and represent the cost of construction for a project that could begin as early as 2015. However, these costs are assumed to decrease over time in real terms as equipment manufacturers, power plant owners, and construction firms gain more experience with certain technologies. The rate at which these costs decline is often referred to as the learning rate.

  EIA determines learning rates at the power plant component level, not for the power plant technology itself because some technologies share the same component types. It is assumed that the knowledge and experienced gained through the manufacture and installation of a given component in one type of power plant can be carried over to the same component in another type of plant. As an example, the experience gained through the construction of natural gas combustion turbine plants can be leveraged to influence the overall cost of building a Natural Gas Combined Cycle unit, which in part, includes the components of a combustion turbine natural gas plant. Other technologies, such as nuclear power and pulverized coal (PC) plants without CCS, do not share component systems, and their learning rates are determined solely as a function of the amount of capacity built over time.

  Technologies and their components are represented in the NEMS model at various stages of maturity. EIA classifies technologies into three such stages: mature, evolutionary, and revolutionary. The initial learning rate is evaluated for each technology. The technology classification determines how the rate of cost reduction changes as each technology progresses through the learning function. Generally, overnight costs for technologies and associated components decline at a specified rate based on a doubling of new capacity. The cost decline is fastest for revolutionary technologies and slower for evolutionary and mature technologies.[6]

[6] U.S. Energy Information Administration, Electricity Market Module Assumptions Document, Table 8.3.

> The capacity additions used to influence learning are primarily developed from NEMS results. However, external capacity additions from international projects are also included for some technologies, to account for additional learning from such projects. For power plant technologies with multiple components, the capacity additions are weighted by the contribution of each component to the overall plant construction cost.[7]

Table 3 classifies the status of each technology and component as modeled in *AEO2016*

The NEMS model also assumes that efficiency for all fossil-fueled plants improves as a result of learning by doing. The power plant heat rates provided by the consultant are intended to represent the characteristics of a plant that starts construction in 2015 referred to as “first-of-a-kind.” NEMS assumes that the heat rate for all fossil fueled technologies declines over time to a level referred to as an “nth-of-a-kind” heat rate.[8] The magnitude of heat rate improvement depends on the current state of the technology, with revolutionary technologies seeing a more significant decline in heat rate than mature technologies. Heat rate improvements are independent of capacity expansion. Fixed and variable O&M are not assumed to achieve learning-related savings. The performance of wind plants, as measured by capacity factor, is also assumed to improve as a result of learning by doing.[9]

Impact of location on power plant capital costs

The estimates provided in this report are representative of a generic facility located in a region without any special issues that would alter its cost. However, the cost of building power plants in different regions of the United States can vary significantly. The report includes location-based cost adjustment tables for each technology in 64 metropolitan areas. These adjustments were made to reflect the impact of remote location costs, costs associated with seismic design that may vary by region, and labor wage and productivity differences by region. In order to reflect these costs in EIA's modeling, these adjustments were aggregated to represent the 22 Electricity Market Module regions. EIA also assumes that the development of certain technologies is not feasible in given regions for geographic, logistical, or regulatory reasons. The regional cost adjustments and development restrictions are summarized in Table 4.

Subsequent peer review of these results indicated that the regional factors used for wind plants do not adequately reflect observed regional variation of wind plant costs, which appear to be substantially determined by factors other than those considered above. In particular, EIA found a significant regional variation in typical plant size that generally correlated with regional variation in installation costs. Therefore, EIA does not use the regional factors included in this report for its analysis of wind technologies. Regional factors used for AEO 2016 and related analyses can be found in Table 8.2 of the AEO 2016 Assumptions document, and are also shown in Table 4.

[7] U.S. Energy Information Administration, Electricity Market Module Assumptions Document, Table 8.4.
[8] U.S. Energy Information Administration, AEO 2016 Cost and Performance Characteristics of New Central Station Electricity Generating Technologies, Table 8.2.
[9] U.S. Energy Information Administration, Renewable Fuels Module

Summary

The estimates provided by the consultant for this report are key inputs for EIA electric market projections, but they are not the sole driver of electric generation capacity expansion decisions. The evolution of the electricity mix in each of the 22 regions modeled in *AEO2016* is sensitive to many factors, including the projected evolution of capital costs over the modeling horizon, projected fuel costs, whether wholesale power markets are regulated or competitive, the existing generation mix, additional costs associated with environmental control requirements, and future electricity demand.

Users interested in additional details regarding these updated cost estimates should review the consultant study prepared by Leidos Engineering, LLC in Appendix B.

Table 1. Updated estimates of power plant capital and operating costs

	Plant Characteristics		Plant Costs (2016$)			
Technology	**Nominal Capacity (MW)**	**Heat Rate (Btu/kWh)**	**Overnight Capital Cost ($/kW)**	**Fixed O&M ($/kW-yr)**	**Variable O&M ($/MWh)**	**NEMS Input**
Coal						
Ultra Supercritical Coal (USC)[10]	650	8,800	3,636	42.1	4.6	N
Ultra Supercritical Coal with CCS (USC/CCS)[11]	650	9,750	5,084	70	7.1	Y
Pulverized Coal Conversion to Natural Gas (CTNG)	300	10,300	226	22	1.3	N
Pulverized Coal Greenfield with 10-15 percent	300	8,960	4,620	50.9	5	N
Pulverized Coal Conversion to 10 percent biomass –	300	10,360	537	50.9	5	Y
Natural Gas						
Natural Gas Combined Cycle (NGCC)	702	6,600	978	11	3.5	Y
Advanced Natural Gas Combined Cycle (ANGCC)[13]	429	6,300	1,104	10	2	Y
Combustion Turbine (CT)	100	10,000	1,101	17.5	3.5	Y
Advanced Combustion Turbine (ACT)	237	9,800	678	6.8	10.7	Y
Reciprocating Internal Combustion Engine (RICE)	85	7,900	1,342	6.9	5.85	N
Uranium						
Advanced Nuclear (AN)	2,234	N/A	5,945	100.28	2.3	Y
Biomass						
Biomass (BBFB)	50	13,500	4,985	110	4.2	N
Wind						
Onshore Wind (WN)	100	N/A	1,877	39.7	0	Y
Solar						
Photovoltaic – Fixed	20	N/A	2,671	23.4	0	N
Photovoltaic – Tracking	20		2,644	23.9	0	N
Photovoltaic – Tracking	150	N/A	2,534	21.8	0	Y
Storage						
Battery Storage (BES)	50	13,500	4,985	100	0	N

[10] USC coal without CCS is not compliant with 111b new source standards for carbon emissions and cannot be built in the AEO2016 forecast.

[11] Ultra Supercritical Coal with 30% CCS

[12] Represents capital cost to retrofit existing coal plants to operate with 10% biomass fuel.

[13] "Advanced"-higher capital cost with reduced operating costs

Table 2. Overnight cost comparison with 2013 estimates

	Overnight Capital Cost (2016 $/kW)		
	2016 Report	2013 report	% Difference
Coal			
Single Unit Advanced PC	N/A	$3,453	N/A
Dual Unit Advanced PC	N/A	$3,121	N/A
Single Unit Advanced PC with CCS	N/A	$5,561	N/A
Dual Unit Advanced PC with CCS	N/A	$5,026	N/A
Single Unit IGCC	N/A	$4,681	N/A
Dual Unit IGCC	N/A	$4,026	N/A
Single Unit IGCC with CCS	N/A	$7,020	N/A
Ultra Supercritical Coal (USC)	$3,636	N/A	5%[14]
Ultra Supercritical Coal with CCS (USC/CCS)	$5,084	N/A	N/A
Pulverized Coal Conversion to Natural Gas (CTNG)	$226	N/A	N/A
Pulverized Coal Greenfield with 10-15 percent biomass (GCBC)	$4,620	N/A	N/A
Pulverized Coal Conversion to 10 percent biomass Co-Firing 30 MW (CTCB)	$537	N/A	N/A
Natural Gas			
Conventional CC	$978	$976	0.3%
Advanced CC	$1,104	$1,088	1%
Advanced CC with CCS	N/A	$2,229	N/A
Conventional CT	$1,101	$1,035	6%
Advanced CT	$678	$719	(6%)
Fuel Cells	N/A	$7,562	N/A
Reciprocating Internal Combustion Engine (RICE)	$1,342	N/A	N/A
Uranium			
Dual Unit Nuclear	$5,945	$5,883	1%
Biomass			
Biomass CC	N/A	$8,702	N/A
Biomass BFB	$4,985	$4,377	12%
Wind			
Onshore Wind	$1,877	$2,354	(25%)
Offshore Wind	N/A	$6,628	N/A

[14] Comparison of costs of coal units without carbon control, despite difference in generation performance (ultra supercritical vs supercritical)

Table 2. Overnight cost comparison with 2013 estimates (cont.)

	Overnight Capital Cost (2016 $/kW)		
	2016 Report	2013 report	% Difference
Solar			
Solar Thermal	N/A	$5,390	N/A
Solar Photovoltaic (20 MW)	$2,671	$4,450	(67%)
Solar Photovoltaic (150 MW)	N/A	$4,120	N/A
Solar Photovoltaic -Tracking (20 MW)	$2,644	N/A	N/A
Solar Photovoltaic - Tracking (150 MW)	$2,534	N/A	N/A
Geothermal – Dual Flash	N/A	$6,641	N/A
Geothermal – Binary	N/A	$4,640	N/A
Municipal Solid Waste			
Municipal Solid Waste	N/A	$8,843	N/A
Hydroelectric			
Conventional Hydroelectric	N/A	$3,123	N/A
Pumped Storage	N/A	$5,626	N/A
Battery Storage (50 MW)	4,985	N/A	N/A

Table 3. Status of technologies and components modeled by EIA

	Revolutionary	Evolutionary	Mature
Pulverized Coal			X
Pulverized Coal with CCS			
- Non-CCS portion of Pulverized Coal Plant			X
- CCS	X		
Integrated Gasification Combined Cycle			
- Advanced Combustion Turbine		X	
- Heat Recovery Steam Generator			X
- Gasifier		X	
- Balance of Plant			X
Conventional Natural Gas Combined Cycle			
- Conventional Combustion Turbine			X
- Heat Recovery Steam Generator			X
- Balance of Plant			X
Advanced Natural Gas Combined Cycle			
- Advanced Combustion Turbine		X	
- Heat Recovery Steam Generator			X
- Balance of Plant			X
Advanced Natural Gas Combined Cycle with CCS			
- Advanced Combustion Turbine		X	
- Heat Recovery Steam Generator			X
- Balance of Plant			X
- CCS	X		
Conventional Natural Gas Combustion Turbine			
- Conventional Combustion Turbine			X
- Balance of Plant			X
Advanced Natural Gas Combustion Turbine			
- Advanced Combustion Turbine		X	
- Balance of Plant			X
Advanced Nuclear	X		
Biomass			
- Pulverized Coal			X
- Fuel Preparation		X	
Geothermal		X	
Municipal Solid Waste/Landfill Gas			X
Conventional Hydroelectric			X
Wind			
- Onshore/Common Components			X
- Offshore Components	X		
Solar Thermal	X		
Solar PV			
- Modules (Utility and End Use)		X	
- Utility Balance of Plant		X	

Table 4. Regional cost adjustments for technologies modeled by NEMS by Electric Market Module (EMM) region[15]

EMM Region	PC	IGCC	PC w/CCS	Conv. CT	Adv. CT	Conv. CC	Adv. CC	Adv. CC w/CCS	Fuel Cell	Nuclear	Biomass	MSW	On-shore Wind	Off-shore Wind	Solar Thermal	Solar PV
1 (ERCT)	0.91	0.92	0.92	0.93	0.95	0.91	0.92	0.9	0.96	0.96	0.93	0.93	0.95	0.92	0.86	0.87
2 (FRCC)	0.92	0.93	0.94	0.93	0.93	0.91	0.92	0.92	0.97	0.97	0.94	0.94	N/A	N/A	0.89	0.9
3 (MROE)	1.01	1.01	0.99	0.99	1.01	0.99	0.99	0.97	0.99	1.01	0.99	0.98	0.99	0.97	N/A	0.96
4 (MROW)	0.95	0.96	0.96	0.98	1.00	0.97	0.97	0.96	0.98	0.98	0.96	0.96	1.03	1.01	N/A	0.95
5 (NEWE)	1.1	1.09	1.05	1.16	1.2	1.16	1.15	1.08	1.01	1.05	1.04	1.02	1.06	1.03	N/A	1.03
6 (NYCW)	N/A	N/A	N/A	1.63	1.68	1.68	1.66	1.5	1.14	N/A	1.26	1.26	N/A	1.29	N/A	N/A
7 (NYLI)	N/A	N/A	N/A	1.63	1.68	1.68	1.66	1.5	1.14	N/A	1.26	1.26	1.25	1.29	N/A	1.45
8 (NYUP)	1.11	1.1	1.05	1.17	1.22	1.16	1.16	1.06	1.00	1.07	1.03	1.00	1.01	0.99	N/A	0.98
9 (RFCE)	1.15	1.14	1.09	1.21	1.25	1.21	1.21	1.12	1.02	1.08	1.07	1.03	1.05	1.03	N/A	1.05
10 (RFCM)	0.98	0.98	0.98	1.01	1.02	1.00	1.00	0.99	0.99	0.99	0.98	0.98	1.00	0.98	N/A	0.97
11 (RFCW)	1.05	1.04	1.02	1.05	1.06	1.04	1.04	1.02	1.00	1.03	1.02	1.00	1.02	1.01	N/A	1.00
12 (SRDA)	0.92	0.93	0.93	0.95	0.96	0.93	0.93	0.92	0.97	0.96	0.93	0.94	0.96	1.00	N/A	0.89
13 (SRGW)	1.07	1.06	1.05	1.05	1.05	1.06	1.05	1.04	1.02	1.03	1.03	1.03	1.04	1.00	N/A	1.05
14 (SRSE)	0.92	0.93	0.93	0.95	0.97	0.93	0.94	0.92	0.97	0.96	0.93	0.94	0.96	0.93	N/A	0.89
15 (SRCE)	0.93	0.94	0.94	0.94	0.95	0.93	0.93	0.92	0.97	0.97	0.94	0.94	0.96	1.00	N/A	0.89
16 (SRVC)	0.89	0.91	0.91	0.91	0.93	0.88	0.89	0.88	0.96	0.95	0.91	0.91	0.95	0.92	N/A	0.84
17 (SPNO)	0.98	0.99	0.98	1.00	1.01	0.99	0.99	0.98	0.99	0.99	0.98	0.98	1.02	N/A	0.97	0.97
18 (SPSO)	0.98	0.99	0.98	1.00	1.01	0.99	0.99	0.98	0.99	0.99	0.98	0.98	1.02	N/A	0.97	0.97
19 (AZNM)	1.00	1.00	0.99	1.03	1.04	1.02	1.02	1.00	0.99	1.00	1.00	0.99	1.03	1.00	0.99	0.99
20 (CAMX)	N/A	N/A	1.12	1.24	1.29	1.25	1.24	1.15	1.03	N/A	1.08	1.06	1.12	1.05	1.13	1.11
21 (NWPP)	1.01	1.01	1.00	1.02	1.03	1.01	1.01	0.99	0.99	1.01	1.00	0.98	1.05	1.02	0.99	0.99
22 (RMPA)	0.99	0.99	0.97	1.02	1.05	1.01	1.01	0.96	0.98	1.01	0.97	0.95	1.03	N/A	0.93	0.93

Note: Geothermal and Hydroelectric plants are not included in the table because EIA uses site specific cost estimates for these technologies which include regional factors.

[15] The regional tables in the report were aggregated to the appropriate Electricity Market Module region in order to represent regional cost factors in NEMS

Appendix A - Acronym List

BFB - Bubbling Fluidized Bed
CC - Combined Cycle
CCS - Carbon Capture and Sequestration
CT - Combustion Turbine
CTCB – Conversion to Biomass Co-Firing
CTNG – Conversion to Natural Gas
GCBC – Greenfield Conversion Biomass Co-Firing
IGCC - Integrated Gasification Combined Cycle
PC - Pulverized Coal
PV – Photovoltaic
RICE – Reciprocating Internal Combustion Engine
USC – Ultra Supercritical Coal

Appendix B – Full Report

EOP III TASK 10688, SUBTASK 4 and TASK 10687, SUBTASK 2.3.1 – REVIEW OF POWER PLANT COST AND PERFORMANCE ASSUMPTIONS FOR NEMS

Technology Documentation Report

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April 2016

Disclaimer

Certain statements included in this report constitute forward-looking statements. The achievement of certain results or other expectations contained in such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause actual results, performance or achievements described in the report to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. We do not plan to issue any updates or revisions to the forward-looking statements if or when our expectations or events, conditions, or circumstances on which such statements are based occur.

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LIST OF ACRONYMS AND ABBREVIATIONS

AC	Alternating Current
AG	Advanced Generation
AG-NGCC	Advanced Generation Natural Gas Combined Cycle
AG-NGCC/CCS	Advanced Generation Natural Gas Combined Cycle with CCS
AGR	Acid Gas Removal
AN	Advanced Nuclear
ASU	Air Separation Unit
BACT	Best Available Control Technology
BBFB	Biomass Bubbling Fluidized Bed
BES	Battery Storage
BFB	Bubbling Fluidized Bed
BOP	Balance-of-Plant
Btu	British Thermal Unit
C	Carbon
CCS	Carbon Capture and Sequestration
C_2H_6	Ethane
C_3H_8	Propane
C_4H_{10}	*n*-Butane
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COS	Carbonyl Sulfide
CT	Combustion Turbine
DC	Direct Current
DCS	Distributed Control System
DLN	Dry Low-NO_X Combustion
EIA	Energy Information Administration
EMM	Electricity Market Module of NEMS
EPC	Engineering, Procurement and Construction
°F	Degrees Fahrenheit
FGD	Flue Gas Desulfurization
FOM	Fixed O&M
GHG	Greenhouse Gas
GSU	Generator Step-up Transformer
GT	Geothermal
H_2S	Hydrogen Sulfide
HHV	High(er) Heating Value
HP	High Pressure
HRSG	Heat Recovery Steam Generator
HY	Hydroelectric
Hz	Hertz
I&C	Instrumentation and Controls
IP	Intermediate Pressure

ISO	International Standard Organization
kg	Kilograms
KJ	Kilojoules
kW	Kilowatt
kWh	Kilowatt-hour
kV	Kilovolt
kVA	kilovolt-amperes
lb	Pound
Leidos	Leidos Engineering, LLC
LHV	Low(er) Heating Value
LP	Low Pressure
MEA	Monoethanolamine
MJ	Mega joules
MMBtu	Million Btu
MSW	Municipal Solid Waste
MW	Megawatt
MWe	Megawatts Electric
MWh	Megawatt-hour
MVA	Mega-volt-amperes
N_2	Nitrogen
NEMS	National Energy Modeling System
NGCC	Natural Gas Combined Cycle
NH_3	Ammonia
NO_X	Oxides of Nitrogen
O_2	Oxygen
O&M	Operating and Maintenance
NOx	Nitrogen Oxides
ppmvd	Parts per Million Volume Dry
PS	Pumped Storage
psia	Pounds per Square Inch Absolute
PV	Photovoltaic
PWR	Pressurized Water Reactor
RCS	Reactor Coolant System
RICE	Reciprocating Internal Combustion Engine
S	Sulfur
SCADA	Supervisory Control and Data Acquisition
scf	Standard Cubic Feet
scm	Standard Cubic Meters
SCR	Selective Catalytic Reduction
SNCR	Selective Non-catalytic Reduction
SO	Solar Thermal
SO_2	Sulfur Dioxide
SRU	Sulfur Recovery Unit
ST	Steam Turbine
TGF	Turbine Generating Facility
U.S.	United States

USC	Ultra Supercritical Coal Facility
USC/CCS	Ultra Supercritical Coal with CCS
V	Volt
VOM	Variable Operating and Maintenance
WFGD	Wet Flue Gas Desulfurization
WN	Onshore Wind
WTG	Wind Turbine Generator

1. INTRODUCTION

This report presents Leidos Engineering, LLC ("Leidos") performance and cost assessment of power generation technologies utilized by the Energy Information Administration ("EIA") in the Electricity Market Module ("EMM") of the National Energy Modeling System ("NEMS"). The assessment for each of the technologies considered includes the following:

- Overnight construction costs, construction lead times, first year of commercial application, typical unit size, contingencies, fixed and variable operating costs, and efficiency (heat rate). The analysis was conducted to ensure that the overnight cost estimates developed for use in the EMM for electric generating technologies are consistent in scope, accounting for generally all costs in the planning and development of a power plant including the basic interconnection to the grid at the plant site and other utility interconnections, but excluding financing costs.
- For emission control technologies, the removal rates for pollutants and other assumptions were examined.
- Review of the regional multipliers that are used to represent local conditions, such as labor rates that are included in EMM.
- Review of the appropriateness of technology-specific project and process contingency assumptions (capturing differences between engineering estimates and realized costs for new technologies).
- Where possible, compare the values used by EIA with those for recently built facilities in the United States ("U.S.") or abroad. Where such actual cost estimates do not exist, an assessment was made between values used by EIA and other analyst estimates, as well as vendor estimates.
- The key factors expected to drive each technology's costs.
- Document the source and basis for final recommendations for altering or retaining the various assumptions.

1.1 TECHNOLOGIES ASSESSED

The following table lists all technologies to be assessed in this project.

TABLE 1-1 – LIST OF TECHNOLOGIES FOR REVIEW

TECHNOLOGY	DESCRIPTION	COMMENTS
Ultra Supercritical Coal (USC)	650 MWe with advanced pollution control technologies	Greenfield Installation
Ultra Supercritical Coal with Carbon Capture and Sequestration (USC/CCS)	650 MWe; supercritical; with advanced pollution control technologies, including CCS technologies	Greenfield Installation
Pulverized Coal Brownfield Conversion to Natural Gas (CTNG)	300 MWe	Brownfield Installation
Pulverized Coal Greenfield with 10%-15% Biomass Co-Firing (GCBC)	300 MWe	Greenfield Installation
Pulverized Coal Brownfield Conversion to Coal with 10% Biomass Co-Firing (CTCB)	300 MWe net plant output; 30 MWe of added Biomass	Brownfield Installation, added 30MWe of Wood Fuel
Conventional Natural Gas Combined Cycle (NGCC)	702 MWe; F-Class system	Greenfield Installation
Advanced Generation Natural Gas Combined Cycle (AG-NGCC)	429 MWe; H-Class system	Greenfield Installation
Conventional Combustion Turbine (CT)	100 MWe; (2) LM 6000 Class turbines	Greenfield Installation
Advanced Combustion Turbine (ACT)	237 MWe; F-Class turbine	Greenfield Installation
Advanced Nuclear (AN)	2,234 234MWe; (2) AP1000 PWR Basis	Brownfield Installation
Biomass Bubbling Fluidized Bed (BBFB)	50 MWe	Greenfield Installation; Wood Fuel
Wind Farm – Onshore (WN)	100 MWe; (56) 1.79 MWe WTG's	Greenfield Installation
Utility-Scale Photovoltaic (PV)	20 MWe –AC Fixed; 20 MWe-AC Tracker and 150 MWe – AC Tracker	Greenfield Installation
Internal Combustion (IC)	85 MWe; (5) Wartsila 17MWe Engines	Greenfield Installation
Battery Storage (BES)	4 MWe	Greenfield Installation

2. GENERAL BASIS FOR TECHNOLOGY EVALUATION BASIS

This section specifies the general evaluation basis used for all technologies reviewed herein.

2.1 LEIDOS ENGINEERING, LLC BACKGROUND

Leidos is a technical solutions and infrastructure consulting firm that has been providing technical and business consulting in the energy industry since 1942. Particularly, Leidos has supported the purchase, sale, financing and Owner's advisory consulting for tens-of-billions of dollars of power plants across the world in all commercial power generating technologies as well as many emerging technologies. This background has supported Leidos' acumen with respect to construction costs, operating costs, technology development and evolution, as well as trends in environmental regulation and compliance.

2.2 BASE FUEL CHARACTERISTICS

This section provides a general fuel basis for each of the fuel types utilized by the technologies considered in this report, which was listed in Table 1-1. Each of the technologies that combust a fuel has the ability to operate over a range of fuels; thus Table 2-1, Table 2-2 and Table 2-3 show a typical fuel specification for coal, natural gas, and wood-biomass, respectively.

TABLE 2-1 – REFERENCE COAL SPECIFICATION

Rank	**Bituminous**	
Seam	**Illinois No. 6 (Herrin)**	
Source	**Old Ben Mine**	
Proximate Analysis (weight %) (Note A)		
	As Received	**Dry**
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile Matter	34.99	39.37
Fixed Carbon	44.19	49.72
Total	100.00	100.00
Sulfur	3	3.38
HHV (1), KJ/kg (2)	27,113	30,506
HHV, Btu/lb (3)	11,666	13,126
LHV (4), KJ/kg	26,151	29,544
LHV, Btu/lb	11,252	12,712
Ultimate Analysis (weight %)		
	As Received	**Dry**
Moisture	11.12	0.00
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	3.0	3.38
Ash	9.70	10.91
Oxygen	6.88	7.75
Total	100.00 (rounded)	100.00 (rounded)

(1) High(er) heating value ("HHV").
(2) Kilojoules per kilogram ("KJ/kg").
(3) British thermal units per pound ("Btu/lb").
(4) Low(er) heating value ("LHV").

TABLE 2-2 – NATURAL GAS SPECIFICATION

Component		Volume Percentage	
Methane	CH_4	93.9	
Ethane	C_2H_6	3.2	
Propane	C_3H_8	0.7	
n-Butane	C_4H_{10}	0.4	
Carbon Dioxide	CO_2	1.0	
Nitrogen	N_2	0.8	
Total		100.0	
		LHV	**HHV**
kJ/kg		47.764	52,970
MJ/scm [(1)]		35	39
Btu/lb		20,552	22,792
Btu/scf [(2)]		939	1,040

(1) Mega joules per standard cubic meter ("MJ/scm").
(2) Standard cubic feet ("scf").

TABLE 2-3 – WOOD BIOMASS SPECIFICATION [(1)]

Component		Volume Percentage	
Moisture		17.27	
Carbon	C	41.55	
Hydrogen	H_2	4.77	
Nitrogen	N_2	0.37	
Sulfur	S	<0.01	
Ash		2.35	
Oxygen [(2)]	O_2	33.75	
Total		100.0	
			HHV
Btu/lb			6,853

(1) As received.
(2) Oxygen by Difference.

2.3 ENVIRONMENTAL COMPLIANCE BASIS

The technology assessments considered the emissions rates after implementation of best available control technology ("BACT"), including sulfur dioxide ("SO_2"), oxides of nitrogen ("NO_X"), particulate matter, mercury, and carbon dioxide ("CO_2"). With respect to CCS technologies, which are not currently considered "proven" or BACT by regulating bodies, Leidos assumed capture and sequestration technologies that are currently in development for large-scale deployment, as discussed herein, and at industry expected rates of CO_2 removal (i.e., 30 percent).

2.4 LOCAL CAPACITY ADJUSTMENTS

For power plants that use CT technologies, adjustments were made for regional ambient conditions. The adjustments took into consideration that CTs are machines that produce power proportional to mass flow. Since air density is inversely proportional to temperature, ambient temperature has a strong influence on the capacity of a given technology utilizing a CT (e.g., peaking power plant, combined-cycle power plant, and some gasification power plants). Additionally, relative humidity impacts the available capacity of a CT and consequently a CT-based power plant, primarily driven by the base assumption that the CT-based technologies incorporate inlet evaporative cooling. By circulating water across a porous media in the CT compressor inlet (across which the air flows), the inlet evaporative cooling reduces the difference between the ambient dry-bulb temperature (the temperature that is typically reported to the public as a measure of "local temperature") and the wet-bulb temperature (a measure of relative humidity). Since inlet evaporative cooling is limited by the wet-bulb temperature, the effectiveness of these devices increases in areas of high dry-bulb temperature and low relative humidity. The final adjustment for ambient conditions made for the CT-based plants is ambient pressure, which on average (notwithstanding high or low pressure weather fronts that pass through a region) takes into consideration elevation (average number of feet above sea level). Air density is proportional to ambient pressure.

Table 2-4 provides the aggregate capacity adjustment for each location, which provides regional differences related to capital costs against the International Standard Organization ("ISO") net capacity for the CT-based power plant technologies.

