# IPM Model – Updates to Cost and Performance for APC Technologies

# $CO_2$ Reduction Retrofit Cost Development Methodology

**Final**

January 2023

Project 13527-002

Eastern Research Group, Inc.

Prepared by

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

**LEGAL NOTICE**



*This work was funded by the U.S. Environmental Protection Agency (EPA) through Eastern Research Group, Inc. (ERG) as a contractor and reviewed by ERG and EPA personnel.*

# $CO_2$ Reduction Retrofit Cost Development Methodology

## Purpose of Cost Algorithms for the IPM Model

The primary purpose of the cost algorithms is to provide generic order-of-magnitude costs for various air quality control technologies that can be applied to the electric power generating industry on a system-wide basis, not on an individual unit basis. Cost algorithms developed for the IPM model are based primarily on a statistical evaluation of cost data available from various industry publications as well as Sargent & Lundy's proprietary database and do not take into consideration site-specific cost issues. By necessity, the cost algorithms were designed to require minimal site-specific information and were based only on a limited number of inputs such as unit size, gross heat rate, baseline emissions, removal efficiency, fuel type, and a subjective retrofit factor.

The outputs from these equations represent the "average" costs associated with the "average" project scope for the subset of data utilized in preparing the equations. The IPM cost equations do not account for site-specific factors that can significantly affect costs, such as flue gas volume and temperature, and do not address regional labor productivity, local workforce characteristics, local unemployment and labor availability, project complexity, local climate, and working conditions. In addition, the indirect capital costs included in the IPM cost equations do not account for all project-related indirect costs a facility would incur to install a retrofit control, such as project contingency.

## Establishment of the Cost Basis

To establish a basis for retrofit of carbon dioxide ($CO_2$) reduction technologies, cost data were collected from the public domain and Sargent & Lundy's (S&L's) recent experience associated with recent amine-based $CO_2$ capture processes implemented as retrofits to power facilities. All data sources were combined to provide a representative $CO_2$ reduction cost basis. Due to the limited availability of actual as-spent costs for $CO_2$ capture projects, the cost estimation tool could not be benchmarked against recently executed projects to confirm how accurately it reflects current market conditions. While the coal-fired applications utilize a robust amount of data sources, from feasibility and FEED studies, it is only recently that feasibility and FEED studies have been completed for NGCC applications of this technology. As such, cost multipliers are used to compare coal-fired capital cost pricing to NGCC applications.

A cost algorithm for pre-combustion $CO_2$ reduction using oxy-combustion technology was not developed. This technology is best reserved for new units, rather than for power plant retrofits. In addition, there are too few examples of retrofits to provide a basis for the costs. Therefore, an algorithm cannot be accurately developed and is not included in the $CO_2$ reduction technology algorithm. For retrofit applications, the oxy-combustion technology will need to be evaluated on a case-by-case basis to justify its cost competitiveness against the almost commercially demonstrated amine-based capture technology.

The least-squares curve fit of the data was defined as a "typical" $CO_2$ capture retrofit for removal of >90% of the inlet $CO_2$. The typical $CO_2$ capture retrofit was based on the following:

- Retrofit Difficulty = 1 (average retrofit difficulty);
- Gross Heat Rate = 10,000 Btu/kWh;
- Type of Coal = PRB;
- Project Execution = Engineer, Procurement, and Construction (EPC) contracts; and
- Typical $CO_2$ capture rate = 90% removal efficiency.

For $CO_2$ capture, the technology is expected to be applicable to any unit size and, depending how much flue gas is treated, would scale up based on multiple parallel capture trains. Transportation, storage, and monitoring (TS&M) of the captured $CO_2$ are not included in the base cost estimates and instead costs can be included as a user input on a $/ton basis.

## $CO_2$ Capture Methodology

### Technology Description

The amine-scrubbing process is the most widely studied and used demonstration process for post-combustion $CO_2$ capture. This process involves passing the flue gas through an absorber column counter-currently with an amine solvent. At low temperatures, the $CO_2$ is absorbed by the amine solvent and removed from the flue gas. The treated flue gas passes through wash levels prior to exiting the stack. The $CO_2$-rich solvent leaves the absorber and is heated and regenerated in the stripper column. Once the $CO_2$ is desorbed from the amine, a concentrated $CO_2$ stream is dehydrated to remove any moisture and compressed to pipeline quality for transportation and/or sequestration. Steam is typically taken from the unit's existing steam cycle and passed through a reboiler to provide the heat needed to strip the $CO_2$ from the amine. While certain applications justify the use of new natural gas auxiliary boilers for steam production, this module is based solely on steam extraction, to avoid additional emissions associated with additional fuel combustion.

