Cost Analysis of Carbon Capture and Sequestration from U.S. Natural Gas-Fired Power Plants

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ABSTRACT: Despite increasing efforts to decarbonize the power sector, the utilization of natural gas-fired power plants is anticipated to continue. This study models existing solvent-based carbon capture technologies on natural gas-fired power plants, using site-specific emissions and regionally defined cost parameters to calculate the cost of CO2 avoided for two scenarios: delivery to and injection within reliable sequestration sites, and delivery and injection for the purpose of CO2-enhanced oil recovery (EOR). Despite the application of credits from the existing federal tax code 45Q, a minimum incentive gap of roughly $38/tCO2 remains for the geologic sequestration of CO2 and $36/tCO2 for CO2-EOR (before consideration of revenue generated from delivered CO2 contracts). At full escalation of 45Q, delivered CO2 costs from this sector for geologic sequestration could reach as low as $22/tCO2. However, given the capital investment required in the near-term, it would be beneficial if the credit provided the greatest economic benefit early on and decreasing over time as deployment continues to ramp up. Additionally, due to the high qualifying limit of 45Q for the power sector, e.g., 500 ktCO2/yr, the tax credit incentivizes the capture of roughly 397 MtCO2/yr at a 90% capture efficiency or 75% of the emissions in this sector, with missed opportunities equating to roughly 118 MtCO2. Advancing the scale of carbon capture and sequestration (CCS) will require both technological advances in the capture technology, cost reductions through the leveraging of existing infrastructure, and increased policy incentives in terms of cost along with the reduction of qualifying limits.

INTRODUCTION

Roughly 1500 million tonnes of CO2 were generated from the combustion of natural gas in the United States in 2018, representing 33% of fossil-based emissions. The technology exists today to avoid roughly half of these emissions through the direct installation of carbon capture and sequestration (CCS) at large (i.e., >100 000 tonnes CO2/yr or 100 ktCO2/yr) point sources consisting mostly of the industrial and electric power sectors (Figure 1). As demonstrated in Figure 2, of all natural gas-fired power plants in the United States, roughly 37% qualify for the federal tax credit 45Q, provided they capture greater than 500 ktCO2/yr. This represents 397 MtCO2/yr or 26% of total emissions associated with natural gas and 75% of emissions of natural gas used for the power sector. Facilities that capture carbon and sequester it geologically or use it for CO2-enhanced oil recovery (EOR) are eligible for 45Q. In the case of CO2 used for EOR, the federal tax credit was $15.29/tCO2 in 2018 and grows linearly in value to $35/tCO2 by 2026. For geologic sequestration of CO2, the credit was $25.70 per ton in 2018 and similarly will grow to $50/tCO2 by 2026.

In fact, in many cases, emissions are much higher than 500 ktCO2/yr. For example, in the Southeastern region of the United States, there are 28 natural gas plants that produce over 2 MtCO2 annually, with the largest plant producing more than 7 MtCO2/yr alone. Although the U.S. dependence on coal is still strong, representing 65% of U.S. electricity-related emissions in 2018, it has exhibited a decline in primary energy consumption of 8.0% from 2017 to 2018 and roughly 27% over the past 5 years. Meanwhile, following an increase in production, the primary consumption of natural gas grew 6% from 2017 to 2018 and roughly 12% over the past 5 years.

Renewable energy such as solar and wind represents low-carbon opportunities that could replace some of these fossil-sourced emissions. Today, wind and solar comprise approximately 8.4% of the electric power sector (Figure 1), which is double that of 2008. In 2018, 6.6 GW (wind) and 4.9 GW (solar) capacities were added in the U.S., while 12.9 GW of coal-generating capacity was retired. Some municipalities have passed legislation encouraging a phase-out of coal power plants in favor of renewables. For example, in response to the Clean Air Clean Jobs Act (CACJA), which mandates the decommissioning of coal-generating power in Colorado, Xcel, the Public Service Company of Colorado closed two coal-fired units in Pueblo county in 2018. Combined, the 2 plants...
produced 660 MW, and the wind and solar used to replace it will generate nearly three times this amount. Additionally, CAJCA endorses natural gas as a transition fuel.