TABLE 2-4 – CT CAPACITY ADJUSTMENTS

State	City	Average Ambient Temperature (°F)	Capacity Adjustment Factor, Temperature Simple Cycle	Average Barometric Pressure (in Hg)	Average Barometric Pressure (psia)	Capacity Adjustment Factor, Barometric Pressure Simple Cycle	Total Capacity Adjustment Factor Simple Cycle	Capacity Adjustment Factor, Temperature Combined Cycle	Capacity Adjustment Factor, Barometric Pressure Combined Cycle	Total Capacity Adjustment Factor Combined Cycle	Conventional Combustion Turbine Simple Cycle: ISO Capacity (MW)	Conventional Combustion Turbine Simple Cycle: Capacity Adjustment (MW)	Conventional Combustion Turbine Simple Cycle: Adjusted Capacity (MW)	Advanced Combution Turbine Simple Cycle: ISO Capacity (MW)	Advanced Combution Turbine Simple Cycle: Capacity Adjustment (MW)	Advanced Combution Turbine Simple Cycle: Adjusted Capacity (MW)	ISO Capacit (MW)
Alaska	Anchorage	35.9	1.09	29.60	14.534	0.990	1.08	1.06	0.989	1.05	100.00	8.14	108.14	237.00	19.29	256.29	702.00
Alaska	Fairbanks	26.9	1.13	29.31	14.391	0.981	1.11	1.08	0.980	1.06	100.00	10.68	110.68	237.00	25.31	262.31	702.00
Alabama	Huntsville	60.3	0.99	29.36	14.416	0.983	0.98	1.00	0.981	0.98	100.00	-2.26	97.74	237.00	-5.36	231.64	702.00
Arizona	Phoenix	72.6	0.95	28.72	14.102	0.963	0.91	0.97	0.960	0.93	100.00	-8.98	91.02	237.00	-21.29	215.71	702.00
Arkansas	Little Rock	61.8	0.99	29.68	14.573	0.992	0.98	0.99	0.992	0.98	100.00	-1.87	98.13	237.00	-4.44	232.56	702.00
California	Los Angeles	63.0	0.98	29.84	14.651	0.997	0.98	0.99	0.997	0.99	100.00	-1.88	98.12	237.00	-4.45	232.55	702.00
California	Redding	62.0	0.99	29.44	14.455	0.985	0.97	0.99	0.984	0.98	100.00	-2.70	97.30	237.00	-6.40	230.60	702.00
California	Bakersfield	65.4	0.97	29.44	14.455	0.985	0.96	0.98	0.984	0.97	100.00	-4.04	95.96	237.00	-9.57	227.43	702.00
California	Sacramento	60.8	0.99	29.93	14.696	1.000	0.99	1.00	1.000	1.00	100.00	-0.72	99.28	237.00	-1.71	235.29	702.00
California	San Francisco	57.1	1.01	29.98	14.720	1.000	1.01	1.00	1.000	1.00	100.00	0.76	100.76	237.00	1.80	238.80	702.00
Colorado	Denver	50.3	1.03	24.66	12.108	0.826	0.86	1.02	0.816	0.83	100.00	-14.48	85.52	237.00	-34.32	202.68	702.00
Connecticut	Hartford	49.9	1.04	29.79	14.627	0.996	1.03	1.02	0.995	1.02	100.00	3.20	103.20	237.00	7.57	244.57	702.00
Delaw are	Dover	56.0	1.01	29.97	14.715	1.000	1.01	1.01	1.000	1.01	100.00	1.20	101.20	237.00	2.84	239.84	702.00
District of Columbia	Washington	53.8	1.02	29.96	14.710	1.000	1.02	1.01	1.000	1.01	100.00	2.08	102.08	237.00	4.93	241.93	702.00
Florida	Tallahassee	67.2	0.97	29.96	14.710	1.000	0.97	0.98	1.000	0.98	100.00	-3.28	96.72	237.00	-7.77	229.23	702.00
Florida	Tampa	72.3	0.95	30.01	14.735	1.000	0.95	0.97	1.000	0.97	100.00	-5.32	94.68	237.00	-12.61	224.39	702.00
Georgia	Atlanta	61.3	0.99	28.94	14.210	0.969	0.96	0.99	0.967	0.96	100.00	-3.96	96.04	237.00	-9.39	227.61	702.00
Haw aii	Honolulu	77.2	0.93	29.96	14.710	1.000	0.93	0.95	1.000	0.95	100.00	-7.28	92.72	237.00	-17.25	219.75	702.00
Idaho	Boise	50.9	1.03	27.03	13.272	0.908	0.94	1.02	0.902	0.92	100.00	-6.28	93.72	237.00	-14.89	222.11	702.00
Illinois	Chicago	49.0	1.04	29.27	14.372	0.980	1.02	1.03	0.978	1.00	100.00	1.89	101.89	237.00	4.48	241.48	702.00
Indiana	Indianapolis	52.3	1.03	29.15	14.313	0.976	1.00	1.02	0.974	0.99	100.00	0.21	100.21	237.00	0.49	237.49	702.00
Iow a	Davenport	50.0	1.04	29.41	14.440	0.984	1.02	1.02	0.983	1.01	100.00	1.94	101.94	237.00	4.60	241.60	702.00
Iow a	Waterloo	46.5	1.05	29.05	14.264	0.973	1.02	1.03	0.971	1.00	100.00	2.14	102.14	237.00	5.08	242.08	702.00
Kansas	Wichita	56.2	1.01	28.56	14.023	0.957	0.97	1.01	0.955	0.96	100.00	-3.18	96.82	237.00	-7.55	229.45	702.00
Kentucky	Louisville	56.1	1.01	29.49	14.480	0.986	1.00	1.01	0.986	0.99	100.00	-0.21	99.79	237.00	-0.49	236.51	702.00
Louisiana	New Orleans	68.1	0.96	29.99	14.725	1.000	0.96	0.98	1.000	0.98	100.00	-3.64	96.36	237.00	-8.63	228.37	702.00
Maine	Portland	46.0	1.05	29.89	14.676	0.999	1.05	1.03	0.999	1.03	100.00	5.08	105.08	237.00	12.04	249.04	702.00
Maryland	Baltimore	55.1	1.02	29.85	14.656	0.999	1.01	1.01	0.999	1.01	100.00	1.46	101.46	237.00	3.46	240.46	702.00
Massachusetts	Boston	51.3	1.03	29.95	14.705	1.000	1.03	1.02	1.000	1.02	100.00	3.08	103.08	237.00	7.30	244.30	702.00
Michigan	Detroit	48.6	1.04	29.31	14.391	0.981	1.02	1.03	0.980	1.01	100.00	2.17	102.17	237.00	5.13	242.13	702.00
Michigan	Grand Rapids	47.2	1.05	29.12	14.298	0.975	1.02	1.03	0.973	1.00	100.00	2.09	102.09	237.00	4.96	241.96	702.00
Minnesota	Saint Paul	46.7	1.05	29.07	14.273	0.973	1.02	1.03	0.972	1.00	100.00	2.13	102.13	237.00	5.05	242.05	702.00
Mississippi	Jackson	65.0	0.98	29.68	14.573	0.992	0.97	0.99	0.992	0.98	100.00	-3.16	96.84	237.00	-7.48	229.52	702.00
Missouri	St. Louis	56.0	1.01	29.41	14.440	0.984	1.00	1.01	0.983	0.99	100.00	-0.42	99.58	237.00	-0.99	236.01	702.00
Missouri	Kansas City	53.6	1.02	28.82	14.151	0.966	0.99	1.01	0.964	0.98	100.00	-1.35	98.65	237.00	-3.19	233.81	702.00
Montana	Great Falls	44.8	1.06	26.19	12.859	0.880	0.93	1.04	0.872	0.90	100.00	-7.05	92.95	237.00	-16.71	220.29	702.00
Nebraska	Omaha	50.6	1.03	28.92	14.200	0.969	1.00	1.02	0.967	0.99	100.00	0.12	100.12	237.00	0.28	237.28	702.00
New Hampshire	Concord	45.1	1.06	29.60	14.534	0.990	1.04	1.03	0.989	1.02	100.00	4.50	104.50	237.00	10.66	247.66	702.00
New Jersey	New ark	54.8	1.02	29.98	14.720	1.000	1.02	1.01	1.000	1.01	100.00	1.68	101.68	237.00	3.98	240.98	702.00
New Mexico	Albuquerque	56.2	1.01	24.72	12.138	0.828	0.84	1.01	0.818	0.82	100.00	-16.23	83.77	237.00	-38.47	198.53	702.00
New York	New York	54.8	1.02	29.98	14.720	1.000	1.02	1.01	1.000	1.01	100.00	1.68	101.68	237.00	3.98	240.98	702.00
New York	Syracuse	47.4	1.05	29.51	14.489	0.987	1.03	1.03	0.986	1.01	100.00	3.28	103.28	237.00	7.76	244.76	702.00
Nevada	Las Vegas	67.1	0.97	27.67	13.586	0.929	0.90	0.98	0.925	0.91	100.00	-10.12	89.88	237.00	-23.99	213.01	702.00
North Carolina	Charlotte	60.1	1.00	29.23	14.352	0.978	0.97	1.00	0.977	0.97	100.00	-2.59	97.41	237.00	-6.14	230.86	702.00
North Dakota	Bismarck	42.0	1.07	28.19	13.841	0.946	1.01	1.04	0.942	0.98	100.00	0.98	100.98	237.00	2.33	239.33	702.00
Ohio	Cincinnati	51.7	1.03	29.50	14.485	0.987	1.02	1.02	0.986	1.00	100.00	1.56	101.56	237.00	3.70	240.70	702.00
Oregon	Portland	54.0	1.02	29.99	14.725	1.000	1.02	1.01	1.000	1.01	100.00	2.00	102.00	237.00	4.74	241.74	702.00
Pennsylvania	Philadelphia	54.3	1.02	29.98	14.720	1.000	1.02	1.01	1.000	1.01	100.00	1.88	101.88	237.00	4.46	241.46	702.00
Pennsylvania	Wilkes-Barre	48.7	1.04	29.00	14.239	0.971	1.01	1.03	0.970	0.99	100.00	1.13	101.13	237.00	2.68	239.68	702.00
Rhode Island	Providence	50.4	1.03	29.92	14.691	1.000	1.03	1.02	1.000	1.02	100.00	3.44	103.44	237.00	8.15	245.15	702.00
South Carolina	Spartanburg	59.0	1.00	29.12	14.298	0.975	0.97	1.00	0.973	0.97	100.00	-2.51	97.49	237.00	-5.94	231.06	702.00
South Dakota	Rapid City	46.6	1.05	26.67	13.095	0.896	0.94	1.03	0.890	0.92	100.00	-5.97	94.03	237.00	-14.14	222.86	702.00
Tennessee	Knoxville	57.6	1.01	29.00	14.239	0.971	0.98	1.00	0.970	0.97	100.00	-2.33	97.67	237.00	-5.52	231.48	702.00
Texas	Houston	67.9	0.96	29.89	14.676	0.999	0.96	0.98	0.999	0.98	100.00	-3.69	96.31	237.00	-8.74	228.26	702.00
Utah	Salt Lake City	52.0	1.03	25.72	12.629	0.864	0.89	1.02	0.855	0.87	100.00	-11.23	88.77	237.00	-26.61	210.39	702.00
Vermont	Burlington	44.6	1.06	29.61	14.539	0.990	1.05	1.04	0.990	1.03	100.00	4.71	104.71	237.00	11.17	248.17	702.00
Virginia	Alexandria	58.0	1.00	29.90	14.681	0.999	1.00	1.00	0.999	1.00	100.00	0.30	100.30	237.00	0.71	237.71	702.00
Virginia	Lynchburg	57.0	1.01	29.31	14.391	0.981	0.99	1.01	0.980	0.98	100.00	-1.13	98.87	237.00	-2.68	234.32	702.00
Washington	Seattle	52.8	1.02	29.52	14.494	0.987	1.01	1.02	0.987	1.00	100.00	1.19	101.19	237.00	2.83	239.83	702.00
Washington	Spokane	47.3	1.05	27.50	13.503	0.923	0.97	1.03	0.919	0.95	100.00	-3.35	96.65	237.00	-7.94	229.06	702.00
West Virginia	Charleston	55.0	1.02	29.00	14.239	0.971	0.99	1.01	0.970	0.98	100.00	-1.32	98.68	237.00	-3.12	233.88	702.00
Wisconsin	Green Bay	43.8	1.06	29.22	14.347	0.978	1.04	1.04	0.977	1.01	100.00	3.77	103.77	237.00	8.93	245.93	702.00
Wyoming	Cheyenne	45.6	1.05	23.93	11.750	0.800	0.84	1.03	0.788	0.81	100.00	-15.71	84.29	237.00	-37.23	199.77	702.00
Puerto Rico	Cayey	72.0	0.95	29.51	14.489	0.987	0.94	0.97	0.986	0.95	100.00	-6.44	93.56	237.00	-15.25	221.75	702.00
		cityrating.com Weatherbase.com		NOAA database							2 x 0 GE LM 6000			1 x 0 Siemens SGT6-5000F5			2x1 Siemer

Notes:
1 Capacity based on a new and clean equipment
2 Capacity is net including auxiliary loads
3 Capacity for combined cycle is based on wet cooling tower

2.5 TECHNOLOGY SPECIFICATIONS

This section provides the base performance specifications for each technology. Table 2-5 provides the current technology specifications.

2.6 COST ESTIMATION METHODOLOGY

The approach taken in this latest cost analysis of capital and operating estimates concentrated primarily in these three areas:

1. Escalation over the past three years.
2. Technology-specific changes in pricing; for example, overall wind and solar capex pricing lowered due to lower equipment pricing.

3. Updated actual costs being made available to Projects with which we are familiar.

2.6.1 Capital Cost

A summary base capital cost estimate ("Cost Estimate") was developed for each power plant technology, based on a generic facility of a certain size (capacity) and configuration, and assuming a non-specific U.S. location with no unusual location impacts (e.g., urban construction constraints) or infrastructure needs (e.g., a project-dedicated interconnection upgrade cost).

Each Cost Estimate was developed assuming costs in first quarter 2016 dollars on an "overnight" capital cost basis. In each Cost Estimate, the total project engineering, procurement and construction ("EPC") cost was organized into the following categories:

- Civil/structural material and installation,
- Mechanical equipment supply and installation,
- Electrical instrumentation and controls ("I&C") supply and installation,
- Project indirect costs, fees and contingency, and
- Owner's costs (excluding project financing costs).

It should be noted that an EPC (turnkey) or equipment supply/balance of plant, as applicable to a given technology, contracting approach was assumed for each of the technologies, which included a risk sharing between the project owner and project construction contractor that, based on our experience, would be required in typical financing markets. This approach does not always result in the lowest cost of construction; however, on average, we believe this approach to result in an achievable cost of construction, given the other considerations discussed herein.

In addition to the base Cost Estimate provided for the given technology, specific regional cost differences were determined. Regional costs for 64 unique locations in the U.S. were analyzed. Eleven subcategories were used (depending on the specific technology under review) to estimate the differences in various regions of the U.S. for the each power plant technology. The regional analyses include, but are not limited to, assessing the cost differences for outdoor installation considerations, air-cooled condensers versus cooling tower issues, seismic design differences, zero-water discharge issues, local enhancements, remote location issues, urban high-density population issues, labor wage and productivity differences, location adjustments, owner cost differences, and the increase in overheads associated with these locations. More detail with respect to regional differences for each given technology is provided in the following sections.

2.6.1.1 Costing Scope

The *civil and structural costs* include allowance for site preparation, such as clearing, roads, drainage, underground utilities installation, concrete for foundations, piling material, structural steel supply and installation, and buildings.

The *mechanical equipment supply and installation* includes major equipment (technology and process dependent), including but not limited to, boilers, scrubbers, cooling towers, combustion turbines ("CT"), steam turbines ("ST") generators, wind turbine generators ("WTG"), PV modules, as well as auxiliary equipment such as material handling, fly and bottom ash handling, pumps, condensers, and balance of plant ("BOP") equipment such as fire protection, as applicable to a given technology.

The *electrical and I&C supply and installation* includes electrical transformers, switchgear, motor control centers, switchyards, distributed control systems ("DCS") and instrumentation, and electrical commodities, such as wire, cable tray, and lighting.

While commodities, project equipment, and site assumptions can vary widely from project-to-project for a given technology, the Cost Estimates are based upon a cross section of projects.

The *project indirect costs* include engineering, distributable labor and materials, craft labor overtime and incentives, scaffolding costs, construction management, and start-up and commissioning. The fees and contingency include contractor overhead costs, fees and profit, and construction contingency. Contingency in this category is considered "contractor" contingency, which would be held by a given contractor to mitigate its risk in the construction of a project.

The *owner's costs* include development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, project management (including third-party management), insurance costs, infrastructure interconnection costs (e.g., gas, electricity), Owner's Contingency, and property taxes during construction. The electrical interconnection cost includes an allowance for the plant switchyard and a subsequent interconnection to an "adjacent" (e.g. within a mile) of the plant, but does not include significant transmission system upgrades.

2.6.2 Operation and Maintenance (O&M) Expenses

O&M expenses consist of non-fuel O&M costs, owner's expenses, and fuel-related expenses. In evaluating the non-fuel O&M expenses for use in the EMM of NEMS, we focused on non-fuel O&M costs associated with the direct operation of the given power plant technology, referred to here as the "Production Related Non-Fuel O&M Expenses," to allow for comparison of O&M costs on the same basis.

Production Related Non-Fuel O&M Expenses include the following categories:

- Fixed O&M ("FOM")
- Variable O&M ("VOM")
- Major Maintenance

Presented below is a brief summary below of the expense categories included within the categories of Fixed O&M, Variable O&M, and Major Maintenance. Further, Sections 3 through 17 provide more specific information related to Production-Related Non-Fuel O&M Expenses for each technology.

Owner's expenses, which are not addressed in this report, include expenses paid by plant owners that are plant specific and can vary significantly between two virtually identical plants in the same geographic region. For example, the owner's expenses include, but are not limited to, property taxes, asset management fees, energy marketing fees, and insurance.

2.6.2.1 Fixed O&M (FOM)

FOM expenses are those expenses (excluding fuel-related costs) incurred at a power plant that do not vary significantly with generation and include the following categories:

- Staffing and monthly fees under pertinent operating agreements
- Typical bonuses paid to the given plant operator

- Plant support equipment which consists of equipment rentals and temporary labor
- Plant-related general and administrative expenses (postage, telephone, etc.)
- Routine preventive and predictive maintenance performed during operations
- Maintenance of structures and grounds
- Other fees required for a project to participate in the relevant National Electric Reliability Council region and be in good standing with the regulatory bodies

Routine preventive and predictive maintenance expenses do not require an extended plant shutdown and include the following categories:

- Maintenance of equipment such as water circuits, feed pumps, main steam piping, and demineralizer systems
- Maintenance of electric plant equipment, which includes service water, DCS, condensate system, air filters, and plant electrical
- Maintenance of miscellaneous plant equipment such as communication equipment, instrument and service air, and water supply system
- Plant support equipment which consists of tools, shop supplies and equipment rental, and safety supplies

2.6.2.2 Variable O&M (VOM)

VOM expenses are production-related costs (excluding fuel-related costs) which vary with electrical generation and include the following categories, as applicable to the given power plant technology:

- Raw water
- Waste and wastewater disposal expenses
- Purchase power (which is incurred inversely to operating hours), demand charges and related utilities
- Chemicals, catalysts and gases
- Ammonia (“NH_3”) for selective catalytic reduction (“SCR”), as applicable
- Lubricants
- Consumable materials and supplies

2.6.2.3 Major Maintenance

Major maintenance expenses generally require an extended outage, are typically undertaken no more than once per year; and are assumed to vary with electrical generation or the number of plant starts based on the given technology and specific original equipment manufacturer recommendations and requirements. These major maintenance expenses include the following expense categories:

- Scheduled major overhaul expenses for maintaining the prime mover equipment at a power plant

- Major maintenance labor
- Major maintenance spare parts costs
- BOP major maintenance, which is major maintenance on the equipment at the given plant that cannot be accomplished as part of routine maintenance or while the unit is in commercial operation.
- Major maintenance expenses are included in the O&M Expenses for each plant. These expenses may be in either the fixed or variable O&M rate depending on the cost structure of the particular plant considering such things as capacity factor, hour and start cycling patterns, O&M contract structure (if applicable), and major maintenance timing triggers.

TABLE 2-5 – TECHNOLOGY PERFORMANCE SPECIFICATIONS

Technology	Fuel	Nominal Capacity (kW) [1]	Nominal Heat Rate (Btu/kWh) [2]	Capital Cost ($/kW) [3]	Fixed O&M ($/kW-yr) [4]	Variable O&M ($/MWh) [5]	SO_2 (lb/ MMBtu [6]	NO_X (lb/MMBtu)	CO_2 (lb/MMBtu)
Ultra Supercritical Coal (USC)	Coal	650,000	8,800	3,636	42.10	4.60	0.1 [7]	0.06	206 [7]
Ultra Supercritical Coal with CCS (USC/CCS)	Coal	650,000	9,750	5,084	70.0	7.10	0.02 [10]	0.06	144 [9]
Pulverized Coal Conversion to Natural Gas (CTNG)	Gas	300,000	10,300	226	22.0	1.30	.001	0.11	117
Pulverizer Coal Greenfield with 10-15 percent biomass (GCBC)	Coal/Biomass	300,000	8,960	4,620	50.90	5.00	0.1	0.06	204
Pulverized Coal Conversion to 10 percent biomass – 30 MW (CTCB)	Coal/Biomass	300,000	10,360	537	50.90	5.00	0.1	0.06	204
NGCC	Gas	702,000	6,600	978	11.00	3.50	0.001	0.0075 [12]	117
AG-NGCC	Gas	429,000	6,300	1,104	10.00	2.00	0.001	0.0075 [12]	117
CT	Gas	100,000	10,000	1,101	17.50	3.50	0.001	0.03 [11]	117
ACT	Gas	237,000	9,800	678	6.80	10.70	0.001	0.03 [11]	117
Advanced Nuclear (AN)	Uranium	2,234,000	N/A	5,945	100.28	2.30	0	0	0
Biomass (BBFB)	Biomass	50,000	13,500	4,985	110.00	4.20	0	0.08	195 [13]
Onshore Wind (WN)	Wind	100,000	N/A	1,877	39.70	0	0	0	0
Photovoltaic - Fixed	Solar	20,000	N/A	2,671	23.40	0	0	0	0
Photovoltaic – Tracking	Solar	20,000		2,644	23.90	0	0	0	0
Photovoltaic – Tracking	Solar	150,000	N/A	2,534	21.80	0	0	0	0
Reciprocating Internal Combustion Engine (RICE)	Gas	85,000	7,900	1,342	6.90	5.85	0.001	0.07	117
Battery Storage (BES)		50,000	13,500	4,985	100.00	0	N/A	N/A	N/A

Footnotes are listed on the next page.

(1) Capacity is net of auxiliary loads.

(2) Heat Rate is on a HHV basis for British thermal units per kilowatt-hour ("Btu/kWh").

(3) Capital Cost excludes financing-related costs (e.g., fees, interest during construction).

(4) FOM expenses exclude owner's costs (e.g., insurance, property taxes, and asset management fees).

(5) VOM expenses include major maintenance but not fuel-related expenses.

(6) Million Btu ("MMBtu").

(7) Based on high sulfur bituminous fuel.

(8)

(9) Assuming 30 percent capture.

(10) Assuming 3 percent sulfur coal at 12,000 British thermal units per pound ("Btu/lb") and a 99.5 percent sulfur removal rate.

(11) Assuming 9 parts per million volume dry ("ppmvd") corrected to 15 percent O_2; simple-cycle E-Class or F-Class engine.

(12) Assuming 2 ppmvd corrected to 15 percent O_2 for F-Class engine.

(13) Does not account for the life-cycle fate of CO_2 after emission from power generation unit.

(14)

(15)

3. ULTRA SUPERCRITICAL COAL (USC)

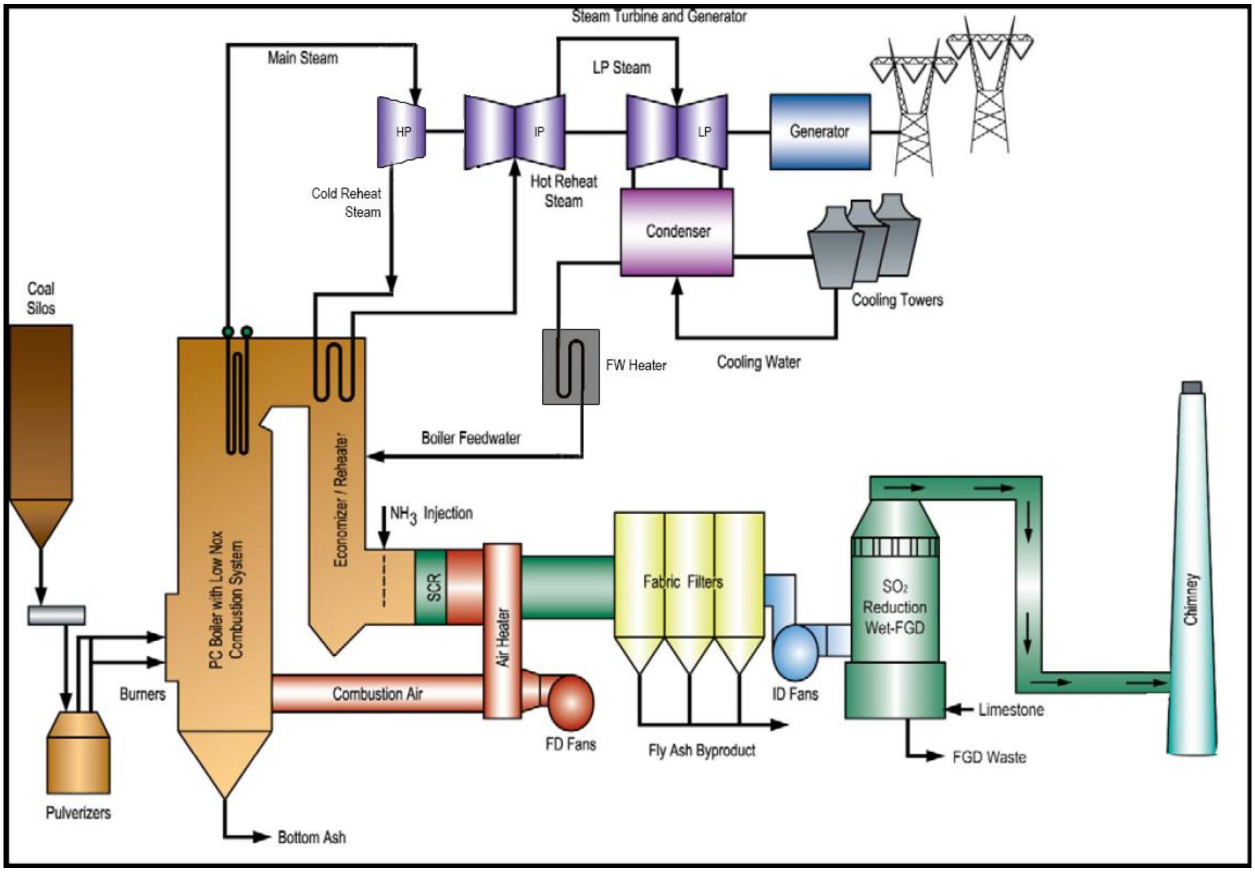
3.1 MECHANICAL EQUIPMENT AND SYSTEMS

The following describes the Ultra Supercritical Coal ("USC") Facility, which is a nominal 650 MW net output coal-fired supercritical steam-electric generating unit built in a Greenfield location. This unit employs a supercritical Rankine power cycle in which coal is burned to produce steam in a boiler, which is expanded through a ST to produce electric power. The steam is then condensed to water and pumped back to the boiler to be converted to steam once again to complete the cycle.

The unit will operate at steam conditions of approximately 3,800 pounds per square inch-absolute ("psia") and 1,112 degrees Fahrenheit ("ºF") at the ST inlet. The superheated steam produced in the boiler is supplied to the ST, which drives an electric generator. After leaving the high-pressure ("HP") ST, the steam is reheated and fed to the intermediate-pressure ("IP") ST. In the low-pressure ("LP") ST, the steam admitted directly from the IP ST expands to condenser pressure and is condensed in the condenser. Cooling tower water is used for the condensing process. Condensate collected in the condenser hotwell is discharged by the main condensate pumps and returned to the deaerator/feedwater storage tank via the LP feedwater heaters. The feedwater pumps discharge feedwater from the feedwater storage tank to the boiler via the HP feedwater heaters. In the boiler, the supercritical fluid is heated for return to the ST.

The combustion air and flue gas systems are designed for balanced draft and start with the ambient air drawn in by the forced draft fans. This air is heated by steam preheaters and the regenerative air heaters. Some of the air is passed through the primary air fans for use in drying and conveying the pulverized coal to the boiler. The air and coal combust in the boiler furnace and the flue gas passes through the furnace and back passes of the boiler, giving up heat to the supercritical fluid in the boiler tubes. The flue gas exiting the boiler economizer enters the SCR equipment for NO_X reduction (low NO_X burners are assumed for the boiler) and into the regenerative air heaters where it transfers heat to the incoming air. From the regenerative air heaters, the flue gas is treated with an injection of hydrated lime, enters a pulse-jet fabric filter (baghouse) for the collection of particulate material, and then flows to the induced draft fans. From the fans, gas enters the Wet Flue Gas Desulfurization ("WFGD") absorber. From the absorber, the flue gas discharges into the stack. Figure 3-1 presents the USC process flow diagram.

FIGURE 3-1 – ULTRA SUPERCRITICAL COAL DESIGN CONFIGURATION



3.2 ELECTRICAL AND CONTROL SYSTEMS

The USC Facility has one ST electric generator. The generator is a 60 Hertz ("Hz") machine rated at approximately 720 mega-volt-amperes ("MVA") with an output voltage of 24 kilovolts ("kV"). The ST electric generator is directly connected to generator step-up transformer ("GSU"), which in turn is connected between two circuit breakers in the high-voltage bus in the USC 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 USC Facility is controlled using a DCS. The DCS provides centralized control of the plant by integrating the control systems provided with the boiler, ST and associated electric generator and the control of BOP systems and equipment.

3.3 OFF-SITE REQUIREMENTS

Coal is delivered to the facility via rail, truck or barge. Water for all processes at the USC Facility can be obtained from one of a variety of sources; however, water is typically sourced from an adjacent river, when possible. The USC Facility uses a water treatment system and a high-efficiency reverse osmosis system to reduce the dissolved solids from the cooling water and to provide distilled water for boiler makeup. Wastewater is sent to an adjacent river or other approved alternative. Further, the electrical interconnection from the USC on-site switchyard is effectuated by a connection to an adjacent utility substation, assumed to be no more than 1 mile from the USC Facility.

3.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the USC Facility with a nominal capacity of 650 MW is \$3,636/kilowatt ("kW"). Table 3-1 summarizes the Cost Estimate categories for the USC Facility.

TABLE 3-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR USC

Technology:	**USC**	
Nominal Capacity (ISO):	**650,000 kW**	
Nominal Heat Rate (ISO):	**8,800 Btu/kWh-HHV**	
Capital Cost Category		**(000s) (January 1, 2016\$)**
Civil Structural Material and Installation		**247,250**
Mechanical Equipment Supply and Installation		**991,831**
Electrical / I&C Supply and Installation		**141,900**
Project Indirects [(1)]		**393,350**
EPC Cost before Contingency and Fee		**1,774,331**
Fee and Contingency		**195,176**
Total Project EPC		**1,969,507**
Owner's Costs (excluding project finance)		**393,901**
Total Project Cost (excluding finance)		**2,363,408**
Total Project EPC	**\$ / kW**	**3,030**
Owner Costs 20% (excluding project finance)	**\$ / kW**	**606**
Total Project Cost (excluding project finance)	**\$ / kW**	**3,636**

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: outdoor installation considerations, seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, owner cost differences, and the increase in overheads associated with these six adjustment criteria.

Outdoor installation locations are considered in geographic areas where enclosed structures for the boilers would not be required due to the low probability of freezing. The locations that were included in outdoor installation are Alabama, Arizona, Arkansas, Florida, Georgia, Louisiana, Mississippi, New Mexico, and South Carolina.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the USC Facility include Fairbanks, Alaska; Great Falls, Montana; Albuquerque, New Mexico; and Cheyenne, Wyoming.

Labor wage and productivity differences were handled as discussed in Section 2.6.1, taking into consideration the amount of labor we estimated for the USC Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Illinois, Indiana, Maine, Maryland, Massachusetts, Minnesota, New York, Ohio, Oregon, Pennsylvania, Virginia, Washington, Wisconsin, and Wyoming.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 3-2 in the Appendix shows the USC capital cost variations for alternative U.S. plant locations, including the difference between the given location and the average location specified for the Cost Estimate.

3.5 O&M ESTIMATE

In addition to the general O&M items discussed in Section 2.6.2, the USC Facility includes the major maintenance for boiler, ST, associated generator, BOP, and emissions reduction catalysts. These major maintenance expenses are included with the VOM expense for this technology and are given on an average basis across the megawatt-hours ("MWh") incurred. Typically, significant overhauls on an USC Facility occur no less frequently than six or seven years. Table 3-3 presents the FOM and VOM expenses for the USC Facility. Table 3-3 presents the O&M expenses for the USC Facility.

TABLE 3-3 – O&M EXPENSES FOR USC (650,000 KW)

Technology:	USC
Fixed O&M Expense	$42.10/kW-year
Variable O&M Expense	$4.60/MWh

3.6 ENVIRONMENTAL COMPLIANCE INFORMATION

As mentioned in Section 3.1, the USC Facility is assumed to include low NO_X combustion burners in the boiler, SCR, and a flue gas desulfurization ("FGD") to further control the emissions of NO_X and SO_2, respectively. Table 3-4 presents the environmental emissions for the USC Facility.

