Carbon Capture & Storage in The United States Power Sector

The Impact of 45Q Federal Tax Credits

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CLEAN AIR TASK FORCE

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Acknowledgments

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SECTION 1

Summary

In February 2018, the United States (U.S.) Congress passed the Bipartisan Budget Act of 2018,[1] expanding the corporate income tax credit for carbon capture and storage (CCS). This tax credit, known as 45Q,[2] was adopted to enable additional deployment of CCS projects in the U.S. – both to achieve economic goals such as meeting energy needs and supporting jobs as well as carbon emission reductions.[3]

CCS is an essential technology in the climate solution toolbox but has not yet been deployed widely enough to meet its full potential. CATF advocated for the expansion of 45Q for several years as a way to provide a performance-based financial incentive to increase deployment of the technology. In June 2018, after the adoption of the expanded 45Q tax credits, CATF retained Charles River Associates (CRA) to perform a modeling analysis, based on assumptions developed in conjunction with CATF, that estimates the impact of this new incentive on CCS deployment in the U.S. power sector by 2030.

The modeling results show that 45Q leads to significant deployment of CCS, capturing and storing approximately 49 million metric tonnes (tonnes) of CO_2 annually in 2030. The estimated CO_2 that will be captured and stored is equivalent to removing roughly 7 million cars from U.S. roads.[4] For perspective, this is greater than the number of new cars sold in the U.S. in all of 2017.[5]

Importantly, the modeling results show that the power sector carbon reductions due to 45Q-induced deployment of CCS are additive to those achieved through renewable sources of electricity generation. That is, the modeling shows that carbon capture-controlled electricity generation replaces uncontrolled fossil-fired power, not new or existing renewable energy. Electricity generation and corresponding emission reductions from renewables remain unaffected by the availability of 45Q.

According to the International Energy Agency (IEA), to limit global temperature rise to below 2 degrees Celsius, U.S. power plants must remove 73.5 million tonnes of CO_2 annually by 2030 through CCS. This power sector target rises steeply to 547 million tonnes of CO_2 annually by 2050.[6] Though a policy pathway doesn't exist yet to meet this 2050 U.S. power sector climate goal fully, CATF's modeling results suggest that 45Q could get us two-thirds of the way to the 2030 U.S. power sector goal, removing 49 million tonnes of CO_2 from atmospheric release. Scientists recently reported that significant negative impacts would be associated with a global temperature rise of 1.5 degrees Celsius, thereby increasing the urgency of even higher levels of CCS deployment.[7]

All of the CCS that the CRA model deploys are retrofits on existing coal and natural gas combined cycle (NGCC) plants close to enhanced oil recovery (EOR) basins, indicating that the additional revenue from EOR creates more favorable economics for CCS deployment relative to storing CO_2 in saline reservoirs. In the real world, these results would mean rapid EOR infrastructure development, which history[8] shows is possible, but may require additional targeted policy support. For CCS to reduce CO_2 emissions from the U.S. power sector to meet the 2 degree scenario goals, as modeled by the IEA, 45Q incentives would need to be accompanied by additional policy actions and incentives to increase the pace at which pipelines and injection sites are permitted, financed, and built. Without targeted policies made to remove bottlenecks and enable more rapid development of CO_2 capture, transport and storage infrastructure, the full impact of 45Q may not be realized.

SECTION 2

Context & Study Design

The Case for CCS

CCS is needed. To avoid the worst effects of climate change, the best available science warns that anthropogenic CO_2 emissions must not only be zeroed out globally by mid-century, but must also decline to negative tonnes per year.[9] CCS must be scaled up in time so that the overall efforts to constrain global temperature rise have a higher chance of success.

Modeling and analysis by the Intergovernmental Panel on Climate Change (IPCC) show that achieving atmospheric concentrations of CO_2 at 450 ppm, and restricting annual average temperature rise to below 2 degrees Celsius above pre-industrial levels, is unlikely in most scenarios with limited CCS availability. IPCC modeling suggests that without CCS the costs of achieving such levels of CO_2 concentration increase by 138 percent.[10] The recent report by the IPCC notes that two out of three pathways that limit overshooting 1.5 degree Celsius temperature rise need CCS to be part of the mix.[11]

CCS is well understood in industrial sectors. Since the 1930's, carbon capture equipment has been used commercially to purify natural gas, hydrogen, and other gas streams found in industrial settings. Since that time, the technology has evolved and grown.[12]

In the U.S., over 23 million tonnes of CO_2 are captured annually from natural gas processing plants, refineries, and fertilizer plants and sold for EOR.[13]

Experimental CO_2 injections began over a half century ago in the West Texas Mead Strawn Oilfield in 1964, and commercial-scale CO_2 flooding began in 1972 at the SACROC field in Texas. More than 850 million tonnes of CO_2 have been injected underground in the U.S. for EOR.[14] Moreover, natural gas companies routinely use deep geologic storage for natural gas reserves, with nearly 3 Tcf stored presently. There are over 400 sites in the U.S. alone where natural gas is injected and stored in saline aquifers, depleted natural gas reservoirs and salt deposits.[15] A mature network of over 4,000 miles of pipelines brings CO_2 to EOR fields in the U.S., while trucks and rail cars operated by specialty chemical companies transport smaller volumes to meet the needs of the food industry and other chemical uses.[16] Every year China captures over 270 million tonnes of high-purity CO_2 from plants that process coal into fertilizers, methanol, substitute natural gas, and a variety of industrial chemicals.[17]

CO_2 storage is permanent, verifiable and abundantly available. Building on a wealth of evidence and experience, a 2018 study published in the journal Nature modeled the possibility of leakage, finding that

CO_2 stored in well-regulated settings has a 98 percent probability that 100 percent of the injected CO_2 will be stored for over 10,000 years.[18] Furthermore, several other studies in the past 5 years have afforded the opportunity to understand the fate of injected CO_2 better.[19]

The U.S. has a regulatory structure in place sufficient to support commercial CCS activities. States and the federal government jointly regulate the transport of CO_2 through pipelines. The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (DOT PHMSA) oversees operation and construction, including design specifications. The U.S. Environmental Protection Agency (EPA) regulates the injection of CO_2 through the Safe Drinking Water Act's Underground Injection Control Program,[20] and the Clean Air Act's Greenhouse Gas Reporting Program[21] provides complementary monitoring, verification and accounting requirements for projects opting into geologic storage. Many states, particularly those with active oil and gas industries, have their own set of regulations that govern the reporting of CO_2 injection for state tax and safety purposes. These include California, Montana, North Dakota, Wyoming, Kansas, Oklahoma, Texas, Louisiana, and Mississippi.[22] In 2018, California adopted their own Quantification Methodology and Permanence Protocol to measure, verify and monitor CO_2 emission reductions from CCS.[23] The U.S. Treasury Department is expected to issue further guidance for claiming 45Q tax credits for CO_2 storage in 2019.

North America has widespread and abundant geologic storage options in deep porous saline brine-bearing formations and depleted oilfields. Geologic carbon management and injection technology, used in both saline and EOR storage projects, is founded upon decades of experience transporting and injecting CO_2 in deep geologic reservoirs and supported by related forms of subsurface fluid management.

<u>CCS is proven in the power sector.</u> Eighty years of experience with CO_2 capture, and half a century of experience with CO_2 management in oilfields[24] is transferring now to the power sector as part of efforts to address climate change. There are power plant performance requirements already established based on the availability of CCS technology. The 2015 U.S. federal CO_2 emission standard for new coal-fired power plants is based on partial CCS.[25] Canada requires coal plants to either close or install CCS by 2030.[26] New York state has proposed regulations requiring existing coal plants to either retrofit with CCS or cease operations by 2021.[27]

The most recent example of CCS in the power sector is the carbon capture retrofit on NRG's W. A. Parish Plant in Texas – Petra Nova Carbon Capture Project. The project captures 90 percent of CO_2 from a 240 MWe slipstream from one unit at an existing coal-fired power plant. In 2017, more than 1 million tonnes of CO_2 were captured and transported by an 80-mile pipeline to the Hilcorp West Ranch Oil Field in Jackson County, Texas for use in EOR.[28]

CCS is already delivering emissions reductions across the globe, but at nowhere near the levels needed to reverse climate trends. Targeted federal policy action to support this vital technology can make CCS an even more readily available carbon reduction option that is cost-competitive with other climate solutions.

Net CO_2 Emission Reductions from CO_2-EOR

Utilization of captured CO_2 in EOR is a well-understood and verifiable process that can deliver CO_2 emission reductions on a life cycle basis. According to analysis done by the IEA,[29] each barrel of oil produced through conventional CO_2-EOR using anthropogenic CO_2 reduces 0.19 tonnes of CO_2 emissions. The following broadly outlines the life cycle of CO_2 emissions from CO_2-EOR and Figure 1 illustrates the same.

CO_2 emissions are reduced through permanent geologic storage. Every barrel of oil produced through conventional CO_2-EOR typically involves injecting 0.3 tonnes of anthropogenic CO_2 into an oilfield. The injected CO_2 helps release crude oil trapped in the pores of the source rock and in the process the CO_2 becomes trapped permanently in those pores.

