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Review of Federal, State, and Regional Tax Strategies and Opportunities for CO2-EOR-Storage and the CCUS Value Chain

U.S. DEPARTMENT OF ENERGY | Fossil Energy

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REVIEW OF FEDERAL, STATE, AND REGIONAL TAX STRATEGIES AND OPPORTUNITIES FOR CO_2-EOR-STORAGE AND THE CCUS VALUE CHAIN

PROMOTING DOMESTIC AND INTERNATIONAL CONSENSUS ON FOSSIL ENERGY TECHNOLOGIES

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Special thanks go to Chris Gladbach who, while a former partner in Orrick's Energy & Infrastructure group, was instrumental in the development of our relationship with USEA.

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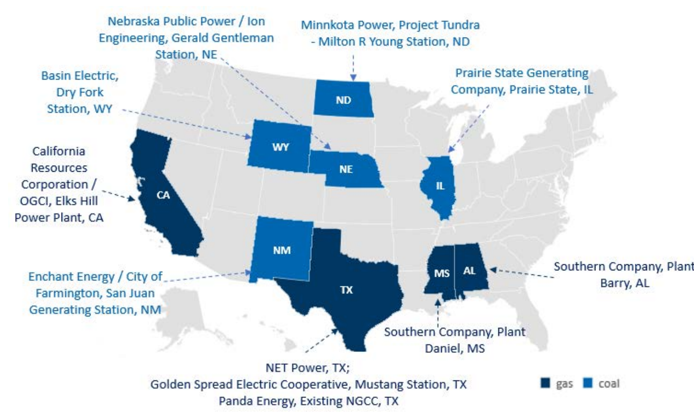
Executive Summary

States, cities, counties, utilities, and corporations in the United States have set important goals for greenhouse gas emission reduction. Seven states including California, Hawaii, Maine, Nevada, New Mexico, New York, and Washington, along with Washington D.C. and Puerto Rico have passed legislation for 100 percent clean or renewable energy mandates or goals. Four other states, including Connecticut, New Jersey, Virginia and Wisconsin have executive orders for 100 percent clean energy goals. Additionally, utilities, independent power producers, and corporations across many sectors of the economy have set carbon-neutral goals in the coming decades.[1] To this end, carbon capture, utilization, and sequestration ("CCUS") will be a vital climate tool for states and other stakeholders to achieve near-zero or even negative carbon emissions in the industrial and power sectors.

Attributable to robust policy support, private sector engagement, and availability of geological storage, the United States has become a global leader in the CCUS space, hosting 10 of the 21 large-scale CCUS projects operating worldwide, capturing 25 million tons per annum of CO_2, or 67 percent of the global capacity.[2,3] Globally, there are three large-scale projects under construction and 35 in various stages of development that together represent 90 million metric tons of CO_2 capture per year.[4]

In the United States, more than 30 CCUS projects are under various phases of development.[5] Power plant retrofits and new builds represent almost half of the proposed projects, and biofuels represents about 25 percent of the proposed projects.[6] Figure ES- 1 provides a map of the proposed CCUS power projects.

Figure ES- 1: U.S. CCUS Power Projects Under Development



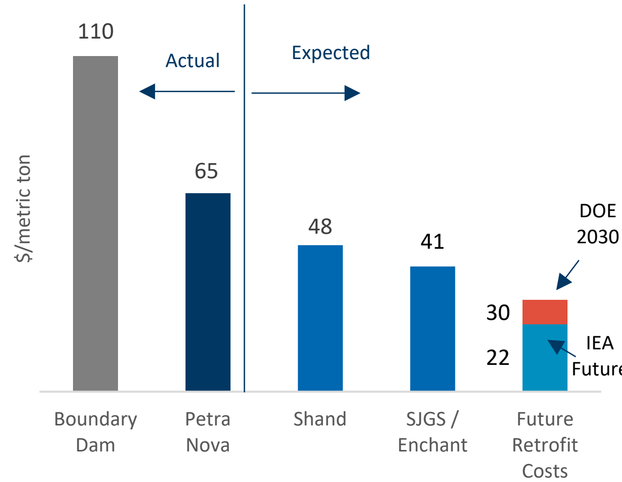
Source: FTI Consulting based on Clean Air Task Force's CCUS Project Tracker.[7]

In the power sector, CCUS costs are projected to continue declining through 'learning by

[1] WRI. https://www.wri.org/blog/2019/12/2019-was-watershed-year-clean-energy-commitments-us-states-and-utilities.
[2] National Petroleum Council. A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage. https://dualchallenge.npc.org/files/NPC%20CCUS%20Chapter%202%20-%20Dec12.pdf.
[3] Global CCS Institute. https://www.globalccsinstitute.com/news-media/press-room/media-releases/carbon-capture-and-storage-pipeline-grows-by-10-large-scale-facilities-globally/.
[4] *Id.*
[5] Clean Air Task Force's CCUS Project Tracker**.** https://www.catf.us/2020/04/the-status-of-carbon-capture-projects-in-the-u-s-and-what-they-need-to-break-ground/.
[6] *Id.*
[7] *Id.*

doing' and technology advancements. As shown in Figure ES- 2, the capture costs of $65 per metric ton for the recently completed Petra Nova retrofit project were almost half the cost of the $110 per metric ton for the older Boundary Dam CCS retrofit project.[8] The expected carbon capture costs for the Shand retrofit project and San Juan Generating Station ("SJGS") / Enchant retrofit are even lower at $45[9] and $41[10] per metric ton, respectively, which are close to the U.S. Department of Energy ("DOE") estimate of $45 per metric ton for 2020[11] and the IEA Clean Coal Centre's estimate of $43 to $45 per metric ton for a CCUS retrofit on a coal-fired power plant.[12] The DOE anticipates retrofit costs to decline to $30 per metric ton by 2030[13], and IEA estimates future retrofit costs through 'learning by doing' to reach $22 per metric ton.[14]

Figure ES- 2: Capture-only Costs for Coal-fired Generator Retrofits



Source: FTI Consulting Research

The Section 45Q federal income tax credit for CCUS will become increasingly attractive as retrofit costs for coal-fired generators and industrial applications fall below $50 per metric ton. As shown in Table ES- 1, the 45Q Credit in 2026 increases linearly, to $35 per metric ton for enhanced oil recovery ("EOR"), enhanced natural gas recovery ("EGR"), and non-EOR CO_2 utilization, and to $50 per metric ton for geologic storage. After 2026, the 45Q Credit amounts will instead be adjusted for inflation.

[8] "Carbon Capture and Storage Commercialization & Deployment," Hardy, Beth, International CCS Knowledge Centre, presented at the USEA CCUS Roadshow Series, January 28, 2020, slide 6.
[9] Id.
[10] "The Economic Case for Power Plant Carbon Capture Retrofits: A Case Study for the San Juan Generating Station – New Mexico," Selch, Jason, October 2019, slide 2.
[11] Testimony of Jeffrey Bobeck before the U.S. House Subcommittee on Energy, Wednesday, June 19, 2019.
[12] "Carbon Capture Utilization and Storage (CCUS)-Status, Barriers and Potential," Kelsall, Greg, IEA Clean Coal Centre, April 15, 2020, slide 28.
[13] Testimony of Jeffrey Bobeck before the U.S. House Subcommittee on Energy, Wednesday, June 19, 2019.
[14] Id.

Table ES- 1: 45Q Credit for Qualifying Facilities

Facility Type	45Q Credit Value in 2026
Geologic Storage	$50 per metric ton
Enhanced Oil Recovery, Enhanced Gas Recovery, and Utilization	$35 per metric ton

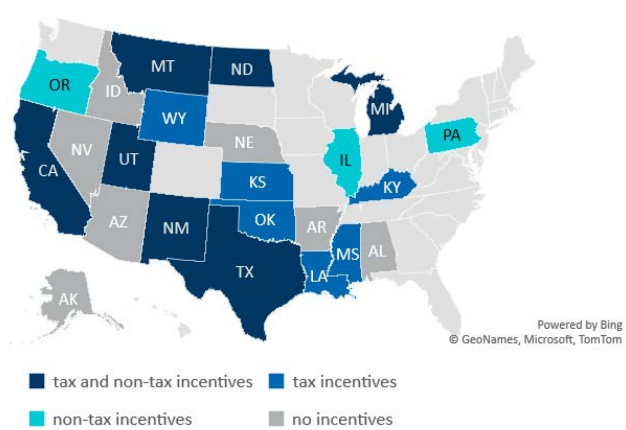
Source: Internal Revenue Code

While the credit typically goes to the owner of the carbon capture equipment by default, the Bipartisan Budget Act of 2018 enables the credit to be directed to the entity that disposes or uses the CO_2.

In addition to the federal 45Q Credit, various states offer complementary tax and non-tax incentives that will further enhance CCUS economics. Out of the 23 states we reviewed, we found that 15 states have meaningful incentive programs, which are detailed below and shown in Figure ES- 3.[15] The types of state tax incentives vary dramatically, ranging in the types of taxes that are available and also in the scale of the incentives, both in terms of the percent reduction of a particular tax and the amount of time the incentive applies to a particular project. States like California, Kansas, Kentucky, Louisiana, Michigan, Mississippi, Montana, North Dakota, Oklahoma, Texas, and Wyoming provide various tax incentives for CCUS deployment, ranging from credits, exemption or reduction of property tax, severance tax, gross receipt tax, and sales tax, etc. Texas has the largest variety of incentives for carbon that is sequestered, typically in connection with EOR. The Texas tax incentives for carbon sequestration include sales tax exemptions, franchise tax credits, and severance tax reductions.

In terms of non-tax incentives, both California and Oregon provide for a system to reduce carbon-intensive fuels under their Low Carbon Fuel Standards ("LCFS") programs by granting credits to suppliers of fuel for supplying fuel that has a lower carbon footprint and requiring suppliers of more carbon-intense fuels to purchase those credits. The value of the credits varies based on marketplace driven supply and demand; however, significant fines for failure to meet benchmark requirements make participation in these programs mandatory. The California LCFS includes a carbon capture and sequestration ("CCS") protocol to allow CCS projects to access the credits, and the Oregon regulations contemplate the use of CCUS when calculating a low-carbon fuel pathway.

Figure ES- 3: States Active in CCUS Incentives



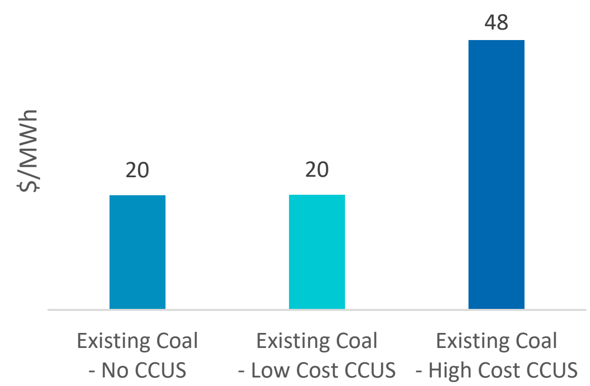
Source: FTI Consulting and Orrick Research

The combination of the 45Q Credit and state tax and non-tax incentives can make CCUS

[15] The additional eight states that were examined that did not have meaningful incentive programs are: Alabama, Alaska, Arizona, Arkansas, Idaho, Nebraska, Nevada, and Utah.

projects competitive to new renewable projects. As shown in Figure ES- 4, according to FTI's calculation, applying the 45Q Credit of $50 per metric ton could result in a levelized cost of electricity ("LCOE") as low as $20 per MWh for coal retrofitted with CCUS, under the low-cost CCUS scenario of $42 per metric ton for capture, or the same as coal without CCUS. However, if capture costs are closer to the high-cost CCUS scenario of $66 per metric ton, the LCOE of existing coal retrofitted with CCUS would be $48 per MWh.

Figure ES- 4: LCOE Comparison for 2026 Online Date (includes Capacity Credit Value)



Source: FTI Consulting Analysis

In addition to making low-carbon coal and natural gas competitive with renewables, the 45Q Credit can enable baseload power to remain online to supply dependable electricity and balance the intermittent generation of wind and solar.

With more than 2 billion metric tons per annum of CCUS opportunities in the U.S.[16], various stakeholders, including financial investors, owners, and operators will be chasing technically feasible and commercially viable 45Q CCUS opportunities.

Financial stakeholders consist of large U.S. corporations and sometimes foreign corporations with a significant U.S. federal income tax base who will be tax equity investors similar to the tax equity investors that invest in wind and solar projects eligible for the production tax credit ("PTC") or investment tax credit ("ITC"). Other financial stakeholders include financial institutions, commercial banks, private equity, and insurance companies.

Owner and Operator stakeholders include fossil-fired power generators (mainly coal and natural gas) and industrial facilities that are challenging to decarbonize, such as those producing ammonia, cement, ethanol, hydrogen, natural gas, petrochemicals, refined oil, and steel. Total CO_2 emissions in the U.S. from the power and industrial sectors in 2018 amounted to 1.8 and 1.5 billion metric tons of CO_2, respectively.[17]

One of the primary deal structures that financial, owner and operator stakeholders likely will apply for 45Q opportunities is a "tax equity" arrangement, where an investor that is able to monetize the 45Q Credit and other tax benefits (e.g., depreciation deductions) invests in a qualifying project through a project company that is treated as a partnership for U.S. federal income tax purposes. An alternative structure will take advantage of the

[16] NPC Report, Chapter 2, Figure 2-1.

[17] EPA. https://cfpub.epa.gov/ghgdata/inventoryexplorer/#allsectors/allgas/econsect/current.

ability of the owner of the carbon capture equipment to transfer the 45Q Credit to an offtaker of the carbon oxide. Section 45Q specifically uses the term carbon oxide, which includes any carbon oxide such as carbon dioxide or carbon monoxide. In this structure, the party that is contractually bound to purchase and either sequester or use the carbon oxide may use the 45Q Credit itself or may enter into a tax equity arrangement with an investor that can monetize the tax benefits.

In addition to financial stakeholders, owner and operators, **federal and state regulatory and non-regulatory agencies** are stakeholders that will continue to play important, supportive and enabling roles in large-scale CCUS deployments. The U.S. Treasury Department, the Department of Energy ("DOE"), the Environmental Protection Agency ("EPA"), and the Department of the Interior are responsible for and involved in establishing regulations under Section 45Q related to the carbon capture rules.

The U.S. EPA and state environmental agencies play a major role in the permitting of enhanced oil and gas recovery (Class II wells) and geologic sequestration (Class VI wells). Forty states have primacy (i.e., delegated authority) to permit Class II wells while only one state, North Dakota, has primacy to permit Class VI wells. There is a significant distinction between Class II and Class VI wells in terms of permitting timeline, costs, and storage potential as shown in Table ES- 2.

Table ES- 2: Indicative Timelines and Costs for Class II vs. Class VI Wells

	Class II	Class VI
Permitting timeline	1 year	3 years[18]
Permitting costs	<$100,000	>$500,000
Monitoring costs per year[19]	$4,000	$320,000

While Class II wells are easier to permit and have lower costs to operate, the potential storage in oil and gas reservoirs via Class II wells is a magnitude lower than saline formations (205 GT vs 8,328 GT), which would be used for geologic storage.[20] Revisions to the Class VI permitting process and assignment of primacy to states will be important for the U.S. EPA to consider if CCUS is expected to become viable in the long term.

Several non-regulatory government agencies are involved in different aspects to advance U.S. CCUS development, including the DOE, which funds large-scale energy infrastructure projects through its loan guarantee program and supports CCUS demonstration projects like the Regional Carbon Sequestration Partnerships Initiative through grants; the U.S. Department of the Interior - U.S. Geological Survey ("USGS"), which conducts national assessments of geologic storage resources and evaluates the national technically recoverable hydrocarbon resources resulting from CO_2 injection and storage; and the U.S. Department of Agriculture

[18] Based on ADM Timeline. "ADM CCS Projects: Experience and Lessons Learned," McDonald, Scott, CSLF Technical Workshop, June 17, 2015.

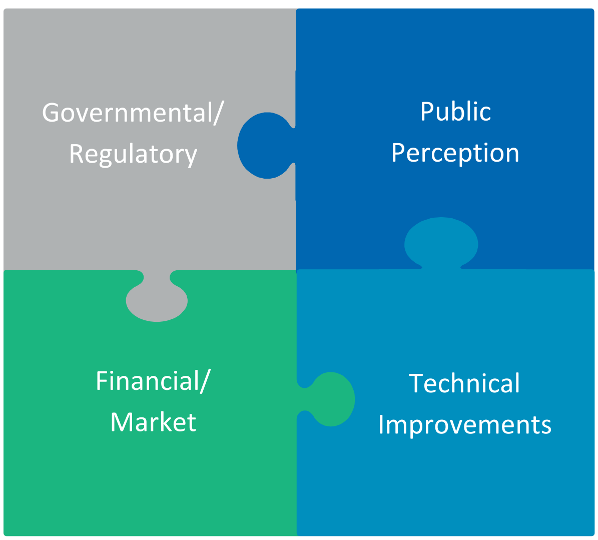
[19] EPA. https://www.epa.gov/sites/production/files/2015-07/documents/subpart-rr-uu-factsheet.pdf.

[20] NETL. https://www.netl.doe.gov/coal/carbon-storage/strategic-program-support/natcarb-atlas.

("USDA"), which provides low-cost financing through its Rural Development and Loan Guarantee Programs.

While all supportive of CCUS deployment, these stakeholders will need to overcome roadblocks and hurdles for successful CCUS market acceptance and penetration. These roadblocks and hurdles can be grouped into four major categories – governmental/regulatory, technical, financial/market, and public perception as depicted in Figure ES- 5 below.

Figure ES- 5: The Interconnected Nature of Major Roadblocks and Hurdles



These four categories are inextricably interconnected as the graphic illustrates. For example, reducing governmental and regulatory roadblocks and hurdles that lower permitting costs and timelines would improve the financial and market viability of projects. As more projects become financially viable and come online, learning by doing will increase, resulting in further cost reductions along with an improved public perception of CCUS as a clean-energy technology. Major solutions to CCUS roadblocks and hurdles will include items such as those listed below.

- Clarifying IRS guidance on 45Q Credit:
  - While existing IRS Guidance provides a safe harbor for tax equity investors in partnerships that capture CO_x, it does not address the situation where the tax credit is assigned to a party that disposes of, utilizes in permitted applications, or uses the CO_x in EOR.
  - While some guidance on measuring lifecycle greenhouse gas emissions is provided, reporting procedures and standards for the IRS, DOE, and EPA review of lifecycle reports have not been provided.
- Changing financial accounting guidance, in particular, the required use of the Hypothetical Liquidation at Book Value.
- Making legislative and regulatory changes that accelerate the buildout of CO_2 pipelines, such as expediting CO_2 pipeline permitting and development.[21]
- Providing loan guarantees to investors.
- Providing cost-sharing of Front-End Engineering Design ("FEED") studies.
- Funding of research and development ("R&D") into advanced technologies such as catalysts, chemical looping, membranes, and solvents.

[21] Utilizing Significant Emissions with Innovative Technologies (USE IT) Act: https://www.epw.senate.gov/public/index.cfm/2019/2/senators-reintroduce-use-it-act-to-promote-carbon-capture-research-and-development.

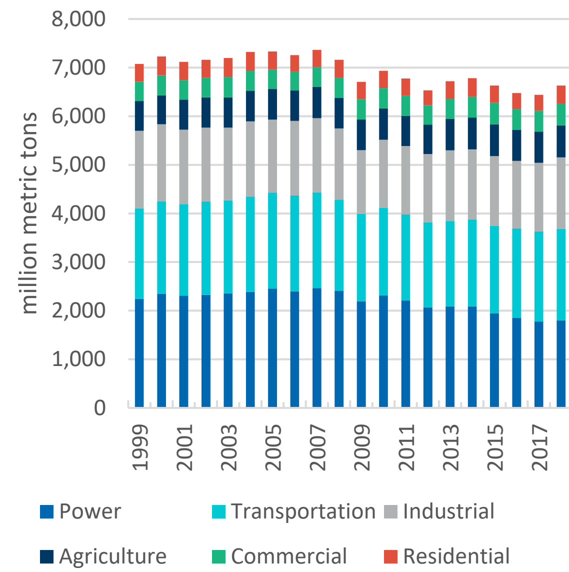
- Addressing Class VI permitting and cost challenges:
  - Developing a process for delegating primacy to states as the EPA may not have the resources to handle an influx of Class VI applicants.
  - Allowing area permits for multiple injection wells instead of a single well.
  - Moving to a risk-based assessment of Class VI wells, similar to the statutory standard imposed by the Safe Drinking Water Act.
  - Eliminating the 50-year post-injection site care period.
  - Allowing monitoring flexibility instead of only direct monitoring, which could create possible leakage pathways.
  - Allowing Class V for demonstration projects.

Lowering the barriers to entry by addressing roadblocks and hurdles facing various stakeholders will accelerate CCUS deployment. As a commercially proven technology, CCUS is ready for substantial scale-up and deployment in the U.S. with the federal Section 45Q and complementary state incentives providing strong financial support. Project sponsors, tax equity investors, owners, and operators are ready to tap into federal, state, and local tax and non-tax incentives to bridge the gap of CCUS costs and the market value of CO_2.

Introduction

In 2018, the United States emitted 6.7 billion metric tons of GHG emissions. Almost half of these emissions (49 percent) came from the power and industrial sectors as illustrated in Figure 1.[22]

Figure 1: U.S. GHG Emissions and GHG Emissions



GHG emissions in the power sector have decreased by 28 percent since 2005 due to fuel mix changes and the penetration of renewables. GHG reductions in other sectors, however, have remained stagnant.

CCUS presents an opportunity to lessen the tension between meeting the nation's energy needs and reducing its greenhouse gas emissions. It can help reduce GHG emissions not only in the power sector but also in the industrial sector through direct capture and utilization and in the transportation sector at ethanol facilities and through EOR, for example.

CCUS is a demonstrated, commercially proven technology path for making deep GHG reductions. In North America, the most recent

[22] EPA. https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks.

CCUS examples in the power sector include the 110-MW coal-fired retrofit of Boundary Dam Unit 3 in Saskatchewan, Canada, and the 240 MW retrofit of W.A. Parish Unit 8 in Texas ("Petra Nova") that is used for enhanced oil recovery.

Both the Boundary Dam and Petra Nova projects are post-combustion capture projects where CO_2 is removed after combustion in the boiler stack. Pre-combustion capture through hydrogen production (e.g., coal gasification) and oxyfuel combustion where a fossil fuel is combusted with pure oxygen are other forms of carbon capture for power generation. In the industrial sector, where CO_2 can often be captured within existing processes, recent CCUS examples include the Air Products Steam Methane Reformer CO_2 capture project in Texas and the ADM Illinois Industrial CCS project.

To help describe and, in some ways, enable the deployment of CCUS, DOE and USEA engaged FTI and Orrick to provide a guide to the current federal, state, and regional tax strategies and opportunities for CO_2 for EOR and storage. This report identifies federal and state incentives and regulatory regimes that are applicable to CCUS in the United States. It then illustrates several deal structures for application of these incentives. In addition, the report describes the various stakeholders that are critical for CCUS deployment, the roadblocks stakeholders face, and potential solutions that would increase the likelihood of the successful progress of CCUS programs as well as CSR and ESG implications.

The goal of this report is to provide interested parties with an overview of the current landscape, the problems that current stakeholders face, and a preview into the developments that are expected in the coming years.