TABLE 3-4 – ENVIRONMENTAL EMISSIONS FOR USC

Technology:	USC
NO_X	0.06 lb/ MMBtu
SO_2	0.1 lb/MMBtu
CO_2	206 lb/MMBtu [(1)]

(1) Variable O&M costs shown in this report do not account for state or regional carbon trading programs

4. ULTRA SUPERCRITICAL COAL WITH CCS (USC/CCS)

4.1 MECHANICAL EQUIPMENT AND SYSTEMS

The plant configuration for the USC with CCS Facility ("USC/CCS") is the same as the USC case with two exceptions: (1) an amine scrubbing system, utilizing monoethanolamine ("MEA") as a solvent, to capture CO_2 from the flue gas, and (2) the scaling of the boiler to a larger size, as described below. The assumed carbon capture was set at 30 percent. The captured CO_2 is compressed to approximately 2,000 psia for injection into a pipeline at the plant fence line as a supercritical fluid. The net output of the USC/CCS Facility case is 650 MW, and since the CCS system requires about 10 percent of the given facility's gross capacity in auxiliary load, the USC/CCS Facility assumes that the boiler is increased by approximately 12 percent (i.e., it is approximately 110 percent the size of the boiler in the USC Facility), which provides the necessary steam to facilitate the capture process and to run a steam-driven compressor for compressing the CO_2 for sequestration. Leidos used 800 MW gross output to obtain the 650 MW net output. Figure 4-1 presents a diagram of the USC and Figure 4-2 presents a diagram of the USC/CCS Facility.

FIGURE 4-1 – USC FACILITY DIAGRAM

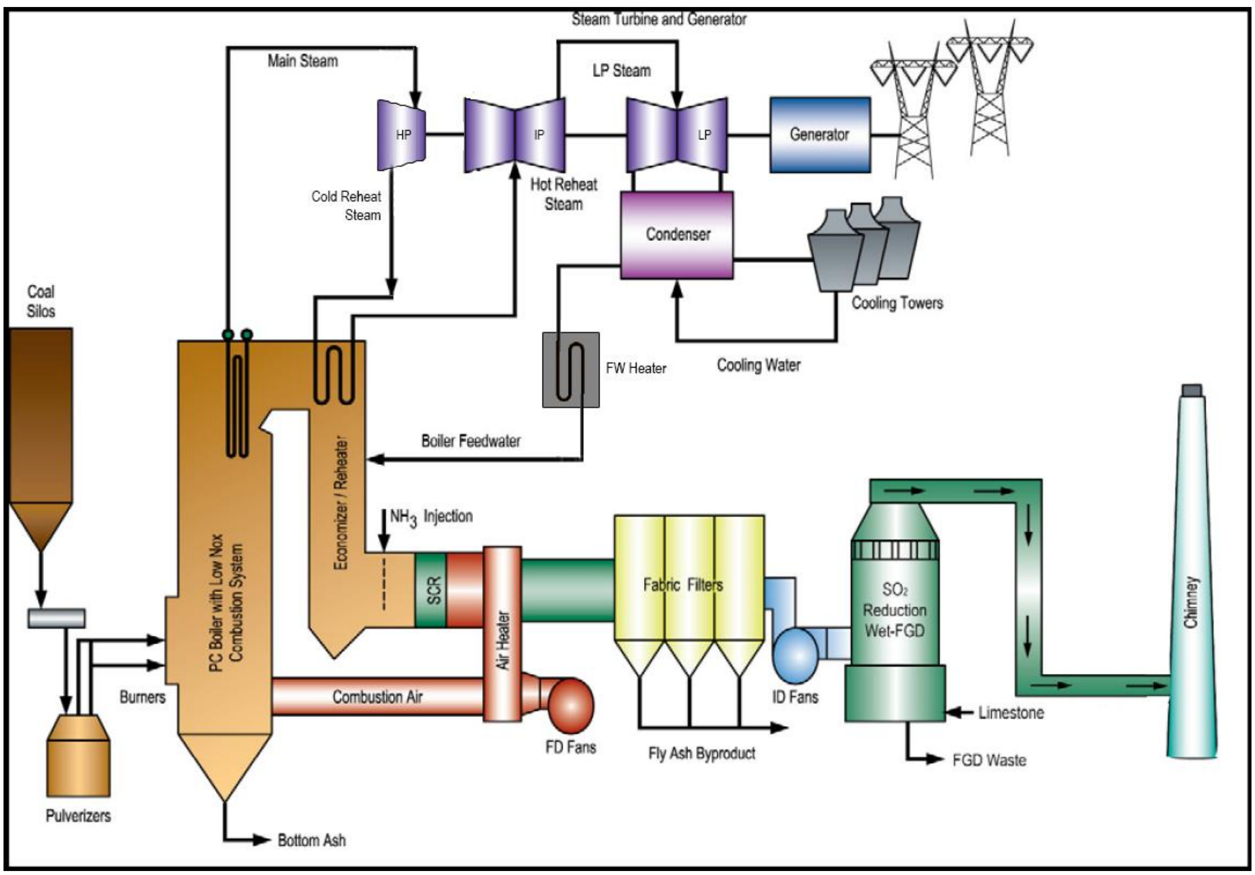
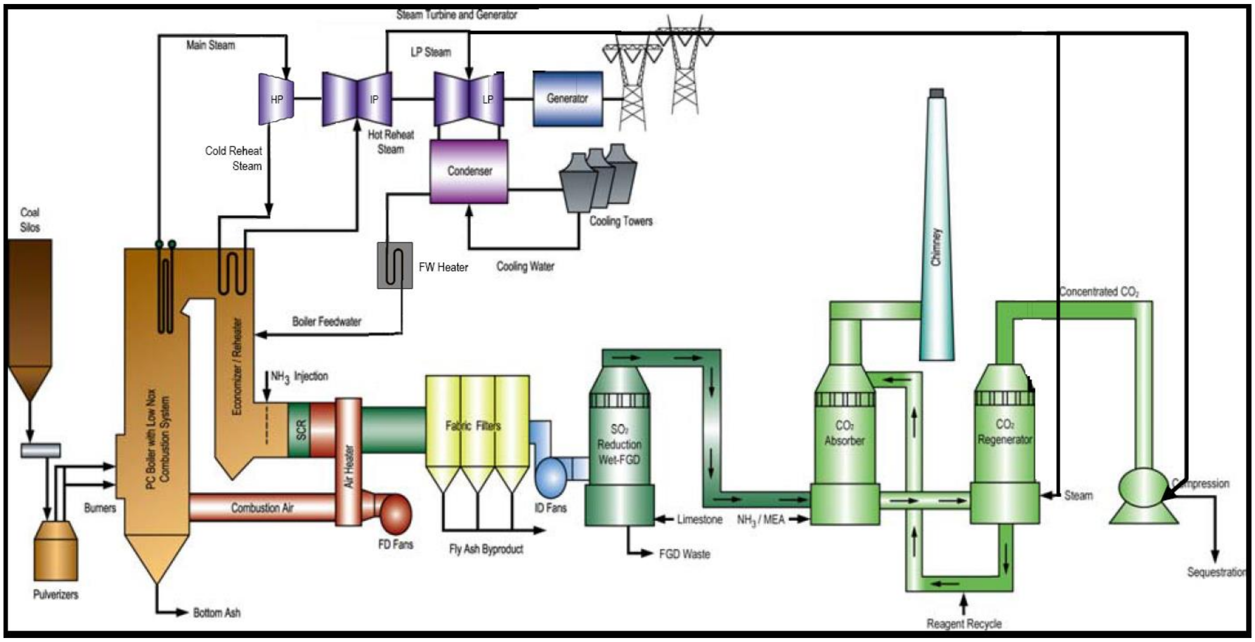


FIGURE 4-2 – USC/CCS FACILITY DIAGRAM



4.2 ELECTRICAL AND CONTROL SYSTEMS

The electrical and control systems for the USC/CCS Facility are materially similar to the USC Facility.

4.3 OFF-SITE REQUIREMENTS

The off-site requirements for the USC/CCS Facility are materially similar to the USC Facility, except that the CO_2 needs sequestering in one of the following geologic formations: (1) exhausted gas storage location, (2) unminable coal seam, (3) enhanced oil recovery, or (4) saline aquifer. To the extent that a sequestration site is not near the given facility being analyzed, transportation for a viable sequestration site has the potential to materially affect the capital cost estimates discussed below.

4.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the USC/CCS Facility with a nominal capacity of 650 MW is $5,084/kW. The capital cost estimate was based on the USC Facility (without CCS) and the base Cost Estimate was increased to include the expected costs of CCS at 30 percent. Since there are limited full-scale pulverized coal facilities operating with CCS in the world, our estimate is based on industry research. Our team tested the veracity of this research against assumptions for implementing the additional equipment necessary to effectuate CCS on an advanced coal facility. Table 4-1 summarizes the Cost Estimate categories for the USC/CCS Facility.

TABLE 4-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR USC/CCS

Technology:		**USC/CCS**
Nominal Capacity (ISO):		**650,000 kW**
Nominal Heat Rate (ISO):		**9,750 Btu/kWh-HHV**
Capital Cost Category		**(000s) (January 1, 2016$)**
Civil Structural Material and Installation		**299,790**
Mechanical Equipment Supply and Installation		**1,414,117**
Electrical / I&C Supply and Installation		**215,293**
Project Indirects [(1)]		**549,580**
EPC Cost before Contingency and Fee		**2,478,780**
Fee and Contingency		**275,176**
Total Project EPC [(2)]		**2,753,956**
Owner Costs (excluding project finance) [(2)]		**550,791**
Total Project Cost (excluding finance)		**3,304,747**
Total Project EPC	**/ kW**	**4,237**
Owner Costs 20% (excluding project finance)	**/ kW**	**847**
Total Project Cost (excluding project finance)	**/ kW**	**5,084**

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.
(2) EPC costs include Sequestration to Plant Fence, Owners cost bears all pipeline costs required past the demarcation point.

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: outdoor installation considerations, seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, owner cost differences, and the increase in overheads associated with these six adjustment criteria. The methodology used for the USC/CCS Facility is the same as that discussed in Section 3.4 for the USC Facility (without CCS).

Table 4-2 in the Appendix shows the USC capital cost variations for alternative U.S. plant locations, including the difference between the given location and the average location specified for the Cost Estimate.

4.5 O&M ESTIMATE

The O&M items for the USC/CCS Facility are the same as those discussed in Section 3.5 for the USC Facility (without CCS), except that adders are included to both FOM and VOM to accommodate the expenses associated with compressor maintenance, sequestration maintenance, and the associated additional labor required to manage, operate, and maintain the additional equipment. Table 4-3 presents the FOM and VOM expenses for the USC/CCS Facility.

TABLE 4-3 – O&M EXPENSES FOR USC/CCS (650,000 KW)

Technology:	USC/CCS
Fixed O&M Expense	\$70.00/kW-year
Variable O&M Expense	\$7.10/MWh

4.6 ENVIRONMENTAL COMPLIANCE INFORMATION

In addition to the equipment utilized for environmental compliance in the USC Facility, the USC/CCS Facility includes an amine scrubber that is intended to remove 30 percent of the CO_2 produced in the combustion process, wherein the captured CO_2 is later compressed to HP and sequestered, as discussed above. Increased amount of SO_2 scrubbing is required to avoid contamination of the MEA. Such costs for increased scrubbing are included. Table 4-4 presents the environmental emissions for the USC/CCS Facility.

TABLE 4-4 – ENVIRONMENTAL EMISSIONS FOR USC/CCS

Technology:	USC/CCS
NO_X	0.06 lb/MMBtu
SO_2	0.02 lb/MMBtu
CO_2	144 lb/MMBtu

5. PULVERIZED COAL BROWNFIELD CONVERSION TO NATURAL GAS (CTNG)

5.1 MECHANICAL EQUIPMENT AND SYSTEMS

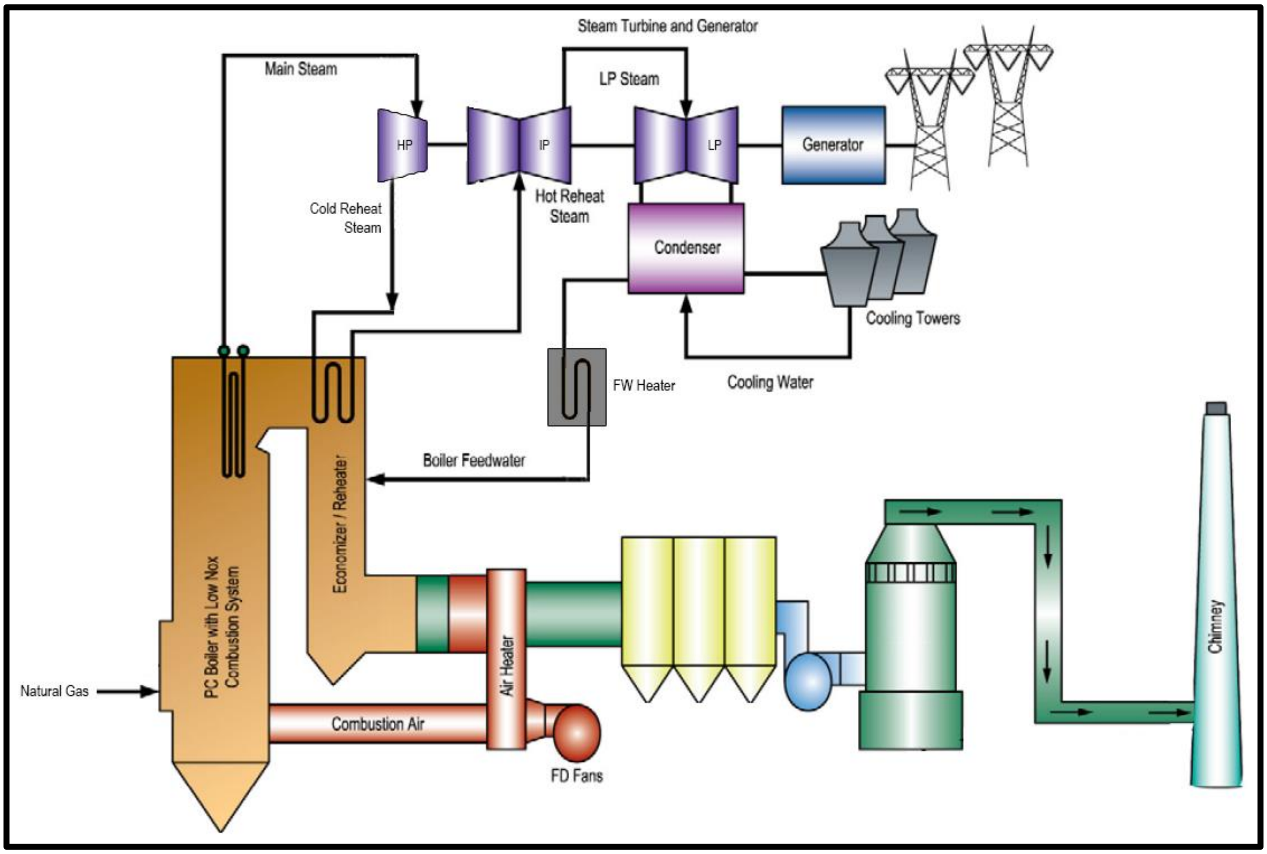
The Conversion from Coal to Natural Gas Facility ("CTNG") is based on an existing 300 MWe Coal plant and converting to a Natural Gas fired plant. The total design capacity is 300 MWe.

The following describes the Pulverized Coal Brownfield Conversion to Natural Gas ("CTNG") Facility, which is a nominal 300 MW net output coal-fired subcritical steam-electric generating unit built in a Brownfield location. This unit employs a subcritical Rankine power cycle in which natural gas burning capability is added, replacing coal, to produce steam in a boiler which is expanded through a ST to produce electric power. The steam is then condensed to water and pumped back to the boiler to be converted to steam once again to complete the cycle.

The unit will operate at steam conditions of approximately 2,600 pounds per square inch-absolute ("psia") and 1,005 degrees Fahrenheit ("ºF") at the ST inlet. The superheated steam produced in the boiler is supplied to the ST, which drives an electric generator. After leaving the high-pressure ("HP") ST, the steam is reheated and fed to the intermediate-pressure ("IP") ST. In the low-pressure ("LP") ST, the steam admitted directly from the IP ST expands to condenser pressure and is condensed in the condenser. Cooling tower water is used for the condensing process. Condensate collected in the condenser hotwell is discharged by the main condensate pumps and returned to the deaerator/feedwater storage tank via the LP feedwater heaters. The feedwater pumps discharge feedwater from the feedwater storage tank to the boiler via the HP feedwater heaters. In the boiler, the subcritical fluid is heated for return to the ST.

The combustion air and flue gas systems are designed for balanced draft and starts with the ambient air drawn in by the forced draft fans. This air is heated by steam preheaters and the regenerative air heaters. The air and natural gas combust in the boiler furnace and the flue gas passes through the furnace and back passes of the boiler, giving up heat to the subcritical fluid in the boiler tubes. The flue gas exiting the boiler economizer enters the regenerative air heaters where it transfers heat to the incoming air. From the regenerative air heaters, the flue gas then flows to the induced draft fans and then into the stack. Figure 3-1 presents the USC process flow diagram.

FIGURE 5-1 – CTNG DESIGN CONFIGURATION



5.2 ELECTRICAL AND CONTROL SYSTEMS

The electrical and control systems for the CTNG Facility are materially similar to the USC Facility with a smaller output capacity.

5.3 OFF-SITE REQUIREMENTS

The off-site requirements for the CTNG Facility are materially similar to the CCNG Facility, except that the Facility will use lower pressure natural gas than that required for the combustion turbines.

5.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the CTNG with a nominal capacity of 300 MW is $226/kW. Table 5-1 summarizes the Cost Estimate categories for the CTNG Facility.

TABLE 5-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR CTNG

Technology:	**CTNG**	
Nominal Capacity (ISO):	**300,000 kW**	
Nominal Heat Rate (ISO):	**10,300 Btu/kWh-HHV [3]**	
Capital Cost Category		**(000s) (January 1, 2016$)**
Civil Structural Material and Installation		**7,820**
Mechanical Equipment Supply and Installation		**26,300**
Electrical / I&C Supply and Installation		**6,370**
Project Indirects [1]		**12,310**
EPC Cost before Contingency and Fee [2]		**52,800**
Fee and Contingency		**6,154**
Total Project EPC		**58,954**
Owner Costs (excluding project finance)		**8,843**
Total Project Cost (excluding finance)		**67,797**
Total Project EPC	**/ kW**	**197**
Owner Costs 15% (excluding project finance)	**/ kW**	**29**
Total Project Cost (excluding project finance)	**/ kW**	**226**

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.
(2) Assumes demolition and mitigation will not be required
(3) Assumes Subcritical for conversion

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, and owner cost differences and the increase in overheads associated with these five adjustments.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the Facility include Fairbanks, Alaska; Great Falls, Montana; Albuquerque, New Mexico; Cheyenne, Wyoming; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.6.1, taking into consideration the amount of labor we estimated for the CTNG Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Illinois, Indiana, Iowa, Kansas, Maine, Maryland, Massachusetts, Michigan, Minnesota, Montana, Nebraska, New York, North Dakota, Ohio, Pennsylvania, South Dakota, West Virginia, Wisconsin, and Wyoming.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 5-2 in the Appendix shows the CTNG capital cost variations for alternative U.S. plant locations, including the difference between the given location and the average location specified for the Cost Estimate.

5.5 O&M ESTIMATE

The O&M for a natural gas fired facility is much lower than a pulverized coal facility since coal conveying and pulverizing equipment is not used. Additionally, the emissions controls equipment that is required for pulverized coal firing is not needed for natural gas firing.

TABLE 5-3 – O&M EXPENSES FOR CTNG

Technology:	CTNG
Fixed O&M Expense	$22.00/kW-year
Variable O&M Expense	$1.30/MWh

5.6 ENVIRONMENTAL COMPLIANCE INFORMATION

Table 5-4 presents environmental emissions for the CTNG Facility. Since the conversion of coal to gas fuel would inherently reduce emissions, the installation of an SCR with gas fuel was not assumed. Low NO_X burners on the gas-fired boiler are assumed.

TABLE 5-4 – ENVIRONMENTAL EMISSIONS FOR CTNG

Technology:	CTNG
NO_X	0.11 lb/MMBtu
SO_2	0.001 lb/MMBtu
CO_2	117 lb/MMBtu

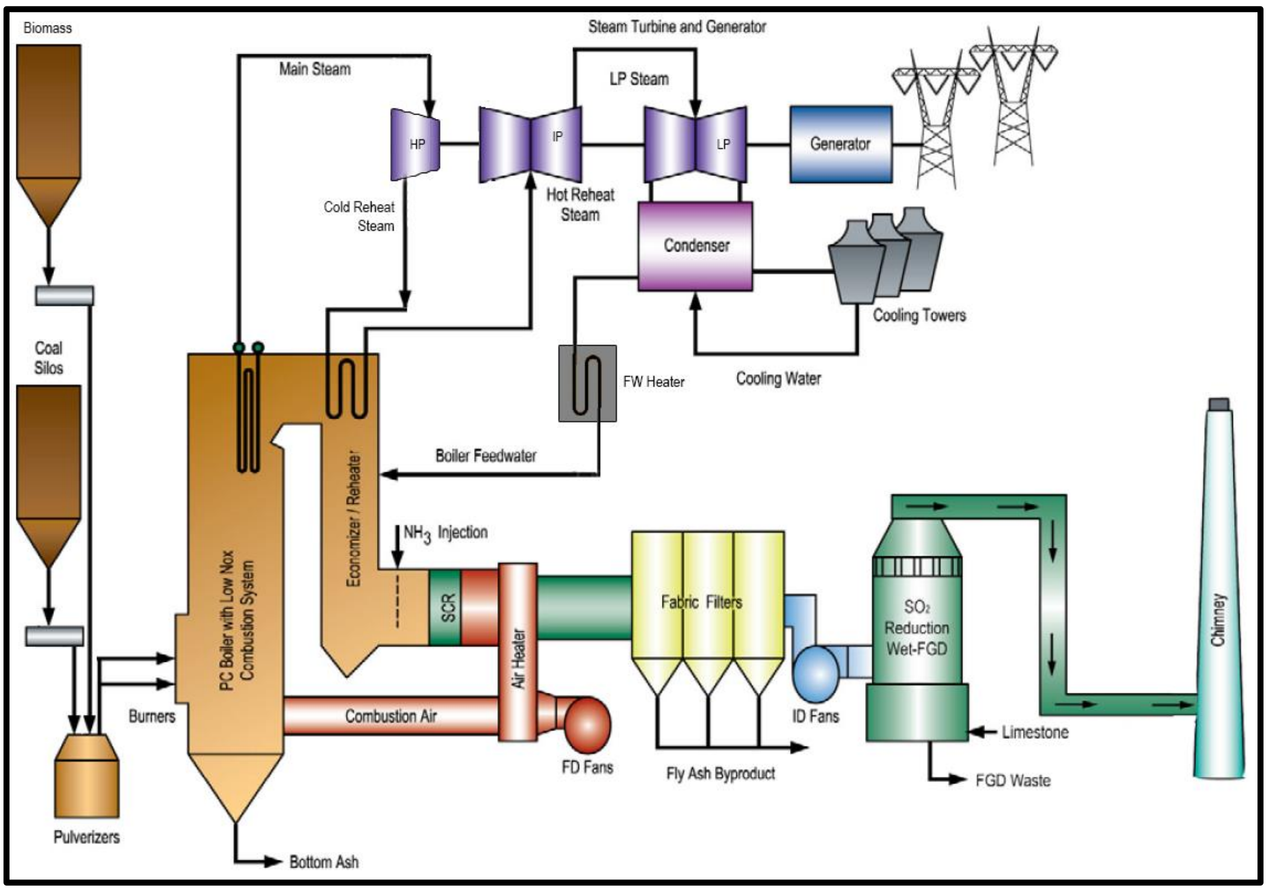
6. PULVERIZED COAL GREENFIELD WITH 10-15% BIOMASS (GCBC)

6.1 MECHANICAL EQUIPMENT AND SYSTEMS

The Coal Co-Firing with 10-15% Biomass Facility ("GCBC") is based on a total design capacity of 300 MWe.

The plant configuration for the Pulverized coal greenfield with 10-15% biomass ("GCBC") is the same as the USC case with two exceptions: (1) the size of the plant is 300 MW net capacity, and (2) the modifications to feed and burn biomass are made to the facility. These modifications would include conveyors, feeders, storage capability, and sootblowers. This biomass fuel for this facility is assumed to be a dry, pelletized fuel which can be mixed directly into the coal pulverizers.

FIGURE 6-1 – GCBC DESIGN CONFIGURATION



6.2 ELECTRICAL AND CONTROL SYSTEMS

The electrical and control systems for the GCBC Facility are materially similar to the USC Facility with a smaller output capacity.

6.3 OFF-SITE REQUIREMENTS

The off-site requirements for the GCBC Facility are materially similar to the USC Facility, except that pelletized biomass will need to be prepared and delivered to the site for storage.

6.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the GCBC Facility with a nominal capacity of 300 MWe is \$4,620/kW. Table 6-1 summarizes the Cost Estimate categories for the GCBC Facility.

TABLE 6-1 – LOCATION-BASED COSTS FOR GCBC

Technology:		**GCBC**
Nominal Capacity (ISO):		**300,000 kW**
Nominal Heat Rate (ISO):		**8,960 Btu/kWh-HHV**
Capital Cost Category		**(000s) (January 1, 2016$)**
Civil Structural Material and Installation		**115,992**
Mechanical Equipment Supply and Installation		**583,500**
Electrical / I&C Supply and Installation		**106,179**
Project Indirects (1)		**228,694**
EPC Cost before Contingency and Fee		**1,034,365**
Fee and Contingency		**120,559**
Total Project EPC		**1,154,924**
Owner Costs (excluding project finance)		**230,985**
Total Project Cost (excluding finance)		**1,385,909**
Total Project EPC	**/ kW**	**3,850**
Owner Costs 20% (excluding project finance)	**/ kW**	**770**
Total Project Cost (excluding project finance)	**/ kW**	**4,620**

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, and owner cost differences and the increase in overheads associated with these five adjustments.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the Coal Biomass Co-Firing Facility include, Fairbanks, Alaska; Great Falls, Montana; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.6.1, taking into consideration the amount of labor we estimated for the GCBC Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, Minnesota, New Jersey, New York, Ohio, Oregon, Rhode Island, Virginia, Washington, and Wisconsin.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 6-2 in the Appendix presents the GCBC Facility capital cost variations for alternative U.S. plant locations.

6.5 O&M ESTIMATE

The O&M expenses for the GCBC facility are materially similar to the pulverized coal fired facility.

TABLE 6-3 – O&M EXPENSES FOR GCBC

Technology:	GCBC
Fixed O&M Expense	$50.90/kW-year
Variable O&M Expense	$5.00/MWh

6.6 ENVIRONMENTAL COMPLIANCE INFORMATION

Since wind utilizes a renewable fuel and no additional fuel is combusted to make power from an Greenfield Coal Biomass Co-Firing Facility, air emissions are not created. Table 6-4 presents environmental emissions for the GCBC Facility.

TABLE 6-4 – ENVIRONMENTAL EMISSIONS FOR GCBC

Technology:	GCBC
NO_X	0.06 lb/MMBtu
SO_2	0.1 lb/MMBtu
CO_2	204 lb/MMBtu

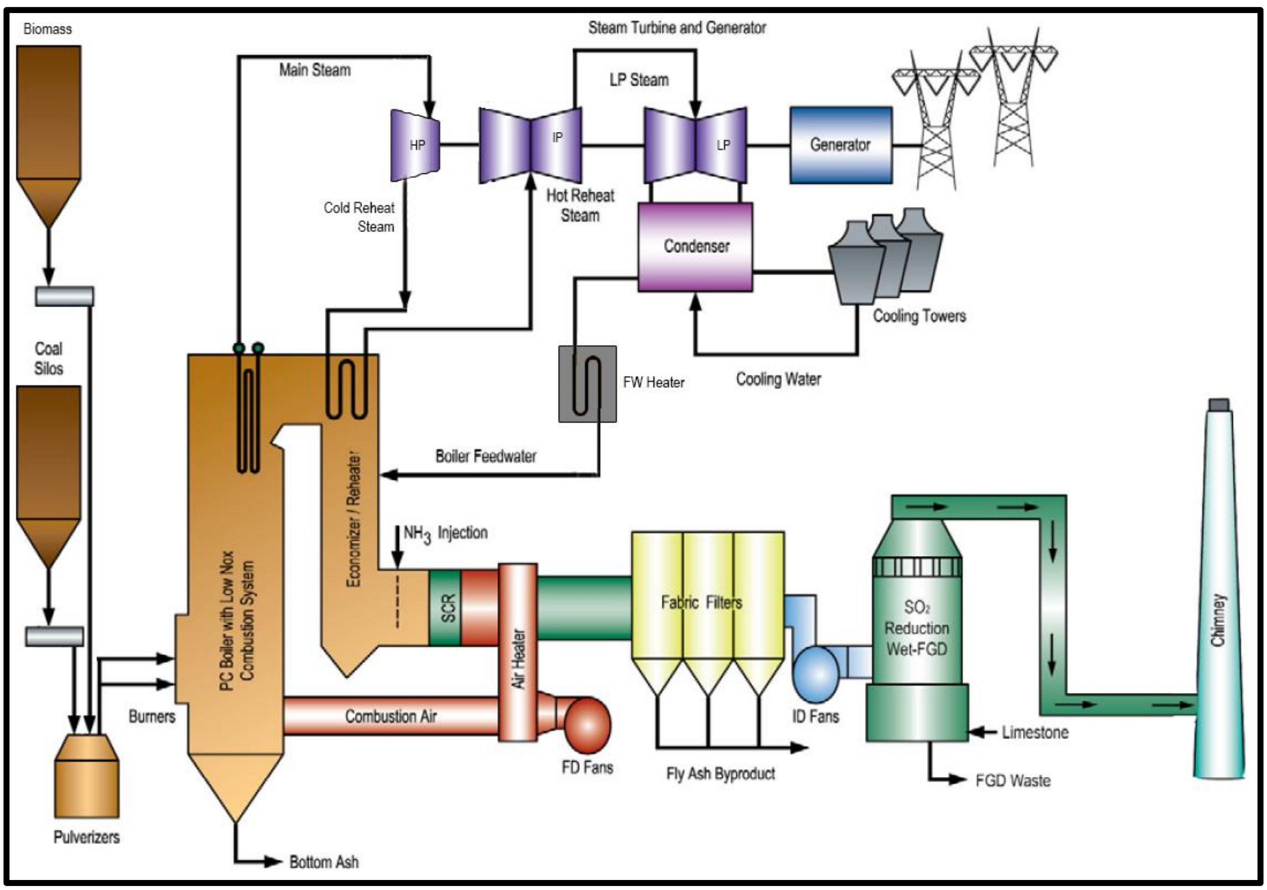
7. PULVERIZED COAL BROWNFIELD CONVERSION TO COAL WITH 10% BIOMASS – 30 MW CO-FIRING (CTCB)

7.1 MECHANICAL EQUIPMENT AND SYSTEMS

The Coal Brownfield Conversion to 10% Biomass Co-Firing Facility ("CTCB") is the addition of 30 MWe to an existing 300 MWe Coal plant; the overall net MWe output will remain 300 MWe.