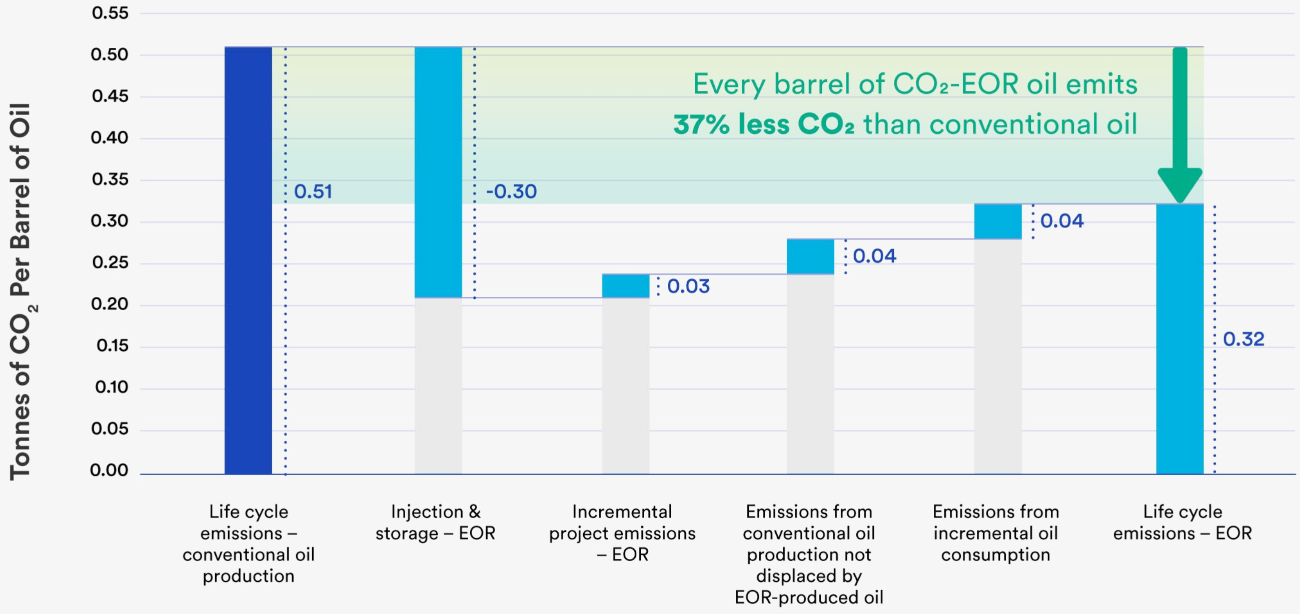
While the injection of 0.3 tonnes of CO_2 is a direct reduction in emissions, understanding the net effect on CO_2 emissions from EOR requires accounting for increases in CO_2 emissions over the life cycle of CO_2-EOR operations.

CO_2 emissions increase at the project level and globally from an increase in oil consumption. At the EOR project level, there are CO_2 emissions increases from processes such as separation and recycling of CO_2 that offset the initial emission reduction of 0.3 tonnes of CO_2. The initial emission reduction is further offset by increased emissions from a marginal increase in global oil consumption. IEA's global oil market analysis estimates that when crude oil produced through CO_2-EOR hits the global oil market, 20 percent of it represents a marginal increase in oil consumption. The rest of the oil supply from CO_2-EOR meets existing oil demand by displacing oil produced through other methods.

But, in the final analysis, EOR yields net CO_2 emissions reductions. Accounting for the CO_2 injected and released over the life cycle (well-to-wheels), the IEA finds that every barrel of oil produced through CO_2-EOR results in a net emission reduction of 0.19 tonnes of CO_2. Compared to life cycle emissions of a conventionally produced oil, EOR-produced oil emits 37 percent less CO_2.

Said another way, for every 0.3 tonnes of CO_2 that are injected and stored through EOR, a net CO_2 reduction occurs, of 0.19 tonnes of CO_2. Expressed as a percentage: for every one tonne of CO_2 that is delivered to an EOR field, 63 percent (0.19 ÷ 0.3) of it is a net CO_2 emission reduction.

FIGURE 1: NET CO_2 EMISSION REDUCTION FROM A BARREL OF OIL PRODUCED THROUGH CO_2 EOR INCLUDING GLOBAL OIL MARKET IMPACTS



Source: CATF analysis of IEA data.

Study Objective

In February 2018, as part of the Bipartisan Budget Act of 2018, the U.S. Congress passed the expansion of the corporate income tax credit for CCS, known as 45Q. This tax credit was adopted to enable additional deployment of CCS projects in the U.S. – both to achieve economic goals such as meeting energy needs and supporting jobs as well as carbon emission reductions.[30]

In June 2018, CATF initiated this economic modeling study to estimate CO_2 emissions reductions achievable in the U.S. power sector resulting from 45Q tax credit for CCS deployment and to develop a baseline to study other incentives for CCS in the future.

Study Design

CATF retained Charles River Associates, developers of the North American Energy and Environment Model (NEEM),[31] to perform the modeling analyses for this project. NEEM is a linear programming model that simulates economic dispatch and minimizes the present value of incremental costs to the electric sector in meeting demand and complying with environmental limits. By using inputs such as energy and pollution control technology cost assumptions, fuel prices, electricity demand growth, and environmental policies (for example, the 2015 required power plant CO_2 emissions limits), and other policies such as renewable portfolio standards, NEEM provides outputs including new electricity resource build patterns, emission allowance prices, and power prices. CATF chose to work with NEEM because the model is widely used by utilities in the U.S. for making strategic capacity and rate decisions.

This modeling study is aimed at testing the incremental impact of the newly expanded 45Q tax credits on CCS deployment. The tax credit requires CCS projects to commence construction before January 1, 2024. To review the near-term CCS deployment levels as a result of the time-limited nature of the incentive, CATF chose to model a 12-year period ending in 2030. Modeling until 2030 also helps in limiting the uncertainty associated with longer term modeling projections. In this report, CATF presents CCS deployment estimates for 2030 on an annual basis.

Key Input Assumptions

45Q Tax Credit

The 45Q tax credit for CCS first became effective in October 2008 and provided eligible corporations with an income tax liability reduction, the value of which depended on whether the captured CO_2 was stored through EOR or stored in saline formations. The value of the tax credits were $10 per tonne of CO_2 for storage through EOR and $20 per tonne of CO_2 for saline storage. These credit values continue to apply to projects that were placed in service before February 9, 2018, after which the expanded 45Q tax credit is applicable.

With the 2018 revision of 45Q, the tax credit for storage of CO_2 through EOR and conversion of captured CO_2 into chemical products, increases from $10 to $35 per tonne of CO_2. For storage in saline reservoirs, the tax credit increases from $20 to $50 per tonne of CO_2. The tax credit value ramps up over ten years as shown in Table 1 below:

TABLE 1: TAX CREDIT VALUE RAMP UNDER 45Q

Calendar Year Beginning In	EOR (Nominal $ per tonne of CO_2)	Saline (Nominal $ per tonne of CO_2)
2017	$12.83	$22.66
2018	$15.29	$25.70
2019	$17.76	$28.74
2020	$20.22	$31.77
2021	$22.68	$34.81
2022	$25.15	$37.85
2023	$27.61	$40.89
2024	$30.07	$43.92
2025	$32.54	$46.96
2026	$35.00	$50.00

Source: 26 U.S.C. § 45Q.

The revised law retains the 45Q eligibility threshold for minimum annual CO_2 volume per project of 500,000 tonnes for power plants, but lowers it for industrial sources and direct air capture to 100,000 tonnes. The legislation makes the tax credit available for non-EOR utilization (such as chemical conversion) and storage of CO_2 with the minimum eligibility threshold set at 25,000 tonnes annually.

Projects must commence construction by January 1, 2024, to be eligible and can claim the tax credit for 12 years from the date the project is placed in service. The expanded tax credit now also applies to the capture and storage of carbon monoxide emitted from industrial processes.

A key feature of this tax credit is that it is performance-based. It is only awarded if and when CO_2 is captured and then stored in conformance with federal requirements.

CATF modeled the 45Q tax credit by assuming a business model in which the CCS operator enters into an agreement with a tax equity investor, who would claim the tax credits instead of the operator. In return, the investor would provide an upfront payment to the CCS operator reflecting the net present value (NPV) of the expected tax credits discounted at 15 percent. Our methodology and related assumptions are further explained in the appendix.

Enhanced Oil Recovery: CO_2 Price and Storage Capacity

CATF retained Advanced Resources International (ARI) to develop NEEM inputs representing CO_2 demand from the EOR industry. ARI is a consulting firm used by the industry and by the U.S. Department of Energy's National Energy Technology Laboratory (DOE NETL) to estimate costs and quantities of oil available for production through CO_2-EOR in U.S. oil-producing basins.

ARI developed annual CO_2 demand curves individually for nine EOR basins in the U.S. for the 12-year modeling period. The total CO_2 demand for each model year correspond to CATF's oil price assumption for that year – the higher the oil price, the higher the demand for CO_2 for EOR. And, the total CO_2 demand is defined in tranches of four CO_2 prices.

In the real world, CCS projects outside of the power sector are also eligible for 45Q tax credits. This means that CO_2 supply from carbon capture on industrial sources and on power plants would compete to meet the total demand for CO_2 from the EOR industry. However, NEEM only represents the power sector, which accounts only for a part of the total CO_2 supply needed to meet CO_2 demand. For this reason, CATF worked with ARI to modify the total CO_2 demand curves such that NEEM only accessed a part of the total CO_2 demand. This allowed the model results to avoid overstating the level of CCS deployment in the power sector. A more detailed description of this assumption can be found in the appendix.

For saline storage capacity and costs, CATF based assumptions on the Geosequestration Cost Analysis Tool (GeoCAT), a model used by EPA. GeoCAT develops total storage potential and reflects available storage capacity at 12 cost "steps," which range between $4.54 per short ton ($4.09 per tonne) and $54 per short ton ($60 per tonne) in 2016$.[32]

ARI also developed CO_2 transportation costs representing the cost of delivering captured CO_2 via pipeline to the closest EOR basin for storage. The CO_2 transport costs are listed in Table 13 in the appendix.

Coal Plant Carbon Capture Retrofit Assumptions

There are two demonstrated approaches to retrofitting coal plants with carbon capture. The first option integrates the capture unit into the coal plant taking steam and electricity from the power plant whose emissions are being captured. In this approach, carbon capture cuts into the existing power plant's steam cycle, resulting in a less efficient plant and a capacity penalty. The carbon capture retrofit on Boundary Dam adopted this approach. The second option is to build a separate gas-fired boiler or cogeneration unit that provides steam and electricity to the capture unit. While this approach involves more capital costs, it offers operational advantages. These advantages include the ability for the coal plant to ramp up and down easily and avoids potential engineering complications that full integration can introduce. The Petra Nova project uses this approach.