Federal Incentives, Programs, and Agencies

45Q Credit

Section 45Q provides a federal income tax credit for CCUS to encourage investment in projects that will reduce the emission of greenhouse gases. From 2008–2018, an incentive of $20 per metric ton for CO_2 geologic storage and $10 per metric ton for CO_2 used for enhanced oil recovery ("EOR") or enhanced natural gas recovery ("EGR") was available. In February 2018, with the passage of the Bipartisan Budget Act of 2018, the Internal Revenue Code ("IRC") of 1986 was amended to improve and extend the credit for CO_2 sequestration. The 45Q Credit was expanded to generally include all carbon oxides ("CO_x") captured.[23] This will permit the utilization of CO_x generated as a result of certain manufacturing processes, such as steel manufacturing. The 45Q Credit is available for a 12-year period, beginning when equipment is placed in service. The credit typically goes to the owner of the carbon capture equipment;

[23] Note that when discussing qualified carbon oxides this report will use CO_x, but the definition of "qualified carbon oxide" provided in Section 45Q only includes the CO_2 captured by direct air capture facilities. Otherwise, "qualified carbon oxide" includes any carbon dioxide *or other carbon oxide* which is captured from an industrial source by carbon capture equipment originally placed in service after the enactment of the Bipartisan Budget Act of 2018.

however, the Act permits the credit to be transferred to the person that disposes or uses the CO_x instead.

As shown in Table 2, the credit increases to $35 per metric ton for EOR, EGR, and non-EOR CO_x utilization;[24] and $50 per metric ton for geologic storage in 2026. Non-EOR utilization includes:

- Photosynthesis or chemosynthesis (e.g., algae or bacteria)
- Chemical conversion
- Other purposes for which a commercial market exists, as determined by the Secretary of the Treasury

Qualified facilities are defined as:

- For facilities that emit less than 500,000 metric tons of CO_x into the atmosphere per year, the facilities must capture at least 25,000 tons of qualified CO_x per year in a manner described in Section 45Q(f)(5).[25]
- For electricity generating facilities that emit 500,000 or more metric tons of CO_x into the atmosphere per year, the facility must capture at least 500,000 tons of qualified CO_x per year.
- For direct air capture facilities or any facility not described above, the facilities must capture at least 100,000 tons of qualified CO_x per year.

Table 1: Facilities and Requirements

Type of Facility	Minimum Annual Capture Requirement and Other Requirements
Any facility other than direct air capture	■ Must capture at least 25,000 metric tons of carbon oxide ■ Facility must emit no more than 500,000 metric tons of carbon oxide ■ Carbon oxide must be utilized in a manner consistent with Section 45Q(f)(5)
Electric generating facility	■ Must capture at least 500,000 metric tons of carbon oxide ■ No minimum or maximum emission requirements
Direct air capture facility or any other facility not described above	■ Must capture at least 100,000 metric tons of carbon oxide

[24] A significant change in the 45Q Credit relates to the ability to obtain the credit for the utilization of the carbon oxide. For purposes of calculating the amount of CO_x utilized by a taxpayer claiming the 45Q Credit, the Secretary of the Treasury, in consultation with the Secretary of Energy and the Administrator of the Environmental Protection Agency, have been given the authority to provide the requirements for the analysis by which taxpayers demonstrate they have either captured and permanently isolated CO_x or displaced CO_x from being emitted into the atmosphere. Taxpayers must demonstrate such capture or displacement based on an analysis of the lifecycle greenhouse gas emissions of the means by which the taxpayer utilized the CO_x.

[25] Section 45Q(f)(5)(A) provides that "utilization of qualified carbon oxide" means (i) the fixation of such qualified carbon oxide through photosynthesis or chemosynthesis, such as through the growing of algae or bacteria; (ii) the chemical conversion of such qualified carbon oxide to a material or chemical compound in which such qualified carbon oxide is securely stored; or (iii) the use of such qualified carbon oxide for any other purpose for which a commercial market exists (with the exception of use as a tertiary injectant in a qualified enhanced oil or natural gas recovery project), as determined by the Secretary.

Table 2: 45Q Credit for Qualifying Facilities

Facility Type	45Q Credit Value in 2026
Geologic Storage	$50 per metric ton
EOR, EGR and Utilization	$35 per metric ton

Source: Internal Revenue Code

Qualified facilities include industrial facilities and direct air capture facilities. To be a qualified facility, the construction of the qualified facility (either an industrial facility or a direct air capture facility) must begin prior to January 1, 2024, and the construction of carbon capture equipment must begin before such date or the original planning and design for the facility must include the installation of the carbon capture equipment.

The IRS provided guidance regarding many open issues related to 45Q Credit on May 28, 2020, when it published a Notice of Proposed Rulemaking (the "Proposed Regulations").[26] The Proposed Regulations are an important step towards the implementation of investment structures that will monetize the 45Q Credit.[27]

Section 43 Federal Enhanced Oil Recovery Credit

The EOR Credit is a 15-percent tax credit for qualified EOR costs incurred by a taxpayer. The EOR credit is reduced when the reference price per barrel of crude oil is more than the base value of $28 (as adjusted by inflation).[28]

A qualified EOR project generally involves increasing the amount of recoverable domestic crude oil through the use of one or more tertiary recovery methods.[29] Qualified tertiary methods include: steam recovery methods (e.g., steam drive injection, cyclic steam injection, and in situ combustion); gas flood recovery methods (e.g., miscible fluid displacement, CO_2 augmented waterflooding, immiscible CO_2 displacement, and immiscible nonhydrocarbon gas displacement); chemical flood recovery methods (e.g., microemulsion flooding and caustic flooding), and mobility control recovery method (polymer augmented waterflooding).[30]

Simply accelerating the recovery of minerals does not qualify as an EOR project. Rather, more than an insignificant increase in the amount of crude oil that will ultimately be recovered is required.[31] A qualified EOR project must also meet other specified requirements provided by the statute, including that the project must be located within the U.S.; the initial implementation of one or more of the qualified tertiary methods must have commenced after December 31, 1990; and the project must be certified through procedures

[26] Notice of Proposed Rulemaking, Fed. Reg. Vol. 85, No. 106 p. 34050. 06/02/2020.
[27] For a discussion of the Proposed Regulations, see Connors and Emmett, "Developers and Tax Equity Investors Receive More Guidance on Carbon Capture Credit Requirements" *Bloomberg Tax Management Memorandum* (June 29,2020)
[28] IRC § 43(b).
[29] Code Sec. 43(c)(2)(A); Code Sec. 193(b)(3).
[30] Code Sec. 43(c)(2)(A)(i) (referring to Code Sec. 193(b)(3)); Treasury Regulations section 1.43-2(e)(2).
[31] Code Sec. 43(c)(2)(A)(i).

described in Treasury Regulations section 1.43-3.[32]

Each year, typically in April or May, the IRS publishes two Notices: one that contains the reference price per barrel of crude oil, and one that contains the inflation adjustment for the prior year. The reference price per barrel of crude oil is the IRS's estimate of the annual average wellhead price per barrel for all domestic crude oil, the price of which is not subject to regulation by the U.S. The inflation adjustment amount is based upon the Gross National Product ("GNP") implicit price deflator for the preceding calendar year divided by the GNP implicit price deflator for 1990.

The table below lists the reference price per barrel of crude oil provided by the IRS and the inflation adjustment amount multiplied by the $28 base value for each year since 1990. As shown in Table 3, due to the high reference price of crude oil, the credit was completely phased out in 2019. However, if the price of oil in 2020 generally remains lower than $48.54 per barrel ($28 multiplied by the inflation adjustment for 2019), which shall be further adjusted for the inflation adjustment released for 2020, the credit may be available for the 2020 tax year. As noted, above, that information can generally be expected in April or May of the subsequent year (*i.e.*, April or May of 2021 for 2020).

Whether a taxpayer will be eligible for the credit will depend on the inflation adjustment that will be applicable to the 2020 tax year and the reference price for oil applicable for the 2020 tax year. The ability to obtain the Section 43 credit in conjunction with the 45Q Credit will further incentivize the development of projects involving EOR and carbon sequestration.

Table 3: Historical Inflation Adjusted Amount and Reference Crude Oil Prices

Year	Inflation Adjustment	Inflation Adjusted Amount	Reference Price per Barrel of Crude Oil	Phase-Out[33]	Credit Allowable[34]
1991	1.0000	$ 28.00	$ 16.50	0%	15%
1992	1.0363	$ 29.02	$ 15.98	0%	15%
1993	1.0708	$ 29.98	$ 14.24	0%	15%
1994	1.0992	$ 30.78	$ 13.19	0%	15%
1995	1.1160	$ 31.25	$ 14.62	0%	15%
1996	1.1485	$ 32.16	$ 18.46	0%	15%
1997	1.1720	$ 32.82	$ 17.24	0%	15%
1998	1.1999	$ 33.60	$ 10.88	0%	15%

[32] Code Sec. 43(c)(2)(A)(ii), (iii); Code Sec. 43(c)(2)(B)

[33] This column provides the percent of the phase-out and is calculated by subtracting the current year's inflation adjusted amount from the prior year's reference price per barrel of crude oil and dividing the difference by 6. For example, the value for 2018, 7.127%, is equal to $48.05 minus $47.62, or $0.43, divided by $6.

[34] This column provides the amount of the Section 43 credit allowable (up to a maximum of 15%) and is calculated by subtracting from 15% the phase-out percentage multiplied by 15%. For example, the value for 2018 is equal to 15% - (7.127% * 15%).

1999	1.2030	$ 33.68	$ 15.56	0%	15%
2000	1.2087	$ 33.84	$ 26.73	0%	15%
2001	1.2353	$ 34.59	$ 21.86	0%	15%
2002	1.2633	$ 35.37	$ 22.51	0%	15%
2003	1.2785	$ 35.80	$ 27.56	0%	15%
2004	1.2952	$ 36.27	$ 36.75	0%	15%
2005	1.3266	$ 37.14	$ 50.26	0%	15%
2006	1.3743	$ 38.48	$ 59.68	100%	0%
2007	1.4222	$ 39.82	$ 66.52	100%	0%
2008	1.4666	$ 41.06	$ 94.03	100%	0%
2009	1.5003	$ 42.01	$ 56.39	100%	0%
2010	1.5203	$ 42.57	$ 74.71	100%	0%
2011	1.5326	$ 42.91	$ 95.73	100%	0%
2012	1.5686	$ 43.92	$ 94.53	100%	0%
2013	1.5968	$ 44.71	$ 96.13	100%	0%
2014	1.5974	$ 44.73	$ 87.39	100%	0%
2015	1.6245	$ 45.49	$ 44.39	100%	0%
2016	1.6464	$ 46.10	$ 38.29	0%	15%
2017	1.6713	$ 46.80	$ 48.05	0%	15%
2018	1.7008	$ 47.62	$ 61.41	7.17%	13.93%
2019	1.7334	$ 48.54	$ 55.55	100%	0%

Department of Energy

The DOE leads R&D efforts by the federal government in carbon capture, utilization, and geological sequestration. Since 1997, the DOE has supported CCUS research and development, and since 2012 Congress has provided more than $4 billion in research, development, and demonstration ("RD&D") funding to the DOE for CCUS activities.[35] As of February 21, 2020, there have been nine research and development projects in the United States that have injected CO_2 as part of large-scale field tests of geological sequestration associated with enhanced oil recovery, four of which are currently injecting and/or storing CO_2.[36]

The U.S. DOE Loan Programs Office ("LPO") has more than $40 billion in loans and loan guarantees available to help deploy large-scale energy infrastructure projects in the United States. While the DOE LPO focuses on debt financing for the deployment of commercial-scale projects, other offices within the DOE offer funding and financing opportunities for RD&D and smaller projects, such as its Regional Carbon Sequestration Partnerships ("RCSP")

[35] Folger, P. (2018). FY2019 Funding for CCS and Other DOE Fossil Energy R&D, Congressional Research Service, July 2, 2018, 2 pp. Accessed October 20, 2019. https://fas.org/sgp/crs/misc/IF10589.pdf.
[36] *See* https://crsreports.congress.gov/product/pdf/IF/IF11345.

Initiative. The DOE started the RCSP initiative in 2003 to characterize each region's potential to store carbon dioxide in different geologic formations.

Table 4 shows the seven RCSPs across the country.

Table 4: DOE Regional Carbon Sequestration Partnerships

Regional Carbon Sequestration Partnerships ("RCSP")		Lead Organization
Big Sky Carbon Sequestration Partnership	BSCSP	Montana State University's Energy Research Institute
Midwest Geological Sequestration Consortium	MGSC	Illinois State Geological Survey
Midwest Regional Carbon Sequestration Partnership	MRCSP	Battelle Memorial Institute
Plains CO_2 Reduction Partnership	PCOR	University of North Dakota Energy and Environmental Research Center
Southeast Regional Carbon Sequestration Partnership	SECARB	Southern States Energy Board
Southwest Regional Partnership on Carbon Sequestration	SWP	New Mexico Institute of Mining and Technology
West Coast Regional Carbon Sequestration Partnership	WESTCARB	California Energy Commission

Source: National Energy Technology Laboratory

In 2019, the DOE announced approximately $110 million in federal funding for cost-shared R&D projects under three funding opportunity announcements ("FOAs")[37] as shown in Table 5. Under the first FOA award, DOE selected nine projects in California, Illinois, Nebraska, New Mexico, North Dakota, Mississippi, Wyoming, and Texas to receive $55.4 million for cost-shared R&D. Under the second FOA, DOE selected four projects to receive up to $20 million. Under the third FOA, the DOE provided up to $35 million for projects to accelerate CCUS deployment through assessing and verifying safe and cost-effective anthropogenic CO_2 commercial-scale storage sites, carbon capture, and purification technologies.

Table 5: DOE Funding Opportunities for CCUS in 2019

FOA	Amount	Scope
1: FEED Studies for CCUS on Coal and Natural Gas Power Plants	$55.4 million	Nine projects to receive funding for R&D
2: Regional Initiative to Accelerate CCUS Deployment	$20 million	Four projects to receive funding for R&D
3: Cost-shared R&D to Accelerate CCUS Deployment	$35 million	Cost-shared R&D projects to assess CCUS

Source: National Energy Technology Laboratory

In April 2020, the DOE announced up to $131 million for CCUS R&D projects through one new FOA and the winners of five project selections from a previous FOA. Under the new FOA, DOE makes up to $46 million available for cost-shared R&D projects that capture and store CO_2 emissions from industrial sources.[38]

USDA Funding Under the Rural Economic Initiative

The U.S. Department of Agriculture's Rural Utilities Service ("RUS") provides assistance on infrastructure or infrastructure improvements to rural communities. Its $60 billion loan portfolio includes $44 billion for electric, $13 billion for water, and $3 billion for telecom. RUS provides low-cost financing with a focus on hard asset lending to any element of the electric infrastructure serving rural customers, including generation, transmission, distribution, smart grid, energy efficiency, cyber and grid security, renewables, and CCUS. While coops are RUS's largest customer base, the programs are also open to investor-owned utilities and municipal and tribal entities.

State Incentives, Programs, and Agencies

This section summarizes various state incentives and programs to encourage CO_2 capture and utilization for EOR and storage in the 23 states we reviewed. Of the 23 states, 15 states have meaningful incentive programs, which are summarized in Table 6 and detailed by state thereafter.[39]

[37] DOE. https://www.energy.gov/articles/us-department-energy-announces-110m-carbon-capture-utilization-and-storage.
[38] DOE. https://www.energy.gov/articles/us-department-energy-announces-131-million-ccus-technologies.
[39] The additional eight states that were examined that did not have meaningful incentive programs are Alabama, Alaska, Arizona, Arkansas, Idaho, Nebraska, Nevada, and Utah.

Table 6: Summary of States Tax and Non-tax Incentives

State	Tax Incentives	Non-tax Incentives
California	EOR Credit	The LCFS (with CCS protocol) provides suppliers of low-carbon fuels with credits that can be sold to suppliers of higher-carbon fuels. California's economy-wide cap-and-trade program covers 80 percent of the state's economy. Operators of low carbon power resources, such as power facilities with CCUS, can mostly avoid carbon allowance costs, providing a competitive advantage in the California electricity market.
Illinois	N/A	Illinois utilities are required to source electricity from "clean coal facilities" as part of the goal for at least 25 percent of electricity in Illinois to come from coal plants that capture and sequester CO_2 emissions by 2025.
Kansas	Accelerated Depreciation	N/A
	Property Tax Exemption	
	Carbon Farming Tax Credit	
Kentucky	Sales and Use Tax Exemption	N/A
	Severance Tax Credit	
	Credit on Corporate Income Taxes	
	Credit on Personal Income Taxes	
Louisiana	Sales and Use Tax Exemption	N/A
	Severance Tax Reduction	
Michigan	Severance Tax Reduction	Integrated Renewable Portfolio Standard includes, to a limited extent, carbon capture and sequestration technology installed on a coal plant towards the renewable target.
Mississippi	Ad Valorem Tax Exemption	N/A
	Severance Tax Reduction	
	Gross Income Tax Reduction	
Montana	Reduced Property Tax	New electric generation capacity fueled by coal constructed after January 1, 2007, is required to capture and sequester at least 50 percent of CO_2 emissions.
New Mexico	Alternative Energy Product Manufacturers Tax Credit Act	Public utilities may recover costs related to clean energy projects.
North Dakota	Sales and Use Tax Exemption	Includes CO_2 pipelines as common carriers.
	Property Taxes Exemption	
	Gross Receipts Tax Reduction	
Oklahoma	Gross Production Tax Exemption	N/A
Oregon	N/A	Clean Fuels Program
Pennsylvania	N/A	A minimum biodiesel content in diesel fuel is required, but the use of non-sulfur diesel fuel derived from coal is permitted as long as the fuel's carbon emissions are offset through geologic carbon sequestration or by participation in a carbon offset program.
Texas	Franchise Tax Credit	Includes CO_2 pipelines as common carriers if certain conditions are met.
	Severance Tax Reductions	
	Sales and Use Tax Exemption	
	Gross Receipts Tax Exemption and Other Tax Incentives	
Wyoming	Sales Tax Exemption	N/A
	Severance Tax Credit	

California

Low Carbon Fuel Standard

The LCFS program in California is a regulatory program designed to encourage the use of cleaner, less carbon-intensive vehicle fuels. The California Air Resource Board's ("CARB") articulated goal for the LCFS program is to reduce the carbon intensity of vehicle fuels used in the state by 20 percent by 2030, compared to a 2010 baseline. The LCFS program has recently been amended to recognize carbon capture and sequestration as a method of reducing the carbon intensity of fuels.

Under the LCFS program, each supplier of vehicle fuels in California[40] is required to achieve a "benchmark" standard of "carbon intensity" of the fuels it supplies in the state. This standard is represented by a fuel's production life cycle CO_2 emissions (expressed as grams of CO_2 equivalent or "gCO_2e")[41] divided by a specified unit of energy [with the unit being the megajoule or "MJ")[42] when that fuel is used for transportation.[43] CARB set the benchmark carbon intensity for gasoline at 91.98 gCO_2e/MJ for 2020. This benchmark declines to 79.55 gCO_2e/MJ in 2030.

The LCFS program drives reductions in carbon intensity by requiring that fuels supplied by regulated entities in California, on average, meet the benchmark. The regulated entity may do this by producing or importing fuels that meet the benchmark or by buying LCFS credits that represent fuels with a lower carbon intensity than the benchmark. Because conventional fuels have carbon intensity values well above the benchmark, the only options for fuel suppliers to meet the requirements are (1) supplying alternative fuels as a significant percentage of total fuel supplied, or (2) buying LCFS credits. There are significant penalties for failing to comply with the benchmarks under California Health & Safety Code section 43027. These include a penalty of $35,000 a day for violations and higher penalties for negligent, willful, and intentional violations.

Credits are generated by using fuels that CARB has approved and to which CARB has assigned a specific carbon intensity value. To assign a carbon intensity, CARB must consider the life cycle greenhouse gas emissions of the fuel. In making that life cycle analysis, CARB considers location, technology, inputs, and energy content, among other factors. As a result, ethanol produced in Iowa may have a different carbon intensity than ethanol produced in Brazil. Each approved fuel that is assigned a carbon intensity value is described as a "pathway". Fuels with a carbon intensity value below the benchmark generate LCFS credits equal to the number of metric tons of CO_2 below the benchmark attributable to the fuel.

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[40] The LCFS program regulates vehicle fuels imported into California and produced in California, with some lack of clarity regarding "production." A producer is an entity that "made or prepared" the fuel. Each such entity is a regulated entity under the LCFS program.

[41] The measure of a carbon equivalent is used to account for different global warming potentials, per ton, of other types of greenhouse gases that may be covered by the program and associated with fuels (e.g., nitrous oxide and methane).

[42] An MJ is a metric unit of energy equivalent to approximately 948 British thermal units. There are approximately 132 MJ in one gallon of gasoline.

[43] The actual measurements are in MTs of CO_2 per MJ.

In January 2019, CARB added CCUS to the LCFS program. It is now possible to generate LCFS credits related to CCUS projects that directly capture CO_2 from the air, as well as CCUS projects associated with the delivery of fuels in California. Eligible projects must sequester CO_2 onshore, in saline or depleted oil and gas reservoirs, or oil and gas reservoirs in connection with enhanced oil recovery, provided that the projects meet the requirements for permanence.

CARB notes four avenues for generating LCFS credits using CCUS projects: (1) use of CCUS when calculating a low-carbon fuel pathway (e.g., ethanol or biodiesel) for a carbon intensity, (2) refinery investment program (e.g., steam methane reforming), (3) innovative crude (e.g., cogeneration at oilfield) or (4) direct air capture.[44] In order to use any of these avenues, CARB must first approve a specific fuel pathway—a description of the sources of fuels and related operations—that is assigned a "carbon intensity" based on overall greenhouse gas emissions associated with the pathway. The reductions of CO_2 emissions associated with the production of fuels achieved through CCUS should result in a lower carbon intensity of a particular fuel pathway. Credits are calculated based on the difference between the carbon intensity of conventional fuels compared to the alternative fuel pathway.

Refineries may be eligible to receive LCFS credits for greenhouse gas reductions using CCUS based on the fuel volumes sold, supplied, or offered for sale in California. Similarly, credits may be generated for crude oil that has been produced or transported using CCUS and delivered to California refineries for processing. Direct air capture and sequestration facilities located outside of California are eligible to generate LCFS credits using CCUS. CCUS projects employed in connection with refineries, crude oil projects and fuel production are eligible for credits based only upon volumes of fuel delivered in California.

It is important to note that there is an active market for LCFS credits. Since 2018, monthly average LCFS credit prices have traded between \$115 and \$210 per metric ton, and monthly traded volumes have ranged from 400,000 to 4.1 million.[45]

Economy-wide Cap-and-Trade

California's economy-wide cap-and-trade program, which is often referred to as Assembly Bill 32 or AB-32, covers approximately 80 to 85 percent of the state's GHG emissions.

AB-32 requires California to return to 1990 levels of greenhouse gas emissions by 2020. The state auctions emissions allowances, and, each year, fewer allowances are auctioned and the annual cap on GHG emissions declines.

[44] *See* https://www.arb.ca.gov/fuels/lcfs/background/basics.html, slide 30. If CO_2 derived from direct air capture is converted to fuels, the project would need to apply for a fuel pathway certification as opposed to obtaining credits for the project itself. *See* 17 CCR §95490(a)(2).

[45] https://ww3.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm

Emitting entities, such as fossil-fuel power generators in the state and those outside the state importing into California, are subject to the cap. They can acquire an allowance through the auction or through the secondary market either through bilateral trades or a broker.

California allowance prices historically have been near the "floor" price or reserve price. The most recent, auctioned allowance prices were near $17 per tonne.[46]

California's and Québec's Cap-and-Trade systems are linked, enabling the mutual acceptance of compliance instruments issued by each jurisdiction.

Operators of low carbon power resources, such as a power generation facility with CCUS, can mostly avoid allowance costs, which, in turn, provides a competitive advantage within the California electricity market.

Enhanced Oil Recovery Credit

California also allows an enhanced oil recovery credit similar to the federal enhanced oil recovery credit under Section 43. The California enhanced oil recovery credit is equal to 5 percent of the qualified enhanced oil recovery costs for qualified oil recovery projects located within California. The main differences between California's credit and the Section 43 credit are (i) the amount of the credit (5 percent for California compared to 15 percent for the Section 43 credit, subject to the phase-out), (ii) California does not allow the enhanced oil recovery credit to taxpayers that are retailers of oil or natural gas or that are refiners of crude oil whose daily refinery output exceed 50,000 barrels, and (iii) taxpayers may carry over the California credit for 15 years and Section 43 is subject to the carryback and carryforward rules of Section 38 (generally, a 1-year carryback and 20-year carryforward).