The plant configuration for the Pulverized coal brownfield with 10% biomass ("GCBC") is the same as the pulverized coal brownfield conversion to natural gas ("CTNG") case with the exception that pulverized coal firing will not be discontinued. The size of the plant is 300 MW net capacity and the modifications to feed and burn biomass are made to the facility. These modifications would include conveyors, feeders, storage capability, and sootblowers. This biomass fuel for this facility is assumed to be a dry, pelletized fuel which can be mixed directly into the coal pulverizers.

FIGURE 7-1 – CTCB DESIGN CONFIGURATION



7.2 ELECTRICAL AND CONTROL SYSTEMS

The electrical and control systems for the CTNG Facility are materially similar to the USC Facility with a smaller output capacity.

7.3 OFF-SITE REQUIREMENTS

The off-site requirements for the CTCB Facility are materially similar to the USC Facility, except that pelletized biomass will need to be prepared and delivered to the site for storage.

7.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the CTCB Facility with a nominal capacity of 300 MW is $537/kW. Table 7-1 summarizes the Cost Estimate categories for the CTCB Facility.

TABLE 7-1 – LOCATION-BASED COSTS FOR CTCB

Technology:		**CTCB**
Nominal Capacity (ISO):		**300,000 kW**
Nominal Heat Rate (ISO):		**10,360 Btu/kWh-HHV**
Capital Cost Category		**(000s) (January 1, 2016$)**
Civil Structural Material and Installation		**11,688**
Mechanical Equipment Supply and Installation		**78,338**
Electrical / I&C Supply and Installation		**4,801**
Project Indirects (1)		**21,846**
EPC Cost before Contingency and Fee		**116,674**
Fee and Contingency		**17,501**
Total Project EPC		**134,175**
Owner Costs (excluding project finance)		**26,835**
Total Project Cost (excluding finance)		**161,010**
Total Project EPC	**/ kW**	**447**
Owner Costs 20% (excluding project finance)	**/ kW**	**89**
Total Project Cost (excluding project finance)	**/ kW**	**537**

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, and owner cost differences and the increase in overheads associated with these five adjustments.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3, and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the CTCB Facility include Fairbanks, Alaska; Great Falls, Montana; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.6.1, taking into consideration the amount of labor we estimated for the CTCB Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, Minnesota, Oregon, Virginia, and Washington.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 7-2 in the Appendix presents the CTCB Facility capital cost variations for alternative U.S. plant locations.

7.5 O&M ESTIMATE

The O&M expenses for a CTCB facility are materially similar to a pulverized coal facility.

TABLE 7-3 – O&M EXPENSES FOR CTCB

Technology:	CTCB
Fixed O&M Expense	$50.90/kW-year
Variable O&M Expense	$5.00/MWh

7.6 ENVIRONMENTAL COMPLIANCE INFORMATION

Table 7-4 presents environmental emissions for the CTCB Facility.

TABLE 7-4 – ENVIRONMENTAL EMISSIONS FOR CTCB

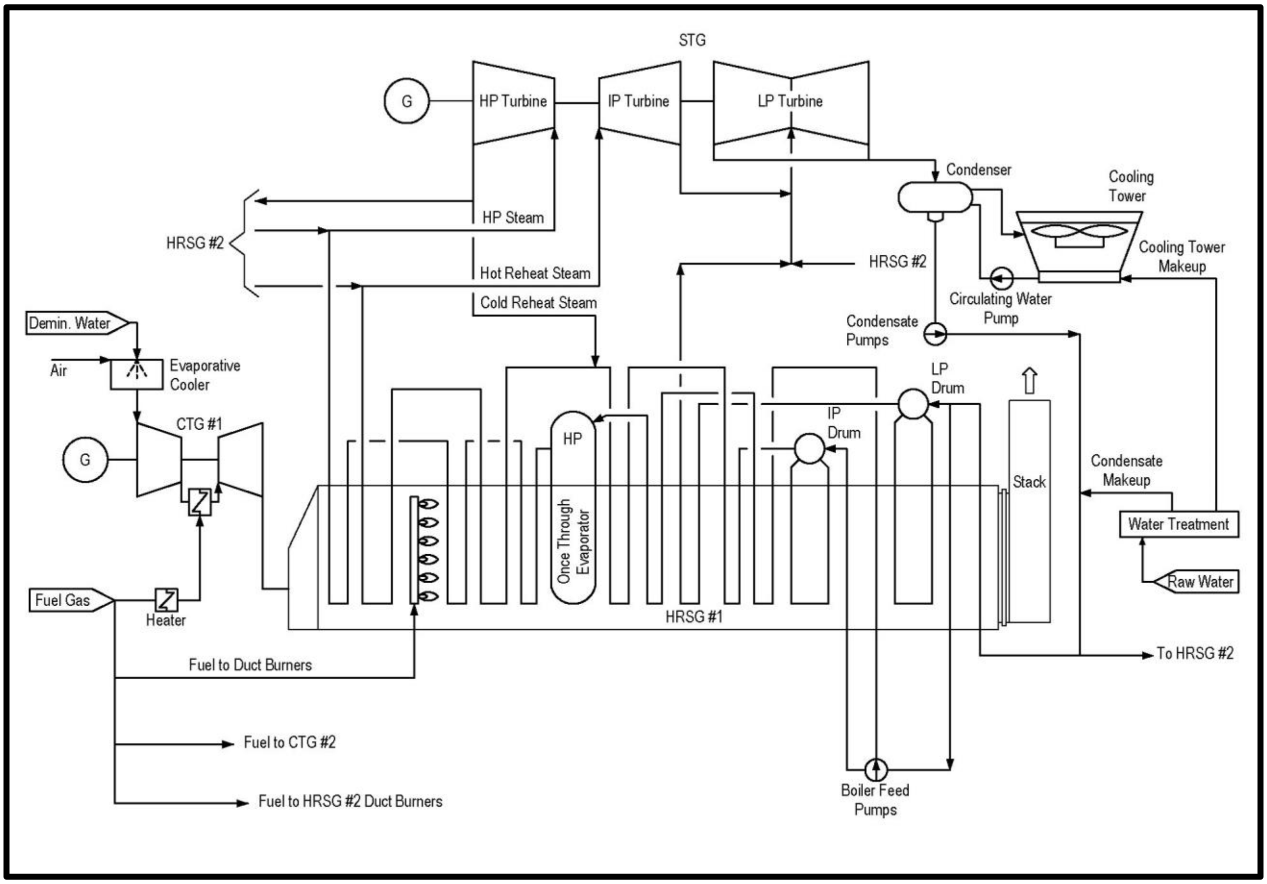
Technology:	CTCB
NO_X	0.06 lb/MMBtu
SO_2	0.1 lb/MMBtu
CO_2	204 lb/MMBtu

8. CONVENTIONAL NATURAL GAS COMBINED CYCLE (NGCC)

8.1 MECHANICAL EQUIPMENT AND SYSTEMS

The Conventional Natural Gas Combined Cycle ("NGCC") produces 702 MW of net electricity. The facility utilizes two natural gas-fueled F5-class CTs and associated electric generators, two supplemental-fired heat recovery steam generators ("HRSG"), and one condensing ST and associated electric generator operating in combined-cycle mode. Each CT is designed to produce nominally 242 MW and includes a dry-low NO_X ("DLN") combustion system and a hydrogen-cooled electric generator. The two triple-pressure HRSGs include integrated deaerators, SCRs, oxidation catalyst for the control of carbon monoxide ("CO"), and supplemental duct firing with associated combustion management. The ST is a single-reheat condensing ST designed for variable pressure operation, designed to produce an additional 246 MW. The ST exhaust is cooled in a closed-loop condenser system with a mechanical draft cooling tower. The CTs are equipped with inlet evaporative coolers to reduce the temperature of the turbine inlet air to increase summer output. The Conventional NGCC plant also includes a raw water treatment system consisting of clarifiers and filters and a turbine hall, in which the CTs, ST, and HRSGs are enclosed to avoid freezing during periods of cold ambient temperatures. Figure 8-1 presents the Conventional NGCC process flow diagram.

FIGURE 8-1 – CONVENTIONAL NGCC DESIGN CONFIGURATION



8.2 ELECTRICAL AND CONTROL SYSTEMS

The Conventional NGCC has two CT electric generators and one ST electric generator. The generators for the CTs are 60 Hz and rated at approximately 215 MVA with an output voltage of 18 kV. The ST electric generator is 60 Hz and rated at approximately 310 MVA with an output voltage of 18 kV. Each CT and ST electric generator is connected to a high-voltage bus in the Conventional NGCC via a dedicated generator circuit breaker, generator GSU, and a disconnect switch. The GSUs increase the voltage from the electric generators from 18 kV to interconnected high voltage.

The Conventional NGCC is controlled using a DCS. The DCS provides centralized control of the facility by integrating the control systems provided with each individual CT and associated electric generator, ST and associated electric generator, and the control of BOP systems and equipment.

8.3 OFF-SITE REQUIREMENTS

Natural gas is delivered to the facility through a lateral connected to the local natural gas trunk line. Water for all processes at the Conventional NGCC Facility is obtained from one of several available water sources (e.g., municipal water supply). The Conventional NGCC Facility uses a water treatment system and a high-efficiency reverse osmosis system to reduce the dissolved solids from the cooling water and to provide distilled water for HRSG makeup. Wastewater is sent to a municipal wastewater system. Further, the electrical interconnection from the Conventional NGCC on-site switchyard is effectuated by a connection to an adjacent utility substation.

8.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the Conventional NGCC Facility with a nominal capacity of 702 MW is $978/kW. Table 8-1 summarizes the Cost Estimate categories for the Conventional NGCC Facility.

TABLE 8-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR CONVENTIONAL NGCC

Technology:	**Conventional NGCC**	
Nominal Capacity (ISO):	**702,000 kW**	
Nominal Heat Rate (ISO):	**6,600 Btu/kWh-HHV**	
Capital Cost Category		**(000s) (January 1, 2016$)**
Civil Structural Material and Installation		**49,126**
Mechanical Equipment Supply and Installation		**324,043**
Electrical / I&C Supply and Installation		**43,753**
Project Indirects [(1)]		**99,220**
EPC Cost before Contingency and Fee		**516,142**
Fee and Contingency		**55,743**
Total Project EPC		**571,885**
Owner Costs (excluding project finance)		**114,377**
Total Project Cost (excluding finance)		**686,262**
Total Project EPC	**/ kW**	**815**
Owner Costs 20% (excluding project finance)	**/ kW**	**163**
Total Project Cost (excluding project finance)	**/ kW**	**978**

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: outdoor installation considerations, air-cooled condensers compared to cooling towers, seismic design differences, zero-water discharge issues, local technical enhancements (e.g., additional noise remediation that is generally required in urban siting), remote location issues, urban – high density population issues, labor wage and productivity differences, location adjustments, owner cost differences, and the increase in overheads associated with these 10 adjustments.

Outdoor installation locations are considered in geographic areas where enclosed structures for the boilers would not be required due to the low probability of freezing. The locations that were included in outdoor installation are Alabama, Arizona, Arkansas, Florida, Georgia, Louisiana, Mississippi, New Mexico, South Carolina, and Puerto Rico.

The potential locations relating to the use of air-cooled condensers in place of mechanical draft wet cooling towers were identified as Arizona, California, Connecticut, Delaware, District of Columbia, Maryland, Massachusetts, New Hampshire, New York, Oregon, Pennsylvania, Rhode Island, Virginia, and Puerto Rico. These locations are identified as those where conservation of water, notwithstanding supply, has been and/or is becoming a significant issue in plant permitting/siting.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

The potential locations relating to the need of zero-water discharge were identified as Arizona, California, Colorado, Connecticut, Delaware, District of Columbia, Maryland, Massachusetts, New Hampshire, New York, Oregon, Pennsylvania, Rhode Island, Virginia, and Puerto Rico. Similar to water usage discussed above in this section on Conventional NGCC, wastewater treatment and disposal is considered a critical permitting/siting issue in these areas.

The locations with local technical enhancements include California, Colorado, Connecticut, Delaware, District of Columbia, Maryland, Massachusetts, Montana, New Jersey, New York, Rhode Island, Vermont, and Virginia. These areas are places where noise, visual impacts, and other technical enhancements generally need to be made by a project developer or utility to comply with the applicable permitting/siting requirements.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the Conventional NGCC include Fairbanks, Alaska; Albuquerque, New Mexico; Cheyenne, Wyoming; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.6.1, taking into consideration the amount of labor we estimated for the Conventional NGCC Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Illinois, Indiana, Iowa, Kansas, Maine, Maryland, Massachusetts, Michigan, Minnesota, Montana, Nebraska, New York, North Dakota, Ohio, Pennsylvania, South Dakota, West Virginia, Wisconsin, and Wyoming.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 8-2 in the Appendix presents the Conventional NGCC capital cost variations for alternative U.S. plant locations, including the difference between the given location and the average location specified for the Cost Estimate.

8.5 O&M ESTIMATE

In addition to the general O&M items discussed in Section 2.6.2, the Conventional NGCC Facility includes the major maintenance for the CTs, as well as the BOP, including the ST, associated electric generators, HRSGs, and emissions reduction catalysts. These major maintenance expenses are included with the VOM expense for this technology and are given on an average basis across the MWhs incurred. Typically, significant overhauls on a Conventional NGCC Facility occur no less frequently than 16,000 operating hour intervals. Recently, some manufacturers are extending these intervals to 25,000 operating hours. Table 8-3 presents the O&M expenses for the Conventional NGCC Facility.

TABLE 8-3 – O&M EXPENSES FOR CONVENTIONAL NGCC

Technology:	Conventional NGCC
Fixed O&M Expense	$11.00/kW-year
Variable O&M Expense	$3.50/MWh

8.6 ENVIRONMENTAL COMPLIANCE INFORMATION

The Conventional NGCC utilizes DLN combustion systems in the primary combustion zone of the CT and best available burner technology with respect to the duct burners in the HRSGs to manage the production of NO_X and CO. Additional control of NO_X and CO is accomplished through an SCR and an oxidization catalyst, respectively. Oxides of sulfur in the Conventional NGCC are managed through the natural gas fuel quality, which is generally very low in sulfur U.S. domestic pipeline quality natural gas, and consequently the low sulfur content translates into SO_2 after combustion. The Conventional NGCC does not include any control devices for CO_2, which is proportional to the heat rate (inversely proportional to the efficiency) of the technology. Water, wastewater, and solid waste compliance are achieved through traditional on-site and off-site methods, and the costs for such compliance are included in the O&M estimate for the Conventional NGCC Facility. Table 8-4 presents environmental emissions for the Conventional NGCC Facility.

TABLE 8-4 – ENVIRONMENTAL EMISSIONS FOR CONVENTIONAL NGCC

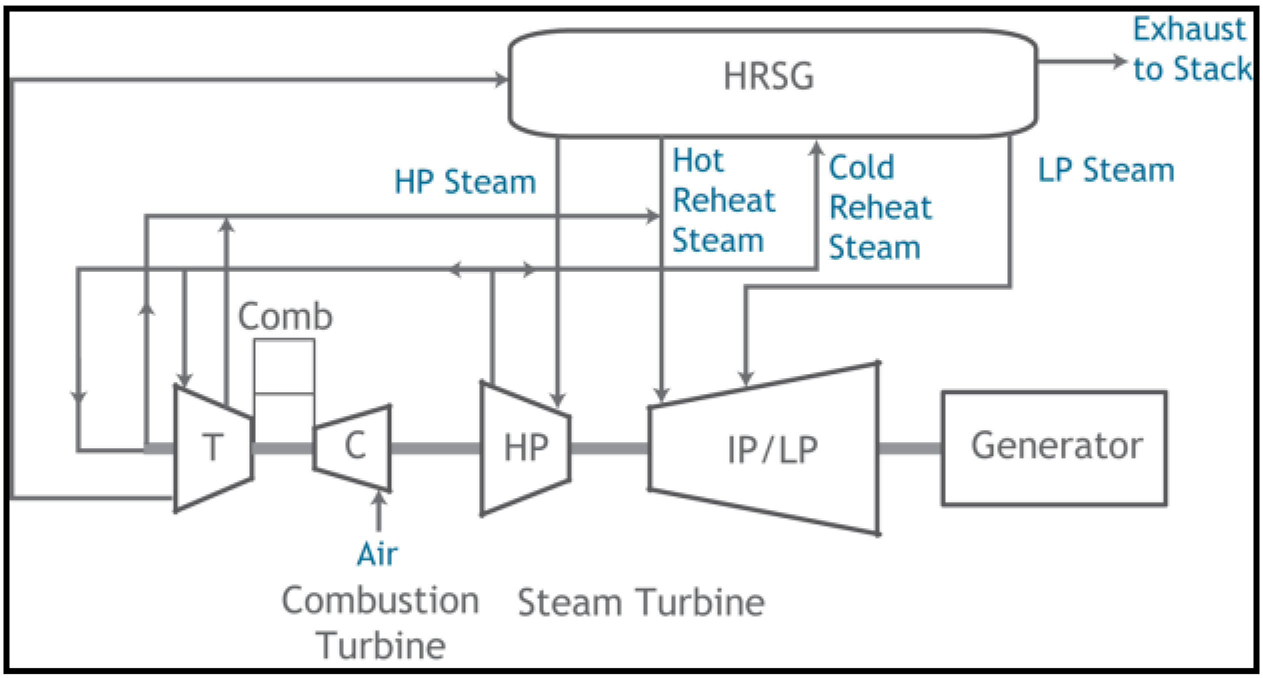
Technology:	Conventional NGCC
NO_X	0.0075 lb/MMBtu
SO_2	0.001 lb/MMBtu
CO_2	117 lb/MMBtu

9. ADVANCED GENERATION NATURAL GAS COMBINED CYCLE (AG-NGCC)

9.1 MECHANICAL EQUIPMENT AND SYSTEMS

The Advanced Generation ("AG")-NGCC design is the same as the Conventional NGCC, except an H-class CT is utilized in lieu of F-class, and there is only one CT/HRSG supporting the ST included. Since the H-class CT design employs steam cooling of both stationary and rotational hot parts, the HRSG systems and the ST are both considered "advanced" designs, as compared to the Conventional NGCC. The AG-NGCC has advantages compared to the Conventional NGCC. The advantages of the AG-NGCC are for the same size of equipment – more megawatt output due to higher firing temperature. The higher firing temperature is due to more technically advanced metallurgical metals and coatings, and blade cooling systems. The AG-NGCC may or may not have a better ramping rate depending on the geographical location of the facility. The net output of the AG-NGCC is 429 MW. Figure 9-1 presents the AG-NGCC process flow diagram.

FIGURE 9-1 – AG-NGCC DESIGN CONFIGURATION



9.2 ELECTRICAL AND CONTROL SYSTEMS

The AG-NGCC electrical and control systems are similar to the Conventional NGCC Facility, except that the sizing of the generators and transformers are larger to support the larger CT and ST equipment utilized in the AG-NGCC.

9.3 OFF-SITE REQUIREMENTS

The off-site requirements for the AG-NGCC Facility are the same as the Conventional NGCC. Refer to Section 8.3 for the description of the Conventional NGCC off-site requirements.

9.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the AG-NGCC Facility with a nominal capacity of 429 MW is $1,104/kW. Table 9-1 summarizes the Cost Estimate categories for the AG-NGCC Facility.

TABLE 9-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR AG-NGCC

Technology:	AG-NGCC	
Nominal Capacity (ISO):	429,000 kW	
Nominal Heat Rate (ISO):	6,300 Btu/kWh-HHV	
Capital Cost Category		**(000s) (January 1, 2016$)**
Civil Structural Material and Installation		25,790
Mechanical Equipment Supply and Installation		214,313
Electrical / I&C Supply and Installation		30,370
Project Indirects (1)		86,695
EPC Cost before Contingency and Fee		357,168
Fee and Contingency		37,503
Total Project EPC		394,671
Owner Costs (excluding project finance)		78,934
Total Project Cost (excluding finance)		473,605
Total Project EPC	/ kW	920
Owner Costs 20% (excluding project finance)	/ kW	184
Total Project Cost (excluding project finance)	/ kW	1,104

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

The locational adjustments for the AG-NGCC Facility similar to those made for the Conventional NGCC Facility.

Table 9-2 in the Appendix presents the AG-NGCC Facility capital cost variations for alternative U.S. plant locations, including the difference between the given location and the average location specified for the Cost Estimate.

9.5 O&M ESTIMATE

The O&M items for the AG-NGCC Facility are the same as those described in Section 8.5 for the Conventional NGCC Facility. Table 9-3 presents the O&M expenses for the AG-NGCC Facility.

TABLE 9-3 – O&M EXPENSES FOR AG-NGCC

Technology:	AG-NGCC
Fixed O&M Expense	$10.00/kW-year
Variable O&M Expense	$2.00/MWh

9.6 ENVIRONMENTAL COMPLIANCE INFORMATION

The environmental compliance strategy and equipment for the AG-NGCC Facility is the same as those described in Section 8.6 for the Conventional NGCC Facility. Table 9-4 presents environmental emissions for the AG-NGCC Facility.

TABLE 9-4 – ENVIRONMENTAL EMISSIONS FOR AG-NGCC

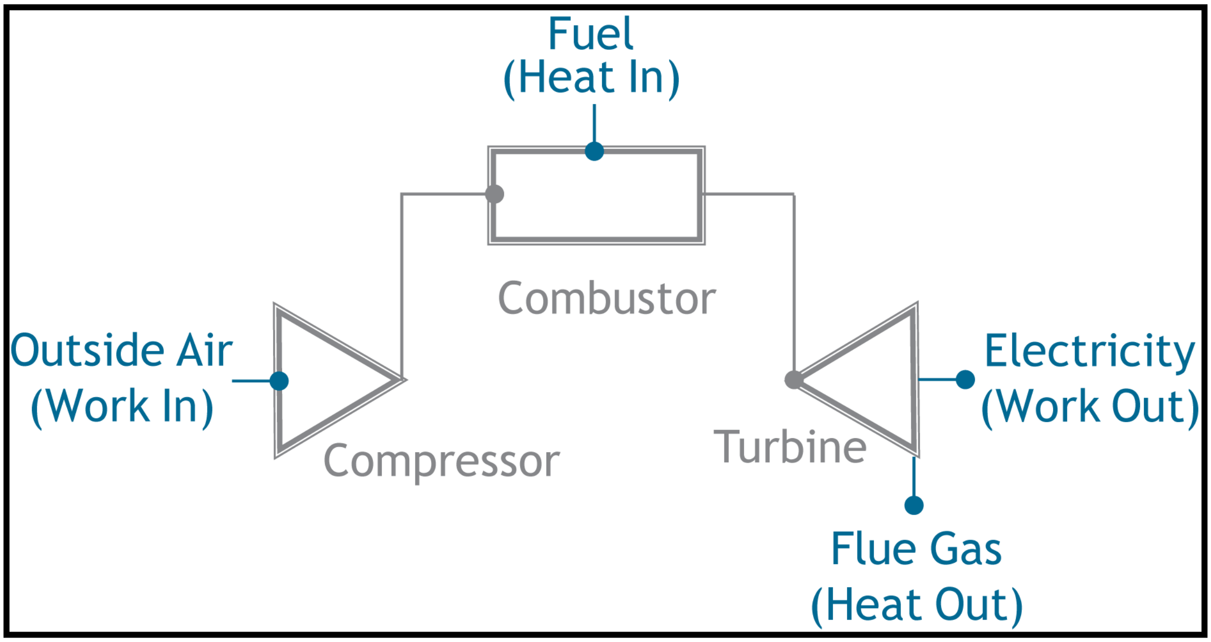
Technology:	AG-NGCC
NO_X	0.0075 lb/MMBtu
SO_2	0.001 lb/MMBtu
CO_2	117 lb/MMBtu

10. CONVENTIONAL COMBUSTION TURBINE (CT)

10.1 MECHANICAL EQUIPMENT AND SYSTEMS

The Conventional Combustion Turbine ("CT") Facility produces 100 MW of electricity using two single natural gas-fueled LM-6000 CTs and associated electric generators in simple-cycle mode. The CTs are equipped with an inlet evaporative cooler to reduce the temperature of the turbine inlet air to increase summer output. Figure 10-1 presents the Conventional CT Facility process flow diagram.

FIGURE 10-1 – CONVENTIONAL CT DESIGN CONFIGURATION



10.2 ELECTRICAL AND CONTROL SYSTEMS

The Conventional CT Facility has two CT electric generators. The generators are 60 Hz machines rated at approximately 101 MVA with an output voltage of 13.8 kV. The CT electric generators are connected to a high-voltage bus in the Conventional CT Facility switchyard via a dedicated generator circuit breaker, GSU, and a disconnect switch. The GSU increases the voltage from the electric generator from 13.8 kV to interconnected transmission system high voltage.

The Conventional CT Facility is controlled using a DCS. The DCS provides centralized control of the facility by integrating the control systems provided with the individual CT and associated electric generator and the control of BOP systems and equipment.

10.3 OFF-SITE REQUIREMENTS

Natural gas is delivered to the facility through an approximately lateral connected to the local natural gas trunk line. Water for the limited processes that utilize water at the Conventional CT Facility is obtained from a one of several available water sources (e.g., municipal water supply). The Conventional CT Facility uses a water treatment system and a high-efficiency reverse osmosis system to reduce the dissolved solids for compressor cleaning. Wastewater is sent to a municipal wastewater system. Further, the electrical interconnection from the Conventional CT on-site switchyard is effectuated by a connection to an adjacent utility substation.

10.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the Conventional CT Facility with a nominal capacity of 100 MW is $1,101/kW. Table 10-1 summarizes the Cost Estimate categories for the Conventional CT Facility.

TABLE 10-1 – BASE PLANT SITE
CAPITAL COST ESTIMATE FOR CONVENTIONAL CT

Technology:		**Conventional CT**
Nominal Capacity (ISO):		**100,000 kW**
Nominal Heat Rate (ISO):		**10,000 Btu/kWh-HHV**
Capital Cost Category		**(000s) (January 1, 2016$)**
Civil Structural Material and Installation		**6,630**
Mechanical Equipment Supply and Installation		**50,350**
Electrical / I&C Supply and Installation		**12,065**
Project Indirects (1)		**14,344**
EPC Cost before Contingency and Fee		**83,390**
Fee and Contingency		**8,339**
Total Project EPC		**91,729**
Owner Costs (excluding project finance)		**18,346**
Total Project Cost (excluding finance)		**110,075**
Total Project EPC	**/ kW**	**917**
Owner Costs 20% (excluding project finance)	**/ kW**	**183**
Total Project Cost (excluding project finance)	**/ kW**	**1,101**

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: outdoor installation considerations, seismic design differences, local technical enhancements (e.g., additional noise remediation that is generally required in urban siting), remote location issues, urban – high density population issues, labor wage and productivity differences, location adjustments, owner cost differences, and the increase in overheads associated with these previous eight location adjustments.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

The locations with local technical enhancements include California, Colorado, Connecticut, Delaware, District of Columbia, Maryland, Massachusetts, New Jersey, New York, Rhode Island, Vermont, and Virginia. These are areas where noise, visual impacts, and other technical enhancements generally need to be made by a project developer or utility to comply with the applicable permitting/siting requirements.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the Conventional CT Facility include Fairbanks, Alaska; Honolulu, Hawaii; Great Falls, Montana; Albuquerque, New Mexico; Cheyenne, Wyoming; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.6.1, taking into consideration the amount of labor we estimated for the Conventional CT Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Hawaii, Illinois, Indiana, Iowa, Kansas, Maine, Maryland, Massachusetts, Michigan, Minnesota, Montana, Nebraska, New York, North Dakota, Ohio, Pennsylvania, South Dakota, West Virginia, Wisconsin, and Wyoming.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 10-2 in the Appendix presents the Conventional CT Facility capital cost variations for alternative U.S. plant locations.

10.5 O&M ESTIMATE

In addition to the general O&M items discussed in Section 2.6.2, the Conventional CT Facility includes the major maintenance for the CT and associated electric generator. These major maintenance expenses are included with the VOM expense for this technology. Significant overhauls on a Conventional CT Facility occur every 25,000 operating hours; with more significant major maintenance outages occurring at 50,000 operating hour intervals. The frequency of starts in relation to operating hours does not have an effect on major maintenance timing for this type of CT, as it does for frame-type units. Table 10-3 presents the O&M expenses for the Conventional CT Facility.

TABLE 10-3 – O&M EXPENSES FOR CONVENTIONAL CT

Technology:	Conventional CT
Fixed O&M Expense	$17.50/kW-year
Variable O&M Expense	$3.50/MWh

10.6 ENVIRONMENTAL COMPLIANCE INFORMATION

Typically, a Conventional CT Facility would be equipped with only the DLN combustion hardware to mitigate emissions. There are some states in the U.S. that do require a "hot" SCR that can operate at the higher exhaust temperatures of a simple-cycle plant, though that equipment was not contemplated herein. Table 10-4 presents environmental emissions for the CT Facility.

TABLE 10-4 – ENVIRONMENTAL EMISSIONS FOR CONVENTIONAL CT

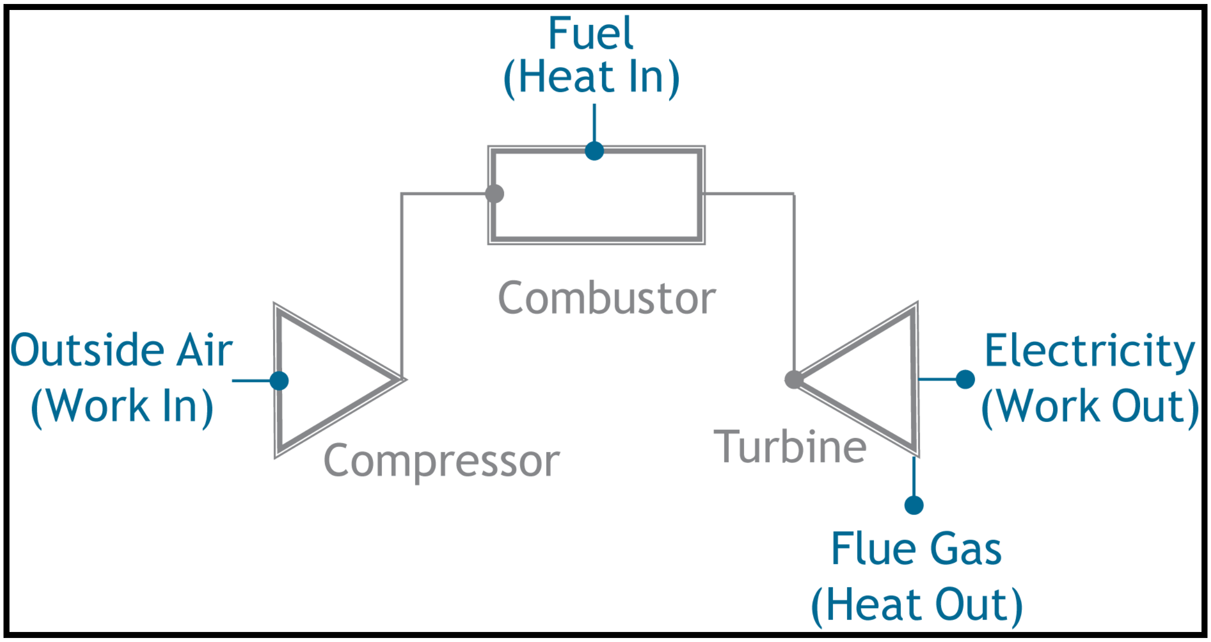
Technology:	Conventional CT
NO_X	0.03 lb/MMBtu
SO_2	0.001 lb/MMBtu
CO_2	117 lb/MMBtu

11. ADVANCED COMBUSTION TURBINE (ACT)

11.1 MECHANICAL EQUIPMENT AND SYSTEMS

The Advanced CT ("ACT") Facility produces 237 MW of electricity using a single natural gas-fueled, F-class CT and associated electric generator. The CT is equipped with an inlet evaporative cooler to reduce the temperature of the turbine inlet air to increase summer output. Figure 11-1 presents the Advanced CT process flow diagram.