To limit degradation of the expensive amine solvent, $SO_2$ and $SO_3$ emissions must be treated prior to the absorber vessel to lower concentrations of these emissions to less than 2 to 10 ppm. If a unit is not already equipped with flue gas desulfurization (FGD) technology, then it will need to be added. Therefore, capital and operating and maintenance (O&M) costs for a wet FGD (WFGD) which is capable of lowering the $SO_2$ concentration down to 2-10 ppm should be included as part of the overall $CO_2$ capture cost. Note that the cost of retrofitting FGD is not included as part of the $CO_2$ cost algorithm.

# $CO_2$ Reduction Retrofit Cost Development Methodology

## Inputs

Several input variables are required to predict future retrofit costs. The gross unit size in MW and carbon content of the fuel are the major variables for the capital estimation. A retrofit factor that equates to the difficulty in construction of the system must be defined. Note that the costs could increase significantly for congested sites or sites with limited adjacent space. One example for the use of a retrofit factor is if a facility needs to minimize additional water consumption. For cases where a hybrid cooling system is required due to limited water availability, a retrofit factor of 1.15 should be used to account for the increase in the capital cost associated with that system.

The gross unit heat rate will factor into the amount of flue gas generated and, ultimately, the size of the absorber, stripper, compressor, and balance of plant costs. Heat rate is an input from the user, with a suggested starting point of 10,000 Btu/kWh for coal-fired boilers, and 6,660 Btu/kWh for natural gas combined cycle (NGCC) facilities.

The $CO_2$ rate will have the greatest influence on the solvent makeup rate and steam required in the regeneration process. The type of fuel (Bituminous, PRB, Lignite, or Natural Gas) will influence the $CO_2$ quantity in the flue gas because of the differing carbon compositions typical in these types of fuels.

The evaluation includes a user-selected option for identifying if the unit is equipped with FGD. If the unit fires coal and is not already equipped with FGD technology, costs for installing a WFGD should also be incorporated. The user is required to use the WFGD IPM cost algorithm to generate the capital and O&M costs for the technology.

Any changes from the base assumptions should be incorporated to derive more accurate costs.

## Outputs

### *Total Project Costs (TPC)*

First, the installed costs are calculated for each required base module. Note that costs to build a pipeline are not included in this cost algorithm; it is assumed that another entity will be funding the $CO_2$ pipeline construction. The base module installed costs include the following:

- All equipment,
- Installation,
- Buildings,
- Foundations,
- Electrical, and
- Retrofit difficulty.

## $CO_2$ Reduction Retrofit Cost Development Methodology

These costs can potentially range widely because of the relatively new nature of the process, as well as site-specific details. Capital costs estimated here are expected to encompass a +/- 50% range.
The base modules are as follows:

| | |
|---|---|
| BMI = | Base capture island cost, including compression |
| BMBOP = | Base balance of plant costs including piping, ductwork, cooling system, steam integration, foundations, etc. |
| BM = | BMI + BMBOP |

The total base module installed cost (BM) is then increased by the following:

- Engineering and construction management costs at 15% of the BM cost;
- Labor adjustment for 6 x 10-hour shift premium, per diem, etc., at 10% of the BM cost; and
- Contractor profit and fees at 10% of the BM cost.

A capital, engineering, and construction cost subtotal (CECC) is established as the sum of the BM and the additional engineering and construction fees.

Additional costs and financing expenditures for the project are computed based on the CECC. Financing and additional project costs include the following:

- Owner's home office costs (owner's engineering, management, and procurement) are included at 5% of the CECC.
- Allowance for Funds Used During Construction (AFUDC) are included at 10% of the CECC and owner's costs. The AFUDC is based on a three-year engineering and construction cycle.

The total project cost is based on a turnkey engineering, procurement, and construction (EPC) contract execution; as such, the total project cost is increased by 15% to account for risk and fees associated with this structure.

Escalation is not included in the estimate because all costs are provided in 2021 dollars and are not representative of recent COVID and inflation related pricing increases. The total project cost (TPC) is the sum of the CECC and the additional costs and financing expenditures.