Despite the U.S. closures of 4.7 GW of natural gas-generating capacity in 2018, 19.3 GW of new natural gas-generating capacity was added, the majority of which were efficient combined cycle units. This is almost twice the combined additions of wind and solar capacities, signaling a continued, strong natural gas presence in the United States.

Despite having a lower carbon intensity than coal-fired power plants, natural gas plants still emit on average 430 gCO₂/kWh. The IPCC identifies that in certain 1.5 and 2°C pathways, natural gas utilization is likely to continue through and after coal phase-out, albeit with varying levels of CCS to curb emissions; thus, it is important to examine CCS cost scenarios for natural gas power plants. Robust cost predictions for CCS are invaluable to the scientific community to inform research targets as well as for policymakers who are charged with developing mechanisms for increased CCS deployment. Other studies have examined the cost of CCS on natural gas plants, but assume a single value for transportation and sequestration costs, typically between $7 and $10/tCO₂. This study identifies case-specific capture, compression, transport, and sequestration costs and considers recent tax code as a mechanism for cost reduction.

The most mature technologies used today for separating CO₂ from the exhaust streams of natural gas combustion are solvents based on chemical amines. However, the separation of CO₂ from NGCC exhaust using the conventional and mature amine technology monoethanolamine (MEA) is beset by several complications. First, the low CO₂ content in NGCC flue gas (i.e., 3−5 mol %) leads to a lower liquid-to-gas ratio when compared to separation from a pulverized coal (PC) power plant flue gas stream (compared at 12−15 mol %). This leads to a slightly higher plant energy penalty, which leads to higher relative costs of CO₂ capture. Second, excess air is required to drive the gas turbines, leading to a flue gas oxygen content of 15% v/v. This can lead to oxidative degradation of the MEA solvent, which increases operating costs. Rubin et al. have carried out extensive research on the costs of implementing amine scrubbing for natural gas facilities. In their research, they consider many variables that could affect the cost of constructing and operating a plant, such as location and surrounding conditions, size, and efficiency. Using these variables, they produced low- and high-cost estimates. For a new plant, the capital cost is between 76 and 121% greater compared to a plant without any capture measures. By their
turbines that yields the closest amount of CO2 produced. The size of the plant was approximated by the number of turbines in the power plant cycle. The 284 natural gas plants of the United States with annual CO2 emissions over 500 kt were grouped according to their annual CO2 emissions, i.e., the size of the plant was approximated by the number of turbines that yields the closest amount of CO2 produced. The capture technology selected in this work involves chemical absorption using Fluor’s Econamine FG Plus, with a solvent consisting of 30% w/w monoethanolamine (MEA) with an oxygen inhibitor.15 FG+ has a lower regenerator heat requirement (174 kJ/mol CO2) than traditional 30 wt % MEA (221 kJ/mol CO2).14 A simple stripper configuration was assumed, where a flash separator is installed to condense and recover the water and solvent vapors exiting the stripper, and a wet cooling tower was used as a cooling system. The plant locations were specified in the software to calculate region-specific cost factors relative to the Midwest (factor of 1.0): Northeast (1.012), Northwest (1.004), South Central (0.982), Southeast (0.985), and Southwest (1.004). Note that the states of RI and NH were not included in the software, which were assumed to follow the calculations associated with the Northeastern region of the United States. The natural gas cost was adapted from the 2018 U.S. average price for electric power,16 i.e., $129.6/mscm ($3.67/mscf). Note that the regional variability in natural gas cost will impact the plant LCOE and in turn the cost of capture. A sensitivity analysis reveals that, as the cost of natural gas changes by ±$1.0/mscf, the cost of capture changes by ±4–5%. Several plant parameters were selected as the default values set in the software, including capacity factor (75%), total CO2 removal constraint (90%), and gas turbine model (GE 7FB).