FIGURE 11-1 – ADVANCED CT DESIGN CONFIGURATION



11.2 ELECTRICAL AND CONTROL SYSTEMS

The Advanced CT Facility has the same general electrical and control systems as the Conventional CT Facility, except that the electric generator is rated at approximately 234 MVA and the corresponding GSU is larger in the Advanced CT Facility.

11.3 OFF-SITE REQUIREMENTS

The off-site requirements for the Advanced CT Facility are materially similar to the Conventional CT Facility.

11.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the Advanced CT Facility with a nominal capacity of 237 MW is \$678/kW. Table 11-1 summarizes the Cost Estimate categories for the Advanced CT Facility.

TABLE 11-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR ADVANCED CT

Technology:	Advanced CT	
Nominal Capacity (ISO):	237,000 kW	
Nominal Heat Rate (ISO):	9,800 Btu/kWh-HHV	
Capital Cost Category		**(000s) (January 1, 2016$)**
Civil Structural Material and Installation		13,660
Mechanical Equipment Supply and Installation		71,245
Electrical / I&C Supply and Installation		17,896
Project Indirects (1)		18,851
EPC Cost before Contingency and Fee		121,652
Fee and Contingency		12,165
Total Project EPC		133,818
Owner Costs (excluding project finance)		26,764
Total Project Cost (excluding finance)		160,582
Total Project EPC	/ kW	565
Owner Costs 20% (excluding project finance)	/ kW	113
Total Project Cost (excluding project finance)	/ kW	678

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

The locational considerations for the Advanced CT Facility are the same as those set forth in the section on the Conventional CT Facility.

Table 11-2 in the Appendix presents the Advanced CT Facility capital cost variations for alternative U.S. plant locations.

11.5 O&M ESTIMATE

In addition to the general O&M items discussed in Section 2.6.2, the Advanced CT Facility includes the major maintenance for the CT and associated electric generator. These major maintenance expenses are included with the VOM expense for this technology, based upon an operating profile of approximately 8 hours of operation per CT start. Typically, significant overhauls on an Advanced CT Facility occur no less frequently than 450 starts; with more significant major maintenance outages occurring at 900 and 1,800 start intervals. Table 11-3 presents the O&M expenses for the Advanced CT Facility.

TABLE 11-3 – O&M EXPENSES FOR ADVANCED CT

Technology:	Advanced CT
Fixed O&M Expense	$6.80kW-year
Variable O&M Expense	$10.70/MWh

11.6 ENVIRONMENTAL COMPLIANCE INFORMATION

The environmental compliance strategy and equipment for the Advanced CT Facility are the same as those used for the Conventional CT Facility (see Section 10.6). Table 11-4 presents environmental emissions for the Advanced CT Facility.

TABLE 11-4 – ENVIRONMENTAL EMISSIONS FOR ADVANCED CT

Technology:	Advanced CT
NO_X	0.03 lb/MMBtu
SO_2	0.001 lb/MMBtu
CO_2	117 lb/MMBtu

12. ADVANCED NUCLEAR (AN)

12.1 MECHANICAL EQUIPMENT AND SYSTEMS

The Advanced Nuclear ("AN") Facility consists of two nominally rated 1,117 MW Westinghouse AP1000 nuclear power units built at a brownfield (existing nuclear facility) site.

The steam cycle of a nuclear powered electric generation facility is similar to other steam-powered generating facilities. The difference is with the source of heat used to generate steam. In units that use fossil fuels, hydrocarbons are burned to heat water, producing steam. In the AP1000, splitting the nucleus (fission) of enriched-uranium atoms provides the energy to heat the water.

Nuclear fuel is a enriched-uranium dioxide ceramic pellet typically encased in a zircalloy tube. The uranium atoms in the pellet absorb neutrons causing the nucleus of the atoms to split, or fission. When the uranium atom splits, a large amount of energy, as well as additional neutrons and fission fragments are released. The resulting nuclei contain a great deal of kinetic energy which ultimately adds heat to the primary coolant. The neutrons can be absorbed by other uranium atoms which then fission, producing more neutrons available for further fissions. The chain reaction is maintained at criticality (e.g., "self-sustaining": neither sub-critical nor super-critical) by controlling the number of thermal neutrons available for fission such that, on average, each fission results in exactly one thermal neutron being used in a subsequent thermal fission. The number of neutrons available is controlled by the temperature (and hence the density) of the water in the nuclear reactor core, the arrangement of neutron absorbing control rods inserted into the core, the design of the core, and by controlling the void fraction and temperature of the coolant water (which both affect the density of water which affects the neutrons available for the fission process). This concept is commonly referred to as "moderation". Moderation is the slowing down or lowering the energy of a fast neutron to a thermal neutron state such that the neutron has a higher probability of resulting in a thermal fission.

The enriched-uranium fuel is contained inside a pressurized water reactor ("PWR"). The AP1000 is a two-loop PWR. The fission of the uranium fuel releases heat to the surrounding water (reactor cooling water), which under pressure does not boil. The pressurized water from the reactor (the primary side) enters a heat exchanger (typically referred to as a steam generator) which converts lower pressure water into steam in the secondary side of the steam generator.

In the primary loop, the cooling water inside the PWR is circulated through the nuclear core by reactor coolant pumps. This cooling water system is termed the Reactor Coolant System ("RCS"). The RCS consists of two heat transfer circuits, with each circuit containing one Delta-125 U-tube type steam generator, two reactor coolant pumps, and a single hot leg and two cold legs for circulating coolant between the reactor and the steam generators. The system also includes a pressurizer, interconnecting piping, and the valves and instrumentation necessary for operational control and the actuation of safeguards. Each AP1000 unit has a 130-foot diameter freestanding containment vessel with four ring sections and an upper and lower head.

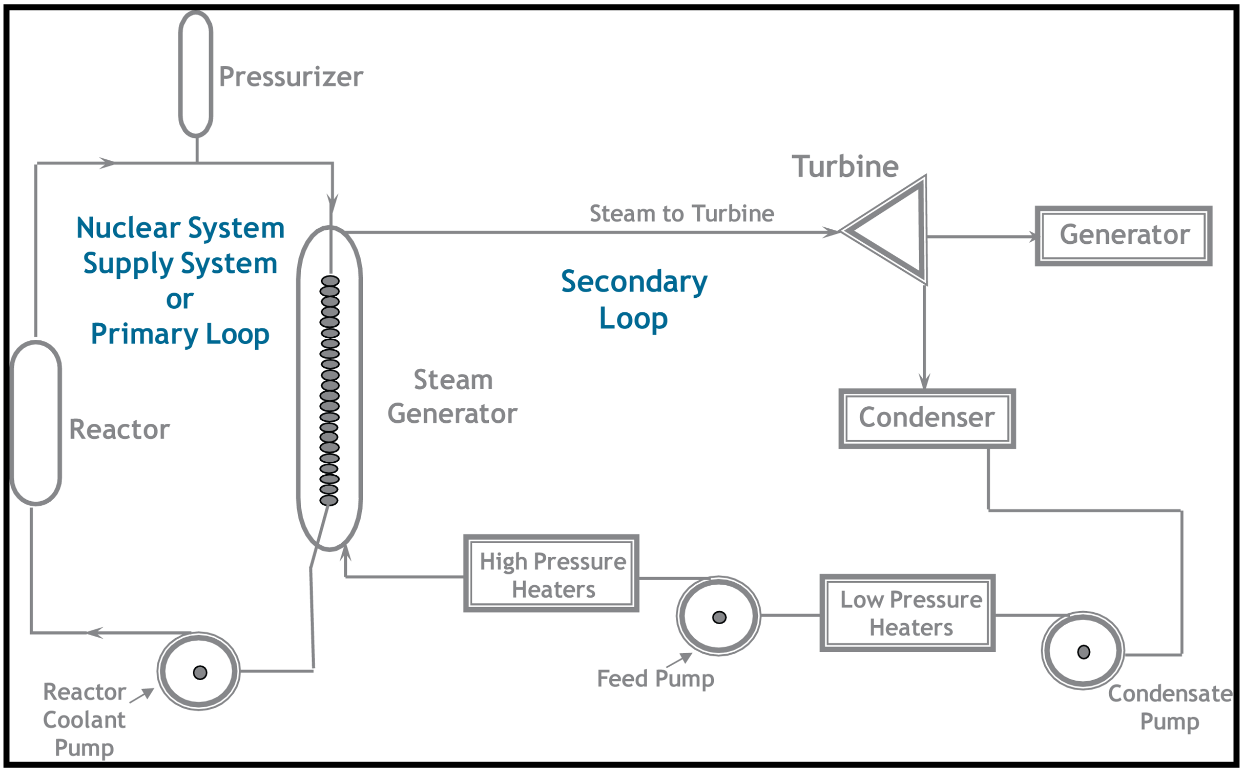
In the secondary loop, the main steam from the steam generator is routed to the HP section of the ST. The ST consists of a double-flow HP ST section and three double-flow LP ST sections in a tandem-compound configuration. As the steam exits the HP section it passes through a moisture separator and reheater. The moisture separator and reheater dries and reheats the steam before it enters the LP ST section, which improves the cycle efficiency and reduces moisture related erosion of the LP ST blades. A portion of the steam is extracted from the HP and LP sections of the ST and with ST exhaust heats the condensate and feedwater before it is sent back to the reactor. The HP and LP STs are connected via a common shaft that drives the generator which produces the electrical power output of approximately 1,100 MW per unit.

The steam that exits the LP section of the ST, as well as the drains from the feedwater heaters, are directed to the condenser. The condenser is a surface condensing (tube type) heat exchanger that is maintained under vacuum to increase the turbine efficiency. The steam condenses on the outside of the tubes and condenser cooling water is circulated through the inside of the tubes.

The passive core cooling system provides protection of the facility against RCS leaks and ruptures. The passive containment cooling system provides for an inherently safe heat sink for the facility. The passive containment cooling system cools the containment following a loss of coolant accident by rapidly reducing the reactor coolant system pressure and promoting the natural circulation of air supplemented by water evaporation to transfer heat through the steel containment vessel and away from critical core components that may be subject to decay heat. The advantage of a passive core system is that less safety related equipment (e.g., pumping systems) is required to remove the decay heat.

Numerous other systems are needed to support and provide redundancy for the cycle process described herein. These include the residual heat removal system, the HP core flooder system, and the LP core flooder system which are redundant systems and are designed to remove heat from the reactor core in the event the normal core cooling system fails. Other support systems include the liquid and solid radioactive waste systems which handle, control, and process radioactive waste from the plant. The reactor containment ventilation system controls and filters airborne radiation. Figure 12-1 presents a simplified process flow diagram for a PWR AN plant.

FIGURE 12-1 – AN DESIGN CONFIGURATION



12.2 ELECTRICAL AND CONTROL SYSTEMS

The AN Facility has one ST 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 ST 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 24 kV to interconnected transmission system high voltage.

The AN Facility is controlled using a DCS. The DCS provides centralized control of the facility by integrating the control systems provided with the reactor, ST and associated electric generator and the control of BOP systems and equipment.

12.3 OFF-SITE REQUIREMENTS

Water for all processes at the AN Facility is obtained from one of several available water supply options; however, water is typically sourced from a nearby water source (e.g., river, lake, or ocean), when possible. The AN Facility uses a water treatment system and a high-efficiency reverse osmosis system to reduce the dissolved solids from the cooling water and to provide distilled water. Non-radioactive wastewater is sent to an adjacent river or other approved wastewater delivery point. Further, the electrical interconnection from the AN on-site switchyard is typically connected to the transmission line through an adjacent utility substation.

12.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the AN Facility with a nominal capacity of 2,234 MW is $5,945/kW. Table 12-1 summarizes the Cost Estimate categories for the AN Facility.

TABLE 12-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR AN

Technology:		**AN**
Nominal Capacity (ISO):		**2,234,000 kW**
Nominal Heat Rate (ISO):		**N/A Btu/kWh-HHV**
Capital Cost Category		**(000s) (January 1, 2016$)**
Civil Structural Material and Installation		**1,927,067**
Mechanical Equipment Supply and Installation		**3,782,925**
Electrical / I&C Supply and Installation		**700,954**
Project Indirects (1)		**3,029,122**
EPC Cost before Contingency and Fee		**9,440,067**
Fee and Contingency		**1,446,413**
Total Project EPC		**10,886,479**
Owner Costs (excluding project finance)		**2,395,025**
Total Project Cost (excluding finance)		**13,281,504**
Total Project EPC	**/ kW**	**4,873**
Owner Costs 22% (excluding project finance)	**/ kW**	**1,072**
Total Project Cost (excluding project finance)	**/ kW**	**5,945**

(2) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, owner cost differences, and the increase in overheads associated with these five adjustments.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the Advanced Nuclear Facility include Fairbanks, Alaska; Albuquerque, New Mexico; and Cheyenne, Wyoming.

Labor wage and productivity differences were handled as discussed in Section 2.6.1, taking into consideration the amount of labor we estimated for the AN Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Illinois, Indiana, Maine, Maryland, Massachusetts, Minnesota, New York, Ohio, Oregon, Virginia, Washington, Wisconsin, and Wyoming.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 12-2 in the Appendix presents the AN Facility capital cost variations for alternative U.S. plant locations.

12.5 O&M ESTIMATE

In addition to the general items discussed in the section of this report entitled O&M Estimate, the AN Facility includes provisions for major maintenance on the steam generators, STs, electric generators, BOP systems, and the reactor (beyond refueling). Table 12-3 presents typical O&M expenses for the AN Facility.

TABLE 12-3 – O&M EXPENSES FOR AN

Technology:	AN
Fixed O&M Expense	$100.28/kW-year
Variable O&M Expense	$2.30/MWh

12.6 ENVIRONMENTAL COMPLIANCE INFORMATION

Environmental compliance with respect to air emissions is effectively not necessary for the AN Facility, as this technology does not combust a fuel as is the case for other non-renewable power technologies. While there are environmental compliance considerations for a given nuclear facility (e.g., spent nuclear fuel), only air emissions were considered in this report. Table 12-4 presents environmental emissions for the AN Facility.

TABLE 12-4 – ENVIRONMENTAL EMISSIONS FOR AN

Technology:	AN
NO_X	0 lb/MMBtu
SO_2	0 lb/MMBtu
CO_2	0 lb/MMBtu

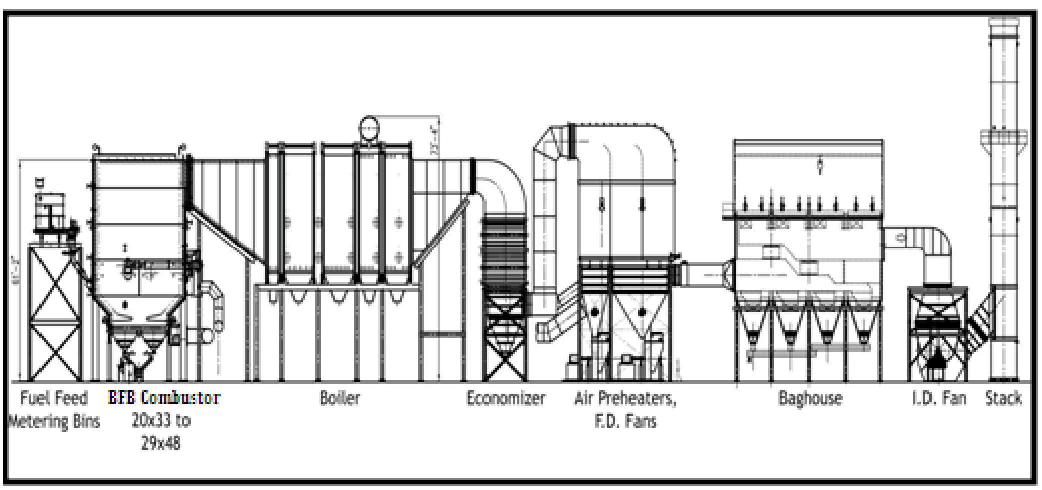
13. BIOMASS BUBBLING FLUIDIZED BED (BBFB)

13.1 MECHANICAL EQUIPMENT AND SYSTEMS

The Biomass BFB ("BBFB") Facility utilizes approximately 2,000 tons per day of wood (at 50 percent maximum moisture) for the production of 50 MW net of electricity. The BBFB Facility consists of a BFB boiler, which will flow to the ST. Steam leaving the ST will be condensed to water in a shell and tube surface condenser. The water will be pumped from the "hotwell" of the condenser through a series of feedwater heaters for purposes of pre-heating the water with ST extraction steam. The combination of feedwater heating and waste heat flowing through the economizer is included to improve cycle efficiency. The water will enter the first feedwater heater where it will be heated using extraction steam from the ST. The water will then flow to the deaerating feedwater heater and into an electric-driven boiler feed pump where the pressure of the water will be increased to approximately 1,800 psia. After leaving the boiler feed pump, the water will flow through two more feedwater heaters. After exiting the last feedwater heater, the water will flow to the economizer section of the BFB boiler for delivery to the combustion section where it will be converted back to steam and the cycle will be repeated. The cooling tower is to be used to cool the circulating water that is used to condense the steam inside the condenser.

In a BFB boiler, a portion of air is introduced through the bottom of the combustor. The bottom of the bed is supported by refractory walls or water-cooled membrane with specially designed air nozzles which distribute the air uniformly. The fuel and limestone are fed into the lower bed. In the presence of fluidizing air, the fuel and limestone quickly and uniformly mix under the turbulent environment and behave like a fluid. Carbon particles in the fuel are exposed to the combustion air. The balance of combustion air is introduced at the top of the lower, dense bed. This staged combustion limits the formation of NO_X. The advantages of BFB boiler technology include fuel flexibility, low SO_2 emissions, low NO_X emissions, and high combustion efficiency. Figure 13-1 presents the BBFB process flow diagram.

FIGURE 13-1 – BBFB DESIGN CONFIGURATION



13.2 ELECTRICAL AND CONTROL SYSTEMS

The BBFB Facility has one ST electric generator. The generator for the ST is a 60 Hz machine rated at approximately 65 MVA with an output voltage of 13.8 kV. The generator breakers for the ST electric generator are bussed together in 15 kV class switchgear that is connected to a high-voltage transmission system at the facility switchyard via a circuit breaker, GSU, and a disconnect switch. The GSU increases the voltage from the electric generators from 13.8 kV to interconnected transmission system high voltage.

The BBFB Facility is controlled using a DCS. The DCS provides centralized control of the facility by integrating the control systems provided with the ST and associated electric generator and the control of BOP systems and equipment.

13.3 OFF-SITE REQUIREMENTS

Biomass is delivered to the BBFB Facility by rail, truck or barge. Water for all processes at the BBFB Facility is obtained from one of several available water sources. The BBFB Facility uses a water treatment system and a high-efficiency reverse osmosis system to reduce the dissolved solids from the cooling water and to provide distilled water for HRSG makeup. Wastewater is sent to a municipal wastewater system or other available wastewater delivery point. Further, the electrical interconnection from the BBFB Facility on-site switchyard is effectuated by a connection to an adjacent utility substation.

13.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the BBFB Facility with a nominal capacity of 50 MW is $4,985/kW. Table 13-1 summarizes the Cost Estimate categories for the BBFB Facility.

TABLE 13-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR BBFB

Technology:		**BBFB**
Nominal Capacity (ISO):		**50,000 kW**
Nominal Heat Rate (ISO):		**13,500 Btu/kWh-HHV**
Capital Cost Category		**(000s) (January 1, 2016$)**
Civil Structural Material and Installation		**15,349**
Mechanical Equipment Supply and Installation		**100,992**
Electrical / I&C Supply and Installation		**22,897**
Project Indirects (1)		**49,598**
EPC Cost before Contingency and Fee		**188,836**
Fee and Contingency		**18,884**
Total Project EPC		**207,720**
Owner Costs (excluding project finance)		**41,544**
Total Project Cost (excluding finance)		**249,264**
Total Project EPC	**/ kW**	**4,154**
Owner Costs 20% (excluding project finance)	**/ kW**	**831**
Total Project Cost (excluding project finance)	**/ kW**	**4,985**

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: outdoor installation considerations, seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, owner cost differences, and the increase in overheads associated with these six adjustments.

Outdoor installation locations are considered in geographic areas where enclosed structures for the boilers would not be required due to the low probability of freezing. The locations that included outdoor installation are Alabama, Arkansas, Florida, Georgia, Hawaii, Louisiana, Mississippi, South Carolina, and Puerto Rico.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the BBFB include Fairbanks, Alaska; Honolulu, Hawaii; Great Falls, Montana; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.6.1, taking into consideration the amount of labor we estimated for the BBFB Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Hawaii, Illinois, Indiana, Maine, Maryland, Massachusetts, Minnesota, New York, Ohio, Oregon, Virginia, Washington, Wisconsin, and Puerto Rico.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 13-2 in the Appendix presents the BBFB Facility capital cost variations for alternative U.S. plant locations.

13.5 O&M ESTIMATE

In addition to the general items discussed in the section of this report entitled O&M Estimate, the BBFB Facility includes the major maintenance for the ST and associated electric generator, as well as the BOP. These major maintenance expenses are included with the VOM expense for this technology and are given on an average basis across the MWhs incurred. Typically, significant overhauls on a BBFB Facility occur no less frequently than 6 to 8 years. Table 13-3 presents the O&M expenses for the BBFB Facility.

TABLE 13-3 – O&M EXPENSES FOR BBFB

Technology:	BBFB
Fixed O&M Expense	$110.00/kW-year
Variable O&M Expense	$4.20/MWh

13.6 ENVIRONMENTAL COMPLIANCE INFORMATION

The BBFB Facility utilizes BFB combustion to control NO_X and CO. SO_2 in the BFB is managed through the use of low-sulfur biomass feedstocks. The BBFB Facility does not include any control devices for CO_2, which is proportional to the heat rate (inversely proportional to the efficiency) of the technology. Water, wastewater, and solid waste compliance are achieved through traditional on-site and off-site methods, and the costs for such compliance are included in the O&M Estimate for the BBFB Facility. Table 13-4 presents environmental emissions for the BBFB Facility.

TABLE 13-4 – ENVIRONMENTAL EMISSIONS FOR BBFB

Technology:	BBFB
NO_X	0.08 lb/MMBtu
SO_2	0 lb/MMBtu
CO_2	195 lb/ MMBtu (1)

(1) Does not account for the life-cycle fate of CO_2 after emission from power generation unit.

14. ONSHORE WIND (WN)

14.1 MECHANICAL EQUIPMENT AND SYSTEMS

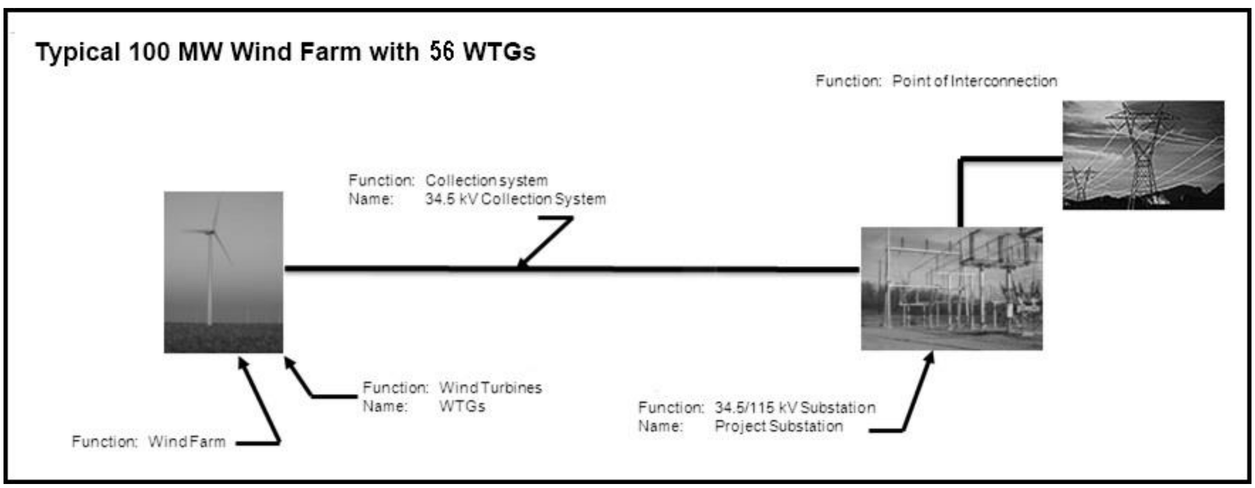
The Onshore Wind (“WN”) Facility is based on 56 wind turbine generators (“WTGs”), each with a rated capacity of 1.79 MW. The total design capacity is 100 MW.

The turbines are each supported by a conical steel tower, which is widest at the base and tapers in diameter just below the nacelle. A foundation provides the tower with a firm anchor to the ground. The nacelle is attached to the top of the tower and contains the main mechanical components of the wind turbine, which include a variable-speed generator, transmission, and yaw drive. The rotor hub connects to the transmission through one end of the nacelle, and the rotor is then connected to the hub. Each WTG has a three-bladed rotor with a diameter of 100 meters and hub height of 80 meters. The WTG has an active yaw system in the nacelle to keep the rotor facing into the wind.

Power is generated by the wind turbines, then converted using an onboard transformer to 34.5 kV AC. It is then delivered to a collection system at the base of each turbine. Power from all turbines will be collected by the underground collection circuit.

The collection system supplies power to a new substation designed to step up the voltage to 115 kV for interconnection with the transmission system. Other facility components include access roads, an O&M building and electrical interconnection facilities. Figure 14-1 presents a picture of a typical WN Facility.

FIGURE 14-1 – WN DESIGN CONFIGURATION



14.2 ELECTRICAL AND CONTROL SYSTEMS

The WN Facility has 56 wind turbine-driven electric generators. Each generator is a doubly-fed induction generator that feeds an AC/DC/AC power converter that provides an output of three-phase, 60 Hz electrical power. The power output available is approximately 1.75 MVA with an output voltage of 575 V stepped up to 34.5 kV using a pad-mounted transformer at the base of the wind turbine. The wind turbine transformers are interconnected on one or more underground collector circuits that are connected to a collector bus through a circuit breaker for each circuit. The collector bus is connected to a high-voltage transmission system through the facility substation, which includes a 34.5 kV switch or circuit breaker, GSU, high-voltage circuit breaker, and a disconnect switch. The GSU increases the voltage from the electric generator from 34.5 kV to interconnected transmission system high voltage.

The WN Facility is controlled using a control system generally referred to as the wind farm supervisory control and data acquisition ("SCADA") system. The SCADA system provides centralized control of the facility by integrating the control systems provided with each of the wind turbines and the control of BOP systems and equipment.

14.3 OFF-SITE REQUIREMENTS

Since wind uses a renewable fuel, the most significant off-site requirements are the construction of and interconnection to roads and the electrical interconnection to the utility high-voltage transmission system, as discussed in Section 14.2.

14.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the WN Facility with a nominal capacity of 100 MW is $1,877/kW. Table 14-1 summarizes the Cost Estimate categories for the WN Facility.

TABLE 14-1 – LOCATION-BASED COSTS FOR WN

Technology:	**WN**	
Nominal Capacity (ISO):	**100,000 kW**	
Nominal Heat Rate (ISO):	**N/A Btu/kWh-HHV**	
Capital Cost Category		**(000s) (January 1, 2016$)**
Civil Structural Material and Installation		**19,690**
Mechanical Equipment Supply and Installation		**122,924**
Electrical / I&C Supply and Installation		**15,450**
Project Indirects (1)		**6,480**
EPC Cost before Contingency and Fee		**164,544**
Fee and Contingency		**12,500**
Total Project EPC		**177,044**
Owner Costs (excluding project finance)		**10,623**
Total Project Cost (excluding finance)		**187,667**
Total Project EPC	**/ kW**	**1,770**
Owner Costs 6% (excluding project finance)	**/ kW**	**106**
Total Project Cost (excluding project finance)	**/ kW**	**1,877**

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, and owner cost differences and the increase in overheads associated with these five adjustments.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Although wind energy projects are typically in remote locations, the following locations are considered very remote and require additional costs due to their locations. These remote locations related to the WN Facility include Fairbanks, Alaska; Honolulu, Hawaii; Great Falls, Montana; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.6.1, taking into consideration the amount of labor we estimated for the WN Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Hawaii, Illinois, Indiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Montana, New Hampshire, New Jersey, New York, North Dakota, and Virginia.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs.

Table 14-2 in the Appendix presents the WN Facility capital cost variations for alternative U.S. plant locations.

14.5 O&M ESTIMATE

In addition to the general items discussed in the section of the report entitled O&M Estimate, the major areas for O&M for an Onshore Wind Facility include periodic gearbox, WTG, electric generator, and associated electric conversion (e.g., GSU) technology repairs and replacement. These devices typically undergo major maintenance every five to seven years. Based on recent experience, most WN operators do not treat O&M on a variable basis, and consequently, all O&M expenses are shown below on a fixed basis. Table 14-3 presents the O&M expenses for the WN Facility.

TABLE 14-3 – O&M EXPENSES FOR WN

Technology:	WN
Fixed O&M Expense	$39.70/kW-year
Variable O&M Expense	$0/MWh

14.6 ENVIRONMENTAL COMPLIANCE INFORMATION

Since wind utilizes a renewable energy source and no fuel is combusted to make power from an Onshore Wind Facility, air emissions are not created. Table 14-4 presents environmental emissions for the WN Facility.