## $CO_2$ Reduction Retrofit Cost Development Methodology

***Fixed O&M (FOM)***

The fixed O&M cost is a function of the additional operations staff (FOMO), maintenance labor and materials (FOMM), and administrative labor (FOMA) associated with the $CO_2$ capture installation. The FOM is the sum of the FOMO, FOMM and FOMA.
The following factors and assumptions underlie calculations of the FOM:

- All the FOM costs were tabulated on a per-kilowatt-year (kW-yr) basis.
- In general, 22 additional shift operators are required for operating the $CO_2$ capture facility. The FOMO was based on the number of additional operations staff required as a function of generating capacity.
- The fixed maintenance materials and labor factor is a direct function of the process capital cost at 2.5% of the equivalent equipment and material portion, which is expected to be 60% of the BM.
- The administrative labor is a function of the FOMO and FOMM at 3% of the sum of (FOMO + 0.4 FOMM).

***Variable O&M (VOM)***

Variable O&M is a function of the following:

- Solvent makeup rates and unit costs,
- Additional power required and unit power cost,
- Loss of production due to steam consumption from the base plant, and
- Makeup water required and unit water cost.

The following factors and assumptions underlie calculations of the VOM:

- All the VOM costs were tabulated on a per-megawatt-hour (MWh) basis.
- A VOM related calculations are estimated using different equations for NGCC and coal-fired applications.
- The solvent makeup cost is a function of total $CO_2$ captured. The capital costs are based on a 90% $CO_2$ reduction design. An indicative value is included but can be adjusted by the user.
- The steam derate is estimated based on the steam extracted for use in the $CO_2$ regeneration process. Steam rate is a function of total $CO_2$ captured.
- The additional power required includes increased fan power to account for the added capture island pressure drop, system pumps, and compressor power. This requirement is a function of total $CO_2$ captured.
- The makeup water rate is a function of total $CO_2$ captured.

- The transportation, storage, and monitoring costs are not included. A cost can be added by the user, based on an evaluated cos with respect to the amount of $CO_2$ captured in ton.

Because of the widely varying consumption of power, steam, water, and solvent associated with the various $CO_2$ capture technologies, the variable O&M costs are developed as a fixed amount based on averages of S&L in-house project data and design assumptions, calculated separately for coal-fired or NGCC applications. Steam turbine derate is not calculated separately, as the derate is expected to be similar based on total steam extraction, regardless of application.

Input options are provided so the user can adjust the variable O&M costs per unit. Average default values are included in the base estimate. The variable O&M costs per unit options are as follows:

- Solvent cost in $/ton of $CO_2$ captured; the cost could vary significantly by process supplier;
- Auxiliary power cost in $/kWh;
- Makeup water costs in $/1,000 gallons;
- Operating labor rate (including all benefits) in $/hr; and
- Transportation, storage, and monitoring costs in $/ton.

The variables that contribute to the overall VOM are shown below:

| | |
|---|---|
| VOMS = | Variable O&M costs for solvent |
| VOMTS = | Variable O&M costs for transportation and storage of capture $CO_2$ |
| VOMP = | Variable O&M costs for additional auxiliary power and steam consumption (lost revenue) |
| VOMM = | Variable O&M costs for makeup water |

The total VOM is the sum of VOMS, VOMTS, VOMP, and VOMM. Table 1 is a complete capital and O&M cost estimate worksheet.

# $CO_2$ Reduction Retrofit Cost Development Methodology

## Table 1. Example 1 (Coal)

Fill in the yellow cells with the known data inputs. The resulting costs are tabulated below. Variable names are defined as outlined in the table.