Illinois

No state tax incentives for carbon capture investments.

Non-Tax Incentives

In 2009, SB 1987 was signed into law.[47] SB 1987 requires 25 percent of electricity in Illinois come from coal plants that capture and sequester CO_2 emissions by 2025.[48]

SB 1592 authorized[49] the Illinois Finance Authority to issue bonds to help finance the development and construction of coal-fired power plants with carbon capture.[50] This law also authorized utilities to assess a charge on customers to be deposited in a Renewable Energy Resources Trust Fund and a Coal Technology Development Assistance Fund to support capturing emissions from coal-fired power plants and to support research on the capture and sequestration of carbon emissions from coal combustion.[51]

Kansas

Accelerated Depreciation

Kansas allows for accelerated depreciation on carbon dioxide capture, sequestration or

[46]https://ww2.arb.ca.gov/sites/default/files/classic//cc/capandtrade/auction/results_summary.pdf
[47]http://www.ilga.gov/legislation/95/SB/PDF/09500SB1987lv.pdf.
[48] 20 ILCS 3855/1-10(c).
[49] See 20 ILCS 3855.
[50] https://www.c2es.org/document/energy-financial-incentives-for-ccs/.
[51]http://www.ilga.gov/legislation/95/SB/PDF/09500SB1592lv.pdf.

utilization machinery and equipment. Taxpayers may elect to deduct from Kansas adjusted gross income an amount equal to 55 percent of the amortizable cost of such equipment in year 1, and 5 percent in years 2 through 10.[52] Specifically, after December 31, 2007, a taxpayer may deduct from adjusted gross income amortized costs of machinery and equipment for CO_2 capture, sequestration, or utilization over a 10-year recovery period.

Property Tax Exemption

Kansas provides a five-year exemption from all property taxes levied under the laws of the state of Kansas for carbon dioxide capture, sequestration or utilization property and any electric generation unit which captures and sequesters all carbon dioxide and other emissions.[53]

Kentucky

Kentucky offers multiple tax incentives for "companies that, in a carbon capture ready manner, construct, retrofit, or upgrade facilities" for various purposes related to increasing the production and sale of various fuels, including synthetic natural gas, chemicals, chemical feedstocks, or liquid fuels from coal, biomass resources, or waste coal through a gasification process.[54] The term "tax incentives" is used by Kentucky to describe the various incentives, which essentially operate as a tax credit to offset the amount of tax owed. The tax incentives include a sale and use tax exemption, a severance tax credit, and a credit on personal income taxes.

To qualify for these tax incentives, facilities must reach certain levels of capital investment. For alternative fuel facilities or gasification facilities using oil shale, tar sands, or coal as the primary feedstock, the minimum capital investment is $100,000,000.[55] For a carbon dioxide transmission pipeline, the minimum capital investment is $50,000,000.[56] The total amount of tax incentives that can be claimed with respect to a project is limited to 50 percent of the capital investment in the eligible project.[57] The developer will need to enter into a "tax incentive agreement" with the Kentucky Economic Development Finance Authority, the terms and conditions of the tax incentives agreement is negotiated and can include one or more of the categories of tax incentives described below.[58] The tax incentive agreement outlines the details of the eligible project, including the minimum capital investment required and the maximum capital investment that may be recovered, the time within which the minimum capital investment shall be made (i.e., the "activation date"). The activation date is the date on which an approved company begins incurring recoverable costs or engaging in recoverable activity pursuant to the tax incentive agreement, the duties, and responsibilities of

[52] Kan. Stat. Ann. §79-32,256.
[53] Kan. Stat. Ann. §79-233(a).
[54] KY. Rev. Stat. Ann. § 154.27-020.
[55] KY. Rev. Stat. Ann. § 154.27-020(4)(a).
[56] KY. Rev. Stat. Ann. § 154.27-020(4)(f).
[57] KY. Rev. Stat. Ann. § 154-27-020(6).
[58] KY. Rev. Stat. Ann. § 154.27-040.

the company, and the Kentucky Economic Development Finance Authority.[59]

Sales and Use Tax Exemption

Kentucky offers a sales and use tax exemption of up to 100 percent of the taxes paid on purchases of tangible personal property made to construct, retrofit, or upgrade an eligible project, subject to the cap equal to 50 percent of the capital investment in the eligible project.[60] This incentive is not available for tangible personal property purchased before the activation date and expires upon the earlier of (i) completion of the construction, retrofit, or upgrade of the project and (ii) five years from the activation date.[61]

Severance Tax Credit

Severance taxes paid on (i) coal that is used by an alternative fuel facility, energy-efficient alternative fuel facility, or a gasification facility, or (ii) natural gas or natural gas liquids that are used in certain alternative fuel facilities, can also be offset up to 80 percent as part of the tax incentive package negotiated.[62] Although it is not a direct requirement of the severance tax incentive, the incentives available are targeting facilities that construct, retrofit, and upgrade the facilities in a carbon capture-ready manner.[63] Coal is subject to a severance tax rate of 4.5 percent of the gross value of the coal severed and/or processed during the applicable reporting period, subject to a minimum of $0.50 per ton.[64] Natural gas is subject to a severance tax rate of 4.5 percent of the gross value of the natural gas severed or processed.[65] If the severance tax is offset by the tax incentive, it is possible for the severance tax rate for coal and natural gas to be reduced to 0.9 percent of the gross value, subject to the statutory minimum of $0.50 per ton for coal.

Credit on Corporate Income Taxes

Tax incentives can offset up to 100 percent of the Kentucky income tax and limited liability entity tax imposed on the income, gross profits, or gross receipts generated by the eligible project.[66]

Credit on Personal Income Taxes

Developers can impose a wage assessment of up to 4 percent of the gross wages paid to employees subject to the Kentucky income tax if (i) the job was created as a result of the eligible project, (ii) the employee is employed to work at the facility, and (iii) the employee is on the payroll of the approved company or an affiliate of the approved company.[67] Construction workers, employees of the developer directly employed in the construction, retrofit, or upgrade of the eligible facility, contract workers, and leased workers are not considered employees for this purpose.[68] The assessment is imposed on the wages paid to the employee and are collected by the developer.[69] The developer retains the

[59] KY. Rev. Stat. Ann. § 154.27-040; KY. Rev. Stat. Ann. § 154.27-010(1) (definition of “activation date”).
[60] KY. Rev. Stat. Ann. § 154.27-020(5)(b); KY. Rev. Stat. Ann. § 139.517.
[61] KY. Rev. Stat. Ann. § 154.27-070(4).
[62] KY. Rev. Stat. Ann. § 154.27-020(5)(c).
[63] KY. Rev. Stat. Ann. § 154.27-020(3).
[64] KY. Rev. Stat. Ann. § 143.020.
[65] KY. Rev. Stat. Ann. § 143A.020.
[66] KY. Rev. Stat. Ann. § 154.27-020(5)(d).
[67] KY. Rev. Stat. Ann. § 154.27-020(5)(e).
[68] KY. Rev. Stat. Ann. § 154.27-080(2)(a)(2).
[69] KY. Rev. Stat. Ann. § 154.27-080(2).

cash collected in the form of the assessment while the employees that are assessed are entitled to a credit against their Kentucky income tax equal to the assessment withheld from their wages.[70] The net effect to the employee's take-home wages is zero, while the employer is able to retain a portion of the cash that would otherwise be paid as wages.

Louisiana

Sales and Use Tax Exemption

Louisiana exempts anthropogenic carbon dioxide from sales and use tax if it is used in a tertiary recovery project that is approved by the Assistant Secretary of the Office of Conservation of the Department of Natural Resources.[71] Geologic sequestration is not a requirement to qualify for the reduced tax rate for such projects.

Severance Tax Reduction

Louisiana provides a 50 percent reduction on the severance tax imposed on production of crude oil from a qualified tertiary recovery project that uses anthropogenic carbon dioxide.[72]

Michigan

Severance Tax Reduction

Michigan provides a reduced severance tax rate on natural gas and oil produced from carbon dioxide secondary or enhanced recovery projects.[73] Geologic sequestration is not a requirement to qualify for the reduced tax rate for EOR projects.

Integrated Renewable Portfolio Standard

In 2008, the Clean, Renewable, and Efficient Energy Act (SB 213) established an integrated renewable portfolio standard ("RPS"), requiring energy providers to provide 10 percent of electricity through renewable energy generation, renewable energy credits, and energy efficiency by 2015. Up to 1 percent of this obligation may be met through the use of "advanced cleaner energy systems," including coal-fired electric generating facilities that capture and permanently sequester 85 percent of CO_2 emissions. In 2016, SB 438 raised the goal to 15 percent by 2021 from 10 percent in 2015.

Mississippi

Ad Valorem Tax Exemption

Mississippi provides a ten-year exemption from all ad valorem taxes, other than taxes imposed for school district purposes, for equipment used to transport carbon dioxide for use in an enhanced oil recovery project in Mississippi.[74] Equipment included in this exemption includes pipelines, dehydrators, compressors and other appurtenant equipment that is used to facilitate the transportation of carbon dioxide. Note that there is no sequestration requirement to qualify for the ad valorem tax exemption.

[70] KY. Rev. Stat. Ann. § 154.27-080(2)(b).
[71] La. Rev. Stat. Ann. § 47:301(10)(gg) & (18)(p).
[72] La. Rev. Stat. Ann § 47:633.4(B)(2).
[73] Mich. Comp. Laws Ann. § 205.303(4); Mich. Comp. Laws Ann. § 205.311a (Carbon dioxide secondary or enhanced recovery project, defined).
[74] Miss. Code Ann. § 27-31-102.

Severance Tax Reduction

Mississippi provides a reduced rate of severance tax for oil produced by an enhanced oil recovery method in which carbon dioxide is used, provided that the carbon dioxide is transported to the oil well site by pipeline.[75] Note that there is no sequestration requirement to qualify for the reduced severance tax rate.

Gross Income Tax Reduction

Mississippi imposes a reduced tax rate on public utilities for electricity, current, power, steam, coal, natural gas, liquefied petroleum gas, or other fuel that is sold to a producer of oil and gas for use (i) directly in enhanced oil recovery using carbon dioxide, and/or (ii) in connection with the permanent sequestration of carbon dioxide in a geological formation.[76]

Montana

Reduced Property Tax

Montana imposes a business equipment tax on business property on all personal property owned by sole proprietors, firms, associations, partnerships, businesses, corporations, or limited liability companies.[77] There are 17 classes of business property, each subject to its own "taxable percentage."[78] Class 15 property includes "carbon sequestration equipment,"[79] and generally, class 15 property is taxed at a rate of 3 percent of its market value. There is, however, a reduced rate of tax available for carbon sequestration equipment that has been certified by the Department of Revenue. The tax rate for carbon sequestration equipment that has been granted this abatement is equal to 1.5 percent of its "reduced market value."[80] The reduced market value is determined under a separate provision that provides a tax abatement for certain facilities, including coal gasification facilities for which carbon dioxide from the coal gasification process is sequestered[81] and carbon sequestration equipment.[82] In order to qualify for the abatement, the facility must have (i) commenced construction after June 1, 2007, and (ii) paid the standard prevailing rate of wages for heavy construction during construction of the facility.[83] Further, for coal gasification facilities that sequester carbon dioxide, the carbon dioxide produced from the gasification process must be sequestered at a rate that is "practically obtainable but may not be less than 65 percent of the OC_2 produced."[84]

Non-Tax Incentives

HB 25, enacted in 2007, prohibits the Montana Public Services Commission from approving applications for electric generation capacity fueled by coal constructed after January 1, 2007, unless at least 50 percent of CO_2 emissions are captured and sequestered.[85]

New Mexico

New Mexico imposes a gross receipts tax for the privilege of engaging in business in New Mexico[86] as well as compensating property and

[75] Miss. Code Ann. § 27-25-503.
[76] Miss. Code Ann. § 27-65-19(b)(ii).
[77] Mont. Code Ann. § 15-6-122.
[78] See Mont. Code Ann. §15-6-122 through §15-6-162.
[79] Mont. Code Ann. §15-6-158(1)(c).
[80] Mont. Code Ann. §15-6-158(4).
[81] Mont. Code Ann. §15-24-3111(3)(d).
[82] Mont. Code Ann. §15-24-3111(3)(l).
[83] Mont. Code Ann. §15-24-3111(4)(a).
[84] Mont. Code Ann. §15-24-3111(4)(d).
[85] http://www.ccsreg.org/bills.php?id=62.
[86] NMSA 1978 § 7-9-4.

services and withholding taxes with respect to employees. The gross receipts tax imposes a tax equal to 5.125 percent of gross receipts of any person engaging in business in New Mexico.[87] The compensating tax, an excise tax imposed on persons using property or services in New Mexico, is imposed at a rate of 5.125 percent on certain property used in New Mexico and 5 percent on certain services used in New Mexico.[88] Employers are required to withhold a portion of employee's wages for payment of income tax at various rates.[89]

Alternative Energy Product Manufacturers Tax Credit

The Alternative Energy Product Manufacturers Tax Credit Act was passed in New Mexico and provides tax incentives to offset the "modified combined reporting taxes."[90] Specifically, the tax incentives are for "alternative energy products," which includes components for integrated gasification combined cycle coal facilities and equipment related to the sequestration of carbon from integrated gasification combined cycle plants.[91] If the developer has been granted approval by the New Mexico Taxation and Revenue Department, the developer is eligible for a credit not to exceed 5 percent of the taxpayer's qualified expenditures.[92] The credit can be used to offset the developer's "modified combined reporting taxes," which includes the gross receipts, compensating and withholding taxes.[93] A qualified expenditure is an expenditure for the purchase of manufacturing equipment made after July 1, 2006, by a taxpayer approved by the department.[94] Manufacturing equipment is defined as an essential machine, mechanism or tool, or a component thereof, used directly and exclusively in a taxpayer's manufacturing operation and that is subject to depreciation pursuant to the Internal Revenue Code of 1986.[95]

The credit available pursuant to the Alternative Energy Product Manufacturers Tax Credit Act is tied to the number of additional employees the developer employs following the application for the credit. For the first $30 million of qualified expenditures claimed by the developer, the developer receives $500,000 of credit for each additional full-time employee employed by the developer one year prior to the date the developer applied for the credit.[96] For qualified expenditures exceeding $30 million, the developer receives $1,000,000 of credit for each additional full-time employee.[97] The developer must apply for the tax credit by submitting a form and must apply on or before the last day of the year following the end of the calendar year in which the qualified expenditure is made.[98]

[87] NMSA 1978 § 7-9-4.
[88] NMSA 1978 § 7-9-7.
[89] NMSA 1978 § 7-3-3.
[90] NMSA 1978 § 7-9J-2.
[91] NMSA 1978 § 7-9J-2(A).
[92] NMSA 1978 § 7-9J-4(A).
[93] NMSA 1978 § 7-9J-2(I).
[94] NMSA 1978 § 7-9J-2(K).
[95] NMSA 1978 § 7-9J-2(E).
[96] NMSA 1978 § 7-9J-5(A).
[97] NMSA 1978 § 7-9J-5(B).
[98] See *Application for Alternative Energy Product Manufacturers Tax* Credit, available at: http://realfile.tax.newmexico.gov/rpd-41330.pdf.

The credit can only be applied against the developer's modified combined tax liability.[99] The credit cannot be transferred to any other person, including affiliates.[100] The credit cannot be applied against any local option gross receipts taxes imposed by counties or municipalities.[101] Although the credit cannot be carried back to tax periods prior to the tax period in which the qualified expenditure was made, it can be carried forward up to five years.[102]

SB 994

In 2009, SB 994 directed the New Mexico Public Regulation Commission to adopt rules to allow public utilities a reasonable opportunity to recover costs related to clean energy projects, including coal-fired power generation with carbon-capture technology meeting certain emissions specifications.

North Dakota

Sales and Use Tax Exemption

North Dakota imposes a sales and use tax at a rate of 5 percent.[103] North Dakota provides an exemption from the sales and use taxes imposed for all gross receipts from sales of carbon dioxide used for enhanced recovery of oil or natural gas.[104] Further, gross receipts from sales of tangible personal property used to construct or expand a system used to compress, gather, collect, store, transport, or inject carbon dioxide for secure geologic storage or use in enhanced recovery of oil or natural gas in the state are exempt from sales and use tax.[105] To qualify, the tangible personal property must be incorporated into a new system and cannot be used to replace an existing system, unless that replacement creates an expansion of the system.[106] The owner of the system must receive a certificate from the tax commissioner that the system constructed or expanded qualifies for the exemption.[107] The developer can either receive the certification before the purchase or after the purchase; if the developer does not have the certificate until after making the purchase, the developer must pay the applicable tax and apply for a refund of the tax paid.[108]

Property Tax Exemption

Except for land, pipelines constructed and necessary associated equipment for the transportation or storage of carbon dioxide for use in enhanced recovery of oil or natural gas or secure geologic storage are exempt from property taxes during construction and for the first ten full taxable years following initial operation.[109]

Coal conversion facilities and any carbon dioxide capture system located at the coal conversion facility and any equipment directly used for secure geologic storage of carbon dioxide or enhanced recovery of oil or natural gas classified as personal property is exempt

[99] N.M. Admin. Code § 3.13.7.14.
[100] *Id.*
[101] N.M. Admin. Code § 3.13.7.12.
[102] N.M. Admin. Code § 3.13.7.12; N.M. Admin. Code § 3.13.7.13.
[103] N.D. Cent. Code § 57-39.2-02.1; N.D. Cent. Code § 57-40.2-02.1.
[104] N.D. Cent. Code § 57-39.2-04(49); N.D. Cent. Code § 57-40.2-04(24).
[105] N.D. Cent. Code § 57-39.2-04.14(1).
[106] *Id.*
[107] N.D. Cent. Code § 57-39.2-04.14(2).
[108] *Id.*
[109] N.D. Cent. Code §57-06-17.1.

from all ad valorem taxes except for taxes on the land on which the facility, capture system, or equipment is located.[110] The exemption does not apply to tangible personal property incorporated as a component part of a carbon dioxide pipeline, but this restriction does not affect eligibility of such a pipeline for the carbon dioxide pipeline exemption.[111] The taxes imposed on the personal property are in lieu of ad valorem taxes on the property.[112]

Gross Receipts Tax Reduction

A tax is imposed on operators of coal conversion facilities for the privilege of producing products at the coal conversion facilities.[113] The tax is equal to 2 percent of the gross receipts derived from the facility.[114] A carbon dioxide capture credit is available for coal conversion facilities that achieve a 20 percent capture of carbon dioxide emissions during a taxable period.[115] The owner of the facility is entitled to a 20 percent reduction of the privilege tax imposed during the applicable taxable period.[116] The facility is entitled to an additional reduction of 1 percent of the privilege tax imposed for every additional 2 percentage points of its capture of carbon dioxide emissions.[117] A maximum 50 percent reduction of the privilege tax imposed is allowed when 80 percent or more of carbon dioxide emissions are captured.[118] A coal conversion facility may receive the reduction in coal conversion tax under this section for ten years from the date of first capture of carbon dioxide emission or for ten years from the date the coal conversion facility is eligible to receive the credit.[119]

Non-Tax Incentives

North Dakota includes CO_2 pipelines as common carriers.[120] Common carriers in the state are granted the right of eminent domain.[121]

Oklahoma

Gross Production Tax Exemption

A tax is imposed on the production of oil and gas based on gross value.[122] The tax is equal to 7 percent of the gross value of the production of oil and gas.[123] An exemption from the gross production tax on oil and gas exists for the “incremental production” that results from the secondary recovery projects.[124] The exemption lasts from the date the project begins until “project payback” is received, or ten years, whichever is shorter.[125]

Oregon

Clean Fuels Program

The Oregon Clean Fuels program requires a reduction of the carbon intensity of Oregon’s transportation fuels by 10 percent by 2025, as compared to 2015 levels.[126] On March 10,

[110] N.D. Cent. Code § 57-60-06.
[111] *Id.*
[112] *Id.*
[113] N.D. Cent. Code § 57-60-02.
[114] N.D. Cent. Code § 57-60-02(1).
[115] *Id.*
[116] *Id.*
[117] *Id.*
[118] N.D. Cent. Code § 57-60-02(1).
[119] *Id.*
[120] N.D. Cent. Code. § 49-19-01.
[120] *Id.*
[122] Okla. Stat. 68 § 1001(B).
[123] *Id.*
[124] Okla. Stat. 68 § 1001(D)(2) & (3).
[125] Okla. Stat. 68 § 1001(D)(2) & (3).
[126] *See* OAR 340-253-0000.

2020, the Governor issued an executive order to require even deeper reductions – 20 percent by 2030 and 25 percent by 2035. Regulations will be developed to implement this order.[127]

The Oregon Clean Fuels Program requires producers of ethanol and biodiesel in Oregon as well as importers (with the exception of small importers) of gasoline, diesel, ethanol and biodiesel to meet required carbon intensity values each year. Carbon intensity is the measure of the GHGs from the lifecycle of a transportation fuel expressed in a measure of grams of carbon dioxide equivalent per megajoule of energy.[128] There are separate carbon intensity values for gasoline and gasoline substitutes and diesel and diesel substitutes. For example, the carbon intensity benchmark for gasoline in 2020 is 95.61 gCO_2e/MJ whereas the benchmark in 2020 for diesel is 96.27 gCO_2e/MJ.[129] The carbon intensity declines each year to meet the state's targeted goals of 88.25 gCO_2e/MJ for gasoline and 88.87 gCO_2e/MJ for diesel by 2025.[130]

Credits under the program are generated when the carbon intensity for a specific fuel is lower than the required carbon intensity for that given year. Deficits are generated when the carbon intensity for a specific fuel is higher than the required carbon intensity for that year. At the end of the year, regulated entities must show that any deficits have been balanced through the generation or acquisition of credits. The average price per credit in 2019 was about $148.[131]

Similar to California, Oregon regulations contemplate the use of CCUS when calculating a low-carbon fuel pathway.[132] As a result, if carbon capture and sequestration was part of an approved fuel pathway with a carbon intensity that was lower than the benchmark carbon intensity for a given year, credits could be generated. The Oregon Clean Fuels program (with CCS protocol) provides suppliers of low-carbon fuels with credits that can be sold to suppliers of higher-carbon fuels. However, as with the California program, no fuel pathways have been approved that include CCUS as part of the carbon intensity calculation, but such pathways are foreseeable.

Pennsylvania

Pennsylvania has no state tax incentives for carbon capture investments; however, it plans to join the Regional Greenhouse Gas Initiative ("RGGI") in 2021[133], which would help support CCUS economics in the state. RGGI is a power-sector cap-and-trade program for CO_2 among ten Mid-Atlantic and Northeastern states – Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont.[134] The

[127] https://drive.google.com/file/d/16islO3GTqxVihqhhIcjGYH4Mrw3zNNXw/view.
[128] *See* OAR 340-253-0040(21).
[129] *See* https://www.oregon.gov/deq/aq/programs/Pages/Clean-Fuels-Regulations.aspx.
[130] https://www.oregon.gov/deq/aq/programs/Pages/Clean-Fuels-Regulations.aspx.
[131] https://www.oregon.gov/deq/aq/programs/Pages/Clean-Fuels-Data.aspx.
[132] *See* OAR 340-253-0400(6)(b)(H).
[133] https://www.dep.pa.gov/Citizens/climate/Pages/RGGI.aspx
[134] https://www.rggi.org/

March 13, 2020 RGGI auction resulted in CO_2 allowance prices of $5.65 per ton.

Non-Tax Incentives

HB 1202, enacted in 2007, establishes standards for biodiesel content in diesel fuel. It allows the use of non-sulfur diesel fuel derived from coal as long as the fuel's carbon emissions are offset through geologic carbon sequestration or by participation in a carbon offset program.[135]

Texas

Texas provides certain tax incentives in connection with CCUS. Below are summaries of the legislation passed in Texas that provide incentives for CCUS. Broadly, Texas has authorized franchise tax credits, reduced state severance tax rates, sales and use tax exemptions, and gross receipts and other tax exemptions.

