6. CO_2 Capture, Storage, and Transport

6.1 CO_2 Capture

The EPA Platform v6 using IPM can build Ultra-Supercritical (USC) Coal and Natural Gas Combined Cycle (NGCC) Electric Generating Units (EGUs) with carbon capture[49] and storage (CCS) technology. In addition, IPM includes a retrofit option to add CCS technology to existing coal steam and NGCC EGUs.

6.1.1 CO_2 Capture for Potential EGUs

Carbon capture for potential USC EGUs is represented as two model plant options with different CO_2 capture efficiencies of 30 percent and 90 percent. EPA Platform v6 can offer CCS with a CO_2 capture efficiency of 90 percent for new NGCC units.[50] The USC with CCS and NGCC with CCS model plant options are configured assuming construction at greenfield sites. The cost and performance data provided in Table 6-1 is based on the Annual Energy Outlook 2017 (AEO 2017). The basis for these costs are studies prepared for the U.S. Department of Energy's (DoE's) Energy Information Administration (EIA).[51,52]

The USC costs were developed for a generic 650-megawatt (MW) net output USC EGU with a nominal heat rate of 8,609 British Thermal Units (Btus) per kilowatt-hour (kW-hr) in 2021. The USC EGU uses a "one-on-one" configuration. That is, the EGU is comprised of one pulverized coal (PC) steam generator and one steam turbine (ST). The steam generator is fired with Illinois No. 6 (Herrin seam, Old Ben Mine) bituminous coal and operates at steam conditions of 3,800 pounds per square inch-absolute (psia) and 1,112 degrees Fahrenheit (^oF). USC with a CCS is equipped with an amine-based, post-combustion CO_2 capture system. Mercury (Hg), sulfur oxides (SO_x), nitrogen oxides (NO_x), and particulate matter (PM) emissions from the USC EGU are controlled with state-of-the-art air pollution control equipment including dry sorbent injection (DSI), activated carbon injection (ACI), wet flue gas desulfurization (WFGD) scrubber; low NO_x burners (LNBs), Selective Catalytic Reduction (SCR), and a fabric filter baghouse.

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49 The term "carbon capture" refers primarily to removing carbon dioxide (CO_2) from the flue gases emitted by fossil fuel-fired EGUs.

50 Note that the NGCC with CCS option is disabled in the EPA Platform v6 initial run.

51 Energy Information Administration (EIA). "*Capital Cost Estimates for Utility Scale Electricity Generating Plants*" (November 2016). "*Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2017*"(January 2017). "*Addendum: Capital Cost Estimates for Utility Scale Electricity Generating Plants*" (April 2017).

52 Note that the science of thermodynamics only refers to subcritical and supercritical states. "Ultra-Supercritical" is an industry term that refers to operating at higher temperatures and/or pressures within the supercritical regime. Distinct liquid and gas phases do not exist in a substance at a temperature and pressure above its critical point.

Table 6-1 Cost and Performance Assumptions for Potential USC and NGCC with and without Carbon Capture[53]

	Advanced Combined Cycle	Advanced Combined Cycle with CCS	Ultrasupercritical Coal with 30% CCS	Ultrasupercritical Coal with 90% CCS	Ultrasupercritical Coal without CCS
Vintage #1 (2021)					
Heat Rate (Btu/kWh)	6,267	7,514	9,644	11,171	8,609
Capital (2016$/kW)	1,081	2,104	4,953	5,477	3,580
Fixed O&M (2016$/kW/yr)	9.9	33.2	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2	7.1	7.1	9.5	4.6
Vintage #2 (2023)					
Heat Rate (Btu/kWh)	6,233	7,504	9,433	10,214	8,514
Capital (2016$/kW)	1,064	2,059	4,863	5,378	3,516
Fixed O&M (2016$/kW/yr)	9.9	33.2	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2	7.1	7.1	9.5	4.6
Vintage #3 (2025-2054)					
Heat Rate (Btu/kWh)	6,200	7,493	9,221	9,257	8,323
Capital (2016$/kW)	1,041	2,003	4,746	5,249	3,431
Fixed O&M (2016$/kW/yr)	9.9	33.2	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2	7.1	7.1	9.5	4.6

The NGCC costs were developed for a generic 702-MW net output NGCC EGU with a nominal heat rate of 6,267 Btus per kW-hr in 2021. The USC EGU uses a "two-on-two-on-one" configuration. That is, the combined cycle technology EGU is comprised of two natural gas-fired F5-class combustion turbines (CTs), two supplementary Heat Recovery Steam Generators (HRSGs), and one ST. The NGCC facility is fueled with pipeline-quality natural gas with a higher heating value (HHV) of 1,040 Btus per standard cubic foot (scf). Steam is produced at 3,800 psia and 1,112 oF. The two HRSGs extract heat from the two CTs to power the one ST. NGCC with a CCS is equipped with an amine-based, post-combustion CO_2 capture system. NO_x emissions from the NGCC EGU are controlled with LNBs and a SCR system.