The capture costs are reported as capital costs (CAPEX) and operating and maintenance costs (OPEX). The total capital cost is the sum of process facility capital, fees, interest, contingency, etc., where process facilities include direct contact cooler, flue gas blower, CO2 stripper, heat exchangers, circulation pumps, solvent regenerator, reboiler, steam extractor, solvent reclaimer and processing unit, and drying and compression unit. The breakdowns of operating and maintenance costs include material replacement costs, electricity, water, CO2 transport and sequestration, and total fixed costs. In addition, the annualized capital cost was calculated by the software, which took into account the levelized carrying charge factor, or fixed charge factor, over the entire life of the plant. A retrofit factor of 1.09 was applied to carbon capture CAPEX.17 A list of parameters used in the economic analysis is provided in Table 1.

Cost Methodology. The calculation of the avoided cost of capture through IECM has been outlined elsewhere, whereby the incremental LCOE due to capture is divided by the net reduction in CO2 emissions per unit energy.1 In this study, the avoided cost of capture is reconstructed from the cost of capture obtained in IECM, the separately calculated (model-specific) compression cost, the model-specific transport cost, an injection cost of $11/tCO2,18 and applicable tax credits via 45Q. This approach was necessary to (a) analyze an additional transport mode (trucking) and (b) use case-specific transportation distances and volumes to obtain less generalized transport cost estimations. Details on the individual cost components are provided below.

Cost Estimate of CO2 Capture. The levelized avoided cost of capture as defined by Rubin19 is

\[
C_{cc'} = \frac{(LCOE)_{CCS} - (LCOE)_{REF}}{\text{kWh(REF)}} - \frac{(LCOE)_{CCS}}{\text{kWh(CCS)}}
\]

(1)

where LCOE is the levelized cost of electricity for the CCS plant and reference (REF) plant, and the denominator takes into account CCS and reference plant emission rates. To calculate the cost of capture alone, compression and transportation must be decoupled from the IECM cost model. In this case, eq 1 yields the avoided cost of capture, excluding contributions from compression and transportation.

| Table 1. List of Relevant Economic Parameters Used in This Study* |
|-----------------------------------|-----------------|-----------------|-----------------|
| plant type                        | NGCC retrofit   | CRF             | 11.28%          |
| retrofit factor                   | 1.09            | plant life      | 30 years        |
| capacity factor                   | 75%             | ref plant. emission rate | 0.3615 kgCO2/kWh |
| cost NG                           | $129.6/mscm     | ref plant. LCOE | 40.36–42.56 $/MWh |
| cost year                         | 2017 (constant) | capture rate    | 90%             |
| discount rate                     | 7.09%           | amine system    | FG+             |
| CCS plant gross power             | 97–1484 MW      | CCS plant net power output (1–5 turbines) | 262–1309 MW |

*All values from the Integrated Environmental Control Module unless otherwise noted.
To avoid confusion with the full reconstructed cost of CO₂ avoided, eq 1 is renamed the levelized adjusted cost of capture \( (C_{\text{ca}}'). \)

**Cost Estimates of Compression and Transport via Trucking vs Pipeline.** Compression is calculated based on the methodology outlined by McCollum and Ogden and others.\(^{21,22}\) Liquefaction costs are calculated assuming conditions of 1.7 MPa and \(-30\)°C.\(^{21}\) Compression for pipeline is calculated assuming 10 MPa using five stages and interstage cooling, a compression ratio of 1.76, and an isentropic efficiency of 0.75. The approximate energies for compression (including cooling) are 111 and 140 kWh/tCO₂ for trucking and pipeline, respectively. Additional compression prior to injection (trucking case) results in an additional energy of 41 kWh/tCO₂. The levelized cost of compression is calculated by adding the levelized amortized capital payment, the purchased cost of electricity per tonne CO₂ compressed, and an 