Definitions

In Texas, a "clean energy project" means a project to construct a coal-fueled, natural gas-fueled, or petroleum coke-fueled electric generating facility, including a facility in which the fuel is gasified before combustion.[136] These facilities must also:

i. have a capacity of at least 200 MW,
ii. satisfy the emissions profile for an "advanced clean energy project" (defined below),
iii. capture at least 70 percent of the carbon dioxide resulting from or associated with the generation of electricity by the facility,
iv. be capable of permanently sequestering in a geological formation the carbon dioxide captured, and
v. be capable of supplying the carbon dioxide captured for purposes of an enhanced oil recovery project.

For this purpose, to "sequester" is defined as injecting carbon dioxide into a geological formation in a manner and under conditions that create a reasonable expectation that at least 99 percent of the carbon dioxide injected will remain sequestered from the atmosphere for at least 1,000 years.[137]

An "advanced clean energy project" means a project that has applied for a permit with the Texas Commission on Environmental Quality between January 1, 2008, and January 1, 2020, and satisfies several other requirements.[138] The requirements include specific reductions to various greenhouse gases, including sulfur dioxide, nitrogen oxide, and carbon dioxide, as well as mercury. Of the emissions that must be reduced, only carbon dioxide that is captured must be sequestered. The definition allows advanced clean energy projects to be either new construction or in connection with the modification of an existing facility and can apply to all or a part of the emissions stream from the facility.

[135] http://www.ccsreg.org/bills.php?id=55; https://www.legis.state.pa.us/CFDOCS/Legis/PN/Public/btCheck.cfm?txtType=PDF&sessYr=2007&sessInd=0&billBody=H&billTyp=B&billNbr=1202&pn=4184.

[136] Texas Tax Code § 171.601.

[137] Texas Natural Resources Code § 120.001(4).

[138] Texas Health and Safety Code § 382.003(1-a).

Franchise Tax Credit

The top franchise tax rate in Texas is 0.75 percent of taxable margin, with a reduced rate for wholesalers and retailers of 0.375 percent.[139] The taxable margin is calculated by starting with income for U.S. federal income tax purposes, making certain adjustments to that income, and subtracting the "cost of goods sold." The cost of goods sold is related to the acquisition and production of certain tangible personal property and real property, with certain industry specific adjustments. A credit is provided for certain clean energy projects based on the amount of the capital investment. [140]

The franchise tax credit applies to clean energy projects, as defined above, with some additional restrictions. First, only newly constructed facilities are eligible for this credit.[141] Second, the credit can only be issued following completion of the project and the electric generating facility associated with the project is fully operational. Third, in addition to the requirement in the definition of the "clean energy project," the project must capture 70 percent of the carbon dioxide resulting from the generation of electricity and the franchise tax credit requires that 70 percent of the carbon dioxide is sequestered.[142] Fourth, the legislation caps the number of projects eligible for the credit at three projects.[143]

The total credit is the lesser of 10 percent of the total capital cost (excluding financing) and $100 million.[144] The total credit claimed by an entity cannot exceed the franchise tax due by the entity; however, the credit can be carried forward for up to 20 years and the franchise tax credit is also assignable to one or more taxable entities.[145]

Severance Tax Reductions

The baseline Texas severance tax on oil and gas is: (i) for the gas severance tax, 7.5 percent of market value of gas produced and saved,[146] (ii) for the oil severance tax, 4.6 percent of market value of oil produced,[147] and (iii) for the condensate tax, 4.6 percent of market value.[148]

Texas provides a 50 percent severance tax reduction for oil from enhanced oil recovery projects so that the oil produced from new or expanded enhanced recovery projects is subject to a 2.3 percent tax on the market value of the oil produced.[149] An "enhanced recovery project" is a project that uses any process for the displacement of oil from the earth other than primary recovery (i.e., the displacement of oil from the earth into the well by means of the natural pressure of the oil reservoir, including artificial lift).[150] Texas provides an additional 50 percent reduction in the severance tax rate for oil from enhanced oil recovery projects if the enhanced oil recovery project uses carbon dioxide (1) captured from an anthropogenic

[139] Texas Tax Code §171.002(a) & (b).
[140] Texas Tax Code § 171.602.
[141] Texas Tax Code §171.602(a).
[142] *Compare* Texas Tax Code § 171.602(b)(4) with Texas Natural Resources Code §120.001(2)(C).
[143] Texas Natural Resources Code §120.004(b).
[144] Texas Tax Code § 171.602(c).
[145] Texas Tax Code § 171.602(d).
[146] Texas Tax Code § 201.052(a).
[147] Texas Tax Code § 202.052(a).
[148] Texas Tax Code § 201.055(b).
[149] Texas Tax Code § 202.052(b).
[150] Texas Tax Code § 202.054(3).

source in the state; (2) that would otherwise be released into the atmosphere as industrial emissions; (3) measurable at the source of capture; and (4) sequestered in one or more geological formations in the state following the enhanced oil recovery process.[151] This means that the severance tax is reduced from 4.6 percent to 1.15 percent for enhanced recovery projects that satisfy these requirements.

Additional requirements to obtain the 1.15 percent rate include a certification from the Railroad Commission of Texas if the carbon dioxide is to be sequestered in an oil or natural gas reservoir, or the Texas Commission on Environmental Quality if carbon dioxide used in the project is to be sequestered in a geological formation other than an oil or natural gas reservoir (or both if both apply).[152] Whichever Texas agency is responsible, it must find that, based on substantial evidence, there is a reasonable expectation that the carbon dioxide is "sequestered" (as defined above) and that the project will include monitoring and verification measures for a period sufficient to demonstrate whether the sequestration program is performing as expected.[153]

Sales and Use Tax Exemption

Texas imposes 6.25 percent sales and use tax on all retail sales, leases, and rentals of most goods and services.[154] However, there is an exemption from sales and use tax for property used in connection with clean energy projects and advanced clean energy projects meeting certain requirements.[155]

The tangible personal property used in connection with CCUS projects is exempt from sales and use tax in Texas if (i) the components are installed to capture carbon dioxide from an anthropogenic emission source, transport or inject carbon dioxide from such a source, or prepare carbon dioxide from such a source for transportation or injection, and (ii) either the project satisfies the requirements for the additional 50 percent reduction in the severance tax rate for enhanced oil recovery projects described above[156] or the carbon dioxide is "sequestered" in Texas.[157]

Gross Receipts Tax Exemption and Other Tax Incentives

Texas has a gross receipts tax imposed on each utility company that makes sales to consumers. The tax rate depends on the population of the town or city in which the consumer lives, with the top rate being 1.997 percent for sales to an incorporated city or town having a population of 10,000 or more.[158] However, sales of electricity generated by an advanced clean energy project are exempt from the gross receipts tax.[159]

Texas property is also subject to various property taxes by municipalities.[160] However, the appraised value of property that is subject

[151] Texas Tax Code § 202.0545(a).
[152] Texas Tax Code § 202.0545(c).
[153] Texas Tax Code § 202.0545(d)(1) & (2).
[154] Texas Tax Code § 151.051.
[155] Texas Tax Code § 151.334.
[156] Texas Tax Code § 151.334(2)(A).
[157] *Compare* Texas Tax Code § 151.334(2)(B) with Texas Natural Resources Code § 120.001(4).
[158] Texas Tax Code § 182.022(b)(3).
[159] Texas Tax Code § 182.022(c).
[160] Texas Tax Code § 302.001.

to school district maintenance and operations ad valorem property taxes may be limited with respect to certain advanced clean energy property if an agreement is entered into between the governing body of a school district and a developer.[161]

Non-Tax Incentives

Under HB 1356 (1991) CO_2 pipelines can become common carriers if the owners agree to certain terms.[162] Generally, common carriers in Texas have a statutory right of eminent domain.[163]

Wyoming

Sales Tax Exemption

Wyoming imposes a sales and use tax at a rate of 4 percent.[164] Certain tangible personal property, including the sale of carbon dioxide and other gases used in tertiary production,[165] receive an exemption from the sales and use tax. Tertiary production means the use of a tertiary enhanced recovery process to recover crude oil from a petroleum reservoir by applying one or more tertiary enhanced recovery techniques that meet the certification requirements of the Wyoming Oil and Gas Conservation Commission or the federal government.[166]

Severance Tax Credit

Wyoming imposes a severance tax on crude oil, lease condensate, or natural gas at a combined rate of 6 percent of the value of the gross product extracted.[167] Carbon dioxide is subject to the Wyoming severance tax as a natural gas.[168] However, where crude oil is produced from injection of carbon dioxide, the severance tax paid on the carbon dioxide is credited against the severance tax imposed on the oil produced.[169]

Examples of Deal Structures

Similar to solar and wind tax equity deals in the market, a "partnership flip" structure could be utilized for CCUS financing. In a typical partnership flip, the tax equity investor is allocated 99 percent of the income, loss, and tax credits until it reaches a target return, typically measured using an internal rate of return. After the tax equity investor achieves its target return the allocations will "flip," so that the tax equity investor's share of income, loss, and tax credits decreases, typically to 5 percent, and the sponsor member will receive 95 percent of these items.

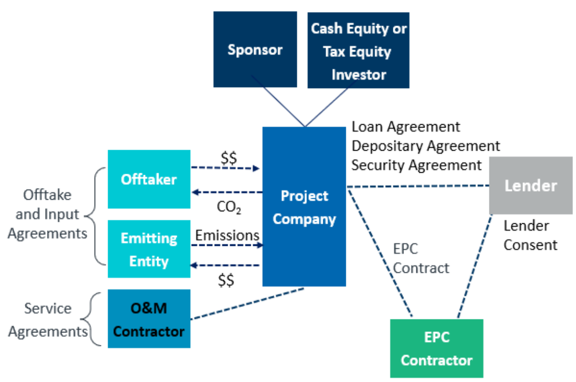
The goal of the partnership flip is to allocate tax benefits to the tax equity investor (who can use the tax benefits to reduce its tax liability) through its equity ownership interest in the Project Company.

Figure 2 shows a representative tax equity partnership flip structure. Under this structure, the Project Company enters into a long-term

[161] Texas Tax Code 313.021; 34 Tex. Admin. Code § 9.1051 (2020).
[162] http://www.ccsreg.org/bills.php?id=89.
[163] Tex. Nat. Res. Code Ann. § 111.019(a).
[164] Wyo. Stat. § 39-15-104(b); Wyo. Stat. § 39-16-104(b).
[165] Wyo. Stat. § 39-15-105(a)(viii)(F); Wyo. Stat. § 39-16-105(a)(viii)(A).
[166] Wyo. Stat. § 39-15-101(a)(xi); Wyo. Stat. § 39-16-101(a)(xi).
[167] Wyo. Stat. § 39-14-204.
[168] *Amoco Production Co. v. State of Wyo.*, State Board of Equalization (1988) 751 P2d 379.
[169] Wyo. Stat. § 39-14-205(d).

contract with the emitting entity, pursuant to which the Project Company will install the carbon capture equipment on or adjacent to the emitting entity's facility and will have rights to capture the CO_2 emissions. The Project Company enters into a long-term contract with an Offtaker, pursuant to which the Offtaker will purchase CO_2 from the Project Company and use it as a tertiary injectant in EOR or store it in secure geological storage.

Figure 2: Representative Tax Equity Partnership Flip Structure

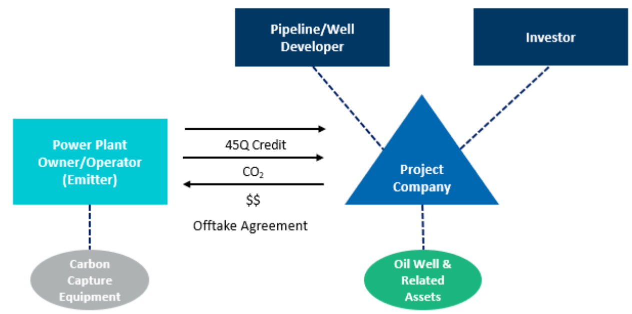


Source: IRS Rev. Proc. 2020-12, Section 5

A partnership flip structure could involve the assignment of 45Q Credit as shown in Figure 3. Under such an arrangement, the tax equity investor takes equity ownership in the Project Company. The Power Plant emits CO_2, captures it, and diverts the CO_2 to the Project Company. The Power Plant assigns credits to the Project Company under the election in Code Section 45Q(f)(3)(B). The Project Company will purchase CO_2 from the Power Plant and use it as a tertiary injectant in EOR and dispose of it in secure geological storage. While the IRS has provided guidance on partnership flips where the partnership owns the assets that capture the CO_2, further guidance will be needed to address the mechanics of a partnership flip that is assigned the 45Q Credit in connection with its disposal of, use or utilization of the CO_x.

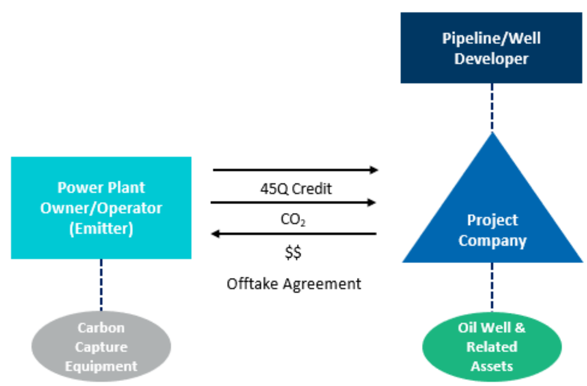
Alternatively, the 45Q Credit could be assigned to an Offtaker, e.g., the owner of an oil well and related assets who will use the CO_2 as a tertiary injectant and dispose of the CO_2 in secure geological storage, as shown in Figure 4.

Figure 3: Partnership Flip Structure – Assignment of 45Q to Project Company



Source: Orrick

Figure 4: Assignment of 45Q to Offtaker



Source: Orrick

Profiles of Sectors and Stakeholders

Financial Stakeholders

The most significant parties driving investments in the current renewables market are tax equity investors. These consist of large U.S. corporations and sometimes foreign corporations with a significant U.S. federal income tax base. In the wind and solar area, some of the prominent names have included some of the largest financial institutions, technology companies, insurance companies, and large regional banks. Many investors view entry into the renewables market as favorable from a branding perspective because of its association with green initiatives. Tax equity investors often seek after-tax returns between 6 and 10 percent for projects claiming the PTC or ITC, but given the uncertainties in the market, it is likely to be higher for 45Q Credit investments, at least for the early years in which structures are implemented. Participation in projects utilizing the PTCs or ITC is generally unavailable to retail investors who might otherwise be familiar with the master limited partnership structure that is commonly used in the fossil fuel sector.[170]

Investors with the ability to use the 45Q Credit will be similar to the tax equity investors that invest in wind and solar projects eligible for the PTC or ITC.[171] The 12-year period during which tax credits are available (as compared to the 10-year period for the PTC for wind projects) is likely to be attractive to these investors. Like the PTC, the 45Q Credit is adjusted for inflation but without the percentage reductions that have been characterized by the PTC.

Because tax equity investors typically invest in projects that are near completion or have already been completed, tax equity investors comparing wind projects eligible for PTCs with projects eligible for the 45Q Credit in a few years may find the 45Q Credit to be a competitive alternative. However, investors that are attracted to the renewables market because of the branding benefits associated with green initiatives may not find some carbon capture programs to be as attractive as others. For example, these investors may shy away from the 45Q Credit if it is generated in connection with enhanced oil recovery projects but may find direct air capture projects, CCUS in saline aquifers, or bioenergy CCUS projects much more appealing.

Finally, while the uncertainty of proven technology may limit investor appetite, the ability of investors to partner with developers that are well-capitalized and have proven track records may offset some of the technology risk.

Owners and Operators

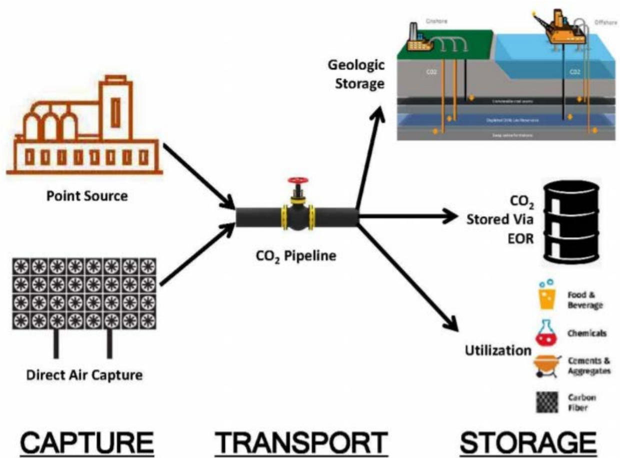
The CCUS value chain involves the capture of CO_2 from emitting sources, subsequent transportation, utilization, or injection to underground storage, as shown in Figure 5. The United States has become a global leader in the CCUS space, hosting 10 of the 21 large-scale CCUS projects operating worldwide, capturing 25 million tons per annum of CO_2, or 67 percent

[170] See Meeting the Dual Challenge, A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage, National Petroleum Council, Chapter 3, page 8 (December 12, 2019) (suggesting an expansion of the master limited partnership ("MLP") rules to allow 45Q Credit eligible projects to be owned by MLPs).

[171] https://fas.org/sgp/crs/misc/R43453.pdf.

of the global capacity.[172,173] Six of the U.S. projects were economically viable due to the combination of a low-cost CO_2 supply and a demand for CO_2 by EOR; the four remaining projects required policy support to be economically viable. Table 7 shows the total estimated capture costs (including capital costs, operating costs, and fuel costs) by facility type per the National Petroleum Council ("NPC") report.

Figure 5: CCUS Value Chain



Source: Carbon Utilization Research Council

CO_2 use is currently an outlet for only a small fraction of the captured CO_2 but may provide a meaningful option with further market and technology development. The operators and owners in these sectors are important stakeholders of the CCUS value chain. CO_2 could be utilized in the production of fuels, chemicals, carbon nanotubes, and building materials. Geological CO_2 utilization options have the greatest potential to advance CCUS by creating CO_2 market demand. While CO_2 has been safely used for EOR for more than 40 years in the United States, there is an increased focus on identifying options for re-use of CO_2 for other purposes. Section 45Q defines "utilization" to include virtually any beneficial use of the CO_x, including (i) the fixation of such qualified CO_x through photosynthesis or chemosynthesis, such as through the growing of algae or bacteria; (ii) the chemical conversion of such qualified carbon oxide to a material or chemical compound in which such qualified carbon oxide is securely stored; or (iii) the use of such qualified CO_x for any other purpose for which a commercial market exists (with the exception of use as a tertiary injectant in a qualified EOR project).[174]

[172] National Petroleum Council. A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage. https://dualchallenge.npc.org/files/NPC%20CCUS%20Chapter%202%20-%20Dec12.pdf.

[173] Global CCS Institute. https://www.globalccsinstitute.com/news-media/press-room/media-releases/carbon-capture-and-storage-pipeline-grows-by-10-large-scale-facilities-globally/.

[174] IRC §45Q(f)(5)(A).

Table 7: Total Estimated Capture Cost for Reference Plans by Facility Type

Facility Type	Reference Plant Size	CO_2 Volume Captured (tons/year)	Unit Total Cost Low-High ($/ton)
Natural Gas Processing	140 million cubic feet per day	24,000	23-35
Ethanol Production	150 million gallon per year	342,000	24-34
Ammonia Production	907,000 tons per year	389,000	21-30
Hydrogen Production	87 million cubic feet per day	340,000	61-88
Cement Plants	1 million tons per year	842,000	64-95
Refinery Fluidized Catalytic Cracking Plants	60,000 barrels per day	374,000	97-150
Steel/Iron Plant	2.54 million tons per year	3,324,000	75-113
Coal Power Plant	550-MW net	3,089,000	83-124
		1,999,000	113-178
		1,272,000	166-268
Industrial Furnaces	4 X 150 MMBtu/hour	220,000	110-171
Natural Gas Power Plant	560-MW net	1,279,000	93-140
		827,000	122-192
		527,000	179-290

Source: National Petroleum Council

CO_2 Used as a Tertiary Injectant in EOR

CO_2 EOR, which pumps CO_2 into the oil-bearing rock formation to recover more oil, is a proven method to sequester CO_2 and extend the productive life of oil fields. The CO_2 helps unlock crude oil from mature oil fields and residual oil zones. As a tertiary oil recovery, CO_2 EOR has the potential to recover an additional 15 to 20 percent of the original oil, almost as much production as the primary and secondary recovery. For CO_2 EOR projects, the recommended supply pipeline CO_2 concentration should be greater than 95 percent.

Fertilizer Industry

The fertilizer industry consumes CO_2 for urea manufacturing, and Nitrogen, Phosphorous and Potash are the building blocks of fertilizers. The United States is the world's fourth-largest producer of nitrogen fertilizers and the second-largest producer of phosphate. In fertilizer manufacturing, greenhouse gas emissions come from ammonia, phosphoric acid, and nitric acid production. High-purity CO_2 is a necessary ingredient in the production of urea fertilizer; therefore, the industry captures CO_2 emitted during ammonia production and re-uses it during the urea production process. According to a report by the Fertilizer Institute, based on 34 participating companies representing 91 percent of the total U.S. fertilizer production capacity, 29 percent of the greenhouse gas emissions in the fertilizer industry were captured in 2018.[175]

Cement Industry

The buildings sector could use CO_2 in the production of construction materials and some North American companies are developing and marketing CO_2 technology in cement curing and production. CO_2 can replace water in the manufacture of concrete in a process called CO_2 curing, or can be a feedstock in its constituents. These applications involve reacting CO_2 with calcium or magnesium minerals to form low-energy carbonate molecules, which is the form of carbon that makes up concrete. CO_2-cured concrete can have a smaller CO_2 footprint and a lower manufacturing cost than conventionally produced concrete. This concrete is a promising application of CO_2 use, while integrating CO_2 into the production of cement itself is at an early stage of development.

Food Industry

The food industry uses food-grade high-purity CO_2 in breweries, carbonated beverages, quick freezing of meats and vegetables, flash drying of food, and grain fumigation, etc. The Warrior Run Generating Station in Maryland uses the amine process to capture CO_2, which is then purified, compressed, and liquefied to produce food-grade CO_2. Warrior Run is discussed in further detail in the Case Study section of this report.

Other Commercial Applications

Other commercial applications include metal fabrication, cooling, fire suppression, dry ice, or agriculture greenhouses to stimulate plant growth.

Regulatory Agencies

These include the Treasury Department, the EPA, the Federal Energy Regulatory Commission (“FERC”), the DOE, and the Department of the Interior. Section 45Q(f)(2) provides that the Secretary of the Treasury, in consultation with the Secretary of Energy, the Administrator of the EPA, and the Secretary of the Interior, shall establish regulations for determining adequate security measures for the geological storage of qualified carbon oxide under Section 45Q(a) such that the qualified carbon oxide does not escape into the atmosphere.[176] Thus, each of these agencies

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[175] The Fertilizer Institute. TFI-SOI-2019-UPDATED-Sustainability-Performance-Indicators. https://www.fertilizerreport.org/wp-content/uploads/2020/02/TFI-SOI-2019-UPDATED-Sustainability-Performance-Indicators.pdf.