| Variable | Designation | Units | Value | Calculation |
|---|---|---|---|---|
| Unit Size (Gross) | A | (MW) | 700 | <--- User Input |
| Retrofit Factor | B | | 1 | <--- User Input (An "average" retrofit has a factor = 1.0) |
| Gross Heat Rate | C | (Btu/kWh) | 10000 | <--- User Input (Default Coal-Fired = 10,000; NGCC = 6,660) |
| Type of Fuel | D | | PRB | <--- User Input |
| CO2 Capture Rate | E | (ton/hr) | 674 | A*C*1000*0.9*Coal Rate /$10^6$ / 2000 (Based on 90% reduction) |
| SO2 Control Technology | F | | FGD | <--- User Input |
| Steam Consumption | G | (lb/hr) | 1,590,900 | Coal: 1.18 * E * 2000 ; NGCC: 1.33 * E * 2000 |
| Aux Power | H | (MW) | 99 | Coal: 0.1465 * E ; NGCC: 0.207 * E |
| Makeup Water Rate | I | (gpm) | 4894 | Coal: 7.26 * E ; NGCC: 9.73 * E |
| Steam Turbine Derate | J | (MW) | 123 | 0.155 * G / 2000 |
| Net Power Reduction | K | (MW) | 222 | H + J |
| Solvent Cost | L | ($/ton CO2 removed) | 3.5 | <--- User Input |
| Aux Power Cost | M | ($/kWh) | 0.03 | <--- User Input |
| Makeup Water Cost | N | ($/kgal) | 1 | <--- User Input |
| Operating Labor Rate | O | ($/hr) | 60 | <--- User Input (Labor cost including all benefits) |
| Transportation, Storage, & Monitoring (TS&M) | P | ($/ton) | 10 | <--- User Input |

### Costs are all based on 2021 dollars

| Capital Cost Calculation | | Example | Comments |
|---|---|---|---|
| Includes - Equipment, installation, buildings, foundations, electrical, minor physical/chemical wastewater treatment and retrofit difficulty | | | |
| BMI ($) = +B24:L34BI | Coal: [883000*(E)] * B ; NGCC: [883000*(E)] * B * 1.45 | $ 595,230,000 | Base CO2 capture island cost including: Absorbers and stacks, strippers, blowers, reagent tanks, heat exchangers, compressors, etc... |
| BMBOP ($) = | Coal: [235200*(E)] * B ; NGCC: [235200*(E)] * B * 1.45 | $ 158,548,000 | Base balance of plant costs including: Cooling system, steam supply, piping, ductwork, foundations, etc... |
| BM ($) = | BMI + BMC + BMBOP | $ 753,778,000 | Total base cost including retrofit factor |
| BM ($/KW) = | | 1077 | Base cost per kW |
| **Total Project Cost** | | | |
| A1 = 15% of BM | | $ 113,067,000 | Engineering and Construction Management costs |
| A2 = 10% of BM | | $ 75,378,000 | Labor adjustment for 6 x 10 hour shift premium, per diem, etc... |
| A3 = 10% of BM | | $ 75,378,000 | Contractor profit and fees |
| **CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3** | | **$ 1,017,601,000** | Capital, engineering and construction cost subtotal |
| **CECC ($/kW) - Excludes Owner's Costs =** | | **1454** | Capital, engineering and construction cost subtotal per kW |
| B1 = 5% of CECC | | $ 50,880,000 | Owners costs including all "home office" costs (owners engineering, management, and procurement activities) |
| **TPC' ($) - Includes Owner's Costs = CECC + B1** | | **$ 1,068,481,000** | Total project cost without AFUDC |
| **TPC' ($/kW) - Includes Owner's Costs =** | | **1526** | Total project cost per kW without AFUDC |
| B2 = 10% of (CECC + B1) | | $ 106,848,000 | AFUDC (Based on a 3 year engineering and construction cycle) |
| C1 = 15% of CECC + B1 | | $ 168,667,000 | EPC G&A and risk fees of 15% |
| **TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2** | | **$ 1,175,329,000** | Total project cost |
| **TPC ($/kW) - Includes Owner's Costs and AFUDC =** | | **1679** | Total project cost per kW |

# $CO_2$ Reduction Retrofit Cost Development Methodology

## Table 1. Example 1 (Coal) Continued

Fill in the yellow cells with the known data inputs. The resulting costs are tabulated below. Variable names are defined as outlined in the table.