6.1.2 CO_2 Capture via Retrofitting Existing EGUs

EPA Platform v6 offers the option of retrofitting CCS to existing coal-fired power plants and NGCC at a CO_2 capture efficiency of 90 percent.[54] The CO_2 capture process is modeled assuming the use of an amine-based, post-combustion CO_2 capture system.

The cost and performance data provided in Table 6-2 is based on the Sargent & Lundy[55] cost algorithm (Attachment 6-1 summarizes this study) and a DoE/National Environmental Technology Laboratory (NETL)

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53 The cost and performance characteristics for these new units are also shown in Table 4-13 and discussed further in Chapter 4.

54 Note that the NGCC with CCS option is disabled in the EPA Platform v6 initial run.

55 Sargent & Lundy. "*IPM Model – Updates to Cost and Performance for APC Technologies – CO_2 Reduction Cost Development Methodology.*" Project 13527-001; February 2017.

study.[56] As part of developing documentation for EPA Platform v6, the capital costs were converted to 2016 dollars from the 2011 dollar basis used in the referenced DoE/NETL study. Note that one of the carbon capture information resources is the Shell Cansolv® technology, which was installed on Unit 3[57] at SaskPower's Boundary Dam Power Station near Estevan, Saskatchewan, Canada in October 2014.[58] One issue that must be addressed when installing an amine-based, post-combustion CO_2 capture system is that sulfur oxides (e.g., SO_2 and sulfur trioxide (SO_3)) in the EGU flue gas can degrade the amine-based solvent used to absorb the CO_2 from the EGU flue gas. Since the amine will preferentially absorb SO_2 before CO_2, it will be necessary to treat the EGU flue gas to lower the sulfur oxide concentration to 10 parts per million by volume (ppmv) or less. Meeting this constraint will require installing supplemental WFGD technology (e.g., the SO_2 "polishing" scrubber referenced in footnote 58), or retrofitting existing FGD.

Table 6-2 Performance and Unit Cost Assumptions for Carbon Capture Retrofits on Coal Plants

Capacity (MW)	Heat Rate (Btu/kWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)
400	9,000	2,595	36.9	18.2	33.62	50.64
	10,000	2,960	41.2	19.7	37.31	59.50
	11,000	3,373	46.1	21.3	41.04	69.61
700	9,000	1,852	23.7	14.9	19.16	23.70
	10,000	2,071	26.1	15.6	21.28	27.03
	11,000	2,302	28.6	16.4	23.41	30.56
1,000	9,000	1,625	19.7	13.94	13.40	15.5
	10,000	1,810	21.6	14.46	14.88	17.5
	11,000	2,001	23.6	14.99	16.37	19.6

Note:

[1]Incremental costs are applied to the derated (after retrofit) MW size.

The capacity-derating penalty and associated heat rate penalty are an output of the Sargent & Lundy model (see section 5.1.1 for further details in regards to these penalties.

6.2 CO_2 Storage

The capacity and cost assumptions for CO_2 storage in EPA Platform v6 are based on the Geosequestration Cost Analysis Tool (GeoCAT); a spreadsheet model developed for the U.S. EPA by ICF, Inc. (ICF) in support of the U.S. EPA's Underground Injection Control (UIC) Program for CO_2 Geologic Storage Wells.[59] For EPA Platform v6, ICF updated the major cost components in the GeoCAT model, including revising onshore and offshore injection and monitoring costs to reflect 2016 industry drilling

[56] DoE/NETL. "*Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity. Revision 3*." DoE/NETL-2015/1723. July 6, 2015. (See https://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Rev3Vol1aPC_NGCC_final.pdf)

[57] At the time of project execution, Sask Power's Boundary Dam Unit 3 was a 43-year old lignite-fired 139 MW net generating unit. Upon completion, Boundary Dam Unit 3 became the first utility-scale power plant retrofitted with CCS technology. Sask Power estimates that the $1.2 billion project extended Unit 3's life by 30 years. Note that the associated energy penalty for installing the CCS technology derated Unit 3 from 139 to 110 MWs.