[176] IRS Notice 2009-83 states that taxpayers claiming the 45Q Credit must comply with certain Monitor, Report, and Verify (“MRV”) requirements promulgated by the EPA in connection with their reporting rules regarding both the emission and use of CO_2 in order to qualify for the 45Q Credit. The MRV procedures require the operator to submit an MRV plan to the EPA for its approval, and to annually report CO_2 volumes, including amounts sequestered, pursuant to the plan. The EPA promulgated final rules regarding the reporting of both CO_2 emissions and CO_2 use (including sequestration) for years after 2010. Subpart RR - Geologic Sequestration of Carbon Dioxide is applicable to the 45Q Credit. See http://www.epa.gov/ghgreporting/reporters/subpart/rr.html. The IRS position is that operators of facilities that are sequestering CO_2 in geologic storage must comply with Subpart RR regardless of whether the CO_2 is currently used as a tertiary injectant in an EOR project or disposed of in geological storage. The EPA’s preamble also states that taxpayers claiming the 45Q Credit after 2010 must follow Subpart RR’s “MRV procedures.” The Proposed Regulations modify the reporting requirements. Instead, they provide that where CO_x is disposed of in secure geologic storage that is not used as a tertiary injectant in an enhanced oil or natural gas recovery project, the operator must comply with Subpart RR, while, where CO_x is used as a tertiary injectant in an enhanced oil or natural gas recovery projects, the operator has the flexibility to choose between complying with Subpart RR or using the standard adopted by the International Organization for Standardization and endorsed by the American National Standards Institute, CSA/ANSI ISO 27916:19. In general, reporting under CSA/ANSI ISO 27916:19 uses mass balance accounting, has established reporting and documentation requirements, and includes requirements for documenting a monitoring program and a containment assurance plan. The containment assurance plan must be certified by a qualified third party. Prop. Reg. § 1.45Q-3(b) and (d).

will be involved in the development of guidance related to the carbon-capture rules, including the drafting of the Treasury Regulations that were proposed in June 2020, more than two years after Section 45Q was amended and this language was added.

Non-Regulatory Government Agencies

DOE Loan Guarantee and Funding Programs

Since 1997, the DOE has supported CCUS R&D, and since 2012 Congress has provided more than $4 billion in RD&D funding to the DOE for CCUS activities. The U.S. DOE Loan Programs Office has more than $40 billion in loans and loan guarantees available to help deploy large-scale energy infrastructure projects in the U.S. Of that amount, $8.5 billion in loan guarantees is available for advanced fossil energy projects, which could include commercial CCUS projects. Over the past decade, LPO has closed more than $30 billion of deals across the energy sector. While the DOE LPO focuses on debt financing for the deployment of commercial-scale projects, other offices within DOE offer funding and financing opportunities for RD&D and smaller projects, such as its Regional Carbon Sequestration Partnerships Initiative. Since 2019, the DOE has announced approximately $110 million in federal funding for cost-shared R&D projects.

U.S. Department of the Interior - U.S. Geological Survey

Authorized by the Energy Independence and Security Act of 2007, the USGS conducts national assessments of geologic storage resources and evaluates the national technically recoverable hydrocarbon resources resulting from CO_2 injection and storage. In 2019, USGS published a report titled "A Probabilistic Assessment Methodology for Carbon Dioxide Enhanced Oil Recovery and Associated Carbon Dioxide Retention,"[177] which provided a national assessment of recoverable oil, gas, and associated CO_2 storage for future CO_2 EOR operations.

USDA Rural Development and Loan Guarantee Programs

The USDA's RUS provides low-cost financing with a focus on hard asset lending to any element of the electric infrastructure serving rural customers, including generation, transmission, distribution, smart grid, energy efficiency, cyber and grid security, renewables, and CCUS. Its $60 billion loan portfolio includes $44 billion in electric, $13 billion in water, and $3 billion in telecom.

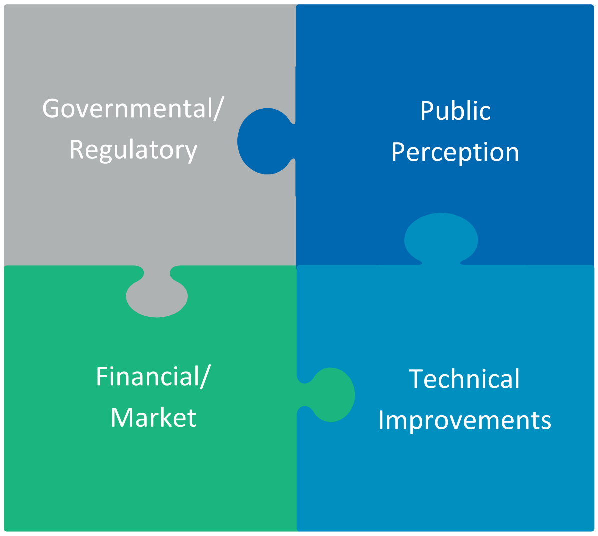
Roadblocks, Hurdles, and Solutions

The roadblocks and hurdles that CCUS faces can be grouped into four major categories – governmental/regulatory, technical, financial/market, and public perception. These four categories are inextricably interconnected as the graphic below illustrates. For example, reducing governmental/regulatory roadblocks and hurdles that lower permitting costs and timelines would improve the financial/market viability of projects. As more projects become financially viable and come online, the learning by doing will increase.

[177] The U.S. Geological Survey. https://pubs.usgs.gov/sir/2019/5115/sir20195115.pdf.

The result will be further cost reductions and an improved public perception of CCUS as a clean energy technology.

Figure 6: The Interconnected Nature of Major Roadblocks and Hurdles



The following sections discuss each of the roadblocks and hurdles in detail and suggest possible solutions that will expedite the market penetration of CCUS.

Governmental and Regulatory

Federal Roadblocks and Hurdles

The main federal roadblock and hurdle is in ensuring the successful implementation of the Section 45Q program. This program requires buy-in by all stakeholders, including investors. Although EOR has been occurring for decades, CCUS in general is still new to the investment market where investors seek to understand and mitigate technological and regulatory risks. Regulatory certainty from the IRS will be a key component in fostering stakeholder confidence and creating a vibrant private investment market for CCUS projects.

The Section 45Q program is still being shaped by IRS guidance, some of which only recently has been published. The need to define "secure geologic storage" in the IRS guidance was one of the most pressing issues. [178] The security of geologic storage is a key technical determination, and some view the technical integrity of the wells used to inject CO_2 remains as an open item.[179] However, this is a risk based on individual perception. A recent National Energy Technology Laboratory report documents two decades of safe geologic

[178] Commenters to the Section 45Q regulations varied in the suggested standard, including with respect to potential application of EPA 40 CFR Section 98 Subpart RR requirements, use of International Organization for Standardization ISO 27916 or the protocol developed under the California LCFS program.

[179] In addition to defining "secure geologic storage," it will be important to determine enforcement and monitoring procedures. A letter sent by U.S. Senator Menendez to IRS Commissioner Rettig on April 18, 2019 highlighted a lack of compliance with the EPA's Monitor, Report and Verify ("MRV") procedures for the tax credit available under Section 45Q prior to the Bipartisan Budget Act of 2018. The letter is available at: https://www.menendez.senate.gov/imo/media/doc/Menendez%2045Q%20Oversight%20Questions%204.18.19.pdf (last accessed May 6, 2020). A letter sent in response to IRS Notice 2019-32 provides a recommended approach for using the ISO 27916 Standard, in addition to Subpart RR, for demonstrating secure geological storage of carbon dioxide, available at: https://www.regulations.gov/document?D=IRS-2019-0026-0110.

storage through DOE's carbon storage R&D program.[180]

The EPA regulates underground wells pursuant to the Underground Injection Control Program.[181] This program has six classes of injection wells, two of which are used in connection with the EOR and sequestration industry.[182] A Class II well is used exclusively to inject fluids for oil and gas production, whereas a Class VI well is the only type of well authorized for the injection of CO_2 into geologic structures for long-term storage or sequestration.[183] One source of debate is whether the EPA requirements governing Class II wells will be adequate for geologic storage, or whether the more rigorous Class VI well requirements will be adopted by the IRS for purposes of the Section 45Q program.

An important reason to understand the requirements for geologic storage and well construction concerns the potential for failure of the containment. If the IRS rules were to require recapture of the tax credit for a failure of these systems, certain stakeholders will bear a significant, long-term technical risk that translates directly into financial losses. The Proposed Regulations generally allow recapture of the 45Q Credit claimed in a particular tax year during the five prior tax years, but the total amount of time during which recapture of 45Q Credit can occur is up to 17 years. Greatly mitigating the potential for a 12 year look back is that credits are recaptured on a last-in, first-out (or LIFO) basis.

While the Proposed Regulations provide a significant amount of guidance, it is likely that the IRS will need to provide additional guidance through the private letter ruling process.

Federal Solutions

As clearly articulated by the Global CCS Institute, "[t]o rapidly scale up the technology in a smooth and steady way, urgent action is required. Governments have a pivotal role to play, by providing a clear, stable and supportive policy framework for CCS."[184] Governments have many policy options from which to choose. For example, policies that disincentivize CO_2 emissions would benefit CCUS in the United States by making CO_2 capture and sequestration more cost-effective. For sources of CO_2 emissions that are a byproduct of industrial processes, like producing ethanol, additional compliance obligations or costs of operation would encourage producers to seek disposal solutions. In a more stringent regulatory environment, monetary incentives like the 45Q Credit or low-carbon fuel programs could help offset costs and create a positive business model.

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[180] "Safe Geologic Storage of Captured Carbon Dioxide: Two Decades of DOE's Carbon Storage R&D Program in Review," National Energy Technology Laboratory, April 13, 2020, available at https://www.netl.doe.gov/sites/default/files/Safe%20Geologic%20Storage%20of%20Captured%20Carbon%20Dioxide_April%2015%202020_FINAL.pdf.

[181] *See* 40 CFR Parts 144 through 148.

[182] *See* EPA description of these well types at https://www.epa.gov/uic/underground-injection-control-well-classes (last visited on April 13, 2020).

[183] *Id*.

[184] Global CCS Institute. GCC Global Status Report. https://www.globalccsinstitute.com/wp-content/uploads/2019/12/GCC_GLOBAL_STATUS_REPORT_2019.pdf.

Legislation can substantially affect the cost-effectiveness of CO_2 costs and solutions. At the federal level, there have been several pieces of legislation introduced in the 116th Congress as shown in Table 8.

Table 8: CCUS Legislation Introduced by the 116th Congress

Bill Number	Short Title	Status	Short Summary of Major Carbon Sequestration Provisions
H.R. 1166 (introduced February 13, 2019)	USE IT Act	Referred to House Subcommittees on the Environment; Environment and Climate Change; Highways and Transit, Energy and Mineral Resources; and Water, Oceans, and Wildlife	Would amend the Clean Air Act by directing the EPA to conduct certain carbon capture research activities. Would require the DOE to submit a report to Congress on the potential risks and benefits to project developers associated with increased storage of CO_2 in deep saline formations and recommendations for federal policy changes to mitigate identified risks. Would direct the Council on Environmental Quality (CEQ) to prepare a report and issue guidance on development of CO_2 pipelines and storage projects.
H.R. 3607 (introduced July 2, 2019)	Fossil Energy Research and Development Act of 2019	House Science, Space, and Technology Committee voted favorably for bill to be reported.	Would amend the Energy Policy Act of 2005 to direct the DOE to carry out a program of research, development, and demonstration for carbon capture and storage (CCS) and conduct large-scale carbon sequestration partnerships through the Regional Carbon Sequestration Partnerships.
H.R. 5883 (introduced February 12, 2020)	To Amend the Internal Revenue Code of 1986 to Provide for an Increased Credit for Carbon Oxide Sequestration for Direct Air Capture Facilities, and for Other Purposes.	Referred to the House Committee on Ways and Means	Would amend the Internal Revenue Code Section 45Q to increase the tax credit for direct air capture (DAC) facilities, remove the deadline for beginning construction of a qualified facility, and reduce the amount of carbon oxide required to be captured by qualifying DAC facilities.
S. 383[185] (introduced	USE IT Act	Written report from the Committee on	Would amend the Clean Air Act by directing the EPA to conduct certain carbon capture research activities. Would require DOE to submit a report to Congress on

[185] A version of S. 383 was incorporated into S. 1790, the National Defense Authorization Act for Fiscal Year 2020, which became law on December 20, 2019 (P.L. 116-92), and S. 2302, America's Transportation Infrastructure Act, which was reported in the Senate on January 8, 2020. Congressional Research Service, In Focus, Carbon Sequestration Legislation in the 116th Congress (updated February 21, 2020) (available at https://crsreports.congress.gov/product/pdf/IF/IF11345 last visited April 2, 2020).

Bill Number	Short Title	Status	Short Summary of Major Carbon Sequestration Provisions
February 7, 2019)		Environment and Public Health Works filed in Senate	the potential risks and benefits to project developers associated with increased storage of CO_2 in deep saline formations and recommendations for federal policy changes to mitigate identified risks. Would direct the CEQ to prepare a report and issue guidance on development of carbon dioxide pipelines and storage projects.
S. 407 (introduced February 7, 2019)	Carbon Capture Modernization Act	Referred to the Committee on Finance	This bill modifies sequestration and other requirements for the qualifying advanced coal project tax credit under Section 48A.
S. 1201 (introduced April 11, 2019)	EFFECT Act	Placed on Senate Legislative Calendar	Would amend the Energy Policy Act of 2005 (P.L. 109-58) to direct DOE to carry out CCS research and development programs. Would require DOE to submit a report to Congress on CCS activities. Would establish an optional program to transition large-scale carbon sequestration demonstration projects into integrated commercial storage complexes.
S. 1288 (introduced May 2, 2019)	Clean Energy for America Act	Referred to the Committee on Finance	This bill modifies, extends, or terminates several existing energy-related tax incentives to provide consolidated tax deductions and credits for the production of or investment in clean electricity, the production of clean transportation fuels, and energy-efficient homes and commercial buildings. The new tax incentives are technology-neutral, and the amounts of the credits or deductions vary based on the levels of carbon emissions (taking into account sequestration) for the incentives for electricity and fuels or energy efficiency in the case of the incentives for energy-efficient homes and commercial buildings.
S. 1763 (introduced June 10, 2019)	Carbon Capture Improvement Act of 2019	Referred to Committee on Finance	This bill authorizes the issuance of tax-exempt facility bonds for the financing of qualified carbon dioxide capture facilities.[186]
S. 2263 (introduced July 25, 2019)	CO_2 Regulatory Certainty Act	Referred to Committee on Finance	Would amend the Internal Revenue Code, Section 45Q, to revise the requirements for the secure geological storage of carbon oxide for the purpose of the tax

[186] In a letter dated April 30, 2020 from the Carbon Capture Coalition ("CCC") to leaders of Congress, CCC suggested certain provisions as part of a broader economic recovery package. Included in the suggested provisions was to adopt a bipartisan proposal amending Section 142(a) to make capital expenditures on industrial and power plant carbon capture and direct air capture technologies eligible for financing with private activity bonds, which would provide project developers access to long-term and fixed-rate tax-exempt debt. This would go further than the Carbon Capture Improvement Act of 2019 S. 1763, 116th Cong. (2019), which would not have included direct air capture technologies as eligible for financing with private activity bonds.

Bill Number	Short Title	Status	Short Summary of Major Carbon Sequestration Provisions
			credits for permanent sequestration and enhanced oil recovery. Would require the Treasury Department to establish regulations setting out these requirements, including compliance with federal environmental statutes and regulations.
S. 2284 (introduced July 25, 2019)	Climate Action Rebate Act of 2019	Referred to the Committee on Finance	This bill imposes a carbon fee on the use, sale, or transfer of certain fossil fuels and fluorinated gases that emit greenhouse gases into the atmosphere. The fee is imposed on producers and importers of such fuels and is deposited into a Climate Action Rebate Fund established by this bill.
S. 3032 (introduced December 12, 2019)	Renewable Energy Transferability Act	Referred to the Committee on Finance	This bill allows tax credits for renewable energy to be transferred to project partners. The bill applies to the tax credits for (1) renewable electricity production, (2) investments in renewable energy property, and (3) carbon oxide sequestration (i.e., the 45Q Credit). The bill includes payments to farmers and landowners to implement carbon sequestration projects but will not be allowed to receive such payments and a credit under Section 45Q.
H.R. 5156 (introduced November 19, 2019)	Carbon Capture and Sequestration Extension Act of 2019	Referred to the House Committee on Ways and Means	This bill extends for one year the 45Q Credit for carbon oxide sequestration.
H.R. 5883 (introduced February 12, 2020)	To amend the Internal Revenue Code of 1986 to provide for an increased credit for carbon oxide sequestration for direct air capture facilities, and for other purposes	Referred to the House Committee on Ways and Means	This bill provides for an increased carbon oxide sequestration tax credit for direct air capture facilities.
H.R. 2 (introduced June 22, 2020)	INVEST in America Act	Reported by the Committee on Transportation and Infrastructure	This bill extends the deadline for beginning construction on a qualified facility to qualify for the 45Q Credit by one year.

Source: Congressional Research Service, In Focus, Carbon Sequestration Legislation in the 116th Congress (updated February 21, 2020) (available at https://crsreports.congress.gov/product/pdf/IF/IF11345).

State Roadblocks and Hurdles

The approaches taken by the various states offering incentives for CCUS are varied. There are reasons different states take different approaches, such as the industries present in the state and the existing tax and regulatory structures. The variety of tax incentives can be seen in the section of this report that discusses the available state tax incentives.

State Solutions

There is value to be added by aggregating knowledge and providing uniformity between states' regulatory and tax incentives with respect to CCUS where possible. Certain for-profit organizations provide information about carbon capture and sequestration and have initiatives based on geographic region to facilitate coordination between states. Other initiatives include associations of governors, such as the Midwestern Governors Association's CCS Task Force.

Additionally, states can evaluate adapting existing policy programs, such as Renewable Portfolio Standards ("RPS"), or creating new policy programs to support CCUS. By including CCUS in an RPS, the program effectively would become a Clean Energy Standard ("CES"). Retail providers then could choose from not just renewable resources to meet their CES obligation but also from clean, fossil resources, such as gas or coal with CCUS. Other low-carbon or carbon free resources also could be included in a CES, making the program an "all-of-the-above" approach to achieving targeted GHG reductions.

Long-term Liability Roadblocks and Hurdles

Two of the most important questions that must be answered if CCUS is to become a large-scale commercially viable technology are:

- What will be the liability of CCUS operators for personal injury, property damage, trespass, and nuisance claims that could arise over the lifetime of a geologic storage project, which could be measured in centuries?
- What is the appropriate institutional framework for managing CCUS sites after closure?[187]

As noted by the NPC Report, under Class VI permitting for saline storage, the default requirement for monitoring is 50 years, or at the discretion of the EPA administrator, whereas under California's LCFS CCS Protocol, the default requirement is 100 years. These potential long-term liabilities and responsibilities can have a detrimental effect on project development. Thus far, there are no insurance products available to appropriately cover these long-term, low-risk scenarios.[188]

Long-term Liability Solutions

Proposals for addressing liability have generally included having governmental agencies assume some or all portion of the related liability.

The NPC recommended that the DOE convene an industry and stakeholder forum to develop a risk-based standard to address long-term liability. Options to be considered for resolving long-term liability should include:

- Applicability and limitations of private insurance
- Government assumption of liability for early mover project to incentivize and de-risk market creation
- Transfer of liability risk and oversight to the government when secure geologic storage is

[187] NPC Report, Chapter 3, pg.21.

[188] NPC Report, Chapter 3, pg.22.

demonstrated, likely with operators paying a fee into a stewardship or trust fund

- Layered responsibility approach for risk pooling among operators and government
- When evaluating damage claims, consider the societal benefit of CO_2 storage.

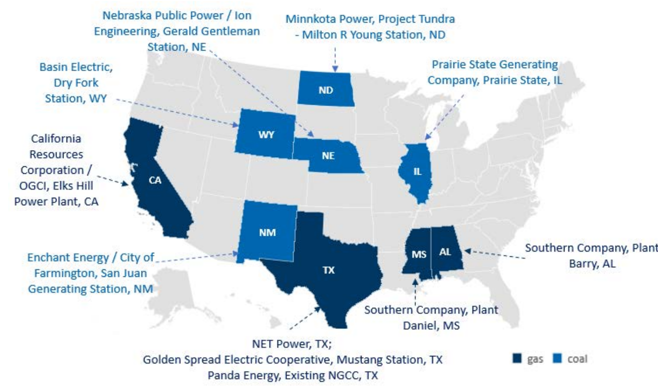
Market and Financial

According to the EPA, the U.S. power and industrial sectors generated 1.8 billion metric tons and 1.5 billion metric tons of CO_2 emissions, respectively, in 2018.[189] This presents an enormous technical market potential for CCUS in the U.S. Assuming an average CCUS project size of 500,000 metric tons, this would amount to more than 6,000 project opportunities for CCUS.

The addressable market, however, would be smaller when considering economics. The Great Plains Institute estimates there are more than 400 near- and medium-term capture opportunities using 45Q Credit in the U.S.[190] Currently, there are more than 30 CCUS projects under various phases of development.[191] Power plant retrofits and new builds represent almost half of the proposed projects, and biofuels represent about 25 percent of the proposed projects.[192] Figure 7 provides a map of the proposed CCUS power projects.

It should be noted that a variable for the power industry is whether the costs of a project, including the addition of carbon capture equipment, will be recoverable through the ratemaking process.[193]

Figure 7: U.S. CCUS Power Projects Under Development



Source: FTI Consulting based on Clean Air Task Force's CCUS Project Tracker.[194]

The projects shown in the figure above have yet to be developed for several reasons. For one, until very recently, the IRS had not provided guidance on quite a few issues. Another likely reason is that CCUS costs are still perceived to be too high.

In the coal power sector, CCUS costs are projected to continue declining through 'learning by doing' and technology advancements. As shown in Figure 8, the capture costs of $65 per metric ton for the

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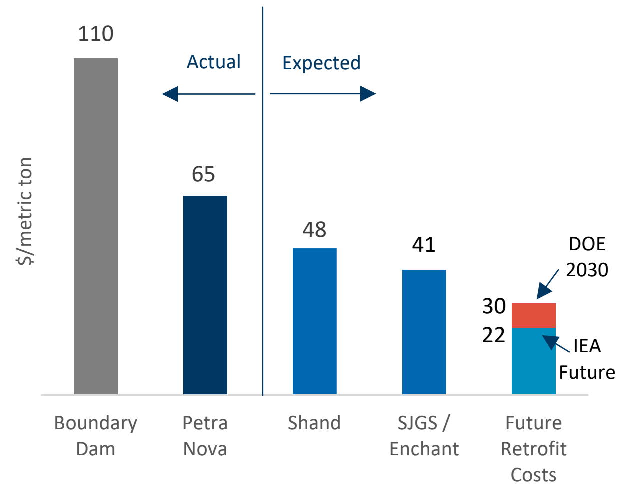
[189] EPA. https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks.
[190] Abramson, Elizabeth, McFarlane, Dane, and Brown Jeff, "Transport Infrastructure for Carbon Capture and Storage: Whitepaper on Regional Infrastructure for Midcentury Decarbonization," Great Plains Institute, June 2020.
[191] Clean Air Task Force's CCUS Project Tracker. https://www.catf.us/2020/04/the-status-of-carbon-capture-projects-in-the-u-s-and-what-they-need-to-break-ground/.
[192] Id.
[193] See "Utility Shelves Ambitious Plan to Limit Carbon," New York Times (July 13, 2011)
[194] Clean Air Task Force's CCUS Project Tracker. https://www.catf.us/2020/04/the-status-of-carbon-capture-projects-in-the-u-s-and-what-they-need-to-break-ground/.

recently completed Petra Nova retrofit project were almost half the cost of the $110 per metric ton for the older Boundary Dam CCS retrofit project.[195] The expected carbon capture costs for the Shand retrofit project and San Juan Generating Station ("SJGS") / Enchant retrofit are even lower at $45[196] and $41[197] per metric ton, respectively, which are close to the U.S. Department of Energy ("DOE") estimate of $45 per metric ton for 2020[198] and the IEA Clean Coal Centre's estimate of $43 to $45 per metric ton for a CCUS retrofit on a coal-fired plant.[199] The DOE anticipates retrofit costs to decline to $30 per metric ton by 2030,[200] and IEA estimates future retrofit costs through 'learning by doing' to reach $22 per metric ton.[201]

Figure 8: Coal-fired Generation Capture-only Costs[202]



Source: FTI Consulting Analysis

In Figure 9 below, we compare the LCOE of existing coal retrofitted with CCUS relative to new wind and solar projects with an online date of 2026. CCUS projects that begin construction by January 1, 2024, will still receive the 45Q Credit. The LCOE values have been reduced to reflect each technologies' firm capacity credit value, which is the reserve margin value that a project provides to the market during peak load conditions. By including capacity credit values, the LCOE comparison becomes fairer.[203]

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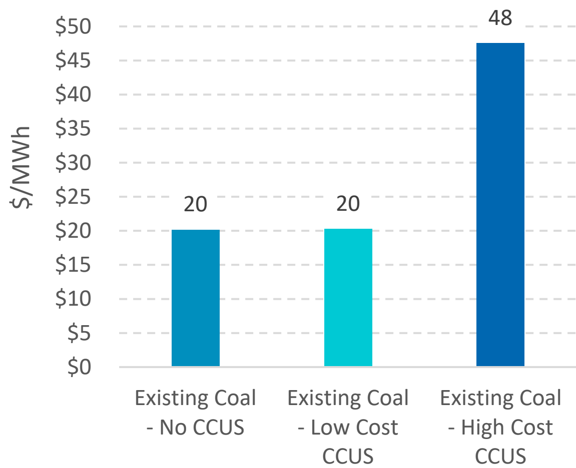
[195] "Carbon Capture and Storage Commercialization & Deployment," Hardy, Beth, International CCS Knowledge Centre, presented at the USEA CCUS Roadshow Series, January 28, 2020, slide 6.
[196] *Id.*
[197] "The Economic Case for Power Plant Carbon Capture Retrofits: A Case Study for the San Juan Generating Station – New Mexico," Selch, Jason, October 2019, slide 2.
[198] Testimony of Jeffrey Bobeck before the U.S. House Subcommittee on Energy, Wednesday, June 19, 2019.
[199] "Carbon Capture Utilisation and Storage (CCUS)-Status, Barriers and Potential," Kelsall, Greg, IEA Clean Coal Centre, April 15, 2020, slide 28.
[200] Testimony of Jeffrey Bobeck before the U.S. House Subcommittee on Energy, Wednesday, June 19, 2019.
[201] *Id.*
[202] NPC Report, Beth Hardy, FTI Analysis, Bobeck, IEA (Kelsall).
[203] Assumed 12.5% firm capacity for wind, 50% for solar, and 100% for existing coal.