Coal fired power station. Photo: Getty Images.

In this study, coal retrofits were modeled based on a Petra Nova-like design. However, instead of a cogeneration plant, CATF assumed a design with a natural gas-fired auxiliary boiler. While this approach did not impact the efficiency of the power plant, it still reduced the plant's overall electricity output by a small amount because electricity from the coal plant was assumed to power the capture unit and CO_2 compression. CATF opted for this more conservative approach because it better addressed integration concerns that utilities may face with initial installations. Also, in a low-gas price environment, which is projected to continue through 2050,[33] this configuration has cost advantages. Carbon capture retrofits have not been represented this way in previous modeling efforts.

The costs and performance assumptions for coal plant retrofits in CATF's model incorporate the costs of a natural gas-fired auxiliary boiler, the additional fuel costs and emissions from combusting the natural gas used to generate steam. Accounting for additional emissions from the boiler, a 90 percent carbon capture system would reduce 79 percent of total CO_2 emissions on a net basis. NEEM allowed partial retrofits using a slipstream from the plant, wherever economic. Details of additional assumptions, such as technology availability, costs, capital charge rates, and fuel prices can be found in the appendix.

SECTION 3

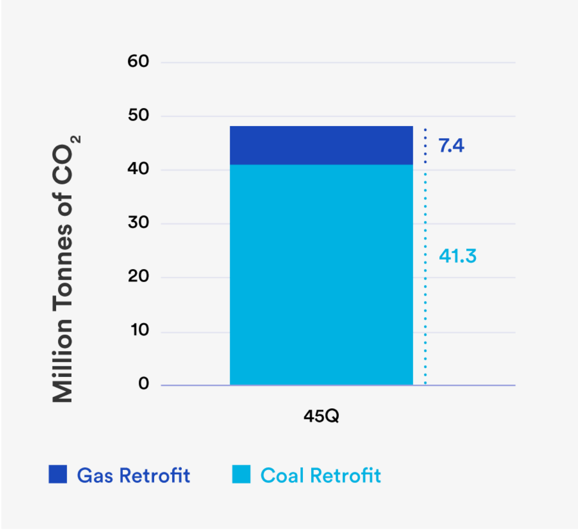
Results & Analysis

CO_2 Captured and Stored in 2030

The modeling results show that the expanded 45Q tax credits drive significant CO_2 emission reductions through carbon capture in the U.S. power sector, and its subsequent storage. Almost 49 million tonnes of CO_2 emissions are cut annually from existing fossil fuel-fired power plants through carbon capture retrofits in 2030. Add in the storage of those tonnes, and that is equivalent to removing roughly seven million cars from American roads.[34]

As shown in Figure 2, coal plant retrofits dominate, capturing 41.3 million tonnes, while retrofits on NGCC plants capture 7.4 million tonnes of CO_2 annually in 2030. These carbon capture retrofit projects rely on EOR revenue to become economic as the model does not show any saline storage as a result of 45Q tax credits. NEEM chooses to build CCS based on a net present value calculation. The fact that the tax credits did not result in any saline storage indicates that the economics of $35 tax credits combined with modeled EOR revenue (see appendix section on EOR) is more favorable than the $50 tax credit for saline storage. In a lower oil price world in which there is reduced EOR storage supply, the model may find saline storage more favorable.

FIGURE 2: CO_2 VOLUME CAPTURED FROM CCS RETROFITS ON EXISTING FOSSIL FUEL-FIRED POWER PLANTS IN 2030



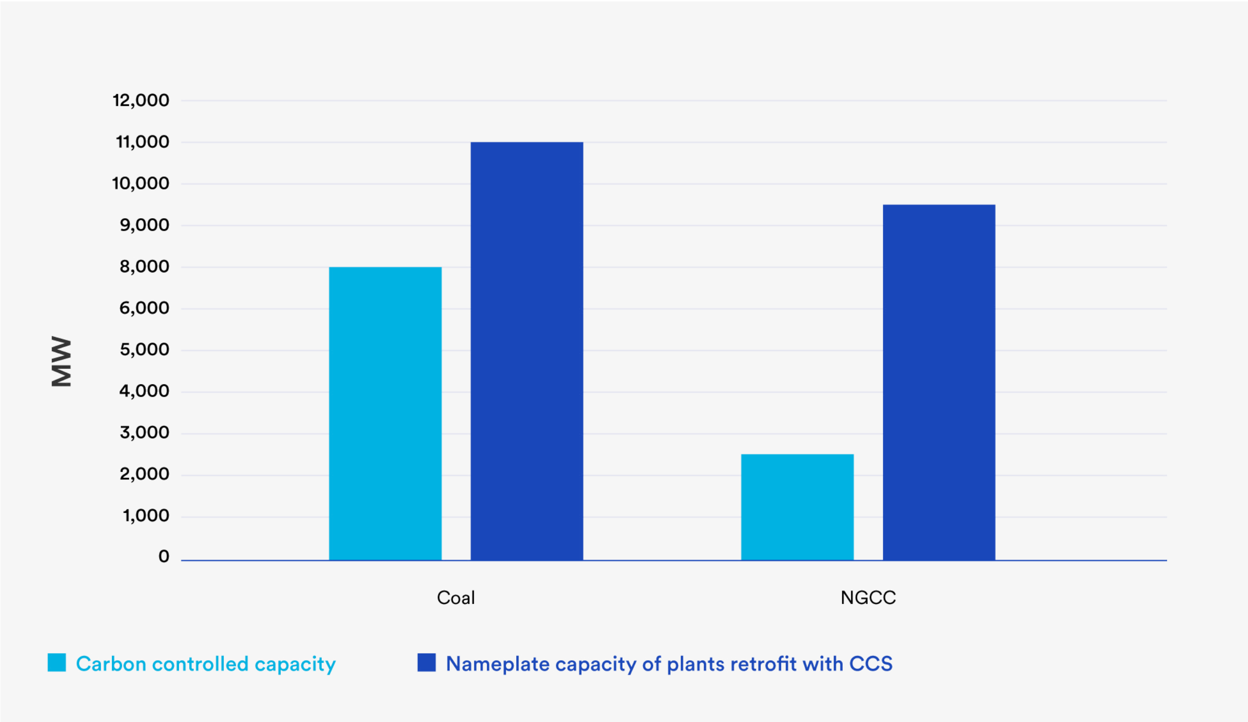
Source: CATF analysis of model results from CRA.

Electricity Generating Capacity with CCS in 2030

The model partially retrofits 45 fossil-fired units with carbon capture. As shown in Figure 3 below, together these units represent 20.4 GW of existing electricity generating capacity with 10.8 GW of coal-fired and 9.6 GW of NGCC plants. The carbon-controlled portion of this generating capacity is 10.8 GW with 8.03 GW of coal and 2.77 GW of NGCC.

Figure 3 also illustrates the potential to further build upon and utilize the infrastructure developed to capture and store the initial 49 million tonnes of CO_2. Additional policies and incentives could deliver deeper emission reductions by incentivizing the capture of more CO_2 emissions readily available at the same sources and the storage of those tonnes in the same locations.

FIGURE 3: CARBON-CONTROLLED GENERATING CAPACITY IN 2030



Source: CATF analysis of IEA data.

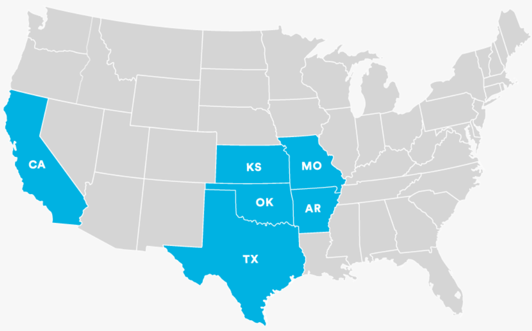
Geographic Distribution of CCS in 2030

All the CCS projects that are built by the model in this scenario were located close to EOR storage supply in California, East & Central Texas, Mid-continent and Permian Basins. Figure 4, on the right, shows the breakdown of carbon-controlled generating capacity by geography.

CCS is Complementary to Renewables

CATF's study results show a diverse mix of electricity generation sources in 2030 in the 45Q scenario. Importantly, the resulting generation mix reveals that carbon-controlled fossil generation does not displace generation from renewable sources. As can be seen in Figure 5 below, the generation from renewables in the 45Q scenario remain close to 550 TWh in 2030 in scenarios with and without 45Q.