| Variable | Designation | Units | Value | Calculation |
|---|---|---|---|---|
| Unit Size (Gross) | A | (MW) | 700 | <--- User Input |
| Retrofit Factor | B | | 1 | <--- User Input (An "average" retrofit has a factor = 1.0) |
| Gross Heat Rate | C | (Btu/kWh) | 10000 | <--- User Input (Default Coal-Fired = 10,000; NGCC = 6,660) |
| Type of Fuel | D | | PRB | <--- User Input |
| CO2 Capture Rate | E | (ton/hr) | 674 | A*C*1000*0.9*Coal Rate /$10^6$ / 2000 (Based on 90% reduction) |
| SO2 Control Technology | F | | FGD | <--- User Input |
| Steam Consumption | G | (lb/hr) | 1,590,900 | Coal: 1.18 * E * 2000 ; NGCC: 1.33 * E * 2000 |
| Aux Power | H | (MW) | 99 | Coal: 0.1465 * E ; NGCC: 0.207 * E |
| Makeup Water Rate | I | (gpm) | 4894 | Coal: 7.26 * E ; NGCC: 9.73 * E |
| Steam Turbine Derate | J | (MW) | 123 | 0.155 * G / 2000 |
| Net Power Reduction | K | (MW) | 222 | H + J |
| Solvent Cost | L | ($/ton CO2 removed) | 3.5 | <--- User Input |
| Aux Power Cost | M | ($/kWh) | 0.03 | <--- User Input |
| Makeup Water Cost | N | ($/kgal) | 1 | <--- User Input |
| Operating Labor Rate | O | ($/hr) | 60 | <--- User Input (Labor cost including all benefits) |
| Transportation, Storage, & Monitoring (TS&M) | P | ($/ton) | 10 | <--- User Input |

**Costs are all based on 2021 dollars**

| | | | |
|---|---|---|---|
| **Fixed O&M Cost** | | | |
| FOMO ($/kW yr) = 22*2080*O/(A*1000) | $ | 3.92 | Fixed O&M additional operating labor costs |
| FOMM ($/kW yr) = BM*0.6*0.025/(B*A*1000) | $ | 16.15 | Fixed O&M additional maintenance material and labor costs |
| FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM) | $ | 0.31 | Fixed O&M additional administrative labor costs |
| **FOM ($/kW yr) = FOMO + FOMM + FOMA + FOMWW** | **$** | **20.39** | Total Fixed O&M costs |
| **Variable O&M Cost** | | | |
| VOMS ($/MWh) = L * E / A | $ | 3.37 | Variable O&M costs for solvent |
| VOMTS ($/MWh) = P * E / A | $ | 9.63 | Variable O&M costs for transportation, storage, and monitoring |
| VOMP ($/MWh) = K * 1000 * M / A | $ | 9.51 | Variable O&M costs for additional auxiliary power and steam required --> Lost Revenue |
| VOMM ($/MWh) =I * 60 / 1000 * N / A | $ | 0.42 | Variable O&M costs for makeup water |
| **VOM ($/MWh) = VOMS + VOMTS + VOMP + VOMM** | **$** | **22.93** | Total Variable O&M costs |

| | | |
|---|---|---|
| Annual Capacity Factor = | 0.85 | |
| Annual MWhs = | 5,212,200 | |
| Annual Heat Input MMBtu = | 52,122,000 | |
| Annual Ton CO2 Created = | 5,577,054 | |
| Annual Ton CO2 Removed = | 5,019,349 | at removal efficiency = 90% |
| Annual Ton CO2 Emission = | 557,705 | |
| Annual Avg CO2 Emission Rate, lb/MWh = | 214 | based on original gross unit load [A] |

| | | | |
|---|---|---|---|
| Annual Capital Recovery Factor = | 0.082 | CO2 Capture | *from DOE 2019 BBS 12B* |
| Annual Capital Cost (Including AFUDC), $ = | | 96,377,000 | |
| Annual FOM Cost, $ = | | 14,270,000 | |
| Annual VOM Cost, $ = | | 119,535,000 | |
| Total Annual CO2 Capture Cost, $ = | | 230,182,000 | |

| | |
|---|---|
| Capital Cost, $/MWh = | 18.49 |
| FOM Cost, $/MWh = | 2.74 |
| VOM Cost, $/MWh = | 22.93 |
| Total CO2 Capture Cost, $/MWh = | 44.16 |

| | |
|---|---|
| Capital Cost, $/ton = | 19 |
| FOM Cost, $/ton = | 3 |
| VOM Cost, $/ton = | 24 |
| Total CO2 Capture Cost, $/ton = | 46 |

# $CO_2$ Reduction Retrofit Cost Development Methodology

## Table 2. Example 1 (NGCC)

Fill in the yellow cells with the known data inputs. The resulting costs are tabulated below. Variable names are defined as outlined in the table.