After applying the Section 45Q Credit level of $50 per metric ton, the LCOE of coal retrofitted with CCUS would be $20 per MWh, or the same as coal without CCUS under the low-cost CCUS scenario of $42 per metric ton for capture. However, if capture costs are closer to the high-cost CCUS scenario of $66 per metric ton, the LCOE of existing coal retrofitted with CCUS would be $48 per MWh.

Figure 9: LCOE Comparison for 2026 Online Date – Includes Capacity Credit Value[204]



Source: FTI Consulting Analysis

The illustration of LCOE ranges in the figure above demonstrates the need for better CCUS cost certainty to solidify investor confidence. Because the cost of capture can vary by plant type and configuration and the cost of transport and storage can vary depending on availability, access, and government regulations, much still needs to be done to narrow the range of costs for CCUS.

Regardless, the 45Q Credit can enable baseload power to remain online to supply dependable electricity and balance the intermittent generation of wind and solar.

Some regions with high renewable penetration and limited baseload capacity, such as California and ERCOT, have had volatile market prices and strained grids. California's "Duck Curve" highlights the challenges of depending on intermittent renewables without adequate baseload capacity.

In ERCOT, 2019 summer prices reached the operating reserve demand curve cap due to tight reserve margins and high temperature events. It should be noted that the formerly retired, coal-fired Gibbons Creek Generating Station near Bryan, TX will be restarted in 2021 to help with tight reserve margins in ERCOT.[205]

Solutions

The market potential for CCUS projects depends on the financial community's willingness to commit to CCUS projects. Increasing regulatory certainty along with lowering and narrowing the range of CCUS costs are critical to this. As noted above, prior to the issuance of the Proposed Regulations, a number of questions related to the 45Q Credit required guidance. While some questions remain, the Proposed Regulations have addressed most of them.

- The main issues for consideration are as follows:

[204] *See* Appendix A for assumptions used to create this chart.

[205] https://www.power-eng.com/2020/05/14/idled-texas-coal-fired-plant-may-restart-as-regulators-anticipate-record-peaks-in-2020-and-2021-summers/#gref

- Whether the credit can be applied to facilities that were constructed prior to February 9, 2018, and that produce CO_x as a byproduct of existing processes?
- What quantification methodology should be used for Class II wells?[206]
- What is the time frame during which 45Q Credit are at risk of recapture?
- What is the mechanism for transferring the 45Q Credit?
- How to analyze lifecycle GHG emissions where CO_x is utilized?
- What are the "commercial markets" in which CO_x may be used?

■ The Proposed Regulations address most of these points.

- An 80/20 Rule was added that allows facilities placed in service prior to February 9, 2018, to qualify as placed in service after that date if certain requirements described above are met.[207]
- The Proposed Regulations permit two quantification methodologies for Class II wells. Operators of Class II wells can either follow the "Subpart RR" rules or the CSA/ANSI ISO 27916:19 ("ISO Standard").[208]
- Under the Proposed Regulations, 45Q Credits earned in a year are netted against any leakage of CO_x and, if leakage exceeds the amount of CO_x sequestered, there is a five-year "lookback period," meaning the 45Q Credit claimed by the taxpayer in the five prior tax years can be recaptured.[209] The Proposed Regulations also have a "post-credit-claiming period" that is the period of time after the taxpayer stops claiming the 45Q Credit that the 45Q Credit can still be recaptured. The post-credit-claiming period ends on the earlier of (i) five years after the last taxable year in which the taxpayer claimed a 45Q Credit, or (ii) the date monitoring ends under the requirements of Subpart RR or the ISO Standard, as applicable.[210] However, subject to the 5-year lookback period, recapture can occur with respect to CO_x that was stored during the entire 12-year credit period. As noted earlier, greatly mitigating the potential for a 12-year lookback is that credits are recaptured on a last-in, first-out (or LIFO) basis.
- The Proposed Regulations provide flexibility in transferring the 45Q Credit to offtakers, allowing some or all of the 45Q Credit to be transferred and allowing transfers to multiple offtakers.[211]
- The Proposed Regulations provide guidance regarding: (i) standards for the lifecycle analysis ("LCA") of emissions that were captured or displaced for purposes of Section 45Q(f)(5)(B); and (ii) the agency with responsibility to review the LCA. The Treasury Department and the IRS will continue to study these issues and have requested comments on how to achieve consistency in boundaries and baselines

[206] As noted above, the comments varied in the standard, including with respect to potential application of EPA 40 CFR Section 98 Subpart RR requirements, use of International Organization for Standardization ISO 27916, or the protocol developed under the California LCFS program.

[207] Prop. Reg. § 1.45Q-3(g)(5).

[208] Prop. Reg. § 1.45Q-3(b)(2).

[209] Prop. Reg. § 1.45Q-5(g)(2).

[210] Prop. Reg. § 1.45Q-5(d).

[211] Prop. Reg. § 1.45Q-1(h)(3).

so that similarly situated taxpayers will be treated consistently. The IRS will grant guidance on specific factual settings.

- The Proposed Regulations do not address the question of what commercial markets for which carbon oxide may be utilized qualify for the 45Q Credit.

The market potential for CCUS projects depends on the financial community's willingness to commit to CCUS projects. Decreasing regulatory uncertainty along with lowering and narrowing the range of CCUS costs are critical to this. The following solutions will be essential to this effort:

- Building out of the CO_2 pipeline system – regulatory, policy, and financial certainty is essential to securing the private investment to deploy CCUS infrastructure. There are approximately 5,000 miles of CO_2 pipelines in the United States.[212] The CO_2 pipelines are predominately concentrated in certain regions, including the Permian Basin, Gulf Coast, Rocky Mountains, and the Mid-Continent. Additional pipelines will be needed to transport captured CO_2 on the scales needed for economical geologic sequestration.

  Legislation that would further enhance CCUS market penetration including:

  - Clarifying the CCUS pipeline permitting review process and extension of the 45Q Credit as proposed in the USE IT Act[213]
  - Expediting CO_2 pipeline permitting
- Providing loan guarantees.
- Cost-sharing of FEED studies.

On a related point, Senate Bill 1763 (the "Carbon Capture Bill") would allow private activity bonds ("PABs") to be used to finance carbon sequestration projects, creating a new source of financing for CCUS projects. PABs are a type of tax-exempt debt instrument that may be issued by state and local governments, the proceeds from which are then lent to the owner of a privately-owned project. PABs must be used for projects that fall within one of the legislatively authorized categories of projects. Although not essential to the adoption by the financial community, the subsidized loans would provide an additional incentive for these investors in the form of tax-exempt interest.

Four of the ten large-scale projects in the United States required significant policy support to be economically viable. In 2009, the American Recovery and Reinvestment Act[214] provided the U.S. DOE $3.4 billion for CCUS projects and activities. The large and rapid influx of funding for industrial-scale CCUS projects was intended to accelerate development and demonstration of CCUS in the United States. Three projects currently in operation, the latter two of which are described later in this report, the Air Products Steam Methane Reformer CO_2 capture project, the ADM Illinois Industrial CCS project, and the Petra Nova CO_2 capture project, all greatly benefited from this funding. A fourth project, the Great Plains Synfuels project, was initially

[212] Oil and Gas, Natural Resources, and Energy Journal, Volume 3, Number 4, Siting Carbon Dioxide Pipeline.

[213] https://www.epw.senate.gov/public/index.cfm/2019/2/senators-reintroduce-use-it-act-to-promote-carbon-capture-research-and-development.

[214] Recovery Act; P.L. 111-5.

constructed from 1981 to 1984 with major financial support from the U.S. government to encourage the development of alternative fuel sources. In 2000, following the construction of an international CO_2 pipeline and entry into a supply agreement, the facility began delivering CO_2 to two oil fields in Canada.[215]

Financial Accounting Treatment Roadblocks and Hurdles

Investors in renewable energy deals must use the Hypothetical Liquidation Book Value ("HLBV") method to present the results of their investment on their financial statements. Under this approach, the expected amount each partner would receive is calculated at the end of the year as if the partnership was liquidated. The method determines how better or worse off the partners are at the end of the period than they were at the beginning of the period in a tax equity structure following the hypothetical liquidation of a project at book value. The HLBV concept comes from guidance proposed by the Accounting Standards Executive Committee of the American Institute of Certified Public Accountants in its Statement of Position Accounting for Investors' Interests in Unconsolidated Real Estate Investments, released November 21, 2000. Although the guidance was never finalized, the HLBV approach is widely accepted and used in the renewable energy industry to allocate equity method investment results to investors. Concerns with the HLBV methods are twofold: (1) the results are not linear from year to year, and (2) the results are reported in pre-tax earnings. Instead, the tax benefit is included in the effective tax rate calculation. Investors view this as distortive.

It should be noted that investments that generate an investment tax credit, including solar investments and the historic tax credit, may use the deferral method of accounting. This method can help mitigate the pre-tax earnings volatility by alleviating the need to write down the investment through pre-tax earnings. Under this method, the tax credit directly offsets the investment mitigating the need to write down the investment through pre-tax earnings. There is some debate regarding the appropriate application of the equity method accounting, including the HLBV method to investments that otherwise qualify for the deferral method of accounting, which may reintroduce pretax earnings volatility to these investments that utilize the investment tax credit.

Many investors would prefer to use the Proportional Amortization Method, adopted in 2014 and available for the low income housing tax credit programs, under which both income and tax credits are reported as financial statement lines.[216] Under the Proportional Amortization Method of accounting, the cost of the investment is amortized pro rata and in the same period as the recognition of either the tax credits and other benefits or only the tax credits allocated to the investor. The tax credits are recognized in the income statement as a component of income taxes attributable to the

[215] NPC CCUS Study December 12, 2019, Chapter 2 - CCUS Supply Chains and Economics 18.

[216] ASB 2014-1.

amortization of the cost of the investment. Thus, in general, there are no pre-tax losses recognized in the financial statements. However, projects utilizing the historic rehabilitation credit, the new markets tax credit, the investment tax credit (solar energy) and the production tax credits are not eligible for the Proportional Amortization Method under current guidance.

Financial Accounting Treatment Solutions

The Financial Accounting Standards Board should be urged to consider wider application of the Proportional Amortization Method so that carbon-capture credit investments qualify for this method of financial statement presentation.[217]

Technical Improvements

Situation and Context

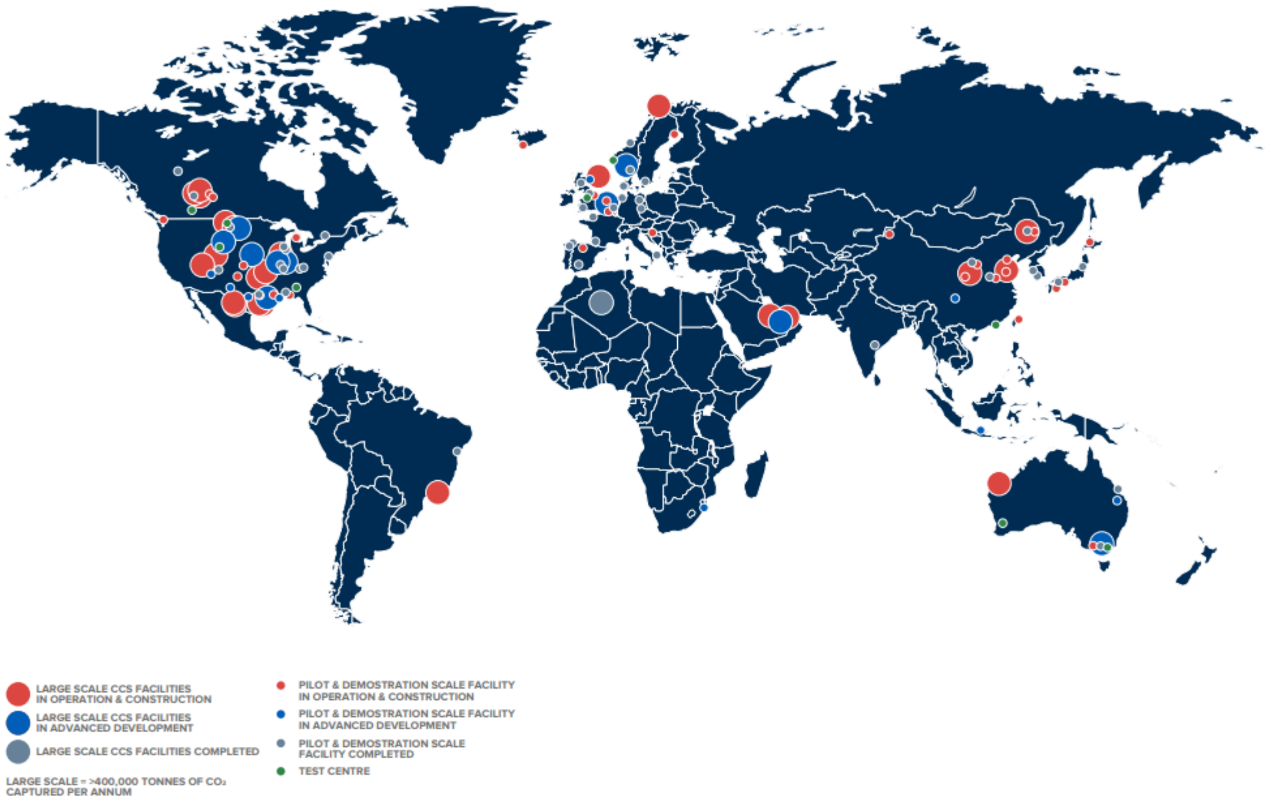
While CCUS has not been deployed on the commercial scale of other clean energy technologies like wind, solar, hydroelectric, and nuclear, the components of CCUS are composed of proven and well-understood technologies:

- Carbon capture has been used commercially to purify natural gas, hydrogen, and other gas streams in industrial settings since the 1930s.[218]
- Utilization and storage of CO_2 have been demonstrated for almost 50 years as CO_2 underground injection and storage was first demonstrated at commercial-scale operations in 1972.[219]

These technologies have been used across the world in sectors such as coal-fired generation, natural gas processing, hydrogen and fertilizer production, bioethanol fermentation, liquid natural gas, and steel. According to the Global CCS Institute, the global capture and storage capacity of projects currently operating or under construction "stands at around 40 million tons per annum."[220] Figure 10 below shows CCUS projects currently operating or under construction.

[217] *See* "Accounting Restrictions Could Hurt Update of Carbon Credit" (Law360, June 22, 2020).
[218] Global Status of CCS 2019: Targeting Climate Change, Global CCS Institute, November 2019, pg. 12.
[219] Global Status of CCS 2019: Targeting Climate Change, Global CCS Institute, November 2019, pg. 12.
[220] *Id.*

Figure 10: Current CCUS Facilities Around the World



Source: Global CCS Institute

Roadblocks and Hurdles

For CCUS to become commercially deployable at large scale, CCUS costs will need to drop below $50 per metric ton of CO_2 to be economically viable with the 45Q Credit. As such, there is a need to improve performance and reduce costs across the CCUS value chain. Improvement opportunities can be grouped into two main categories:

- Learning by doing
- New technologies

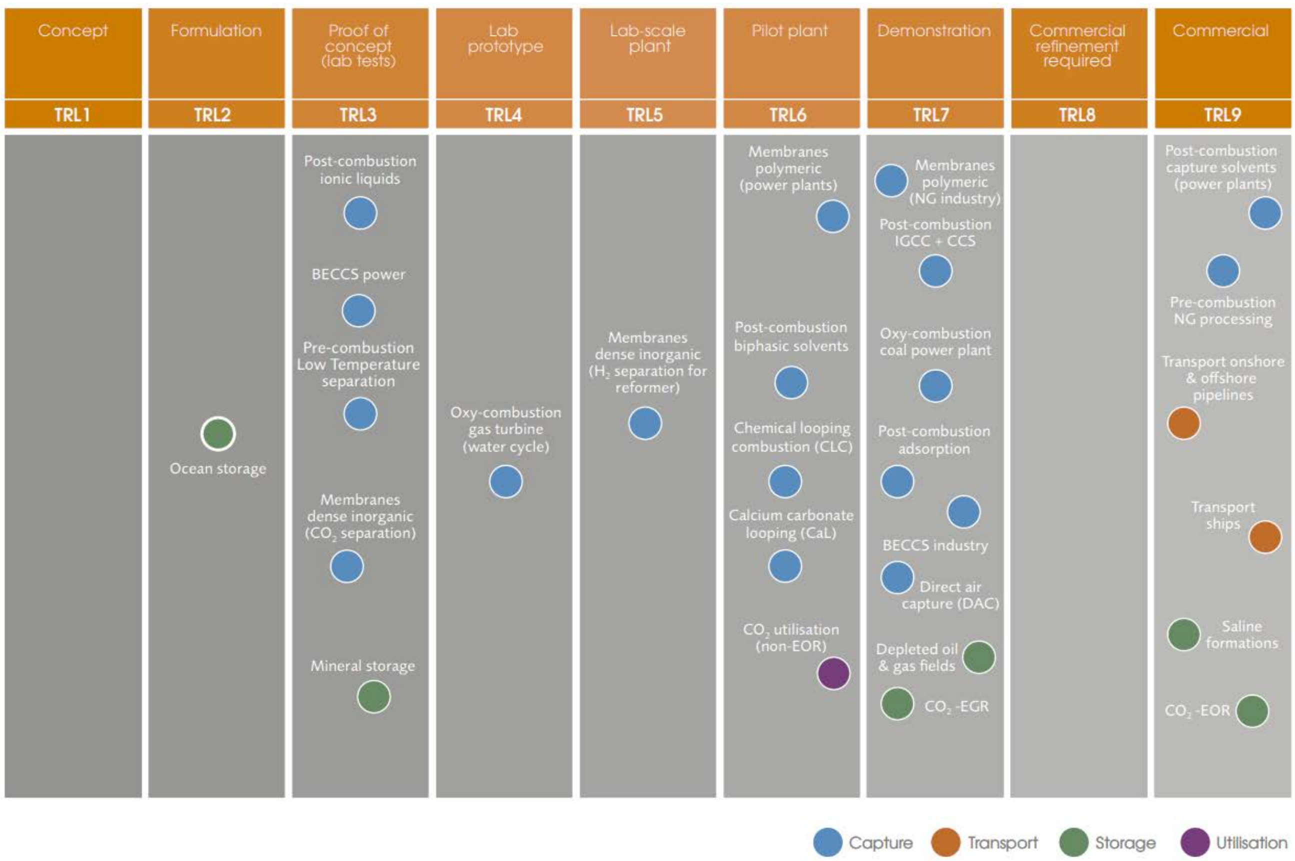
'Learning by doing' is defined as reducing costs and improving efficiency using existing technologies by simply deploying more projects and implementing lessons learned. SaskPower reported in 2015 that, based on project learning from Boundary Dam, they could cut costs by up to 30 percent on new CCS power projects.[221] Also, in 2018 NRG Energy showed that, based on their learnings, their next CO_2 capture retrofit will be at least 20 percent

[221] International CCS Knowledge Centre (2018a), The Shand CCS Feasibility Study Public Report, accessed from https://ccsknowledge.com/pub/documents/publications/Shand%20CCS%20Feasibility%20Study%20Public%20_Full%20Report_NOV2018.pdf.

cheaper, reaching a levelized capture cost of \$47 per metric ton of CO_2.[222]

New technologies will enable further cost reductions and performance improvements. An IChemE Energy Centre report assessed the status of CCUS technologies from concept to fully commercially developed. They bucketed these technologies into nine "technology readiness levels" ("TRL") that qualitatively rank the maturity of technologies through the different stages of the research and development process. The report found that, "[o]f the different CCS technologies at varying stages of development most are at the pilot plant stage (TRL 6) or above"[223] as shown in the figure below.

Figure 11: IChemE Energy Centre Ranking of CCUS Technologies from Concept to Commercial



Source: IChemE Energy Centre

With continued research and development, the portfolio of CCUS technologies will increase, potentially yielding a wider range of applications and low-carbon products as shown in the National Petroleum Council's "Meeting the Dual Challenge" report on CCUS. Continued funding on research, development and demonstration efforts are critical in

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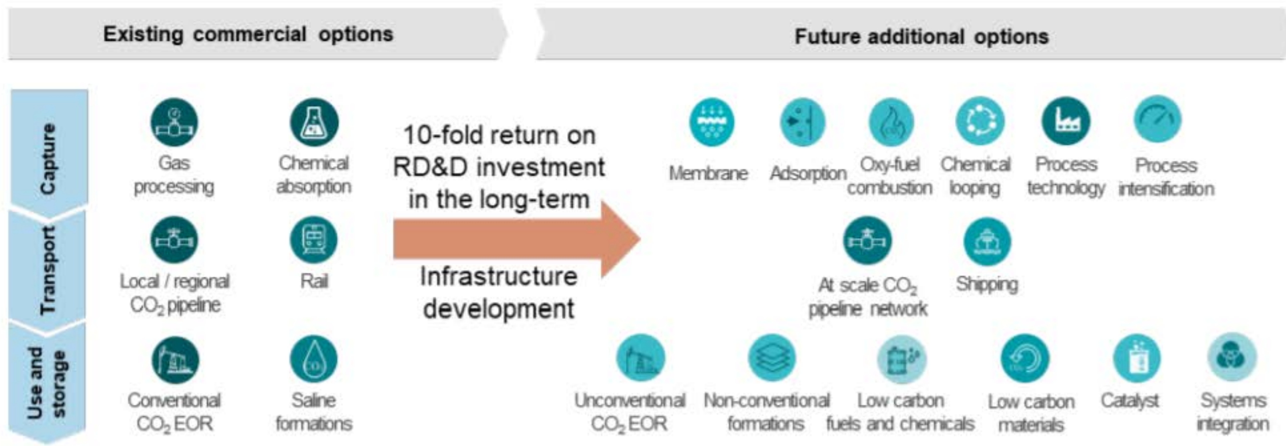
[222] NRDC (2018), NRDC Comments on EPA's NSPS Review Proposal, accessed from https://www.nrdc.org/sites/default/files/nrdc-comments-epa-nsps-review-proposal-20190318.pdf.
[223] IChemE Energy Centre report, April 2018.

commercializing technologies and developing innovative solutions.