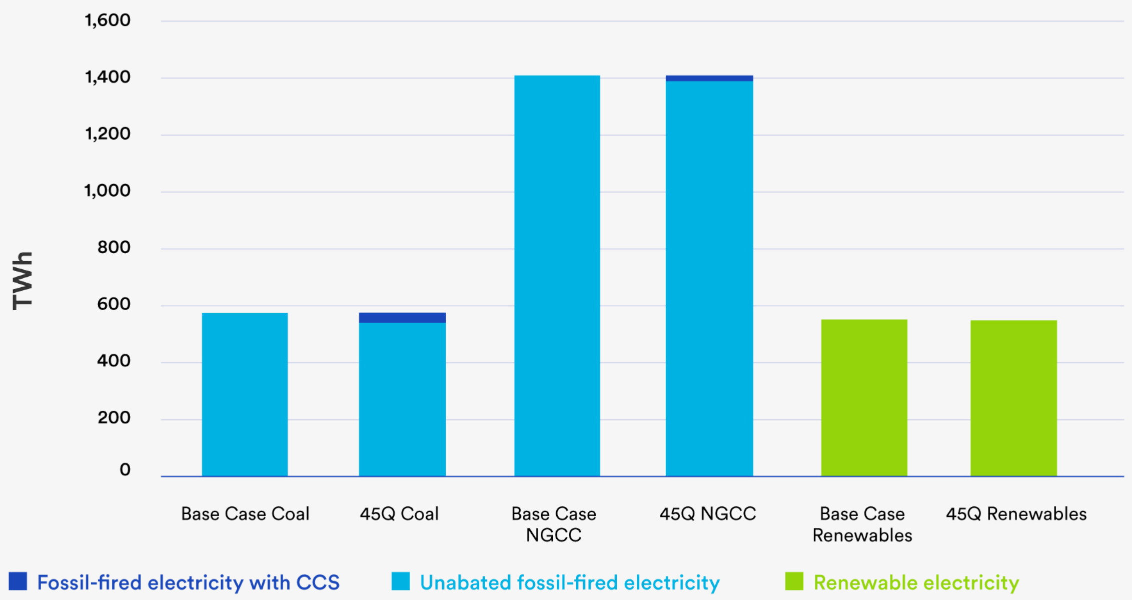
FIGURE 4: GEOGRAPHIC DISTRIBUTION OF UNITS RETROFIT WITH CCS BY 2030



State	Coal Retrofits	Gas Retrofits
Arkansas	173 MW	–
California	–	2276 MW
Kansas	1399 MW	–
Texas	3687 MW	332 MW
Oklahoma	1962 MW	165 MW
Missouri	804 MW	–
Total	**8025 MW**	**2733 MW**

Source: CATF analysis of model results from CRA.

FIGURE 5: CHANGES IN ELECTRICITY GENERATION IN 2030 – BASE CASE VS 45Q SCENARIO



Source: CATF analysis of model results from CRA.

CO_2 Storage: EOR Development Potential

The modeling results show nearly 49 million tonnes per year of CO_2 in 2030 being stored in three EOR basins. The California Basin stores 6.4 million tonnes per year, East & Central Texas stores 19 million tonnes and the Mid-Continent Basin stores 23.5 million tonnes of CO_2.[35]

To assess whether the growth projected by CATF's modeling is reasonable, we compare the modeling results to historic U.S. EOR growth rates. Table 2 below shows the highest levels of annual CO_2 sales for EOR reached over periods shorter or equal to 12 years, for specific basins.[36] This 12-year window is comparable to the period of CATF's modeling.

TABLE 2: INCREMENTAL CO_2 SALES FOR EOR IN THE U.S.

Basin	Incremental CO_2 Sales for EOR
Permian	~19 million tonnes (1980-1990)
Rocky Mountains	~3.6 million tonnes (1986-1990)
Gulf Coast	~17.2 million tonnes (2002-2012)

Source: L. Stephen Melzer.

The historic EOR growth rate in basins ranged from 3.6 to 19 million tonnes per year, suggesting that the CATF modeled growth rates are reasonable. Furthermore, the largest rates of past growth were spurred by tax policy. The growth in the Permian Basin between 1980 and 1990 was driven by a reduced Windfall Profits Tax (WPT)[37] for crude oil production using EOR. Taxes for EOR-produced oil were reduced to 30 percent. In contrast the tax rate for conventional oil production was 70 percent. The impact of this reduced tax rate was significant. Nearly three-quarters of the existing CO_2 pipeline infrastructure was built in the 1980-90 period, soon after which the WPT was phased out. This led the industry to preferentially build EOR infrastructure by developing large natural CO_2 deposits and constructing pipelines.[38] Even after 1990, among other things, other federal tax incentives[39] for CO_2-EOR continued to sustain growth of EOR infrastructure in the U.S. In the Permian Basin specifically, by 2012, total annual CO_2 sales for EOR stood at approximately 33 million tonnes per year.[40]

Among the three basins projected to store CO_2 in CATF's model results, only California currently has no CO_2-EOR infrastructure. CATF's modeling projects California will store 6.4 million tonnes of CO_2 a year by 2030. This growth rate is similar to the experience of the Rocky Mountain region's EOR industry as shown in Table 2. The Rocky Mountains region grew from no EOR to 3.6 million tonnes of CO_2 being purchased for EOR per year in just 5 years, a rate similar to the modeled projection in California. California has an existing thermal recovery industry (EOR using injected steam)[41] and other policies that may help drive CO_2-based EOR. Recently the state developed and adopted a quantification methodology and permanence protocol for CCS that enables CO_2 reductions from storage through EOR to qualify for the the state's Low Carbon Fuel Standard,[42] which currently has credits valued at more than $100 per tonne of CO_2. Efforts to extend the CCS protocol to the state's cap and trade program are expected in the coming years that can further catalyze storage infrastructure development in California.

CATF's modeling shows reasonable EOR growth rates under 45Q, but additional state-level or federal incentives would be needed attain higher, longer-term targets to further reduce carbon emissions not just from the power sector but also various industrial sectors too. To illustrate, the State CO_2-EOR Deployment Work Group, co-convened by Gov. Matt Mead of Wyoming and Gov. Steve Bullock of Montana has published reports collecting a variety of policy options that can be implemented at the state level for spurring CO_2-EOR and CO_2 pipeline development.[43]

Historic growth rates in the EOR industry show the power of financial incentives such as federal tax credits to spur fast infrastructure development. Based on that history, and the availability of potential additional state policy pathways, CATF expects that the projected level of necessary regional CCS and EOR development can be achieved by 2030 to support the needed levels of CO_2 emission reduction.

Climate Change Mitigation Potential

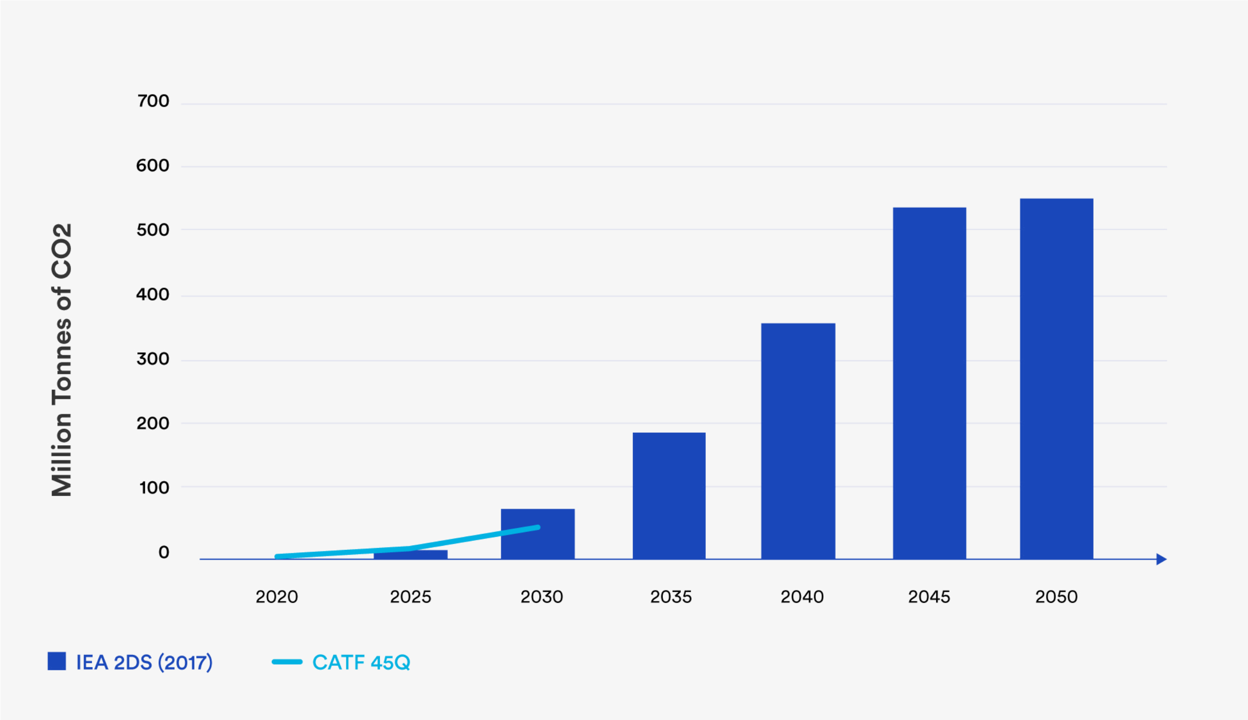
CATF's modeling results show alignment with CCS deployment in IEA's 2 degrees Celsius scenario (2DS), as modeled in Energy Technology Perspectives (ETP) 2017.

IEA's 2DS model was designed to show what is necessary to achieve a 50 percent chance of limiting average global temperature rise to 2 degrees Celsius by 2100. In this scenario, carbon neutrality is achieved before 2100. The IEA considers that outcome highly ambitious, requiring challenging transformations in the global energy sector. While, IEA's modeling uses different assumptions than NEEM to create its global emission trajectories their results are an illustrative yardstick to compare CATF's results against. This is because they provide results broken down by emissions reductions needed to meet 2DS goals by country, sector and technology type such as CCS.

In Figure 6 below, CATF compares the emission reductions our modeling indicates can be delivered by the U.S. power sector given the adoption of CCS, through 2030, with those required in the IEA 2DS model. Note that IEA's 2DS did not model 45Q, whereas CATF's modeling does include the new tax credit. Comparing the two modeling results suggests that 45Q has the potential to deliver power sector emission reductions in line with what is necessary by 2030 to meet the 2DS.

The U.S. Intended Nationally Determined Contibution (NDC) under the 2016 Paris Agreement sets a goal of reducing emissions by 26 to 28 percent below 2005 levels by 2025.[44] CATF modeling suggests that 45Q-led CCS deployment in the power sector alone could contribute 10 percent of those reductions by 2030.

FIGURE 6: CO_2 CAPTURED FROM U.S. POWER SECTOR IN IEA 2-DEGREE SCENARIO AS COMPARED WITH CATF'S 45Q SCENARIO



Source: CATF analysis of CRA model results and IEA Energy Technology Perspectives 2017 data.