[58] The Shell Cansolv® carbon capture system at Boundary Dam Unit 3 uses a proprietary amine solvent to absorb SO_2 and CO_2 from the EGU flue gases. The carbon capture process requires very low SO_2 levels in the flue gases prior to CO_2 capture because, if present, the amine would preferentially absorb SO_2 before CO_2. The Shell Cansolv® SO_2 capture process was installed upstream of the CO_2 scrubber to "polish" the feed to the CO_2 scrubber.

[59] Federal Requirements Under the UIC Program for CO_2 Geologic Sequestration Wells, Federal Register, December 10, 2010 (Volume 75, Number 237), pages 77229-77303.

costs.[60] All cost components in the model were also converted to a 2016 dollar basis. In addition to updating costs in the model, ICF updated storage capacity, well injectivity, and other assumptions by state and offshore area primarily using data from the research program conducted at DoE/NETL.

The GeoCAT model combines detailed characteristics of sequestration capacity by state and geologic setting for the U.S. with costing algorithms for individual components of CO_2 geologic sequestration. The model outputs are regional sequestration cost curves that indicate how much potential storage capacity is available at different CO_2 storage cost points.

The GeoCAT model includes three modules:

1. A unit cost specification module,
2. A project scenario costing module, and
3. A geologic and regional cost curve module.

The unit cost specification module includes data and assumptions for 120 cost elements falling within the following categories:

1. Geologic site characterization
2. Area of review and corrective action (including fluid flow and reservoir modeling during and after injection and identification, evaluation, and remediation of existing wells within the area of review)
3. Injection well and other facilities construction
4. Well operation
5. Monitoring the movement of CO_2 in the subsurface
6. Mechanical integrity testing
7. Financial responsibility (to maintain sufficient resources for activities related to closing and remediation of the site)
8. Post injection site care
9. Site closure
10. General and administrative

Of the ten cost categories for geologic CO_2 sequestration listed above, the largest cost drivers (in roughly descending order of magnitude) are well operation, injection well and other facilities construction, and monitoring the movement of CO_2 in the subsurface. The cost estimates are consistent with the requirements for geologic storage facilities under the UIC Class VI rule[61] and Greenhouse Gas (GhG) Reporting Program Subpart RR[62].

The costs derived in the unit cost specification module are used in the GeoCAT project scenario costing module to develop commercial scale costs for eight sequestration scenarios compliant with UIC Class VI standards:

[60] The major data sources for updating costs was the Bureau of Labor Statistics (BLS) Producers Price Index (PPI) for various products and services related to oil and gas well drilling (https://www.bls.gov/ppi/), the "Joint Association Survey of Drilling Costs" published by the American Petroleum Institute (http://www.api.org/products-and-services/statistics#tab_overview), and the "Well Cost Study" published by the Petroleum Services Association of Canada (https://www.psac.ca/resources/well-cost-study-overview/).

[61] *Supra* Note 59.

[62] Title 40 of the Code of Federal Regulations (CFR), Part 98 (Mandatory GhG Reporting), Subpart RR (Geologic Sequestration of CO_2). See https://ecfr.io/Title-40/sp40.23.98.rr.

1. Deep saline formations
2. Depleted gas fields
3. Depleted oil fields
4. Enhanced oil recovery
5. Enhanced coal bed methane recovery
6. Enhanced shale gas
7. Basalt storage
8. Unmineable coal seams

EPA's GeoCAT application for CO_2 sequestration includes only storage capacity for the first four sequestration scenarios. The last four reservoir types are not included because they are not considered technically mature for CO_2 storage in the foreseeable future.

The current GeoCAT model includes the most recent DoE analysis of the lower-48 states CO_2 sequestration capacities from the "Carbon Sequestration Atlas of the United States and Canada Version 5." [63] ICF enhanced these assessments to include additional details needed for economic modeling such as the distribution of capacity by state, drilling depth, injectivity, etc. The geologic and regional cost curve module applies regionalized unit cost factors to these geologic characterizations to develop regional geologic storage cost curves.[64] The analysis of storage volumes is carried out by regional carbon sequestration partnerships as overseen by NETL in Morgantown, West Virginia. State level onshore and offshore capacity volumes are reported for storage in oil and gas reservoirs and deep saline formations. The great majority of storage volume is in deep saline formations, which are present in many states and in most states with oil and gas production. In the most recent version of the Atlas, offshore storage volumes have also been broken out by DoE into the Gulf of Mexico, Atlantic, and Pacific Outer Continental Shelf (OCS) regions. ICF carried out a separate analysis to break out CO_2 EOR storage potential (consistent with UIC Class VI requirements) from the total potential in oil and gas reservoirs reported in NATCARB.