Figure 12: Current and Future Portfolio of CCUS Technologies



Source: National Petroleum Council, A Roadmap to At-scale Deployment of Carbon Capture, Use, and Storage

Another way to examine the need for technology innovation is by process type:

- **Pre-combustion** - advanced reformer technologies to unlock the potential to combine hydrogen production with CCUS for power, which opens further opportunities across the energy system. Cost reduction is possible using cheaper and more energy-efficient materials and processes;
- **Post-combustion** - R&D into new solvent and absorption processes aimed at lowering cost and improving capture performance, whilst also having the potential to reduce regeneration costs, corrosion effects, environmental impact, and product degradation;
- **Oxyfuel combustion** - new technologies for lower-cost air separation in oxy-combustion, including ion transport membranes. Ceramic materials that conduct oxygen ions at elevated temperatures are an early-stage technology with significant potential for a step change cost reduction in air separation.

An in-depth analysis by Mission Innovation assessed the current gaps in CCUS technologies and identified the most promising directions for basic research needed to achieve long-term global carbon management (Mission Innovation, 2017). This assessment defined Priority Research directions in the four areas of CCUS and cross-cutting topics, as summarized in the table below.

Table 9: CCUS Priority Research Directions

CCUS Priority Research Directions (Mission Innovation, 2017)
1. Capture
■ Designing high-performing solvents for CO_2 capture ■ Creating environmentally friendly solvent processes for CO_2 capture ■ Designing tailor-made sorbent materials ■ Integrating sorbent materials and processes ■ Understanding transport phenomena in membrane materials ■ Designing membrane system architectures ■ Catapulting combustion into the future ■ Producing hydrogen from fossil fuels with CO_2 capture
2. Utilization
■ Designing complex interfaces for enhancing hydrocarbon recovery with carbon storage ■ Valorizing CO_2 by breakthrough catalytic transformations into fuels and chemicals ■ Creating new routes to carbon-based functional materials from CO_2 ■ Designing and controlling molecular-scale interactions for electrochemical and photochemical conversion of CO_2 ■ Harnessing multiscale phenomena for high-performance electrochemical and photochemical transformation of CO_2 ■ Accelerating carbon mineralization by harnessing the complexity of solid–liquid interfaces ■ Tailoring material properties to enable carbon storage in products ■ Tailoring microbial and bio-inspired approaches to CO_2 conversion ■ Hybridizing electrochemical and biological process for CO_2 conversion to fuels, chemical, and nutrients
3. Storage
■ Advancing utilization and multiscale fluid flow to achieve Gt/y capacity ■ Understanding dynamic pressure limits for gigaton-scale CO_2 injection ■ Optimizing injection of CO_2 by control of the near-well environment ■ Developing smart convergence monitoring to demonstrate containment and enable storage site closure ■ Realizing smart monitoring to assess anomalies and provide assurance ■ Improving characterization of fault and fracture systems ■ Achieving next-generation seismic risk forecasting ■ Locating, evaluating, and remediating existing and abandoned wells ■ Establishing, demonstrating, and forecasting well integrity

4. Cross-cutting
■ Integrating experimental, simulation, and machine learning across multiple length scales to guide materials discovery and process development ■ Coupling basic science and engineering for intensified carbon capture, purification, transport, utilization and storage processes ■ Incorporating social aspects into decision-making ■ Developing tools to integrate life cycle technoeconomic, environmental, and social considerations to guide technology portfolio optimization

Source: Mission Innovation

Solutions

Governments and private industry can enable further technology improvement and innovation by working together. Potential solutions include:

- Developing a robust federal direct air capture research, development, demonstration, and deployment ("RDD&D") program[224]
- Expanding support for a federal carbon utilization RDD&D program[225]
- Federal RDD&D investments in carbon capture, utilization, storage and removal[226]
- DOE cost-share for FEED studies
- Research of and the demonstration of projects in various geologic formations that have not been historically used
- Industry activities similar to Direct Air Capture[227]

Public Perception

The public awareness and perception of CCUS can vary considerably by country, CCUS components (capture, transport, and storage), and by stakeholder group (community, market, and socio-political groups). According to a 2013 study, 77 percent of respondents were aware of CCUS, 84 percent in the Netherlands, 61 percent in Canada, and 36 percent in Scotland.[228] Awareness, though, does not always translate to positive perceptions. For example, in the Netherlands, the high awareness level results from failure of the Barendrecht project and the government's prohibition of onshore CO_2 storage.[229]

In the U.S., the anti-fossil, Keep it in the Ground, and general NIMBY movements likely will be resistant to CCUS regardless of its benefits to reducing GHG emissions.

At the component level, studies suggest that transport and storage tend to be more

[224] "Federal Policy Blueprint," Carbon Capture Coalition, May 2019.
[225] *Id.*
[226] *Id.*
[227] https://www.climateadvisers.com/newsfeed/what-companies-are-working-on-carbon-removal-and-carbon-capture/.

[228] P. Ashworth, E. Einsiedel, R. Howell, S. Brunsting, N. Boughen, A. Boyd, et al., Public preferences to CCS: how does it change across countries? Energy Procedia 37 (2013) 7410–7418.
[229] *Id.*

concerning than capture.[230] This concern tends to be around the fear of CO_2 leakage from pipelines or storage, which respondents believe could result in the contamination of drinking water, explosion, and/or asphyxiation.[231] For example, 48.4 percent of respondents in China would prefer if CO_2 storage was located more than 100 km from their home. Similarly, in Australia, studies have shown that 42 percent of respondents would be concerned if CO_2 storage was located near their city.

Perception of CCUS can also vary by the type of stakeholder. For community stakeholders, CCUS perceptions could range from embracing to protesting the technology. Communities that view capture as extending the operating life of an operating facility, certain Native American Tribes for example, may likely support the technology as it will continue to uphold jobs, wages, and local tax revenues. However, communities already opposed to an existing industrial facility may view CCUS as a technology that would allow the facility to continue operations.

For socio-political stakeholders, views on CCUS can range from a technology that undermines alternative fuels, a bridging technology, to a clear solution for reducing GHG emissions. In fact, some of the stakeholders may view CCUS as a conflict with broader sustainability goals in that it extends the use of fossil fuels. In a survey in Australia, 41 percent of respondents viewed CCUS as a temporary solution for greenhouse gas emissions while only 21 percent of respondents were confident in the technology's safety and strict control of the projects.[232] Other socio-political stakeholders view CCUS as a permanent solution given more ambitious temperature targets. According to the IEA's 2017 Energy Technology Perspectives, CCUS accounts for 14 percent of the emissions reductions in the 2°C Scenario ("2DS")[233] relative to the Reference Technology Scenario ("RTS")[234] and 32 percent of the additional emissions reductions needed to achieve the Beyond 2°C Scenario ("B2DS")[235] by 2060. Figure 13 and Figure 14 show the contribution of CCUS and renewables to global CO_2 emission reductions from RTS to 2DS and from 2DS to

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[230] "The Social Acceptance of Carbon Dioxide Utilisation: A Review and Research Agenda," Jones, Christopher R. et al., Frontiers in Research, June 2017.

[231] "Public perception of carbon capture and storage (CCS): A review", Seigo, SelmaL'Orange, Renewable and Sustainable Energy Reviews, Volume 38, October 2014, Pages 848-863.

[232] "The Social Acceptance of Carbon Dioxide Utilisation: A Review and Research Agenda," Jones, Christopher R. et al., Frontiers in Research, June 2017.

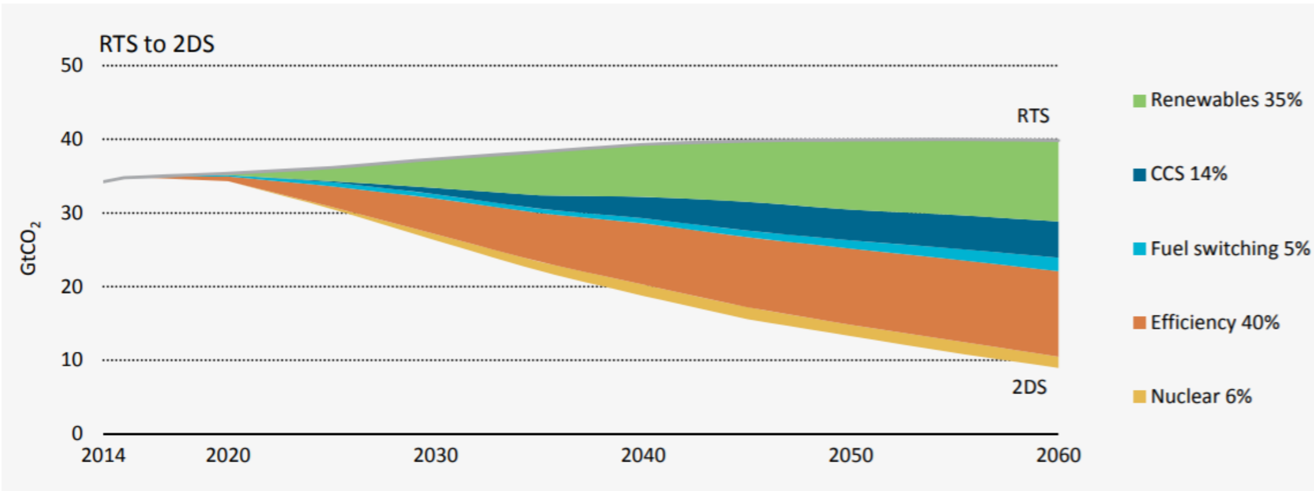
[233] The 2°C Scenario ("2DS") lays out an energy system pathway and a CO_2 emissions trajectory consistent with at least a 50 percent chance of limiting the average global temperature increase to 2°C by 2100. Annual energy sector CO_2 emissions are reduced by 70 percent from today's levels by 2060.

[234] The Reference Technology Scenario provides a baseline scenario that considers existing energy- and climate-related commitments by countries, including Nationally Determined Contributions pledged under the Paris Agreement. The RTS, reflecting the world's current ambitions, is not consistent with achieving global climate mitigation objectives but would still represent a significant shift from a historical "business as usual" approach.

[235] The Beyond 2°C Scenario explores how far deployment of technologies that are already available or in the innovation pipeline could take us beyond the 2DS. Technology improvements and deployment are pushed to their maximum practicable limits across the energy system in order to achieve net-zero emissions by 2060 and to stay net zero or below thereafter, without requiring unforeseen technology breakthroughs or limiting economic growth.

B2DS, respectively. CCUS is a vital solution in addressing society wide GHG emissions, especially in locations that are either physically or economically infeasible for renewable energy resources.

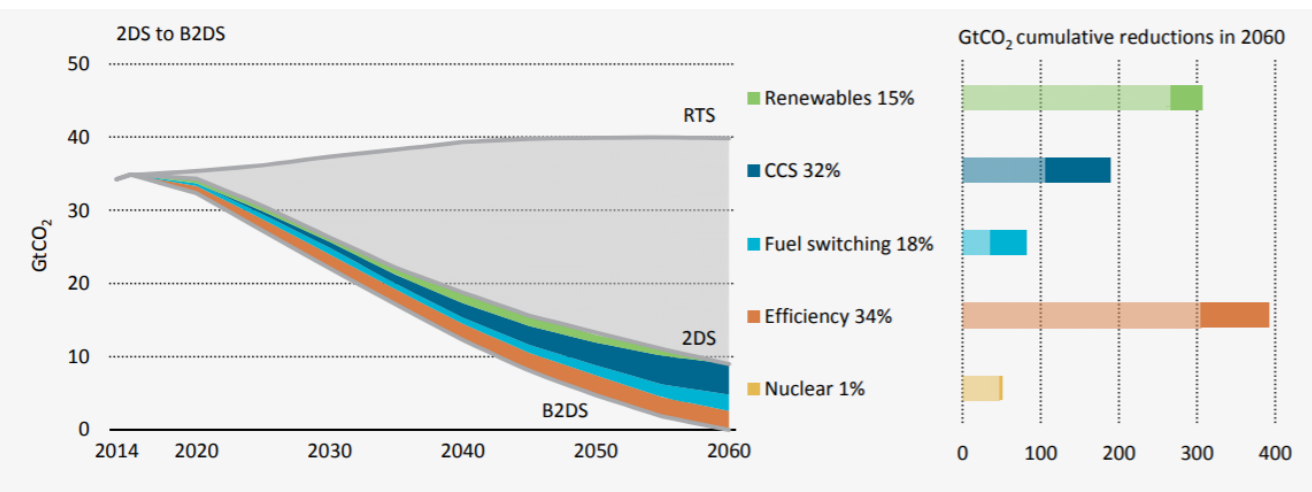
Figure 13: Global CO_2 Emissions Reductions by Technology Area: RTS to 2DS



Note: CO_2 emissions include both energy-related CO_2 emissions and emissions from industrial processes.

Source: International Energy Agency's Energy Technology Perspectives 2017

Figure 14: Global CO_2 Emissions Reductions by Technology Area: 2DS to B2DS



Note: Light areas in the right graph represent cumulative emissions reductions in the 2DS, while dark areas represent additional cumulative emissions reductions needed to achieve the B2DS.

Source: International Energy Agency's Energy Technology Perspectives 2017

The views of societal opinion leaders and industrial-sector decision-makers about whether or not to invest in CO_2 utilization (or particular technology or product options)—shaped by, for example, individual expertise, personal opinions, "bottom-line" considerations, policy support, and media coverage (e.g., Kepplinger, 2007)—will influence the broader socio-political acceptance of CO_2 utilization and, hence, investment and development of the technology.

Solutions

Jones et al.[236] provide a robust framework and set of recommendations to increase the acceptance (positive perception) of CCUS going forward:

- Socio-Political Acceptance
  - A systematic stakeholder analysis in order to identify and clarify the range of stakeholders with connections to the development and deployment of CCUS as well as the reasons for their interest and/or investment in CCUS at the socio-political level.
  - A broader and more detailed analysis of the international media coverage of CO_2 utilization in order to assess emerging perceptions of CO_2 utilization technologies (among the media and reported stakeholders) and how these are influencing the public agenda on CO_2 utilization.
  - A systematic analysis of the broader political agenda regarding CO_2 utilization and how it might influence the investment in and the further R&D of technologies and products. This research should model different investment and development pathways in different policy and legislative scenarios.
- Market Acceptance
  - Detailed identification of market-stakeholders and analysis of their perceptions of CO_2-derived products (including end-consumers) as they become commercially available. This research should seek to compare preferences for different CO_2 utilization options and analyze how the preferences are formed, spread and how they affect choice among different consumer groups.
  - A more detailed and systematic analysis of the acceptance and diffusion of different CO_2 utilization technologies and products among investors. Studies should specifically investigate how the socioeconomic environment and extant path dependencies affect behavior among different investors.
  - Research into intra-firm perception, attitudes, acceptance, and diffusion of CO_2 utilization technologies and products. In particular, the role that "change agents" have in influencing intra-firm decision-making is a relevant area for research.
- Community Acceptance
  - Which of the many "place" and "process" factors identified as influencing local project acceptance are most important in shaping people's attitudes (and behavioral responses) to CO_2 utilization facility development? For example, how does the presence and reliance on extant industrial development in a community affect acceptance of CO_2 utilization facilities?
  - To what extent is the relative indifference shown towards hypothetical CO_2 utilization facilities by communities actually hosting or not hosting facilities and/or facing actual development?

[236] "The Social Acceptance of Carbon Dioxide Utilisation: A Review and Research Agenda," Jones, Christopher R. et al., Frontiers in Research, June 2017.

Corporate Social Responsibility and Environmental, Societal Governance

What is CSR? What is ESG?

CSR and ESG are practices adhered to and reports made by companies to improve their relationships with employees, consumers, the environment, and the wider community. For example, a CSR report could include information about its direct employment, wages and salaries paid to those employees, benefits offered, and efforts made to increase diversity and representation in its workforce. A CSR practice could extend to include a company's effect on suppliers and induced sectors.

Other information included in a CSR report can be the company's environmental impact. The exact data included varies, but common factors include a company's CO_2 or other GHG emissions, calculated through its direct fuel usage or purchase of electricity. For some types of manufacturing firms, GHG emissions include the emissions from industrial processes and from energy usage (e.g., fertilizer and cement manufacturers). Environmental impacts in a CSR report can concentrate on the factors, such as a company's impacts on regional water resources or summarizing their stewardship and cleanup efforts.

ESG is an expanded version of a CSR practice concentrating on data and metrics. An ESG report summarizes a company's efforts to improve these performance metrics over time, such as reducing the carbon-intensity of its production process annually by reducing electricity consumption, through measures like energy-efficient lighting fixtures. Rather than simply reporting current efforts and the state of a company's efforts at corporate responsibility, an ESG practice is a plan for improving its outcomes over time and reporting results that show improvement in important social responsibility factors. Though they vary from company to company, climate and energy often are leading emphases of ESG practices.

How prevalent are CSR and ESG statements?

CSR and ESG statements have become more common. According to the *Harvard Business Review*, 92 percent of the 250 largest companies in the world produced a CSR or ESG report in 2015,[237] increasing from only 64 percent in 2005. As of 2018, Fortune 500 firms spent $20 billion annually on CSR activities.[238]

CSR and ESG activities and statements are prevalent enough that investors are beginning to include scoring of CSR reporting and activities in their investment criteria. Financial institutions are beginning to build financial products, aimed at attracting the investment dollars of younger investors who are more interested in companies with labor-friendly, environmentally responsible, and philanthropically active practices embedded in their business models.[239] Companies such as

[237] "Stop Talking About How CSR Helps Your Bottom Line," Stephan Meier and Lea Cassar, *Harvard Business Review*, January 31, 2018, https://hbr.org/2018/01/stop-talking-about-how-csr-helps-your-bottom-line.

[238] *Id.*

[239] Christopher P. Skroupa, "CSR: How Fortune 500 Companies Measure Up," *Skytop Strategies*, March 23,

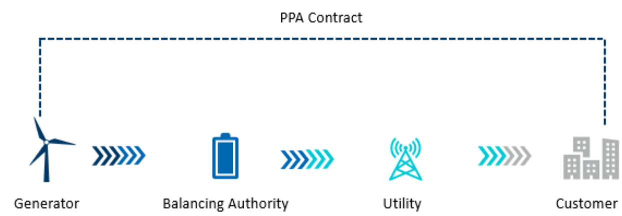
Nationwide Financial Services and New York Life Insurance Company have attracted attention for their robust reporting and satisfactory practices in these areas, bringing positive press and investment towards these enterprises.

Environmental Responsibility and Electricity Markets

One of the most active areas of environmental responsibility for institutions such as corporations, universities, health systems, or other large nonprofit institutions is with purchasing renewable electricity from wholesale markets. Entities such as Apple, Ohio State University, Google, the Philadelphia Area Hospital Group, the University of Oklahoma, Microsoft, Facebook, IKEA, the University of California, Walmart, HP, Amazon, Stanford University, Dow Chemical, Kaiser Permanente, and other firms have purchased financial products called Power Purchase Agreements ("PPAs").[240]

PPAs can be physical or virtual (financial) agreements between a purchaser and a renewable-energy generator. Figure 15 illustrates the basic structure of a PPA, in which the customer takes physical ownership of the electricity produced by the generator and sells it back into the market. In this example, the purchaser agrees to buy the production of a renewable energy unit at agreed upon prices. The developer of the unit then has a guaranteed price or price range to help finance the project, which, in turn, allows a developer to pursue new renewable energy investments. The buyer then "owns" that electricity and sells the clean energy back onto wholesale markets in an amount equal to or in excess of its own purchases for operations.

Figure 15: Structure of PPA



Source: FTI Consulting

Virtual PPAs are agreements for a contract for differences ("CfDs"). In this PPA arrangement, the purchaser and seller agree on a strike price, which can grow over time, and the purchaser and seller settle on the differences above and below the strike price. If a generator sells its electricity on the wholesale market above the strike price, the purchaser pockets the difference. However, if the generator sells its electricity below the strike price, the purchaser must pay the difference. CfDs can have more complex arrangements, such as price collars that limit the extent to which a purchaser pays the seller or receives payments from the seller.

In both a physical and virtual PPA arrangement, the customer or purchaser has encouraged renewable-energy generation and ensured that its own power needs come from, on a net financial basis, renewable sources. The system operator coordinates the sale of this power to utilities or load serving entities, which then

2017, https://skytopstrategies.com/csr-fortune-500-companies-measure/.

[240] https://www.greenbiz.com/sites /default/files/styles/gbz_article_full/public/media-inline/corporate_ppas_amcleanskies_0.png?itok=ZXXGb oKi.

distribute the electricity to the end-customer's physical location, ensuring the functioning of the electricity grid during the transaction.

How could a PPA apply to CCUS?

The structure of a PPA could apply to CCUS to encourage a net reduction in emissions through CCUS. For instance, a company or institution could enter into a PPA agreement with a CCUS facility to "buy" the captured CO_2 from the facility. Like renewable power PPAs, a CCUS PPA would encourage investments in CCUS because the owner/developer has a guaranteed set price for their products, which enables the project to be financed.

In a CCUS PPA arrangement, the purchaser receives a reduction in its emissions profile for purchasing low-carbon electricity to operate its data center, heat and cool buildings, or to run manufacturing facilities or processes, for example. Corporations and institutions interested in improving their CSR and ESG metrics can use a CCUS PPA as an option for reducing their impact on the environment instead of only through the PPA market in renewable energy. CCUS presents a compelling solution in addressing society wide GHG emissions, especially in locations that are challenged to produce physically or economically feasible renewable energy.

Case Studies

Absent a national carbon tax, capturing CO_2 provides little financial incentive for entities to invest in costly CCUS technologies to capture CO_2. Like solar and wind technology, CCUS needs policy support in the form of grants, credits, exemptions, or abatements to lower the initial high cost barriers to successfully build projects that are viable on a commercial scale. This section highlights two projects that are currently in commercial operation, and one that is in the planning stages, to demonstrate different features in terms of technology, scale, and the commercialization of the captured CO_2.

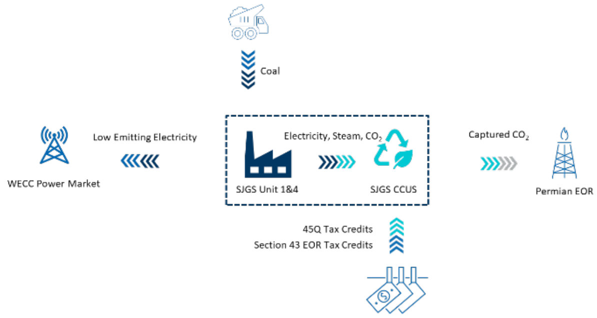
San Juan Generation Station CCUS Project

The San Juan Generating Station ("SJGS") is an 847-MW coal-fired power plant located in Waterflow, New Mexico. The plant currently consists of two units—Units 1 and 4—but was a four-unit plant representing 1,895 MW of capacity until December 2017 when Units 2 and 3 were retired.

Enchant Energy proposed to acquire a 95 percent stake in the SJGS facility, and add amine reactor towers to capture approximately six million metric tons of CO_2 per year, at an estimated capture rate of 90 percent.[241] Enchant Energy would send the captured CO_2 to the Cortez CO_2 pipeline, which is 20 miles east of SJGS. The Cortez pipeline along with the McElmo Creek pipeline serve the McElmo Dome and Doe Canyon CO_2 source fields in southwestern Colorado. Kinder Morgan operates the Cortez pipeline, and Resolute operates the McElmo Creek pipeline. CO_2 from these pipelines is used for EOR operations at EPA-approved geologic storage sites in the Permian Basin. Figure 16 shows the SJGS CCUS project schematic.

[241] "The Economic Case for Power Plant Carbon Capture Retrofits: A Case Study on the San Juan Generating Station – New Mexico," Enchant Energy, October 2019.