SECTION 4

Conclusion

45Q has the potential to support deployment of CCS in the U.S. at levels that can remove approximately 49 million tonnes of CO_2 emissions on a yearly basis by 2030 from the power sector alone. Using IEA's well-to-wheels analysis of life cycle CO_2 emissions from EOR, CATF's results would amount to almost 31 million tonnes of net CO_2 emission reduction. Further, CATF's analysis of historic growth rates in the CO_2-EOR industry in the western U.S. suggests that the infrastructure build out necessary to support the levels our modeling predicts can be achieved by 2030.

45Q offers the opportunity to achieve additional CO_2 emission reductions complementary to reductions that would be achieved by renewable energy growth in the power sector. In this way, the incentive offers a near-term pathway to meeting IEA's 2030 target for CO_2 reduction through CCS in the domestic power sector, an essential step towards achieving global climate goals. However, to stay on track with meeting larger targets for 2050 and beyond, and attempting to not overshoot 1.5 degrees Celsius in global temperature rise, additional policy pathways – particularly at the state level – may need to be explored and analyzed.

SECTION 5

Appendices

Description of NEEM

Existing Units

The NEEM unit database represents all grid-connected electricity generating units in the U.S., and incorporates data on planned plant additions and retirements. Fossil-fired units above 200 MW are modeled individually while units under 200 MW are aggregated by market region based on size, heat rate and existing control equipment. For each named unit, the NEEM database includes existing and planned equipment information, which determines their initial emission rates per pollutant.

TABLE 3: RETROFIT OPTIONS AVAILABLE IN NEEM

	NEEM Retrofit Options
SO_2	Flue gas desulphurization (FGD) Dry Sorbent Injection (DSI)
NOX and PM	Selective catalytic reduction (SCR) Selective non-catalytic reduction (SNCR)
HG	Activated carbon injection (ACI) ACI with fabric filter
CO_2	Carbon capture and storage (SEQ)

Source: CRA.

Emission limits

NEEM represents emissions at the plant level for SO_2, NOX, and mercury (Hg) and other air toxic emissions based on plant fuel choice, operating characteristics and control equipment. NEEM allows for, and may require, environmental retrofits for existing coal-fired units to reduce emissions of SO_2, NOX & PM, Hg, and CO_2. The model reflects that U.S. 2015 new source performance standards for coal plant CO_2 emissions, see note 21, and can choose to add the environmental retrofits over multiple years before making the decision on adding CCS.

Other environmental constraints:

- Renewable Portfolio Standards: State targets represented as annual generation requirement (MWh) from qualifying sources by market region.
- Cross-State Air Pollution Rule and update: Affected units are required to have control technologies installed in select model years.
- Mercury and Air Toxics Standards: Affected units are required to have control technologies installed to meet the national standards for mercury and other air toxics (acid gases, and toxic metals adhering to particulate matter).
- Coal Combustion Residuals: Capital costs of control technologies added as a Fixed Operations and Maintenance (FOM) cost-adder on affected units.

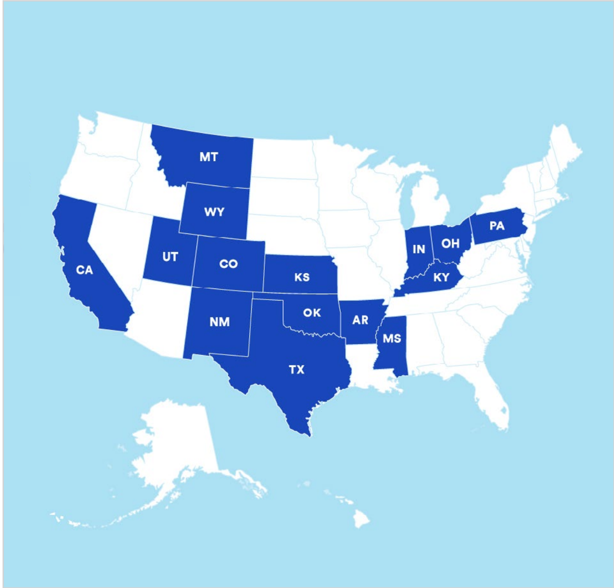
- 316 (b) Cooling Water Requirements: Capital costs of control technologies added as a FOM cost adder on affected units.
- Coal-fired units also can switch coal types by expending the necessary capital to retrofit the plant (not all coal types can be switched without cost).

Regions

NEEM is organized into 42 load regions over which energy for load, peak, demand and many other constraints are defined, as shown in Figure 7A (left). For CATF's study, CRA disaggregated 15 states such that NEEM would output separate results for the generating units located in the selected states, as shown in Figure 7B (right). Remaining results were provided by load region, as in Figure 7A (left).

FIGURE 7A: DEFAULT LOAD REGIONS IN NEEM

FIGURE 7B: STATES SELECTED FOR DISAGGREGATION FOR CATF MODELING

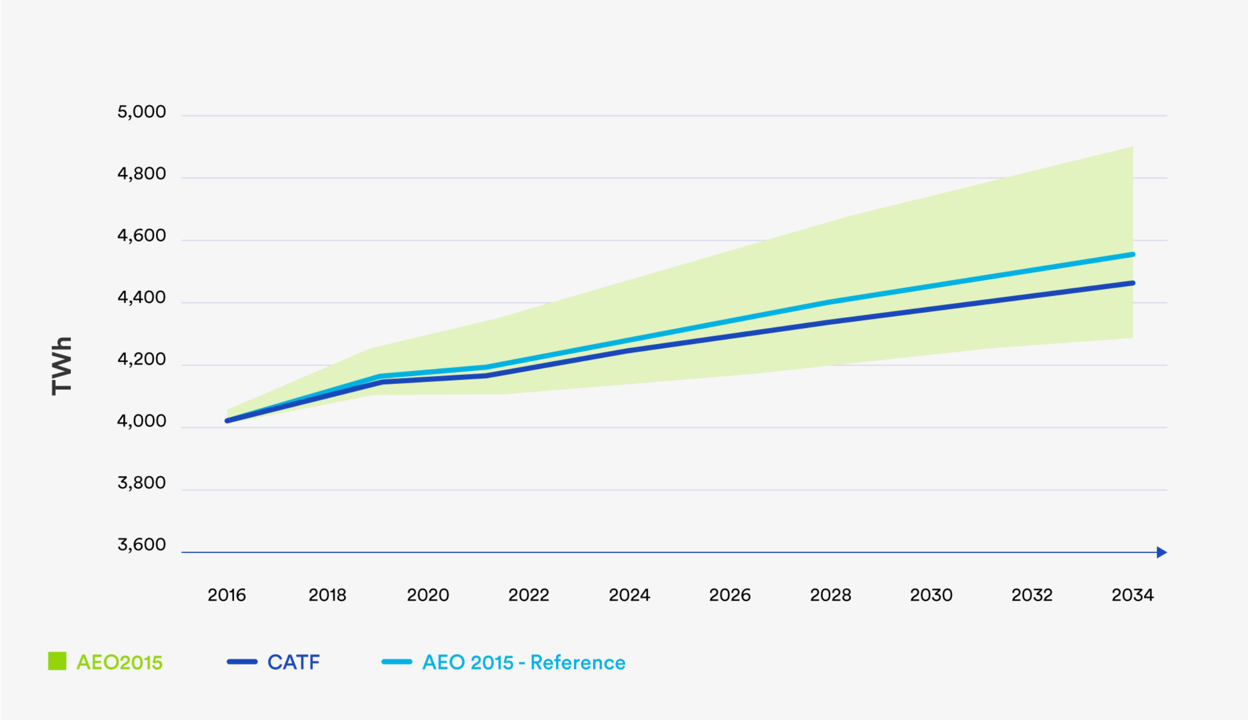


Source: CRA, CATF.

Load Growth Assumptions

CRA applied the relationship between GDP and load growth from the Annual Energy Outlook (AEO) 2015 Reference Case to Moody's GDP forecast, to arrive at the load growth assumption. The forecast falls well within the range of load cases considered by AEO in its high and low growth cases as seen in Figure 8 below.

FIGURE 8 : TOTAL U.S. ENERGY FOR POWER SECTOR LOAD



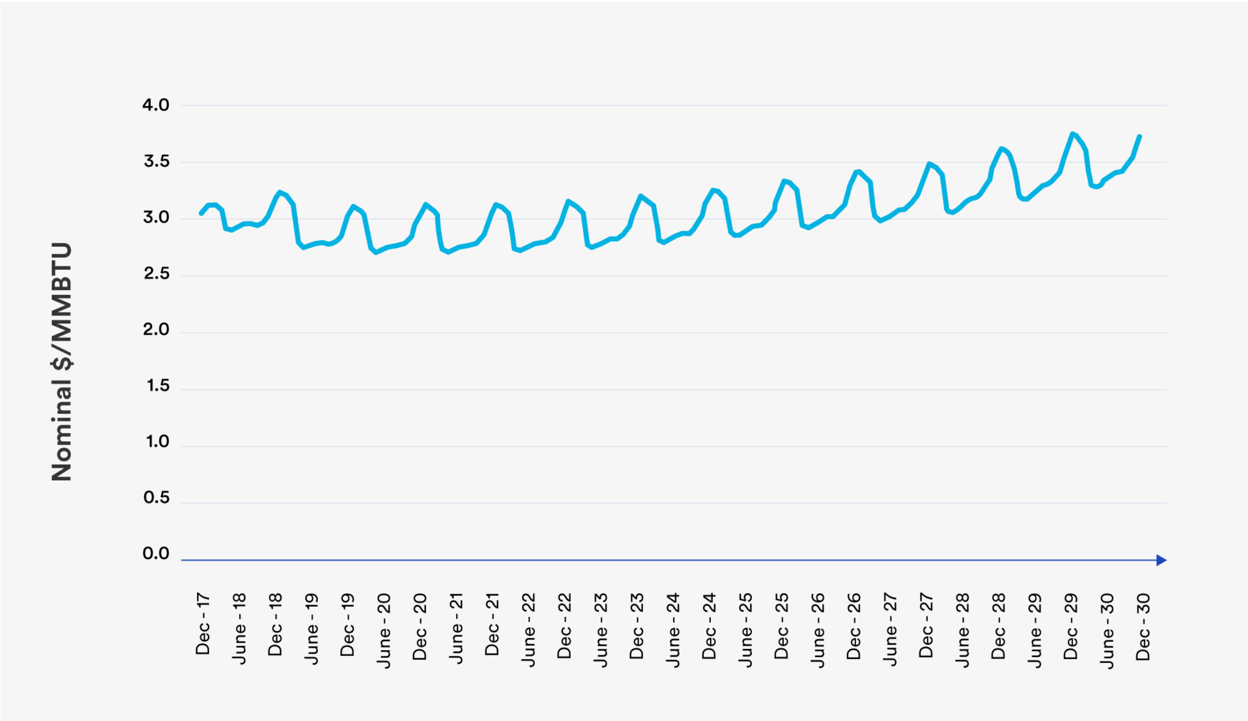
Source: CRA.