\[
C_{\text{co,i}} = \frac{TCC_{\text{comp,i}} \times (CRF + O&M)}{nCO_2} + \omega_{\text{co,i}} \times C_E
\]  

where \( TCC_{\text{comp,i}} \) is the total capital cost of the compression/pumping system, \( CRF \) is the capital recovery factor (Table 1), \( O&M \) is an operation and maintenance factor applied to the total capital cost of compression (taken as 0.04 in this study), \( nCO_2 \) is the total amount of CO₂ compressed in tonnes per year, \( \omega_{\text{co,i}} \) is the total work for compression and cooling, \( C_E \) is the cost of electricity, and the index \( i \) indicates a specific transport mode.

While large-scale CO₂ transport is dominated by pipeline, trucking transport becomes cost-competitive at less than 500 ktCO₂/yr and is favored for the transport of volumes of 200–300 ktCO₂/yr and lower.\(^{23}\) The trucking model used in this work is based largely on the work of Berwick and Farooq,\(^{24}\) using updated fuel emission rates, fuel costs, and labor costs. Source-end use distances were obtained by performing an origin–destination distance matrix over a U.S. street network data set. This set of distances together with the estimated CO₂ demand for each end use served as model inputs. Trucking transport costs are controlled mainly by two factors: hauling capacity and distance traveled. At very low volumes (\(\sim\)5 ktCO₂/yr and below), costs are dominated by trucking lease or purchasing as hauling remains well below the capacity. As delivery closes in on the maximum capacity per truck (here constrained to 100 000 miles of total travel per year), economies of scale are optimized, and costs are minimized. The levelized cost of transport via trucking is calculated from 

\[
C_{\text{tr}} = c_T + \omega_T + f_T
\]  

where \( c_T \) is the levelized unit cost of capacity per tCO₂ delivered amortized over the useful equipment lifetime (here 5 years per truck and an annual cap of 100 000 miles), \( \omega_T \) is the time-averaged variable operating costs ($/tCO₂), including fuel, maintenance, tolls, and labor, and \( f_T \) is the time-averaged fixed operating costs ($/tCO₂), including permits, licenses, and insurance.

Pipeline costs were calculated using the FE/NETL CO₂ transport cost model\(^{25}\) and the regression model of McCoy and Rubin.\(^{26}\) Pipelines were assigned for single source–sink pairings where the geodesic source (NG plant)–sink (EOR or...
sequestration) distance and pipeline capacity served as model inputs. Pipeline transport costs change linearly for fixed volumes (variable distance) and nonlinearly for fixed distance hauls (variable load). This is due to the fact that the increased distance hauling requires a linear increase in pipeline infrastructure (piping and pumps), as well as fixed and variable operating expenses and maintenance, while variable load haul costs are more sensitive to the optimal pipeline diameter, which is determined from the desired pipeline capacity. This study does not take into account escalation factors such as labor, elevation, and material costs. The levelized cost of transport for pipeline \((C_{T,p})\) is taken as the first year break even cost as calculated in the FE/NETL CO2 transport cost model. The cost of injection \((C_i)\) is assumed as $11/tCO2 for both dedicated geologic sequestration27 and CO2-EOR28 based on the average literature costs for injection and monitoring applied to geologic sequestration and EOR. There are several factors that could lead to discrepancies in injection costs such as differences in permeability, injection volume, injection rate, logistics in MRV fitting, and the length of time for postinjection site care. Future analyses on regional case studies should take into account the appropriate data resolution to convey site-specific injection costs.