TABLE 14-4 – ENVIRONMENTAL EMISSIONS FOR WN

Technology:	WN
NO_X	0 lb/ MMBtu
SO_2	0 lb/MMBtu
CO_2	0 lb/MMBtu

15. UTILITY-SCALE PHOTOVOLTAIC (PV) FACILITY

15.1 MECHANICAL EQUIPMENT AND SYSTEMS

The following describes a nominal 20 MW-AC Fixed Photovoltaic ("PV") Facility. An analysis is also provided for a nominal 20 MW-AC PV Tracker Facility and a 150 MW-AC PV Tracker Facility, which is essentially a significant expansion of the 20 MW Facility; however, a detailed technical description (due to the similarities with the 20 MW Facility and the technology associated therewith) is not provided herein. The PV Facility uses numerous arrays of ground-mounted, single-axis tracking PV modules which directly convert incident solar radiation into DC electricity, which can then be inverted to AC. Additional BOP components include metal racks mounted to tracker components (drive motors, gearboxes, linkages, etc.) supported by foundations, DC wiring, combiner boxes where individual series circuits ("strings") of panels are connected prior to being fed into the inverters, DC-to-AC inverters, AC wiring, various switchgear and step-up transformers, and a control system (partly incorporated into the inverter control electronics) to monitor plant output and adjust the balance of voltage and current to yield maximum power. Figure 15-1 presents a picture of a typical PV Facility.

FIGURE 15-1 – TYPICAL PV FACILITY

15.2 ELECTRICAL AND CONTROL SYSTEMS

The 20 MW-AC PV Facility is comprised of 40 half-megawatt building blocks, each block consisting of groups of PV modules connected to a 500 kW-AC inverter. While the ratio of DC module capacity to AC inverter capacity varies, for this analysis we have assumed a ratio of 1.3:1 for the fixed option and 1.2:1 for the tracker option. The project is set up so that the fixed option will have 650 kW-DC of modules per 500 kW-AC inverter, and the tracker option will have 600 kW-DC of modules per 500 kW-AC inverter. Such a ratio is typical of current systems, though higher ratios are becoming more common. Groups of PV modules produce DC electricity and are connected in series to form series "strings" which are then connected in parallel in a combiner box which contains a fuse for each string. The cables are routed from the modules to combiner boxes and a number of combiner boxes are connected to the input of a 500 kW-AC inverter, which converts the aggregate power from DC to three-phase AC electricity at an output voltage of typically 265 V-AC to 420 V-AC. The output voltage of an inverter (or sometimes several inverters connected together) is stepped up to a higher voltage level, typically in the range of 13.8 kV (or 34.5 kV for larger systems) through a GSU connected to the inverter output terminals. The output of two or more inverters is frequently combined into a shared transformer, each of which is rated 1 MVA (or higher for larger groups of inverters). The transformers are connected in groups to form circuits on an underground collection system. The circuits are connected to a 13.8 kV circuit breaker and then to the local utility distribution grid.

Each inverter has its own integral control system. The aggregate of all the inverters and associated DC arrays are monitored through a SCADA system, sometimes provided by the inverter manufacturer.

15.3 OFF-SITE REQUIREMENTS

Unlike other power technologies discussed in this report, the essential off-site requirements for which provisions must be made on a PV Facility are water supply (generally in limited quantities for purposes of module washing once or twice annually) and an electrical interconnection between the PV Facility switchyard and the local utility distribution system. With regard to water supply, we note that some PV facilities purchase water off-site for purposes of module washing.

15.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the PV Facility with a nominal capacity of 20 MW-AC Fixed is 2,671/kW-AC, with a nominal capacity of 20 MW-AC Tracker is 2,644/kW-AC, and with a nominal capacity of 150 MW is $2,534/kW-AC. Table 15-1, Table 15-2, and Table 15-3 summarize the Cost Estimate categories for the PV Facility.

TABLE 15-1 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR PV

Technology:	**PV Fixed**	
Nominal Capacity (ISO):	**20,000 kW/AC – 26,000 kW/DC**	
Nominal Heat Rate (ISO):	**N/A Btu/kWh-HHV**	
Capital Cost Category		**(000s) (January 1, 2016$)**
Civil Structural Material and Installation		**5,239**
Mechanical Equipment Supply and Installation		**23,987**
Electrical / I&C Supply and Installation		**8,994**
Project Indirects (1)		**2,244**
EPC Cost before Contingency and Fee		**40,464**
Fee and Contingency		**4,046**
Total Project EPC		**44,511**
Owner Costs (excluding project finance)		**8,902**
Total Project Cost (excluding finance)		**53,413**
Total Project EPC	**/ kW**	**2,226**
Owner Costs 20% (excluding project finance)	**/ kW**	**445**
Total Project Cost (excluding project finance)	**/ kW**	**2,671**

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

TABLE 15-2 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR PV

Technology:	**PV - Tracker**	
Nominal Capacity (ISO):	**20,000 kW/AC – 24,000 kW/DC**	
Nominal Heat Rate (ISO):	**N/A Btu/kWh-HHV**	
Capital Cost Category		**(000s) (January 1, 2016$)**
Civil Structural Material and Installation		**4,837**
Mechanical Equipment Supply and Installation		**24,608**
Electrical / I&C Supply and Installation		**8,366**
Project Indirects (1)		**2,244**
EPC Cost before Contingency and Fee		**40,055**
Fee and Contingency		**4,005**
Total Project EPC		**44,060**
Owner Costs (excluding project finance)		**8,812**
Total Project Cost (excluding finance)		**52,872**
Total Project EPC	**/ kW**	**2,203**
Owner Costs 12% (excluding project finance)	**/ kW**	**441**
Total Project Cost (excluding project finance)	**/ kW**	**2,644**

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

TABLE 15-3 – BASE PLANT SITE CAPITAL COST ESTIMATE FOR PV

Technology:	**PV - Tracker**	
Nominal Capacity (ISO):	**150,000 kW/AC – 180,000 kW/DC**	
Nominal Heat Rate (ISO):	**N/A Btu/kWh-HHV**	
Capital Cost Category		**(000s) (January 1, 2016$)**
Civil Structural Material and Installation		**36,304**
Mechanical Equipment Supply and Installation		**193,336**
Electrical / I&C Supply and Installation		**53,818**
Project Indirects (1)		**13,991**
EPC Cost before Contingency and Fee		**297,449**
Fee and Contingency		**45,000**
Total Project EPC		**342,449**
Owner Costs (excluding project finance)		**37,669**
Total Project Cost (excluding finance)		**380,118**
Total Project EPC	**/ kW**	**2,283**
Owner Costs 12% (excluding project finance)	**/ kW**	**251**
Total Project Cost (excluding project finance)	**/ kW**	**2,534**

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, owner cost differences, and the increase in overheads associated with these five location adjustments.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the Photovoltaic Facility include

Fairbanks, Alaska; Honolulu, Hawaii; Great Falls, Montana; Albuquerque, New Mexico; Cheyenne, Wyoming; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.6.1, taking into consideration the amount of labor we estimated for the PV Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Hawaii, Illinois, Indiana, Maine, Maryland, Massachusetts, Minnesota, Montana, New York, North Dakota, South Dakota, West Virginia, Wisconsin, and Wyoming.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Tables 15-4, 15-5, and 15-6 in the Appendix present the PV Facility capital cost variations for alternative U.S. plant locations.

15.5 O&M ESTIMATE

The significant O&M items for a PV Facility include periodic inverter maintenance and periodic panel water washing. In general, most PV facility operators do not treat O&M on a variable basis, and consequently, all O&M expenses are shown below on a fixed basis. Table 15-7, Table 15-8, and Table 15-9 present the O&M expenses for the PV Facility. The O&M cost variance listed in the below tables are primarily due to economies of scale and the higher O&M costs associated with the tracking facility.

TABLE 15-7 – O&M EXPENSES FOR PV FIXED FACILITY (20 MW)

Technology:	PV-Fixed
Fixed O&M Expense	$23.40/kW-AC-year
Variable O&M Expense	$0/MWh

TABLE 15-8 – O&M EXPENSES FOR PV-TRACKER FACILITY (20 MW)

Technology:	PV - Tracker
Fixed O&M Expense	$23.90/kW-AC-year
Variable O&M Expense	$0/MWh

TABLE 15-9 – O&M EXPENSES FOR PV-TRACKING FACILITY (150 MW)

Technology:	PV – Tracking
Fixed O&M Expense	$21.80/kW-AC-year
Variable O&M Expense	$0/MWh

15.6 ENVIRONMENTAL COMPLIANCE INFORMATION

Table 15-10 presents environmental emissions for the PV Facility.

TABLE 15-10 – ENVIRONMENTAL EMISSIONS FOR PV

Technology:	Photovoltaic
NO_X	0 lb/ MMBtu
SO_2	0 lb/MMBtu
CO_2	0 lb/MMBtu

16. RECIPROCATING INTERNAL COMBUSTION ENGINE (RICE)

16.1 MECHANICAL EQUIPMENT AND SYSTEMS

The Reciprocating Internal Combustion Engine ("RICE") Electric Generating Facility is based on five Wärtsilä Engines, each with a net rated output capacity of 17 MW. The total design capacity is 85 MW.

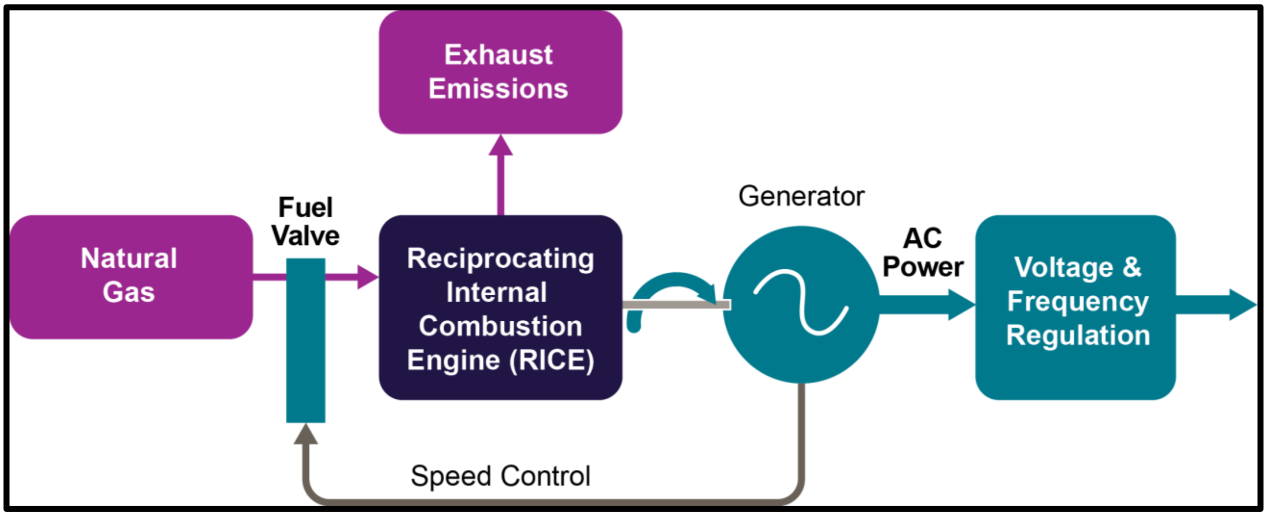
The RICE generating facility is comprised of the engine generating sets which are fired on natural gas; medium voltage generators coupled to each engine; the engine auxiliary systems; and the electrical and control system. The engine auxiliary systems include fuel gas, lubricating oil, compressed air, cooling water, air intake, and exhaust gas systems.

Each engine is a four-stroke, spark-ignited gas engine that operates on the Otto cycle. The engines are comprised of 18 cylinders in a "V" configuration with two inlet valves and two exhaust valves per cylinder. 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 engine block is nodular cast iron and is cast in one piece. The block includes water passages for engine cooling and oil passages for engine lubrication. The crankshaft is forged in one piece and is balanced by counter weights. The engine uses a lean burn gas injection system where the air-fuel mixture contains more air than required for combustion. In this process, ignition of the gas by a spark plug is initiated in a pre-chamber where a richer fuel mixture is used. The flame from the pre-chamber ignites the lean air/fuel mixture in the cylinder.

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. Figure 16-1 represents a simplified process flow diagram for a RICE facility.

FIGURE 16-1 – RICE SCHEMATIC CONFIGURATION



16.2 ELECTRICAL AND CONTROL SYSTEMS

The electrical generator is coupled to the engine flywheel using a flexible coupling. The generator is a medium voltage, synchronous AC generator with a brushless excitation system. The generators are air-cooled using a fan mounted on the generator shaft to provide ambient air for cooling. The generator uses current and voltage measurement transformers to monitor the generator for control and protection.

A generator step-up transformer ("GSU") is used to raise the voltage from the generator to the transmission line voltage. Output from the GSU passes through the Facility switchyard, which provides breaker protection for the Facility and the transmission line as well as disconnect capability so that the Facility can be disconnected from the transmission system when needed. The switchyard also includes metering, a supervisory control and data acquisition system, and communication systems.

The RICE Facility uses a distributed control system that provides plant control, alarms, and safety functions. The control room is located on the Facility site, but the Facility can also be controlled and monitored remotely. The system can be operated in automatic or manual modes. The control system uses the "Wärtsilä Operator Interface System" ("WOIS") for operating the Facility and the "Wärtsilä Information System Environment" ("WISE") for recording and storing information.

16.3 OFF-SITE REQUIREMENTS

Natural gas is delivered to the Facility through a gas lateral connected to the local natural gas trunk line. The natural gas line pressure is reduced at the Facility by a gas regulating system. Water for the limited processes that utilize water is obtained from the municipal water supply. The RICE Facility does not require water treatment for engine cooling unless the water supply contains high levels of solids or dissolved solids. Wastewater is treated using an oil-water separator and then is directed to a municipal wastewater system. The RICE Facility's on-site switchyard is connected to the transmission system through an adjacent utility substation.

16.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the RICE Facility with a nominal capacity of 85 MW is $1,342/kW. Table 16-1 summarizes the Cost Estimate categories for the RICE Facility.

TABLE 16-1 – LOCATION-BASED COSTS FOR RICE

Technology:	RICE	
Nominal Capacity (ISO):	85,000 kW	
Nominal Heat Rate (ISO):	7,900 Btu/kWh-HHV	
Capital Cost Category		(000s) (January 1, 2016$)
Civil Structural Material and Installation		9,473
Mechanical Equipment Supply and Installation		49,716
Electrical / I&C Supply and Installation		10,827
Project Indirects (1)		16,070
EPC Cost before Contingency and Fee		86,086
Fee and Contingency		9,000
Total Project EPC		95,086
Owner Costs (excluding project finance)		19,017
Total Project Cost (excluding finance)		114,103
Total Project EPC	/ kW	1,119
Owner Costs 20% (excluding project finance)	/ kW	224
Total Project Cost (excluding project finance)	/ kW	1,342

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, and owner cost differences and the increase in overheads associated with these five adjustments.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the RICE Facility include Fairbanks, Alaska; Honolulu, Hawaii; Great Falls, Montana; Albuquerque, New Mexico; Cheyenne, Wyoming; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.6.1, taking into consideration the amount of labor we estimated for the RICE Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Hawaii, Illinois, Indiana, Iowa, Kansas, Maine, Maryland, Massachusetts, Michigan, Minnesota, Montana, Nebraska, New York, North Dakota, Ohio, Pennsylvania, South Dakota, West Virginia, Wisconsin, and Wyoming.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 16-2 in the Appendix presents the RICE Facility capital cost variations for alternative U.S. plant locations.

16.5 O&M ESTIMATE

In addition to the general items discussed in the section of the report entitled O&M Estimate, the major areas for O&M for the RICE Facility include engine and generator minor and major maintenance which are based on hours of operation. The maintenance range is from 3,500 hours of operation for typical maintenance items, 12,000 hours of operation for a minor overhaul, and 16,000 hours of operation for a major overhaul. Additionally O&M maintenance and repair includes balance of plant systems such as the compressed air system, fire water system, lube oil system, and the emission control system. Table 16-3 presents the O&M expenses for the RICE Facility, which is based on the RICE Facility operating as a peaking plant.

TABLE 16-3 – O&M EXPENSES FOR RICE

Technology:	RICE
Fixed O&M Expense	$6.90/kW-year
Variable O&M Expense	$5.85/MWh

16.6 ENVIRONMENTAL COMPLIANCE INFORMATION

Each RICE engine generator set utilizes an SCR and oxidation catalyst located in the exhaust system to control NO_X and CO emission from the Facility. Sulfur oxide emissions from the RICE Facility are managed through the natural gas fuel quality, which in the U.S. is generally very low in sulfur. The RICE Facility does not include any control devices for CO_2. Additionally water, wastewater, and solid waste compliance are achieved through traditional on-site and off-site methods, and the costs for such compliance are included in the O&M estimate for the Facility. Table 16-4 presents environmental emissions for the RICE Facility.

TABLE 16-4 – ENVIRONMENTAL EMISSIONS FOR RICE

Technology:	RICE
NO_X	0.07 g/bhp-hr
SO_2	0.001 lb/MMBtu
CO_2	117 lb/MMBtu

17. BATTERY STORAGE (BES)

17.1 MECHANICAL EQUIPMENT AND SYSTEMS

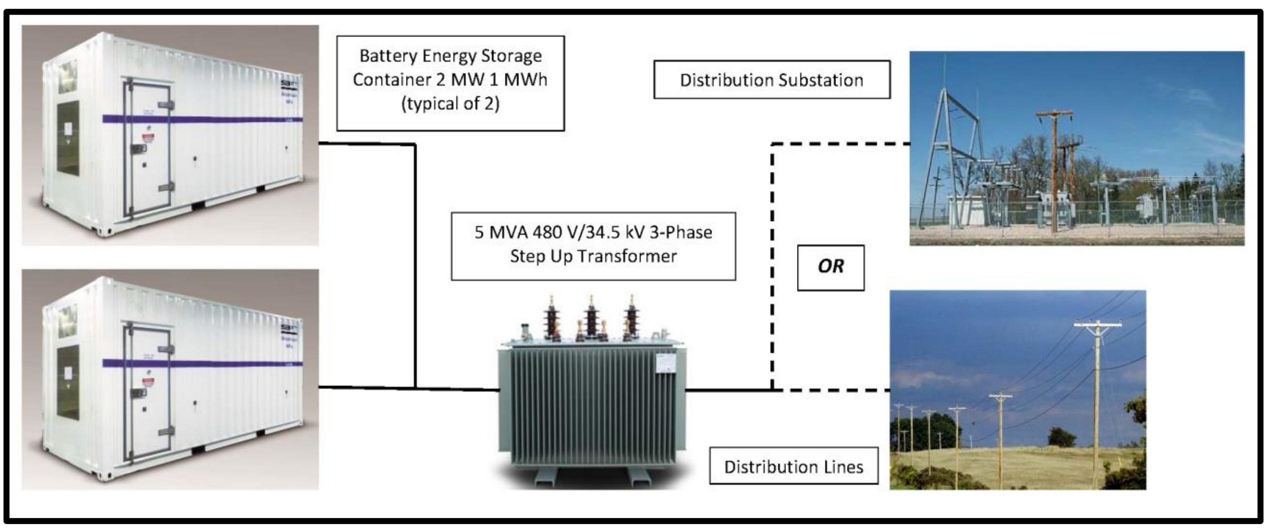
The Battery Storage ("BES") Facility is based on two energy storage modules in 8' x 40' containers, each with a rated capacity of 2.0 MW and 1.0 MWh. The total design capacity is 4.0 MW and 2.0 MWh.

The containers are delivered to the site fully assembled and placed on piers or a pad for their foundation. These are then anchored to their foundations.

Within each container, energy is stored in the battery modules, which are direct current ("DC") elements. They are connected into series strings to form the input voltage for the bi-directional inverter which is called the Power Conversion System ("PCS"). Multiple strings of batteries are connected to the PCS DC input side in parallel to form the container's energy storage capacity. The PCS maintains AC output power quality while the DC input varies with battery string's state of charge and operating current. The output of the PCS is 480 VAC, three phase. Multiple containers are paralleled on the PCS AC output side to form the energy storage capacity of the BES. Each container incorporates the needed internal space conditioning, fans and HVAC; as well as battery modules and the PCS, which consists of multiple paralleled units.

The BES, including its step up transformer and BOP equipment, connect to the grid distribution system. Other facility components include access roads, an O&M building and electrical interconnection facilities. Figure 17-1 presents a picture of a typical BES Facility.

FIGURE 17-1 – BES DESIGN CONFIGURATION



17.2 ELECTRICAL AND CONTROL SYSTEMS

The BES Facility has two energy storage containers. Within each container are appropriate current limiters, sensors, and disconnect switches to isolate faults and facilitate servicing of modules while allowing for continued operation of unaffected elements. Each container's output voltage of 480 VAC is stepped up to 34.5 kV using a pad-mounted transformer located near the BES containers. The output of the 34.5 kV transformer is connected to the grid through appropriate switchgear, current limiters, disconnect switches, and meters.

Each BES container has multiple levels of internal controls. The individual battery modules are each monitored and controlled by a Battery Management Unit ("BMU"). Each battery string is controlled by a Battery String Management Unit ("BSMU") and each container is controlled by a Battery Control Management Unit ("BCMU"). Additionally, each PCS has its own controller to support the many operational use cases of the smart inverters. Each container has its own fire detection and suppression system with its dedicated sensors, annunciators, and controller.

The BES Facility is controlled using a control system generally referred to as its supervisory control and data acquisition ("SCADA") system. The SCADA system provides centralized control of the facility by integrating the control systems provided with each of the PCSs and BCMUs and the control of the BOP systems and equipment. The SCADA may also be connected to the grid's control and dispatch center located remotely from the BES.

17.3 OFF-SITE REQUIREMENTS

The most significant off-site requirements are the construction of and interconnection to roads and the electrical interconnection to the utility transmission & distribution system, as discussed in Section17.2. A BES requires a bi-directional power flow interface to the grid. During BES discharge, it acts as a generation source (or load reduction at its point of interconnection ("POI")) and during charge, it acts as an increased load to the grid at its POI.

17.4 CAPITAL COST ESTIMATE

The base Cost Estimate for the BES Facility with a nominal capacity of 4.0 MW 2.0 MWh is $2,813/kW. Table 17-1 summarizes the Cost Estimate categories for the BES Facility.

TABLE 17-1 – LOCATION-BASED COSTS FOR BES

Technology:	**BES**	
Nominal Capacity (ISO):	**4,000 kW 2,000 kWh**	
Nominal Heat Rate (ISO):	**N/A Btu/kWh-HHV**	
Capital Cost Category		**(000s) (January 1, 2016$)**
Civil Structural Material and Installation		**434**
Mechanical Equipment Supply and Installation		**5,857**
Electrical / I&C Supply and Installation		**1,251**
Project Indirects (1)		**1,718**
EPC Cost before Contingency and Fee		**9,260**
Fee and Contingency		**787**
Total Project EPC		**10,047**
Owner Costs (excluding project finance)		**1,206**
Total Project Cost (excluding finance)		**11,253**
Total Project EPC	**/ kW**	**2,512**
Owner Costs 6% (excluding project finance)	**/ kW**	**302**
Total Project Cost (excluding project finance)	**/ kW**	**2,813**

(1) Includes engineering, distributable costs, scaffolding, construction management, and start-up.

For this type of technology and power plant configuration, our regional adjustments took into consideration the following: seismic design differences, remote location issues, labor wage and productivity differences, location adjustments, and owner cost differences and the increase in overheads associated with these five adjustments.

Seismic design differences among the various locations were based on U.S. seismic map information that detailed the various seismic zones throughout the U.S. No cost increases were associated with seismic Zone 0 and cost step increases were considered for Zones 1, 2, 3 and 4.

Remote location issues are related to geographic areas that typically require installation of man camps, higher craft incentives, and higher per diems are generally required with respect to construction, due to the fact that such areas are long distances from urban areas, where labor is generally abundant. Remote location designations were also considered in locations where higher equipment freight costs are typically incurred, which for example are regions not near established rail or highway access. Remote locations related to the BES Facility include Fairbanks, Alaska; Honolulu, Hawaii; Great Falls, Montana; and Cayey, Puerto Rico.

Labor wage and productivity differences were handled as discussed in Section 2.6.1, taking into consideration the amount of labor we estimated for the BES Facility.

Location adjustments were made to locations where higher cost of living levels are incurred and/or where population density generally correlates to higher construction costs for power and other infrastructure projects. These locations include, but are not limited to, Alaska, California, Connecticut, Delaware, District of Columbia, Hawaii, Illinois, Indiana, Maine, Maryland, Massachusetts, Minnesota, Montana, New York, North Dakota, South Dakota, West Virginia, Wisconsin, and Wyoming.

Owner costs were reviewed based on the need for utility upgrades and/or infrastructure costs such as new facility transmission lines to tie to existing utility transmission substations or existing transmission lines.

Table 17-2 in the Appendix presents the BES Facility capital cost variations for alternative U.S. plant locations.

17.5 O&M ESTIMATE

In addition to the general items discussed in the section of the report entitled O&M Estimate, the major areas for O&M for a BES include visual inspection, maintaining: torque values of connections, the PCS, the fire protection system, and the HVAC for the containers. These are all considered fixed O&M expenses. Battery modules themselves are maintained by the automated controls and require no additional maintenance unless there is a failure, which the controls will annunciate with an alarm. Variable O&M consists of augmentation of the energy storage elements (battery modules) as their capacity degrades with usage (combination of cyclic and calendar aging). This is necessary to make sure the BES can continue to support its rated output throughout the BES operational life. Table 17-3 presents the O&M expenses for the BES Facility.

TABLE 17-3 – O&M EXPENSES FOR BES

Technology:	BES
Fixed O&M Expense	$40.00/kW-year
Variable O&M Expense	$8.00/kWh-year

17.6 ENVIRONMENTAL COMPLIANCE INFORMATION

The BES Facility produces no emissions on discharge. However, during charge the ascribed emissions would be those of the charging generation source. The BES requires 1.18 kWh of recharge for each 1.0 kWh discharged.

TABLE 17-4 – ENVIRONMENTAL EMISSIONS FOR BES

Technology:	BES
NO_X	0 lb/MMBtu
SO_2	0 lb/MMBtu
CO_2	0 lb/MMBtu

APPENDIX 1 – STATE INFORMATION

TABLE 3-2 – LOCATION-BASED COSTS FOR USC (650,000 KW) (JANUARY 1, 2016 DOLLARS)

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alaska	Anchorage	3,636	30%	1,074	4,710
Alaska	Fairbanks	3,636	31%	1,129	4,765
Alabama	Huntsville	3,636	-11%	(389)	3,247
Arizona	Phoenix	3,636	-8%	(284)	3,352
Arkansas	Little Rock	3,636	-7%	(268)	3,368
California	Los Angeles	3,636	16%	585	4,221
California	Redding	3,636	9%	329	3,965
California	Bakersfield	3,636	9%	328	3,964
California	Sacramento	3,636	9%	337	3,973
California	San Francisco	3,636	31%	1,133	4,769
Colorado	Denver	3,636	-9%	(312)	3,324
Connecticut	Hartford	3,636	23%	854	4,490
Delaware	Dover	3,636	20%	738	4,374
District of Columbia	Washington	3,636	35%	1,277	4,913
Florida	Tallahassee	3,636	-8%	(308)	3,328
Florida	Tampa	3,636	-7%	(244)	3,392
Georgia	Atlanta	3,636	-11%	(387)	3,249
Hawaii	Honolulu	N/A	N/A	N/A	N/A
Idaho	Boise	3,636	-4%	(162)	3,474
Illinois	Chicago	3,636	14%	526	4,162
Indiana	Indianapolis	3,636	0%	(7)	3,629
Iowa	Davenport	3,636	-1%	(53)	3,583
Iowa	Waterloo	3,636	-6%	(217)	3,419
Kansas	Wichita	3,636	-7%	(269)	3,367
Kentucky	Louisville	3,636	-7%	(271)	3,365
Louisiana	New Orleans	3,636	-13%	(473)	3,163
Maine	Portland	3,636	-5%	(190)	3,446
Maryland	Baltimore	3,636	1%	30	3,666
Massachusetts	Boston	3,636	32%	1,147	4,783
Michigan	Detroit	3,636	2%	78	3,714
Michigan	Grand Rapids	3,636	-4%	(133)	3,503
Minnesota	Saint Paul	3,636	6%	212	3,848
Mississippi	Jackson	3,636	-7%	(270)	3,366

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Missouri	St. Louis	3,636	2%	76	3,712
Missouri	Kansas City	3,636	0%	(15)	3,621
Montana	Great Falls	3,636	-4%	(132)	3,504
Nebraska	Omaha	3,636	-4%	(159)	3,477
New Hampshire	Concord	3,636	-1%	(30)	3,606
New Jersey	Newark	3,636	11%	406	4,042
New Mexico	Albuquerque	3,636	-6%	(200)	3,436
New York	New York	3,636	36%	1,307	4,943
New York	Syracuse	3,636	-3%	(93)	3,543
Nevada	Las Vegas	3,636	4%	144	3,780
North Carolina	Charlotte	3,636	-12%	(430)	3,206
North Dakota	Bismarck	3,636	-7%	(248)	3,388
Ohio	Cincinnati	3,636	-4%	(133)	3,503
Oregon	Portland	3,636	4%	153	3,789
Pennsylvania	Philadelphia	3,636	15%	537	4,173
Pennsylvania	Wilkes-Barre	3,636	-5%	(164)	3,472
Rhode Island	Providence	3,636	4%	159	3,795
South Carolina	Spartanburg	3,636	-14%	(519)	3,117
South Dakota	Rapid City	3,636	-9%	(333)	3,303
Tennessee	Knoxville	3,636	-10%	(381)	3,255
Texas	Houston	3,636	-12%	(419)	3,217
Utah	Salt Lake City	3,636	-5%	(186)	3,450
Vermont	Burlington	3,636	-3%	(124)	3,512
Virginia	Alexandria	3,636	9%	313	3,949
Virginia	Lynchburg	3,636	-4%	(139)	3,497
Washington	Seattle	3,636	7%	247	3,883
Washington	Spokane	3,636	-3%	(123)	3,513
West Virginia	Charleston	3,636	0%	(11)	3,625
Wisconsin	Green Bay	3,636	-1%	(19)	3,617
Wyoming	Cheyenne	3,636	2%	72	3,708
Puerto Rico	Cayey	N/A	N/A	N/A	N/A

TABLE 4-2 – LOCATION-BASED COSTS FOR USC/CCS FACILITY (650,000 KW) (JANUARY 1, 2016 DOLLARS)

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alaska	Anchorage	5,084	22%	1,124	6,208
Alaska	Fairbanks	5,084	23%	1,190	6,274
Alabama	Huntsville	5,084	-10%	(489)	4,595
Arizona	Phoenix	5,084	-7%	(359)	4,725
Arkansas	Little Rock	5,084	-7%	(364)	4,720
California	Los Angeles	5,084	12%	609	5,693
California	Redding	5,084	7%	332	5,416
California	Bakersfield	5,084	7%	333	5,417
California	Sacramento	5,084	7%	378	5,462
California	San Francisco	5,084	24%	1,233	6,317
Colorado	Denver	5,084	-8%	(397)	4,687
Connecticut	Hartford	5,084	17%	866	5,950
Delaware	Dover	5,084	15%	743	5,827
District of Columbia	Washington	5,084	24%	1,235	6,319
Florida	Tallahassee	5,084	-9%	(444)	4,640
Florida	Tampa	5,084	-4%	(206)	4,878
Georgia	Atlanta	5,084	-10%	(487)	4,597
Hawaii	Honolulu	N/A	N/A	N/A	N/A
Idaho	Boise	5,084	-5%	(267)	4,817
Illinois	Chicago	5,084	12%	630	5,714
Indiana	Indianapolis	5,084	-1%	(45)	5,039
Iowa	Davenport	5,084	-2%	(100)	4,984
Iowa	Waterloo	5,084	-6%	(290)	4,794
Kansas	Wichita	5,084	-7%	(364)	4,720
Kentucky	Louisville	5,084	-7%	(345)	4,739
Louisiana	New Orleans	5,084	-12%	(592)	4,492
Maine	Portland	5,084	-5%	(279)	4,805
Maryland	Baltimore	5,084	-1%	(33)	5,051
Massachusetts	Boston	5,084	24%	1,238	6,322
Michigan	Detroit	5,084	2%	116	5,200
Michigan	Grand Rapids	5,084	-3%	(177)	4,907
Minnesota	Saint Paul	5,084	5%	263	5,347
Mississippi	Jackson	5,084	-7%	(380)	4,704