Fuel Price Assumptions

NEEM uses regional gas prices. CATF used NYMEX futures as the basis for estimating Henry Hub gas prices that are used in the modeling. See Figure 9. Other regional prices are based on over the counter (OTC) trades at major pricing hubs around the U.S. reported by SNL Financial. All of these prices are based on monthly contract values, but since NEEM solves on a seasonal basis, CRA calculates seasonal prices based on the monthly data for use in NEEM.

The OTC futures contracts have no data after summer 2028, while the Henry Hub data ends in 2030. For years where there are no data, CRA maintains the trend in prices over the previous ten years. The futures data is in nominal dollars, which is converted to 2018$ by assuming an inflation rate of 2.3 percent taken from the AEO reference case.

FIGURE 9: NATURAL GAS PRICE FORECAST – HENRY HUB BASED ON NYMEX FUTURES



Source: NYMEX, Natural Gas Henry Hub Natural Gas Futures (Price/Value), (May 25, 2018.)

Oil price assumptions for the near term (i.e., until 2026), are based on NYMEX futures because no NYMEX values were available beyond 2026. Before 2026, as can be seen in Table 4 below, the NYMEX based oil prices follow a declining trend. To develop oil price assumptions for 2027 and beyond, CATF took the view that in the long term, oil prices will rise rather than drop. CATF reviewed oil price projections for the five-year period between 2021 and 2026 in the AEO 2018 High Oil and Gas Resource case. CATF then used the average year on year growth rate found in AEO 2018 projections to extrapolate CATF's oil price assumptions after 2026. The primary function of these oil prices in our model is to determine the volume of EOR storage available for captured CO_2. The High Oil & Gas Resource scenario has the lowest oil prices in its forecast. Using it as the reference for oil price growth helped CATF maintain a conservative view on the corresponding EOR supply in our model.

Coal Prices

NEEM produces coal prices as an output. NEEM optimizes coal burn based on supply curves from the EPA NEEDS v5.13 model.[45] Units are mapped to multiple coal supply basins based on what type of coal the unit can burn, with unique transport costs for each coal basin-unit combination.

TABLE 4: OIL PRICE ASSUMPTIONS

Year	Nominal $/Bbl	Source
2018	$69.87	NYMEX
2019	$64.18	NYMEX
2020	$60.15	NYMEX
2021	$57.28	NYMEX
2022	$55.25	NYMEX
2023	$53.99	NYMEX
2024	$53.49	NYMEX
2025	$53.45	NYMEX
2026	$53.90	NYMEX
2027	$56.06	Growing at 4% yoy
2028	$58.30	Growing at 4% yoy
2029	$60.63	Growing at 4% yoy
2030	$63.06	Growing at 4% yoy
2031	$65.58	Growing at 4% yoy
2032	$68.20	Growing at 4% yoy
2033	$70.93	Growing at 4% yoy
2034	$73.77	Growing at 4% yoy
2035	$76.72	Growing at 4% yoy

Source: CATF analysis and NYMEX Crude Oil Futures Quotes (May 25, 2018.)

Technology Cost Assumptions

New Coal Plants

CATF hired a consultant who developed new plant costs based on NETL estimates.[46] See Tables 5A and 5B.

No new coal plants were allowed to be built without carbon capture in the NEEM runs due to the 2015 CO_2 New Source Performance Standards[47] for new coal- and gas-fired power plants, set at 1,400 lbs. CO_2 per MWh, and based on partial CCS.

Coal Retrofits

The Petra Nova approach to retrofitting the W.A. Parish coal plant with CCS relied on providing a separate source of electricity and steam for the capture unit. Petra Nova opted to build a 75 MW natural gas-fired cogeneration (cogen) unit that supplied 35-40 MW of electricity to the grid while also providing as much as 40 MW of electricity and steam to the capture unit.[48] A cogen unit simplifies the process of installing and using CCS retrofits because it is less disruptive to the coal plant's operation.

TABLE 5A: NEW COAL PLANT ASSUMPTIONS

Technology	Super Critical Pulverized Coal Bituminous 50% Capture	Super Critical Pulverized Coal Bituminous 90% Capture	SCPC Powder River Basin 50% Capture	SCPC Powder River Basin 90% Capture
First Run	2020	2020	2020	2020
Heat Rate (BTU/kWh)	10,379	12,083	10,936	12,634
Capital cost ($2017/kW)	$3,154.90	$3,914.31	$3,633.38	$4,479.15
FOM($2017/kW-yr)	$89.24	$106.37	$100.84	$121.30
VOM ($2017/MWh)	$6.98	$8.92	$8.34	$10.44
Availability	90%	90%	90%	90%

Source: CATF.

TABLE 5B: NEW COAL PLANT ASSUMPTIONS

Technology	SCPC Lignite 50% Capture	SCPC Lignite 90% Capture	IGCCBitSeq45	IGCCBitSeq90
First Run	2020	2020	2020	2020
Heat Rate (BTU/kWh)	11,464	13,361	9,238	10,459
Capital Cost ($2017/kW)	$3,952.65	$4,877.57	$3,248.63	$3,747.33
FOM($2017/kW-yr)	$109.00	$131.38	$102.21	$116.72
VOM ($2017/MWh)	$9.90	$12.38	$8.47	$9.87
Availability	90%	90%	90%	90%

Source: CATF.

The combustion characteristics of the base coal plant do not change, and the specific steam needs of the capture unit can be matched to the cogen plant.[49] CATF developed CCS costs for a variant of the Petra Nova approach for use in our modeling as shown in the Tables 6A and 6B below.

In the CATF approach, steam (but not electricity) is provided to the capture unit by a stand alone gas-fired auxiliary boiler. Electricity for the capture unit is assumed to come from the base coal plant. This reduces the plant's electricity sales by the auxiliary load needed to run compressors and other systems in the post-combustion capture unit. However, because steam comes from a stand alone gas boiler, the heat rate of the coal plant is unchanged. The costs of providing steam to the capture unit are calculated at 2.5 MMBtu of natural gas per tonne of CO_2 captured multiplied by the gas price in $ per MMBtu.[50] Capital costs, variable operations and maintenance (VOM), FOM and auxiliary loads were estimated based on consultations with industry suppliers and NETL estimates.

TABLE 6A: COAL RETROFIT ASSUMPTIONS FOR 200 MW UNITS

Technology	Low Heat Rate	Moderate Heat Rate	High Heat Rate
Heat Rate (Btu/kWh)	9500	10500	11500
Incremental Capital Cost ($2017/kW)	$1,952.00	$2097.00	$2240.00
FOM ($2017/kW-yr)	$27.84	$29.91	$31.95
VOM ($2017/MWh)	$3.13	$3.36	$3.58
CCS Load (MW)	16.83	18.60	20.37
Lbs captured per MWh net	1913.76	2135.86	2362.34
Lbs emitted per MWh net	522.75	583.42	645.29

Source: CATF.

TABLE 6B: COAL RETROFIT ASSUMPTIONS FOR 400 MW UNITS

Technology	Low Heat Rate	Moderate Heat Rate	High Heat Rate
Heat Rate (Btu/kWh)	9500	10500	11500
Incremental Capital Cost ($2017/kW)	$1,501.00	$1613.00	$1,724.00
FOM ($2017/kW-yr)	$21.40	$23.00	$24.59
VOM ($2017/MWh)	$2.37	$2.54	$2.71
CCS Load (MW)	33.65	37.20	40.74
Lbs captured per MWh net	1913.76	2135.86	2362.34
Lbs emitted per MWh net	522.75	583.42	645.29

Source: CATF.

CATF's costs assume Nth-of-a-kind (NOAK) costs where N is at least 5 – that is the costs are associated with the development and operation of the 6th or later system, and therefore benefit from the prior experience of the earlier projects. CATF also assumed that the post-combustion capture approach would be implemented in modules of about 400 MW. This module size has several advantages. First, some coal plants cycle their component units, turning one or more down at night. On a larger coal plant, 400 MW may be close to the turn down capacity of the plant. If the plant pursues a partial capture retrofit, the capture unit could still run at full capacity 24 hours per day, although the plant could vent some CO_2 during the day. Also, this module size is similar to the fully demonstrated size at Petra Nova. The 400 MW CCS retrofit has some economies of scale compared to the 200 MW.

CATF's modeling also assumed that the full capture approach would be implemented in modules. To illustrate, a 400 MW coal plant would have one CCS post-combustion module, while a 800 MW plant would have two modules. By contrast, under an approach that sought to exploit economies of scale, an 800 MW plant might have a single large absorber and stripper (rather than two smaller ones) in order to gain cost efficiencies.