The total cost of CO2 avoided is calculated as

\[
C_{T,p} + \frac{C_{co,1} + C_{ce} + C_{i} (1-x)}{x} = C_q
\]

where the index \(i\) represents either transport mode, \(C_q\) is any applicable tax credit, and \(x\) represents the total life cycle CO2 emitted over the entire transport chain (excluding the capture where those emissions are embodied in \(C_{co,1}\), on a tonne emitted per tonne captured basis. Due to uncertainties in inputs for each cost-modeling step, cost estimates are considered reliable to within \(\pm 12\%\) for pipeline scenarios and \(\pm 19\%\) in trucking scenarios.

GIS Mapping of Natural Gas Power Plants, EOR, and Geologic Sequestration Sites. The shapefiles for sedimentary basins were retrieved from the USGS website for the CO2 geologic sequestration assessment28 in addition to the national oil and gas assessment for sequestration potential in depleted oil and gas reservoirs. The USGS has identified 186 sequestration assessment units (SAUs) in 34 basins.28 Injectivity rates in the sedimentary basins were calculated using the USGS data28 combined with a method developed by Baik et al.30 using the radial form of Darcy’s law for single-phase flow.31 The 72 EOR injection locations over 100 ktCO2/yr were selected out of 101 locations in total. Details about the EOR and geological sequestration sites are described further in the Supporting Information. The CO2 pipeline data are sourced from Stanford University’s Digital Repository.32

**RESULTS AND DISCUSSION**

EOR and Sequestration Opportunities. This study focuses on the cumulative cost of avoiding CO2 emissions from power generation associated with natural gas combustion. In the United States, there are currently 808 natural gas facilities that generate power with emissions greater than or equal to 25 ktCO2/yr. These facilities are mapped in Figure 3. Assuming 90% capture of CO2 from these facilities, 284 or 35% qualify for the federal tax credit 45Q having the potential to capture at least 500 ktCO2/yr. These qualifying facilities have the potential to capture 397 MtCO2/yr assuming a 90% capture efficiency. The remaining 523 facilities are below the qualifying limit, with roughly 96% emitting less than 450 ktCO2/yr. Missed opportunities at facilities not qualifying for the tax credit account for roughly 118 MtCO2/yr.

Also mapped in Figure 3 are existing CO2 pipelines with the primary function today of transporting CO2 that is naturally stored in the earth to CO2-EOR opportunities. Despite the approach by which EOR is conventionally carried out today in the United States, there are advanced EOR practices that may lead to maximum sequestration of CO2. For instance, advanced EOR (A-EOR) and maximum sequestration EOR (MS-EOR)33 exploit both business activities, i.e., oil recovery and CO2 sequestration for profit and involve the injection of larger amounts of CO2 than conventional EOR and ultimately lead to greater oil recovery. A recent study by Núñez-López shows that CO2-EOR may result in more CO2 stored than that generated through processing of and subsequent oxidation of the oil depending on strategic operational choices associated with its production.34 It is important to note that if the CO2 is sourced from avoided emissions, i.e., exhaust streams of natural gas power plants, then the oil recovered through CO2-EOR may not be considered neutral, but rather may have a reduced carbon footprint depending on the amount of CO2 sequestered. The CO2 would have to be removed directly from the atmosphere to result in neutral or potential negative emissions, and the atmospheric concentrations of CO2 are roughly 100 times more dilute than the exhaust streams of natural gas power plants, making that route more costly.

According to IEA,33 A-EOR, and MS-EOR have global sequestration potentials of roughly 250 and 350 GtCO2, respectively, while the cumulative sequestration required for preventing 2 °C warming by 2100 requires approximately 250 Gt of sequestration between 2015 and 2050. The work of Hovorka35 has shown that enhanced sequestration with EOR may be possible by using CO2 in a once-through system rather than recycling it, which is similar to the “stacked sequestration” approach. Although the costs that CO2-EOR producers typically pay for CO2 are proprietary, it has been well established that it is tied to oil prices and are generally found to be in the range of several dollars per thousand standard cubic feet (mscf). At oil prices of $70/bbl, it has been reported that contracts were priced at $27–40/tCO2.36–39 Also, the CO2-EOR producers who own the geologic formations that naturally store CO2 (e.g., Denbury Resources, Kinder Morgan, and Occidental Petroleum) pay significantly less for the CO2, i.e., several U.S. dollars per tonne at comparable oil prices.40 This makes it difficult to assign a static value to CO2 resold for use in EOR. In their analysis, Skone et al. use a range of $20–50/tCO2 for CO2 provided for the purpose of EOR.41 While this study does not include within the cost model revenue generated from the sale of CO2 for the purpose of EOR, the reader can infer cost adjustments using this cost range as a guide.