The results of the project scenario costing module are taken as inputs into the geologic and regional cost curve module of GeoCAT, which generates national and regional cost curves indicating the volume of sequestration capacity in each region and state in the U.S. as a function of total cost per ton of CO_2 including all capital and operating costs. The result is a database of sequestration capacity by state, geologic reservoir type, and cost step.

Table 6-3 shows the NATCARB V storage volumes for the U.S. Lower-48 as allocated to GeoCAT categories. Total Lower-48 capacity is assessed at 8,216 gigatonnes. There are no volumes in the current model for potential storage in depleted gas field reservoirs because these are not reported in NATCARB.

[63] Carbon Sequestration Atlas of the United States and Canada – Version 5 (2015), U.S. Department of Energy, National Energy Technology Laboratory, Morgantown, WV https://www.netl.doe.gov/research/coal/carbon-storage/atlasv. Accessed mid-October 2016 with data updates through 2015.

[64] Detailed discussions of the GeoCAT model and its application for EPA can be found in U.S. Environmental Protection Agency, Office of Water, "Geologic CO_2 Sequestration Technology and Cost Analysis, Technical Support Document" (EPA 816-B-08-009) June 2008, https://www.epa.gov/sites/production/files/2015-07/documents/support_uic_co2_technologyandcostanalysis.pdf and Harry Vidas, Robert Hugman and Christa Clapp, "Analysis of Geologic Sequestration Costs for the United States and Implications for Climate Change Mitigation," Science Digest, Energy Procedia, Volume 1, Issue 1, February 2009, Pages 4281-4288. Available online at https://www.sciencedirect.com/science/article/pii/S1876610209008832.

For EPA Platform v6, GeoCAT represents storage opportunities in 37 of the lower 48 continental states.[65] Louisiana and Texas have both onshore and offshore state-level storage cost curves. In addition, because NATCARB does not provide state-level data, there are multi-state Atlantic offshore and Pacific offshore storage cost curves. The result is 41 storage cost curves shown in Table 6-4.

Table 6-3 Lower-48 CO_2 Sequestration Capacity by Region

					Offshore Allocation in GeoCAT					
		Onshore	Offshore	Total	Louisiana	Texas	GOM Total	Pacific	Atlantic	Total
CO2 Enhanced Oil Recovery	Low	11.2	1.1	12.3						
	Mid	**15.0**	**1.5**	**16.4**	**1.5**	**0.0**	**1.5**	**0.0**	**0.0**	**1.5**
	High	22.5	2.2	24.7						
Depleted Oil	Low	128.0	11.8	139.8						
	Mid	**170.7**	**15.7**	**186.4**	**12.7**	**3.0**	**15.7**	**0.1**	**0.0**	**15.7**
	High	256.0	23.6	279.6						
Unmineable Coal	Low	47.8	2.0	49.8						
	Mid	**63.7**	**2.6**	**66.4**	**0.0**	**0.0**	**0.0**	**2.6**	**0.0**	**2.6**
	High	95.6	4.0	99.5						
Saline	Low	4,252	1,708	5,960						
	Mid	**5,669**	**2,277**	**7,947**	**1,240**	**798**	**2,038**	**37**	**202**	**2,277**
	High	12,477	3,416	15,893						
Totals	Low	4,439	1,723	6,162						
	Mid	**5,919**	**2,297**	**8,216**	**1,254**	**801**	**2,055**	**40**	**202**	**2,297**
	High	12,851	3,446	16,297						
Oil Subtotal	Low	139.2	12.9	152.1						
(EOR plus Depleted Oil Flds.)	**Mid**	**185.6**	**17.2**	**202.8**	**14.16**	**2.97**	**17.13**	**0.05**	**0.00**	**17.18**
	High	278.5	25.8	304.2						

Note: Individual values may not sum to reported totals due to rounding.

The cost curves in Table 6-4 are in the form of step functions. In any given year within the IPM model, a specified amount of storage is available at a particular step price until either the annual storage limit or the total storage capacity is reached. In determining whether the total storage capacity has been reached, the model tracks the cumulative storage used up through the current year. Once the cumulative storage used equals the total storage capacity at that price step, no more storage is available going forward at that particular step price and, so, higher priced steps must be used.