Although the emissions from the auxiliary boiler could be routed through the post-combustion capture plant, the costs developed for this particular approach assumed venting these emissions. Venting lowered the overall CO_2 capture rate from 90 percent to 79 percent.

Other Characteristics

Below are brief descriptions of related characteristics that apply to the coal plant retrofits detailed in Tables 6A and 6B.

- **Capacity factor:** In Tables 6A and 6B, the capacity factor is assumed to be 100 percent in order to to define the base costs and performance characteristics that would be input into NEEM. NEEM chooses to dispatch the coal plant based on the defined scenario and these costs are applied according to how much the coal plant runs.

- **Capture rate is 79 percent:** A 79 percent capture rate represents the net effect of a carbon capture system that captures 90 percent of CO_2 from a slipstream, when accounting for unabated emissions from the natural gas-fired auxiliary boiler that CATF assumes provides steam to power the carbon capture system.

- **No heat rate change due to CCS retrofit:** CATF assumes there is no impact on the unit's heat rate resulting from coal CCS retrofits, because CATF are assuming that a natural gas-fired auxiliary boiler is built to supply steam needed by the carbon capture system to strip CO_2 from the CO_2-amine solution. The CO_2 emissions from the auxiliary boiler and the cost of operating it are reflected in the total captured emissions and operating costs.

- **CCS retrofit imposes a capacity penalty on the coal-fired unit:** The electricity that is required to run CCS related equipment such as pumps and compressors imposes a capacity penalty (CCS Load) on the coal unit. In our performance assumptions CCS load is defined as a percentage of the unit's initial capacity.

New NGCC Plants

CATF consultant developed NGCC retrofit costs based on NETL estimates.[51] See Tables 7 and 8.

TABLE 7: NEW NATURAL GAS PLANT ASSUMPTIONS

Technology	NGCC	Combustion Turbine	NGCC with 90% Capture
First Run	2017	2016	2020
Heat Rate (Btu/kWh)	6,300	9,800	7,968
Capital Cost ($2017/kW)	$1,026.00	$648.00	$1,834.00
FOM ($2017/kW-yr)	$10.10	$6.87	$47.00
VOM ($2017/MWh)	$2.02	$10.81	$2.88
Availability	93%	93%	93%

Sources: AEO 2015 (NGCC, Combustion Turbine), CATF (Incremental costs for 90% capture on new NGCC.)

New NGCC Retrofits

TABLE 8: NGCC RETROFIT ASSUMPTIONS

Technology	NGCC
Heat Rate (BTU/kWh)	7968
Incremental Capital Cost ($2017/kW)	$808
Incremental FOM ($2017/kW-yr)	$18.25
Incremental VOM ($2017/MWh)	$1.14

Source: CATF.

Other Technologies

The version of the NEEM platform that CATF used for this study relies on AEO 2015 as the default source for technology cost assumptions. See Table 9B. CATF opted to modify the cost assumptions for wind and solar PV technologies in order to be conservative about the cost-competitive advantage of fossil fuel-fired electricity with CCS had over renewables. The cost and performance characteristics for wind and solar PV in Table 9A below generally represent the lower end of cost estimates relative to AEO estimates. These costs are based on a levelized cost of energy analysis[52] published by Lazard in November of 2017.

Regional Technology Cost Multipliers

NEEM's regional technology cost multipliers are based on AEO 2013 found in Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants published by the U.S. EIA in April 2013.[53] Since NEEM is a regional model and does not operate at the city level, CRA selected representative cities from EIA's data and applied those cost multipliers to corresponding NEEM regions.

Specifically, for new build coal with CCS and coal retrofits NEEM uses the cost multipliers applicable to advanced coal with 90 percent storage in EIA's data and for all new natural gas with CCS NEEM applied the multipliers as the basis.

TABLE 9A: COST AND PERFORMANCE ASSUMPTIONS FOR NON-FOSSIL TECHNOLOGIES

Technology	Wind	Wind Offshore	PV	Solar Thermal
First Run	2017	2018	2016	2017
Capital Cost ($2017/kW)	$1,050	$4,500	$1,375	$6,047
FOM($2017/kW-yr)	$35.00	$95.00	$10.50	$77.50
Availability	30%	42%	-	-

Sources: AEO 2015 (Wind Offshore, Solar Thermal), Lazard V 11.0 (Wind, PV.)

TABLE 9B: COST AND PERFORMANCE ASSUMPTIONS FOR NON-FOSSIL TECHNOLOGIES

Technology	Geothermal	Biomass	Landfill gas	Nuclear
First Run	2018	2018	2017	2022
Heat Rate (BTU/kWh)	-	-	-	10,460
Capital Cost ($2017/kW)	$5,600	$3,500	$8,170	$5,148
FOM($2017/kw-yr)	-	$50.00	$417.02	$101.00
VOM ($2017/MWh)	$35.00	$10.00	$9.29	$2.32
Availability	70%	80%	90%	90%

Source: AEO 2015.

Financial Assumptions

Capital Charge Rates

Below are the capital charge rates applied to each technology used in NEEM, by ownership. The initial capital charge rate assumptions were taken from Chapter 8 of EPA NEEDs v5.13.[54]

Two tweaks were made for utility-owned and merchant-owned carbon capture retrofits: first, interest during construction was incorporated and second the capital charge rates for plants were reduced to incorporate the impact of the 45Q business model described in the section below.

Interest During Construction

Calculations were made by Jeff Brown of Stanford Steyer-Taylor Center of Energy Policy and Finance in conjunction with CRA to incorporate interest during construction at 7 percent for investor-owned utility (IOU)[55] and 10.5 percent for independent power producer (IPP) with the assumption of 4 years of construction time for new coal plants with CCS, 3 years for coal retrofits, new NGCC, and new NGCC with CCS, and 2 years for wind, solar, or NGCC retrofit.

The units in NEEM have a technology lifetime, and it depends on the unit type, typically 20-40 years. Once a unit reaches this age, it must refurbish the existing equipment or retire the unit. This represents an additional capital investment to keep a unit operating past its technical lifetime. The "refurbish" capital charge rate in Table 10 is the cost of capital for lifetime extensions.

45Q Tax Credit for EOR - Business Model Assumption

In general, the chosen business model for the modeling assumes that an outside investor will purchase the CCS equipment and lease it back to the operator of the power plant with CCS. The investor will take the actual 45Q tax credits for EOR but will pay the CCS operator an upfront sum equal to the NPV of the expected cash flow from the 45Q tax credits for EOR, using a 15 percent discount rate. This upfront sum is subtracted from the capital cost of the CCS system. This business model was assumed because it is similar to the approach seen in the tax equity partnerships that allow investors with a tax liability that is large enough to absorb and take advantage of the tax credits provided for wind and solar energy projects. According to J.P. Morgan, in 2017, $10 billion were invested via tax equity deals for wind and solar projects.[56]

Below are details of how CATF calculated the business model's impact on the capital charge rates:

- When the capital cost of CCS units are lowered due to the discounted upfront investment from the tax equity investor, the debt that needs to be borrowed is reduced. This in turn lowers the overall capital charge rates.

- While running the scenario, NEEM uses 'perfect foresight,' which means that the model knows before deciding to build CCS how much the plant will run each year over the course of the entire modeling period. With this information NEEM calculates the volume of CO_2 that will be captured and stored and what the discounted value of the 45Q payments would be. But NEEM cannot calculate capital charge rates. NEEM requires these rates to be inputs. Hence the capital charge rate calculations must be made outside the model and require making assumptions about how much the plants with CCS will run.

    - Typically, CCS retrofitted portion of the units run flat out. NEEM would generally not build CCS unless it plans to run the unit. Accounting for forced outage, the CCS portion of the units have capacity factors between 90 and 95 percent. To be conservative, CATF assumed that a unit will run at 85 percent capacity factor.

    - Total emissions from that unit and the corresponding captured CO_2 volume were then calculated. Total tax credit value was calculated by multiplying captured CO_2 volume by the tax credit for EOR for each of the 12 years that the unit can get credit. Note that the year it comes into service matters because the 45Q tax credits ramp up over time.

- Assuming that the investor is willing to capitalize those tax credits at a discount rate of 15 percent, the total tax credit value for 12 years was discounted back to arrive at the capital cost reduction allowed at the time of investment. Considering the 45Q construction window, only units/retrofits that come online from 2020-2028 were allowed to get 45Q benefits.
- Capital payments were calculated for possible build years and the capital cost for building in that year was reduced by that amount. Reduced capital costs accordingly reduce the capital charge rates. Final capital charge rate inputs are as follows, in Table 10.

- In the model runs, NEEM calculates the capital cost reduction per unit, per year available, accounting for the value of the tax rebate in a given year, as well as the capacity and heat rate effects of CCS equipment where appropriate. If the model chose to store captured CO_2 in saline reservoirs, then the difference between the EOR and saline credits was treated as cost of storage.