In addition to CO2-EOR opportunities, Figure 3 also includes geological sequestration in sedimentary basins in the contiguous United States. Basins suitable for CO2 injection have capacities ranging from 0.74 to 1800 GtCO2, with a total sequestration resource of 2740 GtCO2. The sequestration potential is large enough to offset all U.S. CO2 emissions and potentially significant enough to sequester the 2035 ± 205 GtCO2 emitted globally from 1870 to 2015.41 The feasibility of
CO₂ sequestration also relies on the injectivity of CO₂ in the appropriate sandstone and limestone formations. Injectivities range from 254 to 138,000 ktCO₂/yr, with the average weighted by a basin capacity of 22,500 ktCO₂/yr. This is true when considering a single injection point at the centroid of each basin. In reality, basins will have multiple injection points with injection projects localized according to various parameters, including the geology, the need for CO₂ injection, the ownership of the land, in addition to public acceptance.

Avoided Cost of Capture. Figure 4 illustrates the emission-weighted average avoided cost of capture, including separation, on-site compression, delivery (via trucking or pipeline), and injection of CO₂ to dedicated geologic sequestration or CO₂-EOR sites. These average costs are reported before consideration of the federal tax credit 45Q and do not include revenue from CO₂ resale to EOR. The cost of capture is invariant to the delivery mode and assumes an average value of $53/tCO₂, with a low value of $42/tCO₂ pointing to a high capacity (>6 MtCO₂/yr) NGCC plant in the Southeast and high value of $66/tCO₂ assigned to a borderline case (ca. 500 ktCO₂/yr) in the Southwest. Compression costs are similar for each mode, as power requirements are similar when considering the higher compression ratio and overall pressure for pipeline and the cooling power required in liquefaction. Additional small discrepancies exist in the equipment capital between the two approaches (i.e., for the additional refrigeration requirement).

Hence, the major differentiating factor in these configurations is the cost of CO₂ transport. Spatial analysis shows that the average trucking route from NG facilities to the nearest EOR facility is approximately 660 miles, with values ranging from 7 to 1500 miles. Of the 284 cases considered, only 4 yielded trucking as the least cost option. However, these are all cases where the volume of transport is very low (approaching 500 ktCO₂/yr) and the delivery distance great, resulting in average transport costs of $110/tCO₂. While pipeline is considered more economical, due to the average distances reported here, pipeline transport incurs a cost of ca. $40/tCO₂ avoided or roughly 25% of the total supply chain cost. Comparatively, geologic sequestration is, in general, more well distributed than EOR opportunities (Figure 3), which results in a lower average transport requirement of ca. 250 miles. Here, the cost for trucking and pipeline is more comparable, yet in the 284 cases studied, pipeline is more economical in every case, with an average transport cost of $15/tCO₂.