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Missouri	St. Louis	5,084	2%	83	5,167
Missouri	Kansas City	5,084	0%	(25)	5,059
Montana	Great Falls	5,084	-4%	(198)	4,886
Nebraska	Omaha	5,084	-4%	(206)	4,878
New Hampshire	Concord	5,084	-3%	(163)	4,921
New Jersey	Newark	5,084	10%	510	5,594
New Mexico	Albuquerque	5,084	-5%	(245)	4,839
New York	New York	5,084	30%	1,543	6,627
New York	Syracuse	5,084	-2%	(120)	4,964
Nevada	Las Vegas	5,084	3%	159	5,243
North Carolina	Charlotte	5,084	-11%	(548)	4,536
North Dakota	Bismarck	5,084	-7%	(371)	4,713
Ohio	Cincinnati	5,084	-4%	(205)	4,879
Oregon	Portland	5,084	3%	146	5,230
Pennsylvania	Philadelphia	5,084	12%	604	5,688
Pennsylvania	Wilkes-Barre	5,084	-4%	(213)	4,871
Rhode Island	Providence	5,084	3%	137	5,221
South Carolina	Spartanburg	5,084	-13%	(656)	4,428
South Dakota	Rapid City	5,084	-9%	(473)	4,611
Tennessee	Knoxville	5,084	-10%	(484)	4,600
Texas	Houston	5,084	-10%	(529)	4,555
Utah	Salt Lake City	5,084	-5%	(277)	4,807
Vermont	Burlington	5,084	-7%	(340)	4,744
Virginia	Alexandria	5,084	5%	254	5,338
Virginia	Lynchburg	5,084	-5%	(239)	4,845
Washington	Seattle	5,084	5%	264	5,348
Washington	Spokane	5,084	-3%	(160)	4,924
West Virginia	Charleston	5,084	-2%	(99)	4,985
Wisconsin	Green Bay	5,084	-1%	(58)	5,026
Wyoming	Cheyenne	5,084	-1%	(29)	5,055
Puerto Rico	Cayey	N/A	N/A	N/A	N/A

TABLE 5-2 – LOCATION-BASED COSTS FOR CTNG FACILITY (300,000 KW) (JANUARY 1, 2016 DOLLARS)

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alaska	Anchorage	226	117%	264	490
Alaska	Fairbanks	226	136%	307	533
Alabama	Huntsville	226	-13%	(30)	196
Arizona	Phoenix	226	-7%	(16)	210
Arkansas	Little Rock	226	-6%	(14)	212
California	Los Angeles	226	73%	164	390
California	Redding	226	17%	39	265
California	Bakersfield	226	27%	61	287
California	Sacramento	226	29%	66	292
California	San Francisco	226	119%	269	495
Colorado	Denver	226	7%	15	241
Connecticut	Hartford	226	69%	157	383
Delaware	Dover	226	69%	155	381
District of Columbia	Washington	226	110%	249	475
Florida	Tallahassee	226	-12%	(26)	200
Florida	Tampa	226	-9%	(21)	205
Georgia	Atlanta	226	-1%	(3)	223
Hawaii	Honolulu	N/A	N/A	N/A	N/A
Idaho	Boise	226	-3%	(6)	220
Illinois	Chicago	226	25%	56	282
Indiana	Indianapolis	226	5%	11	237
Iowa	Davenport	226	7%	15	241
Iowa	Waterloo	226	0%	-	226
Kansas	Wichita	226	0%	(1)	225
Kentucky	Louisville	226	-9%	(21)	205
Louisiana	New Orleans	226	11%	24	250
Maine	Portland	226	0%	(1)	225
Maryland	Baltimore	226	56%	126	352
Massachusetts	Boston	226	93%	211	437
Michigan	Detroit	226	14%	31	257
Michigan	Grand Rapids	226	3%	7	233
Minnesota	Saint Paul	226	15%	35	261
Mississippi	Jackson	226	-8%	(19)	207

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Missouri	St. Louis	226	12%	28	254
Missouri	Kansas City	226	3%	7	233
Montana	Great Falls	226	23%	51	277
Nebraska	Omaha	226	4%	9	235
New Hampshire	Concord	226	3%	6	232
New Jersey	Newark	226	53%	119	345
New Mexico	Albuquerque	226	10%	23	249
New York	New York	226	167%	378	604
New York	Syracuse	226	35%	80	306
Nevada	Las Vegas	226	7%	16	242
North Carolina	Charlotte	226	-14%	(31)	195
North Dakota	Bismarck	226	-1%	(3)	223
Ohio	Cincinnati	226	0%	-	226
Oregon	Portland	226	10%	23	249
Pennsylvania	Philadelphia	226	41%	92	318
Pennsylvania	Wilkes-Barre	226	6%	13	239
Rhode Island	Providence	226	50%	114	340
South Carolina	Spartanburg	226	-16%	(37)	189
South Dakota	Rapid City	226	-5%	(11)	215
Tennessee	Knoxville	226	-14%	(31)	195
Texas	Houston	226	-17%	(38)	188
Utah	Salt Lake City	226	2%	4	230
Vermont	Burlington	226	22%	49	275
Virginia	Alexandria	226	39%	88	314
Virginia	Lynchburg	226	-9%	(20)	206
Washington	Seattle	226	14%	32	258
Washington	Spokane	226	-1%	(3)	223
West Virginia	Charleston	226	10%	23	249
Wisconsin	Green Bay	226	3%	6	232
Wyoming	Cheyenne	226	17%	38	264
Puerto Rico	Cayey	226	29%	66	292

TABLE 6-2 – LOCATION-BASED COSTS FOR GCBC FACILITY (300,000 KW) (JANUARY 1, 2016 DOLLARS)

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alaska	Anchorage	4,620	25%	1,138	5,758
Alaska	Fairbanks	4,620	27%	1,246	5,866
Alabama	Huntsville	4,620	-13%	(608)	4,012
Arizona	Phoenix	4,620	-10%	(450)	4,170
Arkansas	Little Rock	4,620	-9%	(424)	4,196
California	Los Angeles	4,620	16%	719	5,339
California	Redding	4,620	9%	393	5,013
California	Bakersfield	4,620	7%	334	4,954
California	Sacramento	4,620	9%	406	5,026
California	San Francisco	4,620	31%	1,445	6,065
Colorado	Denver	4,620	-11%	(515)	4,105
Connecticut	Hartford	4,620	21%	956	5,576
Delaware	Dover	4,620	17%	780	5,400
District of Columbia	Washington	4,620	21%	991	5,611
Florida	Tallahassee	4,620	-10%	(466)	4,154
Florida	Tampa	4,620	-8%	(362)	4,258
Georgia	Atlanta	4,620	-13%	(605)	4,015
Hawaii	Honolulu	N/A	N/A	N/A	N/A
Idaho	Boise	4,620	-6%	(285)	4,335
Illinois	Chicago	4,620	17%	769	5,389
Indiana	Indianapolis	4,620	-5%	(232)	4,388
Iowa	Davenport	4,620	-2%	(85)	4,535
Iowa	Waterloo	4,620	-8%	(350)	4,270
Kansas	Wichita	4,620	-10%	(447)	4,173
Kentucky	Louisville	4,620	-10%	(449)	4,171
Louisiana	New Orleans	4,620	-16%	(732)	3,888
Maine	Portland	4,620	-9%	(409)	4,211
Maryland	Baltimore	4,620	-3%	(123)	4,497
Massachusetts	Boston	4,620	26%	1,219	5,839
Michigan	Detroit	4,620	2%	114	4,734
Michigan	Grand Rapids	4,620	-5%	(215)	4,405
Minnesota	Saint Paul	4,620	7%	317	4,937
Mississippi	Jackson	4,620	-9%	(416)	4,204

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Missouri	St. Louis	4,620	1%	65	4,685
Missouri	Kansas City	4,620	-1%	(48)	4,572
Montana	Great Falls	4,620	-6%	(260)	4,360
Nebraska	Omaha	4,620	-6%	(268)	4,352
New Hampshire	Concord	4,620	-2%	(72)	4,548
New Jersey	Newark	4,620	17%	774	5,394
New Mexico	Albuquerque	4,620	-8%	(367)	4,253
New York	New York	4,620	34%	1,588	6,208
New York	Syracuse	4,620	-1%	(32)	4,588
Nevada	Las Vegas	4,620	2%	104	4,724
North Carolina	Charlotte	4,620	-16%	(717)	3,903
North Dakota	Bismarck	4,620	-9%	(400)	4,220
Ohio	Cincinnati	4,620	-7%	(306)	4,314
Oregon	Portland	4,620	2%	110	4,730
Pennsylvania	Philadelphia	4,620	9%	424	5,044
Pennsylvania	Wilkes-Barre	4,620	-6%	(288)	4,332
Rhode Island	Providence	4,620	11%	494	5,114
South Carolina	Spartanburg	4,620	-18%	(829)	3,791
South Dakota	Rapid City	4,620	-12%	(538)	4,082
Tennessee	Knoxville	4,620	-14%	(627)	3,993
Texas	Houston	4,620	-15%	(676)	3,944
Utah	Salt Lake City	4,620	-8%	(358)	4,262
Vermont	Burlington	4,620	-5%	(223)	4,397
Virginia	Alexandria	4,620	5%	254	4,874
Virginia	Lynchburg	4,620	-7%	(315)	4,305
Washington	Seattle	4,620	6%	260	4,880
Washington	Spokane	4,620	-5%	(221)	4,399
West Virginia	Charleston	4,620	-1%	(29)	4,591
Wisconsin	Green Bay	4,620	-2%	(111)	4,509
Wyoming	Cheyenne	4,620	-10%	(441)	4,179
Puerto Rico	Cayey	4,620	-8%	(348)	4,272

TABLE 7-2 – LOCATION-BASED COSTS FOR CTCB FACILITY (300,000 KW) (JANUARY 1, 2016 DOLLARS)

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alaska	Anchorage	537	66%	352	889
Alaska	Fairbanks	537	74%	400	937
Alabama	Huntsville	537	-14%	(74)	463
Arizona	Phoenix	537	-9%	(49)	488
Arkansas	Little Rock	537	-9%	(46)	491
California	Los Angeles	537	62%	331	868
California	Redding	537	35%	187	724
California	Bakersfield	537	38%	202	739
California	Sacramento	537	35%	188	725
California	San Francisco	537	97%	521	1,058
Colorado	Denver	537	-12%	(62)	475
Connecticut	Hartford	537	58%	309	846
Delaware	Dover	537	52%	281	818
District of Columbia	Washington	537	72%	388	925
Florida	Tallahassee	537	-11%	(60)	477
Florida	Tampa	537	-9%	(47)	490
Georgia	Atlanta	537	-14%	(74)	463
Hawaii	Honolulu	N/A	N/A	N/A	N/A
Idaho	Boise	537	-5%	(28)	509
Illinois	Chicago	537	40%	213	750
Indiana	Indianapolis	537	-5%	(26)	511
Iowa	Davenport	537	-2%	(11)	526
Iowa	Waterloo	537	-8%	(45)	492
Kansas	Wichita	537	-10%	(53)	484
Kentucky	Louisville	537	-10%	(54)	483
Louisiana	New Orleans	537	-18%	(95)	442
Maine	Portland	537	1%	4	541
Maryland	Baltimore	537	16%	85	622
Massachusetts	Boston	537	88%	473	1,010
Michigan	Detroit	537	4%	19	556
Michigan	Grand Rapids	537	-5%	(28)	509
Minnesota	Saint Paul	537	14%	75	612
Mississippi	Jackson	537	-9%	(49)	488

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Missouri	St. Louis	537	6%	31	568
Missouri	Kansas City	537	1%	3	540
Montana	Great Falls	537	2%	9	546
Nebraska	Omaha	537	-6%	(30)	507
New Hampshire	Concord	537	0%	-	537
New Jersey	Newark	537	16%	88	625
New Mexico	Albuquerque	537	-8%	(43)	494
New York	New York	537	37%	198	735
New York	Syracuse	537	-3%	(16)	521
Nevada	Las Vegas	537	4%	23	560
North Carolina	Charlotte	537	-16%	(84)	453
North Dakota	Bismarck	537	-10%	(52)	485
Ohio	Cincinnati	537	-10%	(52)	485
Oregon	Portland	537	28%	150	687
Pennsylvania	Philadelphia	537	12%	64	601
Pennsylvania	Wilkes-Barre	537	-5%	(28)	509
Rhode Island	Providence	537	7%	39	576
South Carolina	Spartanburg	537	-18%	(98)	439
South Dakota	Rapid City	537	-13%	(70)	467
Tennessee	Knoxville	537	-14%	(77)	460
Texas	Houston	537	-16%	(88)	449
Utah	Salt Lake City	537	-4%	(24)	513
Vermont	Burlington	537	-4%	(20)	517
Virginia	Alexandria	537	46%	247	784
Virginia	Lynchburg	537	-10%	(53)	484
Washington	Seattle	537	20%	105	642
Washington	Spokane	537	-4%	(20)	517
West Virginia	Charleston	537	0%	1	538
Wisconsin	Green Bay	537	-6%	(31)	506
Wyoming	Cheyenne	537	-10%	(53)	484
Puerto Rico	Cayey	537	6%	34	571

TABLE 8-2 – LOCATION-BASED COSTS FOR NGCC FACILITY (702,000 KW) (JANUARY 1, 2016 DOLLARS)

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alaska	Anchorage	978	30%	296	1,274
Alaska	Fairbanks	978	35%	346	1,324
Alabama	Huntsville	978	-11%	(112)	866
Arizona	Phoenix	978	1%	8	986
Arkansas	Little Rock	978	-9%	(84)	894
California	Los Angeles	978	28%	270	1,248
California	Redding	978	15%	148	1,126
California	Bakersfield	978	17%	163	1,141
California	Sacramento	978	19%	183	1,161
California	San Francisco	978	43%	423	1,401
Colorado	Denver	978	1%	10	988
Connecticut	Hartford	978	28%	271	1,249
Delaware	Dover	978	26%	256	1,234
District of Columbia	Washington	978	34%	328	1,306
Florida	Tallahassee	978	-11%	(106)	872
Florida	Tampa	978	-6%	(58)	920
Georgia	Atlanta	978	-9%	(86)	892
Hawaii	Honolulu	N/A	N/A	N/A	N/A
Idaho	Boise	978	-5%	(48)	930
Illinois	Chicago	978	12%	122	1,100
Indiana	Indianapolis	978	-1%	(13)	965
Iowa	Davenport	978	0%	(1)	977
Iowa	Waterloo	978	-4%	(40)	938
Kansas	Wichita	978	-5%	(52)	926
Kentucky	Louisville	978	-7%	(67)	911
Louisiana	New Orleans	978	-14%	(137)	841
Maine	Portland	978	-6%	(58)	920
Maryland	Baltimore	978	18%	177	1,155
Massachusetts	Boston	978	37%	360	1,338
Michigan	Detroit	978	5%	46	1,024
Michigan	Grand Rapids	978	-2%	(17)	961
Minnesota	Saint Paul	978	7%	65	1,043
Mississippi	Jackson	978	-9%	(90)	888

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Missouri	St. Louis	978	3%	32	1,010
Missouri	Kansas City	978	0%	1	979
Montana	Great Falls	978	2%	16	994
Nebraska	Omaha	978	-2%	(20)	958
New Hampshire	Concord	978	7%	64	1,042
New Jersey	Newark	978	19%	185	1,163
New Mexico	Albuquerque	978	-3%	(32)	946
New York	New York	978	63%	619	1,597
New York	Syracuse	978	16%	154	1,132
Nevada	Las Vegas	978	3%	25	1,003
North Carolina	Charlotte	978	-11%	(106)	872
North Dakota	Bismarck	978	-6%	(56)	922
Ohio	Cincinnati	978	-5%	(46)	932
Oregon	Portland	978	11%	110	1,088
Pennsylvania	Philadelphia	978	23%	226	1,204
Pennsylvania	Wilkes-Barre	978	-2%	(18)	960
Rhode Island	Providence	978	22%	216	1,194
South Carolina	Spartanburg	978	-15%	(143)	835
South Dakota	Rapid City	978	-8%	(77)	901
Tennessee	Knoxville	978	-10%	(96)	882
Texas	Houston	978	-11%	(108)	870
Utah	Salt Lake City	978	-4%	(41)	937
Vermont	Burlington	978	-1%	(11)	967
Virginia	Alexandria	978	16%	157	1,135
Virginia	Lynchburg	978	-7%	(72)	906
Washington	Seattle	978	4%	43	1,021
Washington	Spokane	978	-3%	(26)	952
West Virginia	Charleston	978	0%	2	980
Wisconsin	Green Bay	978	-2%	(19)	959
Wyoming	Cheyenne	978	5%	52	1,030
Puerto Rico	Cayey	978	9%	92	1,070

TABLE 9-2 – LOCATION-BASED COSTS FOR AG-NGCC FACILITY (429,000 KW) (JANUARY 1, 2016 DOLLARS)

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alaska	Anchorage	1,104	28%	314	1,418
Alaska	Fairbanks	1,104	32%	349	1,453
Alabama	Huntsville	1,104	-8%	(93)	1,011
Arizona	Phoenix	1,104	5%	52	1,156
Arkansas	Little Rock	1,104	-6%	(61)	1,043
California	Los Angeles	1,104	29%	318	1,422
California	Redding	1,104	17%	187	1,291
California	Bakersfield	1,104	19%	215	1,319
California	Sacramento	1,104	19%	215	1,319
California	San Francisco	1,104	41%	458	1,562
Colorado	Denver	1,104	2%	17	1,121
Connecticut	Hartford	1,104	27%	302	1,406
Delaw are	Dover	1,104	26%	284	1,388
District of Columbia	Washington	1,104	33%	365	1,469
Florida	Tallahassee	1,104	-7%	(81)	1,023
Florida	Tampa	1,104	-6%	(67)	1,037
Georgia	Atlanta	1,104	-6%	(67)	1,037
Haw aii	Honolulu	1,104	44%	486	1,590
Idaho	Boise	1,104	-2%	(24)	1,080
Illinois	Chicago	1,104	9%	104	1,208
Indiana	Indianapolis	1,104	0%	(4)	1,100
Iow a	Davenport	1,104	1%	8	1,112
Iow a	Waterloo	1,104	-2%	(27)	1,077
Kansas	Wichita	1,104	-3%	(32)	1,072
Kentucky	Louisville	1,104	2%	26	1,130
Louisiana	New Orleans	1,104	-11%	(116)	988
Maine	Portland	1,104	-3%	(38)	1,066
Maryland	Baltimore	1,104	20%	216	1,320
Massachusetts	Boston	1,104	34%	376	1,480
Michigan	Detroit	1,104	4%	42	1,146
Michigan	Grand Rapids	1,104	-1%	(9)	1,095
Minnesota	Saint Paul	1,104	5%	56	1,160
Mississippi	Jackson	1,104	-6%	(67)	1,037

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Missouri	St. Louis	1,104	4%	44	1,148
Missouri	Kansas City	1,104	1%	8	1,112
Montana	Great Falls	1,104	10%	111	1,215
Nebraska	Omaha	1,104	-1%	(9)	1,095
New Hampshire	Concord	1,104	11%	122	1,226
New Jersey	Newark	1,104	15%	170	1,274
New Mexico	Albuquerque	1,104	-2%	(22)	1,082
New York	New York	1,104	55%	610	1,714
New York	Syracuse	1,104	17%	187	1,291
Nevada	Las Vegas	1,104	8%	93	1,197
North Carolina	Charlotte	1,104	-7%	(81)	1,023
North Dakota	Bismarck	1,104	-3%	(33)	1,071
Ohio	Cincinnati	1,104	-3%	(31)	1,073
Oregon	Portland	1,104	14%	150	1,254
Pennsylvania	Philadelphia	1,104	22%	246	1,350
Pennsylvania	Wilkes-Barre	1,104	0%	(4)	1,100
Rhode Island	Providence	1,104	23%	253	1,357
South Carolina	Spartanburg	1,104	-10%	(115)	989
South Dakota	Rapid City	1,104	-5%	(52)	1,052
Tennessee	Knoxville	1,104	-7%	(76)	1,028
Texas	Houston	1,104	-8%	(89)	1,015
Utah	Salt Lake City	1,104	-1%	(12)	1,092
Vermont	Burlington	1,104	3%	37	1,141
Virginia	Alexandria	1,104	18%	197	1,301
Virginia	Lynchburg	1,104	-5%	(52)	1,052
Washington	Seattle	1,104	5%	53	1,157
Washington	Spokane	1,104	-1%	(15)	1,089
West Virginia	Charleston	1,104	2%	23	1,127
Wisconsin	Green Bay	1,104	-1%	(12)	1,092
Wyoming	Cheyenne	1,104	7%	72	1,176
Puerto Rico	Cayey	1,104	13%	143	1,247

TABLE 10-2 – LOCATION-BASED COSTS FOR CT FACILITY (100,000 KW) (JANUARY 1, 2016 DOLLARS)

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alaska	Anchorage	1,101	26%	286	1,387
Alaska	Fairbanks	1,101	30%	334	1,435
Alabama	Huntsville	1,101	-7%	(73)	1,028
Arizona	Phoenix	1,101	-4%	(48)	1,053
Arkansas	Little Rock	1,101	-4%	(45)	1,056
California	Los Angeles	1,101	16%	175	1,276
California	Redding	1,101	5%	56	1,157
California	Bakersfield	1,101	6%	71	1,172
California	Sacramento	1,101	8%	84	1,185
California	San Francisco	1,101	28%	312	1,413
Colorado	Denver	1,101	-2%	(22)	1,079
Connecticut	Hartford	1,101	16%	178	1,279
Delaware	Dover	1,101	15%	164	1,265
District of Columbia	Washington	1,101	22%	245	1,346
Florida	Tallahassee	1,101	-5%	(60)	1,041
Florida	Tampa	1,101	-4%	(46)	1,055
Georgia	Atlanta	1,101	-4%	(47)	1,054
Hawaii	Honolulu	1,101	45%	499	1,600
Idaho	Boise	1,101	-2%	(27)	1,074
Illinois	Chicago	1,101	9%	101	1,202
Indiana	Indianapolis	1,101	-1%	(6)	1,095
Iowa	Davenport	1,101	1%	9	1,110
Iowa	Waterloo	1,101	-2%	(25)	1,076
Kansas	Wichita	1,101	-3%	(33)	1,068
Kentucky	Louisville	1,101	-5%	(53)	1,048
Louisiana	New Orleans	1,101	-8%	(93)	1,008
Maine	Portland	1,101	-4%	(40)	1,061
Maryland	Baltimore	1,101	9%	99	1,200
Massachusetts	Boston	1,101	23%	251	1,352
Michigan	Detroit	1,101	4%	39	1,140
Michigan	Grand Rapids	1,101	-1%	(8)	1,093
Minnesota	Saint Paul	1,101	5%	55	1,156
Mississippi	Jackson	1,101	-4%	(49)	1,052

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Missouri	St. Louis	1,101	3%	31	1,132
Missouri	Kansas City	1,101	0%	3	1,104
Montana	Great Falls	1,101	1%	16	1,117
Nebraska	Omaha	1,101	-1%	(10)	1,091
New Hampshire	Concord	1,101	0%	-	1,101
New Jersey	Newark	1,101	15%	165	1,266
New Mexico	Albuquerque	1,101	0%	(3)	1,098
New York	New York	1,101	44%	481	1,582
New York	Syracuse	1,101	6%	68	1,169
Nevada	Las Vegas	1,101	8%	87	1,188
North Carolina	Charlotte	1,101	-7%	(82)	1,019
North Dakota	Bismarck	1,101	-3%	(32)	1,069
Ohio	Cincinnati	1,101	-3%	(32)	1,069
Oregon	Portland	1,101	2%	20	1,121
Pennsylvania	Philadelphia	1,101	11%	122	1,223
Pennsylvania	Wilkes-Barre	1,101	-1%	(8)	1,093
Rhode Island	Providence	1,101	12%	130	1,231
South Carolina	Spartanburg	1,101	-9%	(97)	1,004
South Dakota	Rapid City	1,101	-4%	(49)	1,052
Tennessee	Knoxville	1,101	-7%	(75)	1,026
Texas	Houston	1,101	-8%	(86)	1,015
Utah	Salt Lake City	1,101	-2%	(23)	1,078
Vermont	Burlington	1,101	3%	33	1,134
Virginia	Alexandria	1,101	7%	78	1,179
Virginia	Lynchburg	1,101	-5%	(52)	1,049
Washington	Seattle	1,101	4%	39	1,140
Washington	Spokane	1,101	-2%	(19)	1,082
West Virginia	Charleston	1,101	2%	20	1,121
Wisconsin	Green Bay	1,101	-1%	(11)	1,090
Wyoming	Cheyenne	1,101	7%	72	1,173
Puerto Rico	Cayey	1,101	3%	35	1,136

TABLE 11-2 – LOCATION-BASED COSTS FOR ACT FACILITY (237,000 KW) (JANUARY 1, 2016 DOLLARS)

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alaska	Anchorage	678	40%	268	946
Alaska	Fairbanks	678	46%	311	989
Alabama	Huntsville	678	-5%	(36)	642
Arizona	Phoenix	678	-3%	(21)	657
Arkansas	Little Rock	678	-3%	(19)	659
California	Los Angeles	678	24%	166	844
California	Redding	678	6%	42	720
California	Bakersfield	678	9%	62	740
California	Sacramento	678	10%	69	747
California	San Francisco	678	41%	275	953
Colorado	Denver	678	1%	9	687
Connecticut	Hartford	678	24%	160	838
Delaware	Dover	678	23%	157	835
District of Columbia	Washington	678	37%	248	926
Florida	Tallahassee	678	-5%	(32)	646
Florida	Tampa	678	-4%	(25)	653
Georgia	Atlanta	678	-1%	(10)	668
Hawaii	Honolulu	678	71%	483	1,161
Idaho	Boise	678	-1%	(10)	668
Illinois	Chicago	678	9%	63	741
Indiana	Indianapolis	678	1%	9	687
Iowa	Davenport	678	2%	14	692
Iowa	Waterloo	678	-1%	(4)	674
Kansas	Wichita	678	-1%	(6)	672
Kentucky	Louisville	678	-4%	(26)	652
Louisiana	New Orleans	678	-7%	(50)	628
Maine	Portland	678	-1%	(7)	671
Maryland	Baltimore	678	18%	122	800
Massachusetts	Boston	678	32%	217	895
Michigan	Detroit	678	5%	32	710
Michigan	Grand Rapids	678	1%	5	683
Minnesota	Saint Paul	678	6%	38	716
Mississippi	Jackson	678	-3%	(23)	655

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Missouri	St. Louis	678	4%	29	707
Missouri	Kansas City	678	1%	6	684
Montana	Great Falls	678	7%	48	726
Nebraska	Omaha	678	1%	6	684
New Hampshire	Concord	678	1%	5	683
New Jersey	Newark	678	19%	126	804
New Mexico	Albuquerque	678	3%	19	697
New York	New York	678	58%	394	1,072
New York	Syracuse	678	12%	78	756
Nevada	Las Vegas	678	12%	82	760
North Carolina	Charlotte	678	-6%	(39)	639
North Dakota	Bismarck	678	-1%	(8)	670
Ohio	Cincinnati	678	-1%	(5)	673
Oregon	Portland	678	3%	23	701
Pennsylvania	Philadelphia	678	14%	97	775
Pennsylvania	Wilkes-Barre	678	1%	10	688
Rhode Island	Providence	678	17%	117	795
South Carolina	Spartanburg	678	-7%	(46)	632
South Dakota	Rapid City	678	-3%	(17)	661
Tennessee	Knoxville	678	-6%	(38)	640
Texas	Houston	678	-7%	(46)	632
Utah	Salt Lake City	678	0%	-	678
Vermont	Burlington	678	7%	47	725
Virginia	Alexandria	678	13%	87	765
Virginia	Lynchburg	678	-4%	(25)	653
Washington	Seattle	678	5%	33	711
Washington	Spokane	678	-1%	(5)	673
West Virginia	Charleston	678	3%	22	700
Wisconsin	Green Bay	678	0%	3	681
Wyoming	Cheyenne	678	43%	293	971
Puerto Rico	Cayey	678	9%	61	739

TABLE 12-2 – LOCATION-BASED COSTS FOR AN FACILITY (2,234,000 KW) (JANUARY 1, 2016 DOLLARS)

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alaska	Anchorage	5,945	13%	787	6,732
Alaska	Fairbanks	5,945	13%	799	6,744
Alabama	Huntsville	5,945	-4%	(227)	5,718
Arizona	Phoenix	5,945	-3%	(156)	5,789
Arkansas	Little Rock	5,945	-3%	(158)	5,787
California	Los Angeles	5,945	8%	470	6,415
California	Redding	5,945	5%	278	6,223
California	Bakersfield	5,945	6%	332	6,277
California	Sacramento	5,945	5%	299	6,244
California	San Francisco	5,945	17%	1,029	6,974
Colorado	Denver	5,945	-3%	(173)	5,772
Connecticut	Hartford	5,945	13%	772	6,717
Delaware	Dover	5,945	12%	704	6,649
District of Columbia	Washington	5,945	22%	1,281	7,226
Florida	Tallahassee	5,945	-4%	(216)	5,729
Florida	Tampa	5,945	-2%	(106)	5,839
Georgia	Atlanta	5,945	-4%	(226)	5,719
Hawaii	Honolulu	N/A	N/A	N/A	N/A
Idaho	Boise	5,945	-2%	(102)	5,843
Illinois	Chicago	5,945	6%	362	6,307
Indiana	Indianapolis	5,945	1%	59	6,004
Iowa	Davenport	5,945	-1%	(46)	5,899
Iowa	Waterloo	5,945	-2%	(134)	5,811
Kansas	Wichita	5,945	-3%	(158)	5,787
Kentucky	Louisville	5,945	-3%	(149)	5,796
Louisiana	New Orleans	5,945	-5%	(285)	5,660
Maine	Portland	5,945	-1%	(38)	5,907
Maryland	Baltimore	5,945	2%	135	6,080
Massachusetts	Boston	5,945	15%	884	6,829
Michigan	Detroit	5,945	1%	65	6,010
Michigan	Grand Rapids	5,945	-1%	(82)	5,863
Minnesota	Saint Paul	5,945	2%	143	6,088
Mississippi	Jackson	5,945	-3%	(176)	5,769