CO_2 storage opportunities are relevant not just to power sector sources, but also to sources in other industrial sectors. Therefore, before being incorporated as a supply representation into EPA Platform v6, the original CO_2 storage capacity in each storage region was reduced by an estimate of the storage that would be occupied by CO_2 generated by other industrial sector sources at the relevant level of cost effectiveness (represented by $/ton CO_2 storage cost).

To do this, ICF first estimated the level of industrial demand for CO_2 storage in each CO_2 storage region in a scenario where the value of abating CO_2 emissions is assumed to be $150 per ton (this abatement value is relevant not only to willingness to pay for storage but also for the cost of capture

[65] The states without identified storage opportunities in EPA Initial Case v6 are Connecticut, Iowa, Maine, Massachusetts, Minnesota, Nevada, New Hampshire, New Jersey, Rhode Island, Vermont, and Wisconsin. These states were either not assessed or were found to not have storage opportunities in NATCARB for the four sequestration scenarios included in EPA's inventory, (i.e., deep saline formations, depleted gas fields, depleted oil fields, and enhanced oil recovery).

and transportation of the abated CO_2).[66] Then, for each region, ICF calculated the ratio of the industrial demand to total storage capacity available for a storage price of less than $10 per ton. (An upper limit of $10 per ton was chosen because the considerable amount of storage available up to that price could be expected to accommodate the industrial demand for CO_2 storage.) Converting this to a percent value and subtracting from 100 percent, ICF obtained the percent of storage capacity available to the electricity sector at less than $10 per ton. Finally, the "Annual Step Bound (MMTons)" and "Total Storage Capacity (MMTons)" was multiplied by this percentage value for each step below $10 per ton[67] in the cost curves for the region to obtain the reduced storage capacity that went into the storage cost curves for the electric sector in EPA Platform v6 initial run. Thus, the values shown in Table 6-4 represent the storage available specifically to the electric sector.

The price steps in the Table 6-4 are the same from region to region. (That is, STEP9 [column 2] has a step cost value of $9.07/Ton [column 3] across all storage regions [column 1]. This across-region price equivalency holds for every step.) However, the amount of storage available in any given year (labeled "Annual Step Bound (MMTons)" in column 4) and the total storage available over all years (labeled "Total Storage Capacity (MMTons)" in column 5) vary from region to region. In any given region, the cost curves are the same for every run year, indicating that over the modeling time horizon no new storage is being identified to augment the current storage capacity estimates. Given that additional geologic research will be done in the future to identify suitable storage sites, particularly once a substantial market for geologic storage services is established, this assumption is not meant to imply that no additional storage could be added. Such additional capacity could be represented in the model if model runs exhaust key components of the currently estimated storage capacity.

6.3 CO_2 Transport

Each of the 64 IPM model regions can send CO_2 to the 41 regions represented by the storage cost curves in Table 6-4. The associated transport costs (in 2016$/Ton) are shown in Table 6-5. For the model, ICF has also updated assumptions about the costs of CO_2 pipelines. These costs were derived by first calculating the pipeline distance from each of the CO_2 Production Regions to each of the CO_2 Storage Regions listed inTable 6-4. Since there are large economies of scale for pipelines, CO_2 transportation costs depend on how many power plants and industrial CO_2 sources could share a pipeline over a given distance. Consequently, the method assumes that the longer the distance from the source of the CO_2 to the sink for the CO_2, the greater the chance for other sources to share in the transportation costs, including pipeline costs (in $/inch-mile) and cost of service (in $/ton per 75 miles). These cost components are functions of the required diameter and thickness of the pipeline and the flow capacity of the pipeline, which themselves are functions of the assumed number of power plants using the pipeline.

<u>List of tables that are uploaded directly to the web:</u>

Table 6-4 CO_2 Storage Cost Curves in EPA Platform v6

Table 6-5 CO_2 Transportation Matrix in EPA Platform v6

Attachment 6-1 CO_2 Reduction Cost Development Methodology

[66] The approach that ICF employed to estimate industrial demand for CO2 storage is described in ICF International, "Methodology and Results for Initial Forecast of Industrial CCS Volumes," January 2009.

[67] Zero and negative cost steps represent storage available from enhanced oil recovery (EOR) where oil producers either pay or offer free storage for CO_2 that is injected into mature oil wells to enhance the amount of oil recovered. The value of the CO_2 for EOR is calculated using the average price of crude oil from the 2016 Annual Energy Outlook Reference Case for the years 2025 to 2040, or $109/bbl in 2016 dollars. There is also a market for CO_2 injection in enhanced coal bed methane (ECBM) production. ECBM is excluded from EPA's inventory as discussed earlier.