| Variable | Designation | Units | Value | Calculation |
|---|---|---|---|---|
| Unit Size (Gross) | A | (MW) | 700 | <--- User Input |
| Retrofit Factor | B | | 1 | <--- User Input (An "average" retrofit has a factor = 1.0) |
| Gross Heat Rate | C | (Btu/kWh) | 6660 | <--- User Input (Default Coal-Fired = 10,000; NGCC = 6,660) |
| Type of Fuel | D | | NGCC | <--- User Input |
| CO2 Capture Rate | E | (ton/hr) | 245 | A*C*1000*0.9*Coal Rate /$10^6$ / 2000 (Based on 90% reduction) |
| SO2 Control Technology | F | | None | <--- User Input |
| Steam Consumption | G | (lb/hr) | 652,900 | Coal: 1.18 * E * 2000 ; NGCC: 1.33 * E * 2000 |
| Aux Power | H | (MW) | 51 | Coal: 0.1465 * E ; NGCC: 0.207 * E |
| Makeup Water Rate | I | (gpm) | 2388 | Coal: 7.26 * E ; NGCC: 9.73 * E |
| Steam Turbine Derate | J | (MW) | 51 | 0.155 * G / 2000 |
| Net Power Reduction | K | (MW) | 102 | H + J |
| Solvent Cost | L | ($/ton CO2 removed) | 3.5 | <--- User Input |
| Aux Power Cost | M | ($/kWh) | 0.03 | <--- User Input |
| Makeup Water Cost | N | ($/kgal) | 1 | <--- User Input |
| Operating Labor Rate | O | ($/hr) | 60 | <--- User Input (Labor cost including all benefits) |
| Transportation, Storage, & Monitoring (TS&M) | P | ($/ton) | 10 | <--- User Input |

### Costs are all based on 2021 dollars

| Capital Cost Calculation | | Example | Comments |
|---|---|---|---|
| Includes - Equipment, installation, buildings, foundations, electrical, minor physical/chemical wastewater treatment and retrofit difficulty | | | |
| BMI ($) = +B24:L34BI | Coal: [883000*(E)] * B ; NGCC: [883000*(E)] * B * 1.45 | $ 314,267,000 | Base CO2 capture island cost including: Absorbers and stacks, strippers, blowers, reagent tanks, heat exchangers, compressors, etc… |
| BMBOP ($) = | Coal: [235200*(E)] * B ; NGCC: [235200*(E)] * B * 1.45 | $ 83,710,000 | Base balance of plant costs including: Cooling system, steam supply, piping, ductwork, foundations, etc… |
| BM ($) = | BMI + BMC + BMBOP | $ 397,977,000 | Total base cost including retrofit factor |
| BM ($/KW) = | | 569 | Base cost per kW |
| **Total Project Cost** | | | |
| A1 = 15% of BM | | $ 59,697,000 | Engineering and Construction Management costs |
| A2 = 10% of BM | | $ 39,798,000 | Labor adjustment for 6 x 10 hour shift premium, per diem, etc… |
| A3 = 10% of BM | | $ 39,798,000 | Contractor profit and fees |
| **CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3** | | **$ 537,270,000** | Capital, engineering and construction cost subtotal |
| **CECC ($/kW) - Excludes Owner's Costs =** | | **768** | Capital, engineering and construction cost subtotal per kW |
| B1 = 5% of CECC | | $ 26,864,000 | Owners costs including all "home office" costs (owners engineering, management, and procurement activities) |
| **TPC' ($) - Includes Owner's Costs = CECC + B1** | | **$ 564,134,000** | Total project cost without AFUDC |
| **TPC' ($/kW) - Includes Owner's Costs =** | | **806** | Total project cost per kW without AFUDC |
| B2 = 10% of (CECC + B1) | | $ 56,413,000 | AFUDC (Based on a 3 year engineering and construction cycle) |
| C1 = 15% of CECC + B1 | | $ 89,052,000 | EPC G&A and risk fees of 15% |
| **TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2** | | **$ 620,547,000** | Total project cost |
| **TPC ($/kW) - Includes Owner's Costs and AFUDC =** | | **886** | Total project cost per kW |

# $CO_2$ Reduction Retrofit Cost Development Methodology

## Table 2. Example 2 (NGCC) Continued

Fill in the yellow cells with the known data inputs. The resulting costs are tabulated below. Variable names are defined as outlined in the table.