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Missouri	St. Louis	5,945	2%	92	6,037
Missouri	Kansas City	5,945	0%	10	5,955
Montana	Great Falls	5,945	-1%	(88)	5,857
Nebraska	Omaha	5,945	-1%	(85)	5,860
New Hampshire	Concord	5,945	-1%	(54)	5,891
New Jersey	Newark	5,945	4%	248	6,193
New Mexico	Albuquerque	5,945	-2%	(93)	5,852
New York	New York	5,945	9%	557	6,502
New York	Syracuse	5,945	6%	345	6,290
Nevada	Las Vegas	5,945	2%	130	6,075
North Carolina	Charlotte	5,945	-4%	(233)	5,712
North Dakota	Bismarck	5,945	-3%	(172)	5,773
Ohio	Cincinnati	5,945	0%	(15)	5,930
Oregon	Portland	5,945	3%	191	6,136
Pennsylvania	Philadelphia	5,945	3%	182	6,127
Pennsylvania	Wilkes-Barre	5,945	-1%	(77)	5,868
Rhode Island	Providence	5,945	1%	85	6,030
South Carolina	Spartanburg	5,945	-5%	(293)	5,652
South Dakota	Rapid City	5,945	-4%	(220)	5,725
Tennessee	Knoxville	5,945	-4%	(214)	5,731
Texas	Houston	5,945	-4%	(245)	5,700
Utah	Salt Lake City	5,945	-1%	(75)	5,870
Vermont	Burlington	5,945	-2%	(136)	5,809
Virginia	Alexandria	5,945	6%	338	6,283
Virginia	Lynchburg	5,945	-1%	(31)	5,914
Washington	Seattle	5,945	4%	246	6,191
Washington	Spokane	5,945	-1%	(52)	5,893
West Virginia	Charleston	5,945	-1%	(35)	5,910
Wisconsin	Green Bay	5,945	1%	43	5,988
Wyoming	Cheyenne	5,945	3%	178	6,123
Puerto Rico	Cayey	N/A	N/A	N/A	N/A

TABLE 13-2– LOCATION-BASED COSTS FOR BBFB FACILITY (50,000 KW) (JANUARY 1, 2016 DOLLARS)

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alaska	Anchorage	4,985	19%	956	5,941
Alaska	Fairbanks	4,985	22%	1,101	6,086
Alabama	Huntsville	4,985	-15%	(729)	4,256
Arizona	Phoenix	4,985	-10%	(523)	4,462
Arkansas	Little Rock	4,985	-10%	(512)	4,473
California	Los Angeles	4,985	10%	510	5,495
California	Redding	4,985	9%	447	5,432
California	Bakersfield	4,985	8%	386	5,371
California	Sacramento	4,985	9%	461	5,446
California	San Francisco	4,985	29%	1,445	6,430
Colorado	Denver	4,985	-12%	(601)	4,384
Connecticut	Hartford	4,985	20%	1,012	5,997
Delaw are	Dover	4,985	16%	804	5,789
District of Columbia	Washington	4,985	25%	1,244	6,229
Florida	Tallahassee	4,985	-11%	(565)	4,420
Florida	Tampa	4,985	-9%	(444)	4,541
Georgia	Atlanta	4,985	-15%	(726)	4,259
Haw aii	Honolulu	4,985	46%	2,318	7,303
Idaho	Boise	4,985	-7%	(331)	4,654
Illinois	Chicago	4,985	18%	877	5,862
Indiana	Indianapolis	4,985	-3%	(140)	4,845
Iow a	Davenport	4,985	-2%	(100)	4,885
Iow a	Waterloo	4,985	-8%	(410)	4,575
Kansas	Wichita	4,985	-10%	(521)	4,464
Kentucky	Louisville	4,985	-10%	(523)	4,462
Louisiana	New Orleans	4,985	-18%	(876)	4,109
Maine	Portland	4,985	-10%	(497)	4,488
Maryland	Baltimore	4,985	-4%	(186)	4,799
Massachusetts	Boston	4,985	26%	1,319	6,304
Michigan	Detroit	4,985	3%	136	5,121
Michigan	Grand Rapids	4,985	-5%	(251)	4,734
Minnesota	Saint Paul	4,985	7%	365	5,350
Mississippi	Jackson	4,985	-10%	(504)	4,481

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Missouri	St. Louis	4,985	2%	85	5,070
Missouri	Kansas City	4,985	-1%	(53)	4,932
Montana	Great Falls	4,985	-6%	(307)	4,678
Nebraska	Omaha	4,985	-6%	(312)	4,673
New Hampshire	Concord	4,985	-2%	(81)	4,904
New Jersey	Newark	4,985	15%	755	5,740
New Mexico	Albuquerque	4,985	-9%	(427)	4,558
New York	New York	4,985	42%	2,099	7,084
New York	Syracuse	4,985	-4%	(187)	4,798
Nevada	Las Vegas	4,985	3%	125	5,110
North Carolina	Charlotte	4,985	-17%	(836)	4,149
North Dakota	Bismarck	4,985	-9%	(468)	4,517
Ohio	Cincinnati	4,985	-8%	(379)	4,606
Oregon	Portland	4,985	2%	115	5,100
Pennsylvania	Philadelphia	4,985	10%	500	5,485
Pennsylvania	Wilkes-Barre	4,985	-7%	(333)	4,652
Rhode Island	Providence	4,985	6%	278	5,263
South Carolina	Spartanburg	4,985	-20%	(986)	3,999
South Dakota	Rapid City	4,985	-13%	(630)	4,355
Tennessee	Knoxville	4,985	-15%	(732)	4,253
Texas	Houston	4,985	-16%	(791)	4,194
Utah	Salt Lake City	4,985	-8%	(410)	4,575
Vermont	Burlington	4,985	-5%	(257)	4,728
Virginia	Alexandria	4,985	5%	233	5,218
Virginia	Lynchburg	4,985	-8%	(389)	4,596
Washington	Seattle	4,985	6%	291	5,276
Washington	Spokane	4,985	-5%	(256)	4,729
West Virginia	Charleston	4,985	-1%	(33)	4,952
Wisconsin	Green Bay	4,985	-3%	(152)	4,833
Wyoming	Cheyenne	4,985	-10%	(515)	4,470
Puerto Rico	Cayey	4,985	-3%	(169)	4,816

TABLE 14-2 – LOCATION-BASED COSTS FOR WN FACILITY (100,000 KW) (JANUARY 1, 2016 DOLLARS)

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alaska	Anchorage	1,877	30%	559	2,436
Alaska	Fairbanks	1,877	56%	1,042	2,919
Alabama	Huntsville	1,877	-5%	(95)	1,782
Arizona	Phoenix	1,877	-3%	(59)	1,818
Arkansas	Little Rock	1,877	-3%	(55)	1,822
California	Los Angeles	1,877	15%	279	2,156
California	Redding	1,877	12%	219	2,096
California	Bakersfield	1,877	13%	253	2,130
California	Sacramento	1,877	12%	222	2,099
California	San Francisco	1,877	20%	384	2,261
Colorado	Denver	1,877	3%	51	1,928
Connecticut	Hartford	1,877	8%	155	2,032
Delaware	Dover	1,877	6%	109	1,986
District of Columbia	Washington	1,877	10%	195	2,072
Florida	Tallahassee	1,877	-4%	(80)	1,797
Florida	Tampa	1,877	-3%	(62)	1,815
Georgia	Atlanta	1,877	-5%	(95)	1,782
Hawaii	Honolulu	1,877	35%	649	2,526
Idaho	Boise	1,877	5%	99	1,976
Illinois	Chicago	1,877	14%	259	2,136
Indiana	Indianapolis	1,877	-1%	(11)	1,866
Iowa	Davenport	1,877	6%	115	1,992
Iowa	Waterloo	1,877	4%	70	1,947
Kansas	Wichita	1,877	3%	62	1,939
Kentucky	Louisville	1,877	-4%	(68)	1,809
Louisiana	New Orleans	1,877	-7%	(125)	1,752
Maine	Portland	1,877	7%	140	2,017
Maryland	Baltimore	1,877	1%	28	1,905
Massachusetts	Boston	1,877	11%	200	2,077
Michigan	Detroit	1,877	3%	48	1,925
Michigan	Grand Rapids	1,877	-1%	(17)	1,860
Minnesota	Saint Paul	1,877	10%	197	2,074
Mississippi	Jackson	1,877	-3%	(62)	1,815

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Missouri	St. Louis	1,877	3%	55	1,932
Missouri	Kansas City	1,877	0%	9	1,886
Montana	Great Falls	1,877	8%	155	2,032
Nebraska	Omaha	1,877	5%	93	1,970
New Hampshire	Concord	1,877	8%	155	2,032
New Jersey	Newark	1,877	10%	184	2,061
New Mexico	Albuquerque	1,877	4%	76	1,953
New York	New York	1,877	25%	462	2,339
New York	Syracuse	1,877	0%	1	1,878
Nevada	Las Vegas	1,877	9%	165	2,042
North Carolina	Charlotte	1,877	-6%	(105)	1,772
North Dakota	Bismarck	1,877	4%	81	1,958
Ohio	Cincinnati	1,877	-4%	(66)	1,811
Oregon	Portland	1,877	9%	171	2,048
Pennsylvania	Philadelphia	1,877	5%	90	1,967
Pennsylvania	Wilkes-Barre	1,877	-2%	(32)	1,845
Rhode Island	Providence	1,877	3%	58	1,935
South Carolina	Spartanburg	1,877	-7%	(124)	1,753
South Dakota	Rapid City	1,877	2%	38	1,915
Tennessee	Knoxville	1,877	-5%	(98)	1,779
Texas	Houston	1,877	-6%	(116)	1,761
Utah	Salt Lake City	1,877	6%	113	1,990
Vermont	Burlington	1,877	6%	110	1,987
Virginia	Alexandria	1,877	3%	64	1,941
Virginia	Lynchburg	1,877	-4%	(67)	1,810
Washington	Seattle	1,877	4%	67	1,944
Washington	Spokane	1,877	6%	110	1,987
West Virginia	Charleston	1,877	0%	4	1,881
Wisconsin	Green Bay	1,877	-2%	(41)	1,836
Wyoming	Cheyenne	1,877	3%	63	1,940
Puerto Rico	Cayey	1,877	9%	169	2,046

TABLE 15-4 – LOCATION-BASED COSTS FOR PV FIXED FACILITY (20,000 KW) (JANUARY 1, 2016 DOLLARS)

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alaska	Anchorage	2,671	22%	593	3,264
Alaska	Fairbanks	2,671	43%	1,154	3,825
Alabama	Huntsville	2,671	-14%	(368)	2,303
Arizona	Phoenix	2,671	-10%	(276)	2,395
Arkansas	Little Rock	2,671	-10%	(261)	2,410
California	Los Angeles	2,671	9%	244	2,915
California	Redding	2,671	10%	272	2,943
California	Bakersfield	2,671	8%	221	2,892
California	Sacramento	2,671	10%	280	2,951
California	San Francisco	2,671	21%	549	3,220
Colorado	Denver	2,671	-7%	(182)	2,489
Connecticut	Hartford	2,671	10%	262	2,933
Delaware	Dover	2,671	6%	153	2,824
District of Columbia	Washington	2,671	6%	162	2,833
Florida	Tallahassee	2,671	-10%	(280)	2,391
Florida	Tampa	2,671	-8%	(217)	2,454
Georgia	Atlanta	2,671	-14%	(366)	2,305
Hawaii	Honolulu	2,671	62%	1,652	4,323
Idaho	Boise	2,671	-7%	(177)	2,494
Illinois	Chicago	2,671	20%	533	3,204
Indiana	Indianapolis	2,671	-5%	(123)	2,548
Iowa	Davenport	2,671	-2%	(51)	2,620
Iowa	Waterloo	2,671	-8%	(210)	2,461
Kansas	Wichita	2,671	-10%	(271)	2,400
Kentucky	Louisville	2,671	-10%	(272)	2,399
Louisiana	New Orleans	2,671	-16%	(439)	2,232
Maine	Portland	2,671	-7%	(180)	2,491
Maryland	Baltimore	2,671	-6%	(148)	2,523
Massachusetts	Boston	2,671	16%	419	3,090
Michigan	Detroit	2,671	2%	66	2,737
Michigan	Grand Rapids	2,671	-5%	(129)	2,542
Minnesota	Saint Paul	2,671	7%	187	2,858
Mississippi	Jackson	2,671	-9%	(253)	2,418

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Missouri	St. Louis	2,671	1%	24	2,695
Missouri	Kansas City	2,671	-1%	(35)	2,636
Montana	Great Falls	2,671	-5%	(127)	2,544
Nebraska	Omaha	2,671	-6%	(164)	2,507
New Hampshire	Concord	2,671	3%	80	2,751
New Jersey	Newark	2,671	14%	383	3,054
New Mexico	Albuquerque	2,671	-3%	(74)	2,597
New York	New York	2,671	42%	1,128	3,799
New York	Syracuse	2,671	-2%	(61)	2,610
Nevada	Las Vegas	2,671	2%	56	2,727
North Carolina	Charlotte	2,671	-16%	(436)	2,235
North Dakota	Bismarck	2,671	-8%	(220)	2,451
Ohio	Cincinnati	2,671	-10%	(265)	2,406
Oregon	Portland	2,671	-1%	(28)	2,643
Pennsylvania	Philadelphia	2,671	9%	248	2,919
Pennsylvania	Wilkes-Barre	2,671	-7%	(179)	2,492
Rhode Island	Providence	2,671	5%	134	2,805
South Carolina	Spartanburg	2,671	-19%	(504)	2,167
South Dakota	Rapid City	2,671	-11%	(303)	2,368
Tennessee	Knoxville	2,671	-14%	(379)	2,292
Texas	Houston	2,671	-15%	(405)	2,266
Utah	Salt Lake City	2,671	-9%	(230)	2,441
Vermont	Burlington	2,671	-5%	(140)	2,531
Virginia	Alexandria	2,671	-3%	(85)	2,586
Virginia	Lynchburg	2,671	-10%	(270)	2,401
Washington	Seattle	2,671	2%	63	2,734
Washington	Spokane	2,671	-5%	(139)	2,532
West Virginia	Charleston	2,671	0%	(1)	2,670
Wisconsin	Green Bay	2,671	-5%	(125)	2,546
Wyoming	Cheyenne	2,671	-8%	(209)	2,462
Puerto Rico	Cayey	2,671	-3%	(68)	2,603

TABLE 15-5 – LOCATION-BASED COSTS FOR PV TRACKER FACILITY (20,000 KW)

(JANUARY 1, 2016 DOLLARS)

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alaska	Anchorage	2,644	23%	599	3,243
Alaska	Fairbanks	2,644	44%	1,161	3,805
Alabama	Huntsville	2,644	-14%	(378)	2,266
Arizona	Phoenix	2,644	-11%	(284)	2,360
Arkansas	Little Rock	2,644	-10%	(268)	2,376
California	Los Angeles	2,644	9%	247	2,891
California	Redding	2,644	10%	276	2,920
California	Bakersfield	2,644	8%	224	2,868
California	Sacramento	2,644	11%	284	2,928
California	San Francisco	2,644	21%	560	3,204
Colorado	Denver	2,644	-7%	(191)	2,453
Connecticut	Hartford	2,644	10%	267	2,911
Delaw are	Dover	2,644	6%	155	2,799
District of Columbia	Washington	2,644	6%	161	2,805
Florida	Tallahassee	2,644	-11%	(288)	2,356
Florida	Tampa	2,644	-8%	(224)	2,420
Georgia	Atlanta	2,644	-14%	(377)	2,267
Haw aii	Honolulu	2,644	63%	1,657	4,301
Idaho	Boise	2,644	-7%	(183)	2,461
Illinois	Chicago	2,644	21%	544	3,188
Indiana	Indianapolis	2,644	-5%	(127)	2,517
low a	Davenport	2,644	-2%	(53)	2,591
low a	Waterloo	2,644	-8%	(216)	2,428
Kansas	Wichita	2,644	-11%	(279)	2,365
Kentucky	Louisville	2,644	-11%	(280)	2,364
Louisiana	New Orleans	2,644	-17%	(452)	2,192
Maine	Portland	2,644	-7%	(190)	2,454
Maryland	Baltimore	2,644	-6%	(155)	2,489
Massachusetts	Boston	2,644	16%	429	3,073
Michigan	Detroit	2,644	3%	67	2,711
Michigan	Grand Rapids	2,644	-5%	(132)	2,512
Minnesota	Saint Paul	2,644	7%	191	2,835
Mississippi	Jackson	2,644	-10%	(260)	2,384

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Missouri	St. Louis	2,644	1%	24	2,668
Missouri	Kansas City	2,644	-1%	(36)	2,608
Montana	Great Falls	2,644	-5%	(132)	2,512
Nebraska	Omaha	2,644	-6%	(169)	2,475
New Hampshire	Concord	2,644	3%	79	2,723
New Jersey	Newark	2,644	15%	394	3,038
New Mexico	Albuquerque	2,644	-3%	(80)	2,564
New York	New York	2,644	44%	1,153	3,797
New York	Syracuse	2,644	-2%	(64)	2,580
Nevada	Las Vegas	2,644	2%	58	2,702
North Carolina	Charlotte	2,644	-17%	(449)	2,195
North Dakota	Bismarck	2,644	-9%	(227)	2,417
Ohio	Cincinnati	2,644	-10%	(273)	2,371
Oregon	Portland	2,644	4%	102	2,746
Pennsylvania	Philadelphia	2,644	10%	255	2,899
Pennsylvania	Wilkes-Barre	2,644	-7%	(184)	2,460
Rhode Island	Providence	2,644	5%	138	2,782
South Carolina	Spartanburg	2,644	-20%	(518)	2,126
South Dakota	Rapid City	2,644	-12%	(313)	2,331
Tennessee	Knoxville	2,644	-15%	(390)	2,254
Texas	Houston	2,644	-16%	(417)	2,227
Utah	Salt Lake City	2,644	-4%	(107)	2,537
Vermont	Burlington	2,644	-1%	(14)	2,630
Virginia	Alexandria	2,644	-3%	(87)	2,557
Virginia	Lynchburg	2,644	-11%	(278)	2,366
Washington	Seattle	2,644	2%	64	2,708
Washington	Spokane	2,644	-5%	(143)	2,501
West Virginia	Charleston	2,644	0%	(2)	2,642
Wisconsin	Green Bay	2,644	-5%	(129)	2,515
Wyoming	Cheyenne	2,644	-8%	(217)	2,427
Puerto Rico	Cayey	2,644	-3%	(76)	2,568

TABLE 15-6 – LOCATION-BASED COSTS FOR PV TRACKER FACILITY (150,000 KW)

(JANUARY 1, 2016 DOLLARS)

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alaska	Anchorage	2,534	22%	569	3,103
Alaska	Fairbanks	2,534	44%	1,124	3,658
Alabama	Huntsville	2,534	-13%	(319)	2,215
Arizona	Phoenix	2,534	-9%	(239)	2,295
Arkansas	Little Rock	2,534	-9%	(226)	2,308
California	Los Angeles	2,534	9%	232	2,766
California	Redding	2,534	10%	253	2,787
California	Bakersfield	2,534	8%	209	2,743
California	Sacramento	2,534	10%	260	2,794
California	San Francisco	2,534	20%	500	3,034
Colorado	Denver	2,534	-8%	(206)	2,328
Connecticut	Hartford	2,534	9%	238	2,772
Delaw are	Dover	2,534	6%	143	2,677
District of Columbia	Washington	2,534	7%	167	2,701
Florida	Tallahassee	2,534	-10%	(242)	2,292
Florida	Tampa	2,534	-7%	(188)	2,346
Georgia	Atlanta	2,534	-13%	(317)	2,217
Haw aii	Honolulu	2,534	64%	1,631	4,165
Idaho	Boise	2,534	-4%	(89)	2,445
Illinois	Chicago	2,534	16%	417	2,951
Indiana	Indianapolis	2,534	-4%	(104)	2,430
Iow a	Davenport	2,534	1%	21	2,555
Iow a	Waterloo	2,534	-5%	(117)	2,417
Kansas	Wichita	2,534	-7%	(170)	2,364
Kentucky	Louisville	2,534	-9%	(236)	2,298
Louisiana	New Orleans	2,534	-15%	(380)	2,154
Maine	Portland	2,534	-8%	(201)	2,333
Maryland	Baltimore	2,534	-5%	(117)	2,417
Massachusetts	Boston	2,534	15%	375	2,909
Michigan	Detroit	2,534	2%	57	2,591
Michigan	Grand Rapids	2,534	-4%	(112)	2,422
Minnesota	Saint Paul	2,534	9%	229	2,763
Mississippi	Jackson	2,534	-9%	(219)	2,315

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Missouri	St. Louis	2,534	1%	20	2,554
Missouri	Kansas City	2,534	-1%	(30)	2,504
Montana	Great Falls	2,534	-1%	(37)	2,497
Nebraska	Omaha	2,534	-3%	(77)	2,457
New Hampshire	Concord	2,534	1%	22	2,556
New Jersey	Newark	2,534	13%	332	2,866
New Mexico	Albuquerque	2,534	-4%	(109)	2,425
New York	New York	2,534	40%	1,012	3,546
New York	Syracuse	2,534	-2%	(48)	2,486
Nevada	Las Vegas	2,534	4%	114	2,648
North Carolina	Charlotte	2,534	-15%	(378)	2,156
North Dakota	Bismarck	2,534	-5%	(123)	2,411
Ohio	Cincinnati	2,534	-9%	(229)	2,305
Oregon	Portland	2,534	2%	41	2,575
Pennsylvania	Philadelphia	2,534	8%	215	2,749
Pennsylvania	Wilkes-Barre	2,534	-6%	(155)	2,379
Rhode Island	Providence	2,534	5%	116	2,650
South Carolina	Spartanburg	2,534	-17%	(436)	2,098
South Dakota	Rapid City	2,534	-8%	(195)	2,339
Tennessee	Knoxville	2,534	-13%	(329)	2,205
Texas	Houston	2,534	-14%	(351)	2,183
Utah	Salt Lake City	2,534	-5%	(135)	2,399
Vermont	Burlington	2,534	-2%	(56)	2,478
Virginia	Alexandria	2,534	-3%	(73)	2,461
Virginia	Lynchburg	2,534	-9%	(234)	2,300
Washington	Seattle	2,534	2%	54	2,588
Washington	Spokane	2,534	-2%	(56)	2,478
West Virginia	Charleston	2,534	0%	1	2,535
Wisconsin	Green Bay	2,534	-4%	(106)	2,428
Wyoming	Cheyenne	2,534	-4%	(109)	2,425
Puerto Rico	Cayey	2,534	-1%	(33)	2,501

TABLE 16-2 – LOCATION-BASED COSTS FOR RICE FACILITY (85,000 KW) (JANUARY 1, 2016 DOLLARS)

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alaska	Anchorage	1,342	23%	308	1,650
Alaska	Fairbanks	1,342	27%	361	1,703
Alabama	Huntsville	1,342	-10%	(136)	1,206
Arizona	Phoenix	1,342	-8%	(101)	1,241
Arkansas	Little Rock	1,342	-7%	(96)	1,246
California	Los Angeles	1,342	14%	185	1,527
California	Redding	1,342	5%	73	1,415
California	Bakersfield	1,342	6%	82	1,424
California	Sacramento	1,342	8%	102	1,444
California	San Francisco	1,342	27%	356	1,698
Colorado	Denver	1,342	-4%	(60)	1,282
Connecticut	Hartford	1,342	15%	199	1,541
Delaware	Dover	1,342	13%	173	1,515
District of Columbia	Washington	1,342	18%	241	1,583
Florida	Tallahassee	1,342	-8%	(112)	1,230
Florida	Tampa	1,342	-7%	(92)	1,250
Georgia	Atlanta	1,342	-8%	(110)	1,232
Hawaii	Honolulu	1,342	37%	498	1,840
Idaho	Boise	1,342	-4%	(49)	1,293
Illinois	Chicago	1,342	11%	147	1,489
Indiana	Indianapolis	1,342	-2%	(23)	1,319
Iowa	Davenport	1,342	0%	3	1,345
Iowa	Waterloo	1,342	-4%	(50)	1,292
Kansas	Wichita	1,342	-5%	(65)	1,277
Kentucky	Louisville	1,342	-6%	(85)	1,257
Louisiana	New Orleans	1,342	-7%	(100)	1,242
Maine	Portland	1,342	-6%	(80)	1,262
Maryland	Baltimore	1,342	5%	71	1,413
Massachusetts	Boston	1,342	22%	291	1,633
Michigan	Detroit	1,342	3%	46	1,388
Michigan	Grand Rapids	1,342	-2%	(23)	1,319
Minnesota	Saint Paul	1,342	6%	75	1,417
Mississippi	Jackson	1,342	-7%	(98)	1,244

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Missouri	St. Louis	1,342	3%	34	1,376
Missouri	Kansas City	1,342	0%	(1)	1,341
Montana	Great Falls	1,342	1%	7	1,349
Nebraska	Omaha	1,342	-2%	(30)	1,312
New Hampshire	Concord	1,342	0%	(6)	1,336
New Jersey	Newark	1,342	16%	211	1,553
New Mexico	Albuquerque	1,342	-4%	(49)	1,293
New York	New York	1,342	44%	585	1,927
New York	Syracuse	1,342	4%	56	1,398
Nevada	Las Vegas	1,342	2%	29	1,371
North Carolina	Charlotte	1,342	-10%	(135)	1,207
North Dakota	Bismarck	1,342	-4%	(60)	1,282
Ohio	Cincinnati	1,342	-5%	(63)	1,279
Oregon	Portland	1,342	1%	17	1,359
Pennsylvania	Philadelphia	1,342	11%	151	1,493
Pennsylvania	Wilkes-Barre	1,342	-2%	(30)	1,312
Rhode Island	Providence	1,342	11%	146	1,488
South Carolina	Spartanburg	1,342	-13%	(176)	1,166
South Dakota	Rapid City	1,342	-7%	(88)	1,254
Tennessee	Knoxville	1,342	-9%	(121)	1,221
Texas	Houston	1,342	-10%	(135)	1,207
Utah	Salt Lake City	1,342	-4%	(50)	1,292
Vermont	Burlington	1,342	1%	16	1,358
Virginia	Alexandria	1,342	5%	68	1,410
Virginia	Lynchburg	1,342	-6%	(85)	1,257
Washington	Seattle	1,342	4%	47	1,389
Washington	Spokane	1,342	-3%	(36)	1,306
West Virginia	Charleston	1,342	1%	18	1,360
Wisconsin	Green Bay	1,342	-2%	(28)	1,314
Wyoming	Cheyenne	1,342	-2%	(25)	1,317
Puerto Rico	Cayey	1,342	-1%	(16)	1,326

TABLE 17-2 – LOCATION-BASED COSTS FOR BES FACILITY (4,000 KW) (JANUARY 1, 2016 DOLLARS)

State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Alaska	Anchorage	2,813	19%	525	3,338
Alaska	Fairbanks	2,813	32%	903	3,716
Alabama	Huntsville	2,813	-4%	(122)	2,691
Arizona	Phoenix	2,813	-3%	(85)	2,728
Arkansas	Little Rock	2,813	-3%	(79)	2,734
California	Los Angeles	2,813	8%	212	3,025
California	Redding	2,813	3%	75	2,888
California	Bakersfield	2,813	3%	83	2,896
California	Sacramento	2,813	3%	78	2,891
California	San Francisco	2,813	11%	309	3,122
Colorado	Denver	2,813	-4%	(102)	2,711
Connecticut	Hartford	2,813	6%	156	2,969
Delaware	Dover	2,813	4%	109	2,922
District of Columbia	Washington	2,813	7%	189	3,002
Florida	Tallahassee	2,813	-3%	(96)	2,717
Florida	Tampa	2,813	-3%	(75)	2,738
Georgia	Atlanta	2,813	-4%	(121)	2,692
Hawaii	Honolulu	2,813	32%	910	3,723
Idaho	Boise	2,813	-2%	(51)	2,762
Illinois	Chicago	2,813	5%	152	2,965
Indiana	Indianapolis	2,813	-1%	(24)	2,789
Iowa	Davenport	2,813	-1%	(18)	2,795
Iowa	Waterloo	2,813	-3%	(72)	2,741
Kansas	Wichita	2,813	-3%	(88)	2,725
Kentucky	Louisville	2,813	-3%	(89)	2,724
Louisiana	New Orleans	2,813	-5%	(151)	2,662
Maine	Portland	2,813	-3%	(84)	2,729
Maryland	Baltimore	2,813	0%	9	2,822
Massachusetts	Boston	2,813	7%	210	3,023
Michigan	Detroit	2,813	1%	28	2,841
Michigan	Grand Rapids	2,813	-2%	(44)	2,769
Minnesota	Saint Paul	2,813	3%	77	2,890
Mississippi	Jackson	2,813	-3%	(82)	2,731

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State	City	Base Project Cost ($/kW)	Location Variation	Delta Cost Difference ($/kW)	Total Location Project Cost ($/kW)
Missouri	St. Louis	2,813	1%	34	2,847
Missouri	Kansas City	2,813	0%	(2)	2,811
Montana	Great Falls	2,813	0%	5	2,818
Nebraska	Omaha	2,813	-2%	(51)	2,762
New Hampshire	Concord	2,813	0%	(7)	2,806
New Jersey	Newark	2,813	5%	137	2,950
New Mexico	Albuquerque	2,813	-3%	(72)	2,741
New York	New York	2,813	25%	700	3,513
New York	Syracuse	2,813	-1%	(29)	2,784
Nevada	Las Vegas	2,813	1%	30	2,843
North Carolina	Charlotte	2,813	-5%	(140)	2,673
North Dakota	Bismarck	2,813	-2%	(63)	2,750
Ohio	Cincinnati	2,813	-3%	(86)	2,727
Oregon	Portland	2,813	1%	16	2,829
Pennsylvania	Philadelphia	2,813	3%	96	2,909
Pennsylvania	Wilkes-Barre	2,813	-2%	(51)	2,762
Rhode Island	Providence	2,813	2%	57	2,870
South Carolina	Spartanburg	2,813	-6%	(163)	2,650
South Dakota	Rapid City	2,813	-3%	(92)	2,721
Tennessee	Knoxville	2,813	-4%	(126)	2,687
Texas	Houston	2,813	-5%	(140)	2,673
Utah	Salt Lake City	2,813	-2%	(53)	2,760
Vermont	Burlington	2,813	-1%	(38)	2,775
Virginia	Alexandria	2,813	-1%	(24)	2,789
Virginia	Lynchburg	2,813	-3%	(88)	2,725
Washington	Seattle	2,813	2%	48	2,861
Washington	Spokane	2,813	-1%	(38)	2,775
West Virginia	Charleston	2,813	1%	18	2,831
Wisconsin	Green Bay	2,813	-1%	(30)	2,783
Wyoming	Cheyenne	2,813	-2%	(68)	2,745
Puerto Rico	Cayey	2,813	5%	130	2,943