TABLE 10: CAPITAL CHARGE RATE INPUTS TO NEEM

Ownership	IOU	IPP
Combustion Turbine	8.77%	13.16%
Combustion Turbine refurbish	14.43%	17.68%
Combined Cycle	8.02%	12.97%
Combined Cycle refurbish	12.02%	15.76%
Combined Cycle w/ CCS	7.88%	13.07%
Combined Cycle w/ CCS refurbish	11.54%	15.29%
Coal w/ CCS	7.66%	14.84%
Coal w/ CCS refurbish	8.60%	13.03%
Nuclear	8.74%	17.14%
Nuclear Refurbish	8.77%	13.16%
Wind/Landfill Gas	8.08%	12.20%
Wind/Landfill Gas	13.63%	16.66%
Solar/Geothermal	8.29%	12.44%

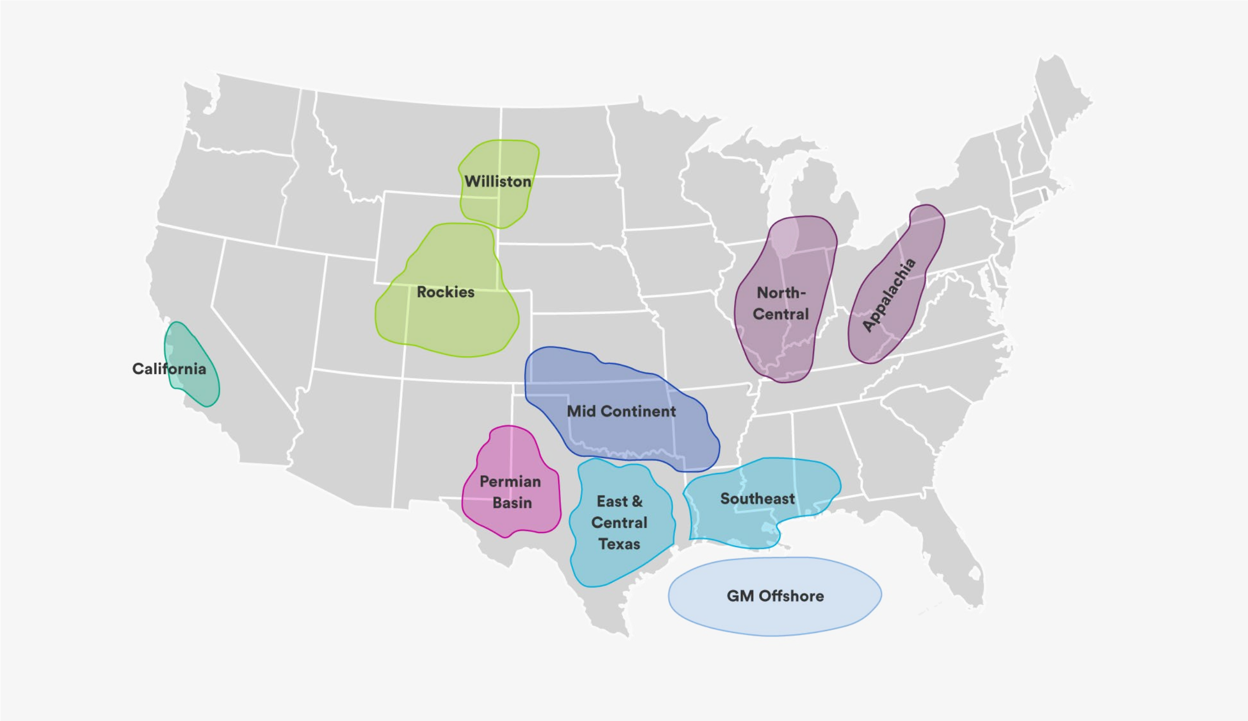
Source: Analysis by CRA and CATF.

CO_2 Storage Capacity Assumptions

ARI developed annual CO_2 demand curves individually for nine EOR basins in the U.S. for the 12-year modeling period. Figure 10 below shows the nine basins. The total CO_2 demand for each model year correspond to CATF's oil price assumption for that year – the higher the oil price, the higher the demand for CO_2 for EOR. And, the total CO_2 demand is defined in tranches of four CO_2 prices.

In the real world, CCS projects outside of the power sector are also eligible for 45Q tax credits. This means that CO_2 supply from carbon capture on industrial sources and on power plants would compete to meet the total demand for CO_2 from the EOR industry. However, NEEM only represents the power sector, which accounts only for a part of the total CO_2 supply needed to meet CO_2 demand. For this reason, CATF worked with ARI to modify the total CO_2 demand curves such that NEEM only accessed a part of the total CO_2 demand. This allowed the model results to avoid overstating the level of CCS deployment in the power sector.

FIGURE 10: EOR BASINS REPRESENTED IN CO_2 DEMAND CURVES DEVELOPED BY ARI



Source: ARI.

Based on ARI estimates of regional and annual non-power sector CO_2 supply, CATF assumed that 205 million tonnes of CO_2 captured through CCS outside the power sector will be stored through CO_2-EOR. Table 11 shows the breakdown of the 205 million tonnes of CO_2 by basin. These volumes were then deducted from the total annual CO_2 demand curves that ARI developed for each EOR basin.

Non-power sector CO_2 volumes from Table 11 entirely satisfied the CO_2 demand for EOR in the Williston Basin, the Rockies region, the Gulf Coast, and the Illinois, Michigan, and Appalachia Basins. Our model thus assumes zero demand for CO_2 from the power sector in these basins. Only four EOR basins have demand for CO_2 unmet by non-power sector CO_2: Permian, Mid-continent, East & Central Texas and California.

Tables 12A to 12D below show the CO_2 demand across four EOR basins that can be met by CO_2 captured through CCS on power plants in the model.

TABLE 11: ALLOCATION OF NON-POWER SECTOR OR INDUSTRIAL SECTOR CO_2 SUPPLY TO EOR BASINS

EOR Basin	Non-power sector CO_2 assumed to be stored through EOR (million tonnes per year)
Appalachia	2.01
California	7.82
East & Central Texas	36.55
Illinois/Michigan	12.45
Mid Continent	32.64
Permian Basin	62.14
Rockies	25.45
Southeast Gulf Coast	20.76
Williston	5.24
TOTAL in EOR Basins	205

Source: ARI and CATF analysis.

TABLE 12A: CO_2 DEMAND FOR EOR IN THE PERMIAN BASIN (MILLION TONNES)

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Oil Price	$57.28	$57.28	$53.99	$53.49	$53.45	$53.90	$56.06	$58.30	$60.63	$63.06
$45/Tonne of CO_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
$30/Tonne of CO_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7
$10/Tonne of CO_2	21.9	16.1	12.5	11.1	10.9	12.2	18.4	24.8	30.8	35.2
$0/Tonne of CO_2	33.4	27.5	23.8	22.4	22.3	23.6	29.8	36.3	42.3	46.1

Source: ARI and CATF analysis.

TABLE 12B: CO_2 DEMAND FOR EOR IN THE MIDCONTINENT BASIN (MILLION TONNES)

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Oil Price	$57.28	$55.25	$53.99	$53.49	$53.45	$53.90	$56.06	$58.30	$60.63	$63.06
$45/Tonne of Co_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.1
$30/Tonne of Co_2	16.6	12.6	10.0	9.0	9.0	9.9	14.2	18.7	23.0	26.4
$10/Tonne of Co_2	25.1	20.9	18.3	17.3	17.2	18.1	22.6	27.2	31.5	34.3
$0/Tonne of Co_2	26.3	22.4	20.0	19.1	19.0	19.8	24.0	28.2	32.2	35.1

Source: ARI and CATF analysis.

TABLE 12C: CO_2 DEMAND FOR EOR IN THE EAST & CENTRAL TEXAS BASIN (MILLION TONNES)

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Oil Price	$57.28	$55.25	$53.99	$53.49	$53.45	$53.90	$56.06	$58.30	$60.63	$63.06
$45/Tonne of Co_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
$30/Tonne of Co_2	13.3	8.9	6.1	5.0	4.9	5.9	10.6	15.6	20.3	24.1
$10/Tonne of Co_2	22.7	18.3	15.7	14.6	14.5	15.5	20.1	24.8	29.4	33.0
$0/Tonne of Co_2	29.1	24.6	21.8	20.7	20.6	21.6	26.4	31.3	35.9	39.0

Source: ARI and CATF analysis.

TABLE 12D: CO_2 DEMAND FOR EOR IN THE CALIFORNIA BASIN (MILLION TONNES)

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Oil Price	$57.28	$55.25	$53.99	$53.49	$53.45	$53.90	$56.06	$58.30	$60.63	$63.06
$45/Tonne of Co_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
$30/Tonne of Co_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	2.1
$10/Tonne of Co_2	7.0	5.9	5.2	5.0	4.9	5.2	6.3	7.5	8.9	10.8
$0/Tonne of Co_2	17.6	15.9	14.8	14.4	14.3	14.7	16.5	18.4	20.1	21.2

Source: ARI and CATF analysis.

Saline Storage

For saline storage capacity and costs, CATF based assumptions on the Geosequestration Cost Analysis Tool (GeoCAT), a model used by EPA. GeoCAT develops total storage potential and reflects available storage capacity in each U.S. state at 19 levels of negative and positive cost "steps," which range between $4.09 per tonne and $60 per tonne in 2016$.

Transport Costs

CO_2 transport cost assumptions were developed by ARI. CO_2 sources in states that have access to EOR storage capacity in the same state were mapped to that EOR storage site as their first "sink." Some states were mapped to a second EOR basin too, based on proximity. Table 13 shows the transport costs that the model would have to account for while deciding to build CCS in various locations.

TABLE 13: CO_2 TRANSPORT COSTS FROM SOURCE OF CO_2 TO ASSIGNED EOR STORAGE SITES (SELECTED STATES SHOWN HERE)

State	Basin	Transport Cost ($/tonne)	Basin 2	Transport Cost ($/tonne)
AR	Mid Continent	$4.72	N/A	N/A
CA	California	$5.80	N/A	N/A
CO	Rockies	$6.64	N/A	N/A
IN	North-Central	$6.16	N/A	N/A
KY	North-Central	$6.16	Appalachia	$9.56
KS	Mid Continent	$4.72	N/A	N/A
OH	North-Central	$6.16	Appalachia	$9.56
OK	Mid Continent	$4.72	N/A	N/A
MS	Southeast	$5.87	N/A	N/A
MT	Williston	$10.61	N/A	N/A
NM	Permian Basin	$4.72	N/A	N/A
PA	Appalachia	$9.56	N/A	N/A
TX	Permian Basin	$4.72	East & Central Texas	$4.72
UT	Rockies	$6.64	N/A	N/A
WY	Rockies	$6.64	Williston	$10.61

Source: ARI.

SECTION 6

Endnotes

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