| Variable | Designation | Units | Value | Calculation |
|---|---|---|---|---|
| Unit Size (Gross) | A | (MW) | 700 | <--- User Input |
| Retrofit Factor | B | | 1 | <--- User Input (An "average" retrofit has a factor = 1.0) |
| Gross Heat Rate | C | (Btu/kWh) | 6660 | <--- User Input (Default Coal-Fired = 10,000; NGCC = 6,660) |
| Type of Fuel | D | | NGCC | <--- User Input |
| CO2 Capture Rate | E | (ton/hr) | 245 | A*C*1000*0.9*Coal Rate /$10^6$ / 2000 (Based on 90% reduction) |
| SO2 Control Technology | F | | None | <--- User Input |
| Steam Consumption | G | (lb/hr) | 652,900 | Coal: 1.18 * E * 2000 ; NGCC: 1.33 * E * 2000 |
| Aux Power | H | (MW) | 51 | Coal: 0.1465 * E ; NGCC: 0.207 * E |
| Makeup Water Rate | I | (gpm) | 2388 | Coal: 7.26 * E ; NGCC: 9.73 * E |
| Steam Turbine Derate | J | (MW) | 51 | 0.155 * G / 2000 |
| Net Power Reduction | K | (MW) | 102 | H + J |
| Solvent Cost | L | ($/ton CO2 removed) | 3.5 | <--- User Input |
| Aux Power Cost | M | ($/kWh) | 0.03 | <--- User Input |
| Makeup Water Cost | N | ($/kgal) | 1 | <--- User Input |
| Operating Labor Rate | O | ($/hr) | 60 | <--- User Input (Labor cost including all benefits) |
| Transportation, Storage, & Monitoring (TS&M) | P | ($/ton) | 10 | <--- User Input |

**Costs are all based on 2021 dollars**

| | | | |
|---|---|---|---|
| **Fixed O&M Cost** | | | |
| FOMO ($/kW yr) = 22*2080*O/(A*1000) | $ | 3.92 | Fixed O&M additional operating labor costs |
| FOMM ($/kW yr) = BM*0.6*0.025/(B*A*1000) | $ | 8.53 | Fixed O&M additional maintenance material and labor costs |
| FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM) | $ | 0.22 | Fixed O&M additional administrative labor costs |
| **FOM ($/kW yr) = FOMO + FOMM + FOMA + FOMWW** | **$** | **12.67** | Total Fixed O&M costs |
| **Variable O&M Cost** | | | |
| VOMS ($/MWh) = L * E / A | $ | 1.23 | Variable O&M costs for solvent |
| VOMTS ($/MWh) = P * E / A | $ | 3.51 | Variable O&M costs for transportation, storage, and monitoring |
| VOMP ($/MWh) = K * 1000 * M / A | $ | 4.37 | Variable O&M costs for additional auxiliary power and steam required --> Lost Revenue |
| VOMM ($/MWh) =I * 60 / 1000 * N / A | $ | 0.21 | Variable O&M costs for makeup water |
| **VOM ($/MWh) = VOMS + VOMTS + VOMP + VOMM** | **$** | **9.31** | Total Variable O&M costs |

| | | |
|---|---|---|
| Annual Capacity Factor = | 0.85 | |
| Annual MWhs = | 5,212,200 | |
| Annual Heat Input MMBtu = | 34,713,252 | |
| Annual Ton CO2 Created = | 2,030,725 | |
| Annual Ton CO2 Removed = | 1,827,653 | at removal efficiency = 90% |
| Annual Ton CO2 Emission = | 203,073 | |
| Annual Avg CO2 Emission Rate, lb/MWh = | 78 | based on original gross unit load [A] |

| | | | |
|---|---|---|---|
| Annual Capital Recovery Factor = | 0.082 | CO2 Capture | *from DOE 2019 BBS 12B* |
| Annual Capital Cost (Including AFUDC), $ = | | 50,885,000 | |
| Annual FOM Cost, $ = | | 8,869,000 | |
| Annual VOM Cost, $ = | | 48,527,000 | |
| Total Annual CO2 Capture Cost, $ = | | 108,281,000 | |
| Capital Cost, $/MWh = | | 9.76 | |
| FOM Cost, $/MWh = | | 1.70 | |
| VOM Cost, $/MWh = | | 9.31 | |
| Total CO2 Capture Cost, $/MWh = | | 20.77 | |
| Capital Cost, $/ton = | | 28 | |
| FOM Cost, $/ton = | | 5 | |
| VOM Cost, $/ton = | | 27 | |
| Total CO2 Capture Cost, $/ton = | | 59 | |