The implication of geographical opportunity distribution and application of federal tax credit 45Q is illustrated in Figure 5. Application of 45Q (a $26 tax credit for delivery to geologic sequestration and $15 tax credit for delivery to CO₂-EOR, for qualifying facilities) effectively absorbs the cost of compression and injection; thus, given the relatively flat cost of capture, the total avoided cost is most sensitive to transport. The broad span of costs for delivery to EOR sites is due to the range of proximity to natural gas CO₂ capture sites (i.e., 7–1500 miles), where the more distributed sequestration sites lead to a smaller cost range. The low-end values for geologic sequestration ($38 and $42/tCO₂) could be viewed as conservative values based on the current 45Q tax credit values. Taking these projections to the full escalated value ($50/tCO₂) by 2026 and accounting for a flat 2.1% rate of inflation over that same time period lead to a low cost of $22–26/tCO₂. The low-end pipeline configuration for EOR ($56/tCO₂) could realize a value of $46/tCO₂ by 2026 using these assumptions.

Pathways for Further Cost Reductions. As indicated previously, the federal tax credit falls short of offsetting the cost of CO₂ avoided, even at full escalation. If one assumes optimistic revenue from CO₂ resale for EOR (i.e., $40/tCO₂), the incentive gap is roughly $6/tCO₂ for the low-cost case and $46/tCO₂ for the average NGCC/CO₂-EOR configuration. In addition, further R&D toward advanced solvents that may require less heat for regeneration has the potential to reduce costs up to 10% as previously noted, leading to a reduced
average cost of the capture of $45/tCO₂. The addition of compression, transport, and sequestration reveals that increased policy incentives in terms of cost along with the reduction of qualifying limits are necessary to maximize impact.

One limitation of the transport model used in this study is the exclusion of hubs or feeder-trunk optimized pipeline systems in favor of single source–sink pairings. It is shown that the avoided cost of capture is largely dependent on the cost of transport, and the cost of transport is dependent on the volume moved. Transport cost reductions may be realized through the optimization of hub transportation networks where CO₂ at several, lower volume facilities is collected to exploit economies of scale. Figure 6 shows two regions that may be considered carbon hubs where significant anthropogenic CO₂ may be produced to replace the natural CO₂ that is currently used today for EOR. In fact, 13% of the U.S. natural gas-fired power plants having the potential to capture

Figure 6. Regions of carbon “hub” potential surrounding the existing CO₂ pipelines and neighboring sinks, including both EOR and geologic sequestration in the Permian Basin (top) and Gulf Coast (bottom).
more than 25 ktCO₂/yr are located less than 100 miles from these two carbon hubs. The capture potential around the Louisiana–Mississippi and Texas–New Mexico pipelines is roughly 66 and 17 MtCO₂/yr, respectively, with a total capture potential of nearly 84 MtCO₂/yr, corresponding to nearly 18% of the CO₂ capture potential from natural gas-fired power plants in the United States. Roughly 74 MtCO₂/yr of the total potential CO₂ captured are from plants emitting more than 500 ktCO₂/yr, which are currently eligible for the 45Q tax credit.

In the vicinity of the Louisiana–Mississippi hub and the Texas–New Mexico pipelines, 22 and 5 natural gas plants qualifying for 45Q are located less than 20 miles from a CO₂ pipeline, having the opportunity to capture 34 and 4.6 MtCO₂/yr, respectively. Another potential 11 and 24 MtCO₂/yr captured qualifying for 45Q are located between 20 and 50 miles and between 50 and 100 miles from the pipelines, respectively. Missed opportunities (i.e., those not qualifying for the 45Q tax credit) would have the potential to capture additional 2.6, 4.7, and 2.6 MtCO₂/yr by natural gas power plants located within 20 miles, between 20 and 50 miles, and between 50 and 100 miles of CO₂ pipeline, respectively. These carbon hubs surrounding the existing CO₂ pipelines may serve as low-hanging fruit to EOR operators to source CO₂ while minimizing transport costs through the leverage of existing infrastructure.

**ASSOCIATED CONTENT**

Supporting Information
The Supporting Information is available free of charge at https://pubs.acs.org/doi/10.1021/acsest.9b06147.

Cost model with baseline assumptions; learning through CO₂-EOR; geological sequestration methodology; trucking transportation analysis (PDF)

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**Notes**

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