Figure 16: SJGS CCUS Project Schematic



Source: FTI Consulting Analysis

Under a funding award up to $21.9 million, including $15.5 million from DOE and $4.4 million from non-DOE sources, New Mexico Institute of Mining and Technology is performing a commercial-scale site characterization of a storage complex located in northwest New Mexico to accelerate the deployment of integrated carbon capture and storage technology at the SJGS. The data obtained from this characterization will be used to prepare, submit, and attain a Class VI permit for construction.[242]

A Sargent & Lundy ("S&L") study estimates that the cost of CO_2 capture at SJGS will range from $39 to $43 per metric ton, which includes capital expenditures, fixed and variable operating and maintenance costs, and financing. The S&L study estimates that the operating and maintenance costs will be $16 per metric ton.

Enchant Energy intends to use the 45Q Credit for the project and estimates the project will generate $2.5 billion in tax credits over twelve years, which is almost twice the estimated capital expenditures for the retrofit.

Additionally, Enchant Energy projects that the sales of the pipeline quality CO_2 will fully cover the annual operating and maintenance costs.

Altogether, the Enchant Energy project would generate significant socioeconomic benefits. First, the project would reduce regional CO_2 emissions significantly by 6 million metric tons per year. Second, the project would keep SJGS financially viable as a low-cost dispatching facility, which, in turn, would sustain 458 direct jobs at the SJGS facility and the nearby Westmoreland coal mine, support 1,000 non-direct jobs, and generate about $8 million in annual local tax revenues.

Petra Nova W.A. Parish CO_2 Capture and Sequestration Project

W.A. Parish CO_2 Capture and Sequestration Project, owned by Petra Nova Parish Holdings, a 50/50 joint venture between NRG Energy and JX Nippon Oil and Gas Exploration, is the world's largest operating commercial-scale post-combustion CO_2 capture system installed on an existing coal-fired power plant. The project captures 90 percent of the CO_2 emitted from a 240-MW flue gas stream on an existing coal-fired power plant (W.A. Parish Generating Station) located in Thompsons, Texas, southwest of Houston. The project has a designed capacity to capture and store 1.6 million tons of CO_2 per year[243] through a CO_2 capture technology called the Kansai Mitsubishi Carbon Dioxide Recovery process, which was jointly developed by MHI and the Kansai Electric Power Company. The captured

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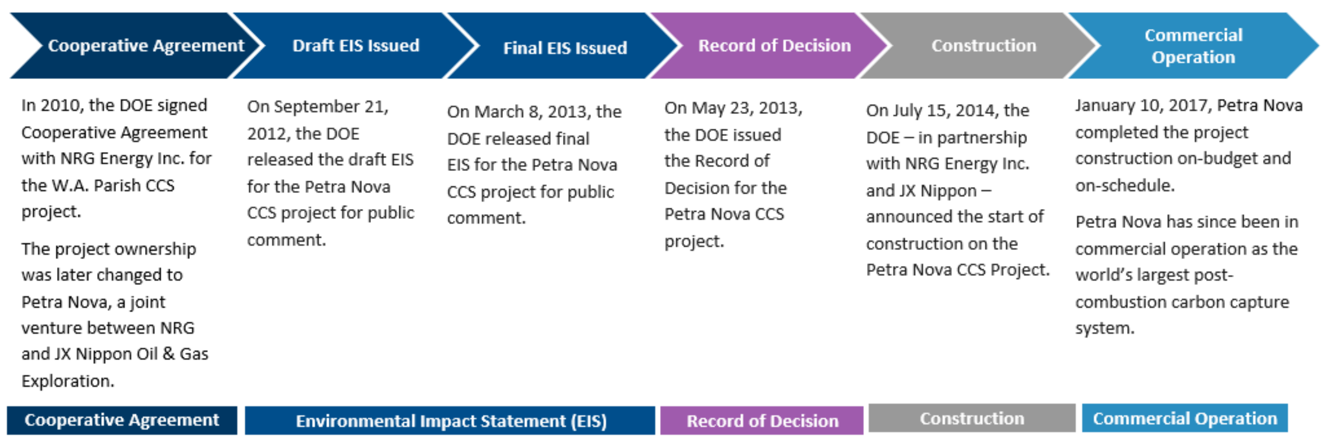
[242] DOE. https://www.energy.gov/fe/foa-1999-project-selections.

[243] DOE press release dated January 11, 2017. Petra Nova, World's Largest Post-Combustion Carbon-Capture Project, Begins Commercial Operation. https://www.energy.gov/fe/articles/petra-nova-world-s-largest-post-combustion-carbon-capture-project-begins-commercial.

CO_2 is compressed, dried, and transported through an 80-mile pipeline to West Ranch oil field, located near Vanderbilt, Texas, for EOR, and then it is ultimately sequestered. The project is expected to boost production at West Ranch from 500 barrels per day to approximately 15,000 barrels per day.[244] It is estimated that the field holds 60 million barrels of oil recoverable from EOR operations. Figure 17 shows the project development timeline of key milestones, and Figure 18 shows the layout of the key components.

The project reduces greenhouse gas emissions and earns economic return through increasing oil production.[245] The project demonstrated that carbon capture, when used in conjunction with revitalizing oil field production, could provide a positive financial return under certain assumptions of oil prices for projects strategically sited to access the EOR market, and with the support of a CCUS tax credit. To date, the Petra Nova project has captured nearly 4 million short tons of CO_2, resulting in the production of over 4.2 million barrels of oil through EOR.[246]

Figure 17: Petra Nova CO_2 Capture and Sequestration Project Timeline



Source: National Energy Technology Laboratory

[244] DOE press release dated April 13, 2017. Secretary Perry Celebrates Successful Completion of Petra Nova Carbon Capture Project. https://www.energy.gov/articles/secretary-perry-celebrates-successful-completion-petra-nova-carbon-capture-project.

[245] NRG. https://www.nrg.com/case-studies/petra-nova.html.

[246] DOE press release dated January 28, 2020. Assistant Secretary for Fossil Energy Speaks About the Future Direction of CCUS https://www.energy.gov/fe/articles/assistant-secretary-fossil-energy-speaks-about-future-direction-ccus.

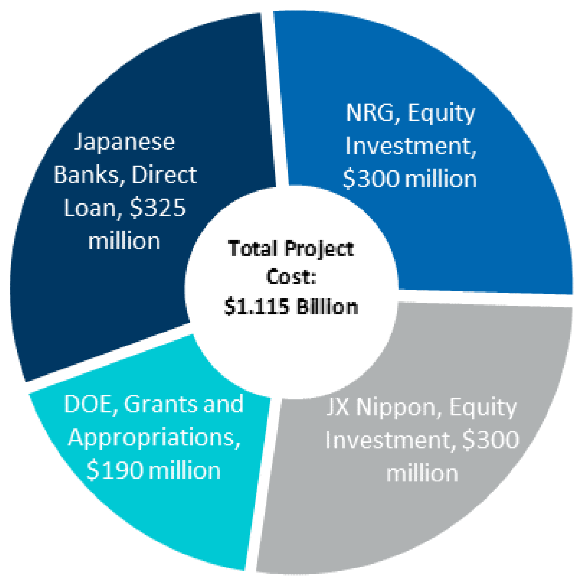
Figure 18: Petra Nova CO_2 Capture and Sequestration Project Layout

Source: Petra Nova

The $1 billion Petra Nova project was completed on time and on budget, with a successful public-private partnership that includes the NRG JX Nippon 50/50 joint venture, federal, state, and international lending agencies, and technology providers as shown in Figure 19. Funding came from the following:

- Japanese Bank for International Cooperation and Mizuho Bank provided $335 million direct loans.
- The DOE provided $190 million in grants, composed of $167 million financial assistance through the original Clean Coal Power Initiative Round 3, and $23 million under Section 313 of the FY2016 Consolidated Appropriations Act.[247]
- NRG invested $300 million in equity, receiving a 25 percent stake in the oil extracted.
- JX Nippon invested $300 million in equity, receiving a 25 percent stake in the oil extracted.
- The state of Texas provided various tax abatement, credits, and exemptions, which served to reduce risk for developers and make the CCUS project more commercially viable.
  - 50 percent enhanced oil recovery tax abatement
  - Anthropogenic CO_2 project tax abatement
  - Franchise tax credits
  - Property tax exemptions
  - Sales tax exemptions

Figure 19: Petra Nova CO_2 Capture and Sequestration Project Funding Structure



Source: FTI Consulting Research

[247] DOE Office of Fossil Energy. https://www.energy.gov/fe/petra-nova-wa-parish-project.

Warrior Run Generating Station

The AES Corporation owns and operates the Warrior Run Generating Station ("Warrior Run"), a 180-MW coal-fired power plant located south of Cumberland, Maryland, that achieved commercial operation in 2000. Warrior Run deploys a single boiler, single-turbine circulating fluidized bed combustion unit to generate electricity under a 30-year PPA as a co-generator Qualifying Facility under the Public Utility Regulatory Policies Act of 1978. [248] The fuel source of the plant is Maryland-mined local coal delivered by truck.

This plant uses the amine process to extract approximately 4 percent of the flue gas.[249] The captured CO_2 is then purified, compressed and liquefied to produce 115 tons per day of food-grade CO_2. Alternatively, the captured CO_2 could be sold to companies to use in fire extinguishers and dry ice. The CO_2 facility requires 5 percent of the steam production, in addition to 1.3 MW of internal load.

The Warrior Run facility could be retrofitted further to capture more of the CO_2 either for utilization or storage and a possible future retrofit could take advantage of the 45Q Credit.

[248] 16 U.S.C. §796(18)(A) and 18 CFR 292.203.
[249] National Energy Technology Laboratory's (NETL) Carbon Capture and Storage (CCS) Database; http://energywv.org/assets/files/Energy-Summit-Presentations/2014/08_Peter_Bajc.pdf.

Appendix A: Levelized Cost of Electricity Assumptions for 2026 Online Date

Assumption	Existing Coal	Coal with CCUS - Low	Coal with CCUS - High
Capex ($/kW)	N/A	$1,620[a]	$2,700[a]
Fixed O&M ($/kW-y)	$40.00[b]	$19.30[c]	$59.30[d]
Variable O&M ($/kW-y)	$2.50[b]	$8.43[c]	$10.93[d]
Heat Rate (MMBtu/MWh)[b]	9.50	13.50	13.50
Fuel Price ($/MMBtu)[b]	$2.00	$2.00	$2.00
Capacity Factor[b]	85%	85%	85%
Discount Rate[e]	N/A	12%	12%
Lifetime (years)[e]	N/A	20	20
Emissions Capture Rate[b]	0%	90%	90%
Transport and Storage Cost ($/metric ton)		$14.00[f]	$14.00[f]
Tax Credit[b]	N/A	$50/metric ton 45Q	$50/metric ton 45Q
Capacity Value ($/kW-year)[b]	$50	$50	$50
Firm Capacity Credit[b]	100%	100%	100%

Sources:

[a] Computed from NPC Report, Chapter Two: CCUS Supply Chains and Economics, Table 2-4

[b] FTI Assumption

[c] Computed as the difference between Coal with CCUS – High and Existing Coal

[d] AEO Electricity market Module, Table 3, Ultra-Supercritical Coal with CCS

[e] NPC Report, Chapter Two: CCUS Supply Chains and Economics, Figure 2-1

[f] NPC Report, Chapter Two: CCUS Supply Chains and Economics, Figure 2-6

Appendix B: Discussion on Class II and Class VI Wells for Long-term Storage

Project developers planning to use the 45Q Credit will need to obtain permits for injection wells for long-term storage of CO_2 from their projects. The EPA regulates wells under its Underground Injection Control ("UIC") program, which consists of six classes of injection wells.[250] Each well class is based on the type and depth of the injection activity, and the potential for that injection activity to result in endangerment of an underground source of drinking water ("USDW"). "Class II" wells are used exclusively to inject fluids associated with oil and natural gas production. "Class VI" wells are used for injection of carbon dioxide into underground subsurface rock formations for long-term storage, or geologic sequestration ("GS").

UIC regulations mandate the consideration of a variety of measures to assure that injection activities will not endanger underground sources of drinking water (USDWs). The concept of endangerment is defined in the Federal Code of Regulations (40 CFR 144.12) as follows:[251]

> *(a) No owner or operator shall construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR part 142 or may otherwise adversely affect the health of persons.*

Class II wells are associated with EOR or enhanced natural gas production. As oil and natural gas is produced from an underground formation, it leaves a permeable and porous volume that can be readily filled with CO_2. Because oil and natural gas reservoirs have held hydrocarbons for thousands to millions of years, they are ideal sites for long-term, secure storage of CO_2.[252] The CO_2 can help re-pressurize the formation and push some of the remaining oil or gas to the surface. The CO_2 mixed with the oil is recovered and reinjected into the reservoir as part of a closed-loop cycle. Approximately 99% of the CO_2 used in EOR is ultimately trapped in hydrocarbon-producing geologic formations.[253]

Class VI wells, however, are less proven as to their long-term storage efficacy. Class VI wells are likely to be completed mainly in underground saline formations, which are porous formations filled with brine water and span large volumes deep underground.[254] Other formations such as unmineable coal seams, organic-rich shales, and basalt formations are also candidates for Class VI wells.

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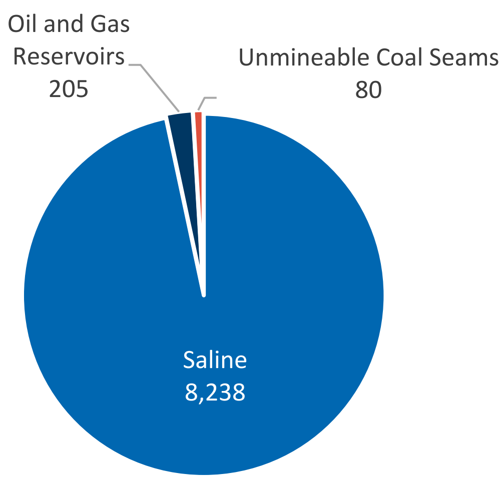
[250] EPA. https://www.epa.gov/uic/underground-injection-control-well-classes.
[251] *Id.*
[252] NETL. https://www.netl.doe.gov/coal/carbon-storage/faqs/carbon-storage-faqs.
[253] National Petroleum Council's "Meeting the Dual Challenge" report, Chapter 2.
[254] NETL. https://www.netl.doe.gov/coal/carbon-storage/faqs/carbon-storage-faqs.

According to NETL, U.S. saline formations represent the largest storage potential of all formation types at 8,238 billion metric tons of CO_2 ("Gt"). This is an order of magnitude higher than oil and gas reservoirs at 205 Gt and two orders of magnitude higher than unmineable coal areas at 80 Gt[255] as shown in Figure 20 below.

Figure 20: CO_2 Storage Potential by Reservoir Type (Gt)



The latest EPA data shows that are more than 180,000 Class II wells in operation while there are only two Class VI wells in operation.[256] The two Class VI wells are located at the Archer Daniels Midland ("ADM") Decatur ethanol facility in Illinois. The facility is located near the center of the Mt. Simon geologic saline formation in the Cratonic Basin, which is 60,000 square miles and has an estimated CO_2 storage capacity between 27 to 109 billion metric tons.[257]

ADM, which began injecting CO_2 on April 7, 2017, will permanently store up to 1.1 million metric tons of CO_2 annually or up to 5.5 million metric tons over five years, demonstrating the commercial-scale applicability of GS technology.[258]

While Class VI wells are ideally suited for long-term CO_2 storage given the enormous potential capacity of saline formations, their permitting timeline and costs along with monitoring costs are significantly higher than Class II wells as shown in Table 10.

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[255] NETL. https://www.netl.doe.gov/coal/carbon-storage/strategic-program-support/natcarb-atlas.
[256] EPA. https://www.epa.gov/uic/uic-injection-well-inventory.
[257] "ADM CCS Projects: Experience and Lessons Learned," McDonald, Scott, CSLF Technical Workshop, June 17, 2015.
[258] "EPA Seeks Comments on Plan to Modify an Existing Carbon Storage Permit. Archer Daniels Midland Co. Decatur, Illinois." EPA Fact Sheet published November 2016. Available online at https://www.epa.gov/sites/production/files/2016-11/documents/adm-permit-modification-fs-201611-54pp.pdf.

Table 10: Indicative Timelines and Costs for Class II vs. Class VI Wells

	Class II	Class VI
Permitting Timeline	1 year	3 years[259]
Permitting Costs	<$100,000	>$500,000
Annual Monitoring Costs[260]	$4,000	$320,000

EPA regulatory programs under certain statutes may be delegated to States and Native American Tribes ("Tribes"), if the State or Tribe demonstrates the ability to conduct an appropriate permitting review consistent with EPA regulations. Under the UIC program, most States have achieved primary regulatory authority (or primacy) for most of the classes of UIC permits (other than Class VI wells). Delegation to States and Tribes indicates that the technical requirements for issuing permits have been standardized and that the knowledge required for issuing permits in compliance with applicable law has been disseminated from the EPA to States and Tribes. By authorizing States and Tribes to issue UIC permits, the EPA effectively spreads the review work and such delegations of authority can result in more efficient and timely permit reviews.[261]

Forty States have primacy to permit Class II wells – 24 States and 2 Tribes have UIC Class II primacy under SDWA Section 1425 and 16 States and 3 territories have UIC Class II primacy under SDWA Section 1422.[262] For Class VI wells, however, only North Dakota has primacy while the EPA directly implements the Class VI program in all other States, territories, and tribal areas.[263] The lack of approvals of State and Tribal programs for Class VI wells reflects the relatively recent issuance of the relevant regulations (2010) and the developing nature of the technology and industry.

The utilization of underground formations for the storage of CO_2 is relatively well developed in connection with EOR and the use of Class II wells. The utilization of available storage capacity in saline formations is in a significantly earlier state of development. While 45Q project developers may tend towards developing Class II wells for reasons of costs and availability, they likely will seek to utilize Class VI to provide additional options for long-term storage. In fact, some developers have already recognized this. According to the Clean Air Task Force's CCUS Project Tracker, about 10 percent of announced 45Q projects plan on using both Class II and Class VI wells.[264]

Wells that are initially permitted as Class II wells may be converted to Class VI wells if they meet the technical requirements. Accordingly, developers will have the option of pursuing a Class II well permit and eventually switching to a Class VI well, or pursuing a Class VI well permit initially. Class II wells may

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[259] Based on ADM Timeline. "ADM CCS Projects: Experience and Lessons Learned," McDonald, Scott, CSLF Technical Workshop, June 17, 2015.
[260] EPA. https://www.epa.gov/sites/production/files/2015-07/documents/subpart-rr-uu-factsheet.pdf.
[261] EPA. https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program.
[262] *Id.*
[263] *Id.*
[264] CATF CCUS Project Tracker. Accessed on June 16, 2020 at https://www.catf.us/2020/04/the-status-of-carbon-capture-projects-in-the-u-s-and-what-they-need-to-break-ground/.

have to be converted to Class VI wells when there is an increased risk to USDWs compared to Class II operations.[265] The mechanics of conversion to a Class VI well could be complicated, in situations where a State or Tribe has primacy over a Class II well and the EPA is reviewing the application to convert that well to a Class VI well. The EPA may address the conversion process in updated Class VI regulations that the EPA initially planned to issue in approximately 2016. There are a number of potential updates and revisions that the EPA could adopt to help reduce the costs, timelines, and risks associated with Class VI wells, some of which include the following: [266,267]

- **Reduce Permitting Delays**: The EPA could speed permitting of Class VI wells. The NPC recommends issuing a drill to permit within six months. The primary impediment is making sure that the EPA has a clear technical framework and communicates the requirements to the regulated community. These changes are likely to occur naturally, as the program develops, but could be accelerated by delegating primacy to States.
- **Allow Area Permits**: Instead of issuing a permit for a single well, the EPA should allow applicants the option of being permitted for multiple injection wells in a single formation. The documentation to justify permits for Class VI wells in the same formation would be very similar and duplicative. The permit application process and review could be simplified for multiple, similar wells.
- **Move to a Risk-Based Structure**: The purpose of the UIC program is to protect USDWs. Class VI wells (which inject only CO_2) present a nominal risk to USDWs. Accordingly, the EPA may be able to streamline review of Class VI well applications by excluding, or at least standardizing, the elements of permit review that focus on protection of drinking water. The EPA should apply the statutory Safe Drinking Water Act standard for endangerment to Class VI wells to allow risk-based permitting, operation, and monitoring.
- **Eliminate the 50-year Post–Injection Site Care Period**: The default should be shortened to a period more commensurate with anticipated risks. At the minimum, should adjust its computational modeling requirements for post-injection site care requirements with respect to small demonstration projects to make them fit for purpose.
- **Allow Monitoring Flexibility**: The Class VI program requires testing and monitoring to track the CO_2 plume and pressure front by direct methods in the injection zone, such as monitoring wells. It is important to avoid unnecessary penetrations of the injection zone to minimize possible leakage pathways. The EPA should consider technological alternatives.
- **Developing a Process to Give States Primacy**: With the high number of potential 45Q applicants to the Class VI program, the EPA may not have the resources to quickly issue permits to all qualified applicants. If States and Tribes are trained and delegated authority to administer the program, and can bring to bear additional resources, it is likely that the permitting process can be expedited.

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[265] 40 CFR 144.19.

[266] "CCUS After the Pandemic," Eames, Frederick R., National Law Review, June 9, 2020. See also "Class VI Permits," Van Vorhees, Bob, 2019 Midwest Carbon Sequestration Science Conference, "April 24, 2019."

[267] NPC Report, Chapter Three: Policy, Regulatory, and Legal Enablers, pp. 30-31.

- **Allow Class V for Demonstration Projects**: Many states already have primacy for Class V and can determine if a project is experimental. As noted by the NPC, "the effort to apply the Class VI provisions to smaller scale R&D projects has imposed permitting and regulatory compliance costs that far exceed any real or potential benefits in terms of environmental protection. In particular, the administrative and permitting costs have limited the scientific content of projects on fixed budgets to the long-term detriment of advances in scientific knowledge and CCUS technologies."[268]
- **Conduct Planned Periodic Reviews of Class VI Program**: EPA should undertake the planned periodic review of Class VI rules, guidance, and implementation of so that they are aligned with a site-specific and performance-based approach.

[268] NPC Report, Chapter Three: Policy, Regulatory, and Legal Enablers, pg. 31.

Appendix C: Abbreviations

2DS: 2°C Scenario

ADM: Archer Daniels Midland

B2DS: Beyond 2°C Scenario

CARB: California Air Resource Board

CCC: Carbon Capture Coalition

CCS: Carbon Capture and Storage

CCUS: Carbon Capture, Utilization, and Sequestration

CO_X: All Carbon Oxides

CSG: Corporate Social Responsibility

DOE: Department of Energy

EGR: Enhanced Natural Gas Recovery

EOR: Enhanced Oil Recovery

EPA: Environmental Protection Agency

ESG: Environmental, Social, and Governance

FEED: Front-End Engineering Design

GS: Geologic Sequestration

Gt: Billion Metric Tons

FOA: Funding Opportunity Announcements

GHG: Greenhouse Gas

GNP: Gross National Product

HLBV: Hypothetical Liquidation Book Value

IRC: Internal Revenue Code

IRS: Internal Revenue Service

ITC: Investment Tax Credit

MRV: Monitor, Report, and Verify

LCA: Lifecycle Analysis

LCFS: Low-Carbon Fuel Standard

LCOE: Levelized Cost of Electricity

LPO: Loan Programs Office

NPC: National Petroleum Council

PPA: Power Purchase Agreements

PTC: Production Tax Credit

R&D: Research and Development

RCSP: Regional Carbon Sequestration Partnerships

RD&D: Research, Development, and Demonstration

RDD&D: Research, Development, Demonstration, and Deployment

RTS: Reference Technology Scenario

RUS: Rural Utilities Service

SJGS: San Juan Generating Station

TRL: Technology Readiness Levels

UIC: Underground Injection Control

USDA: U.S. Department of Agriculture

USDW: Underground Source of Drinking Water

USE IT Act: Utilizing Significant Emissions with Innovative Technologies Act

USGS: U.S. Geological Survey