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CO2 PIPELINE INFRASTRUCTURE FOR SEQUESTRATION PROJECTS

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I. INTRODUCTION

Since the principal author first published an article in 2009 regarding the regulatory landscape for carbon dioxide ("CO2") pipeline infrastructure, we have seen a significant change in the global sensitivity to the need for a carbon transition, and a much stronger consensus on the need to do so to mitigate climate change. Unlike the initial thinking around carbon capture and sequestration in 2009, there is no longer a consensus case for clean coal. Significant tax and other incentives have been provided in some countries (including the United States) for removing and sequestering carbon from waste gas streams. There is a significant expansion of the potential beneficial uses of CO2 that can reduce our carbon footprint and enhance sequestration opportunities, and there is a growing interest in using such incentives to subsidize purely geologic sequestration without further beneficial use. While the federal regulatory framework is relatively unchanged (apart from the availability of tax incentives), an increasing number of states have decided to grant eminent domain to CO2 pipelines to further enhance their viability. This article provides an overview of the current market and regulatory landscape for CO2 pipelines, with a particular focus on eminent domain for CO2 pipeline infrastructure to be used for enhanced oil recovery ("EOR"), sequestration, and burgeoning commercial uses.

II. MARKET INCENTIVES FOR CO2 SEQUESTRATION AND PIPELINE PROJECTS

Contrary to popular portrayals, CO2 emissions are not only waste gas, but also a potentially valuable commodity, whether for beneficial use of the CO2 or using CO2 removal and sequestration credits and other incentives to create a revenue stream. While this article surveys the legal landscape applicable to CO2 sequestration pipeline projects (including EOR), we first discuss other uses for CO2 because as additional uses for CO2 develop and become more popular, the market for, and incentive to develop, CO2 pipeline projects will expand. By

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2030, CO2-based products could be worth between $800 billion and $1 trillion, and the use of CO2 for producing fuel, enriching concrete and generating power alone could reduce GHG emissions by a billion metric tons yearly.[1] As beneficial uses and tax incentives for CO2 separation and sequestration increase, so will the market for CO2 off-gas streams. Carbon capture, storage, and utilization projects are highly capital-intensive projects, but they can and will be developed if there is a market for them.[2] With the potential to decarbonize existing energy production and industry in the U.S. and maintain jobs, the supply of CO2 is likely to increase.

A. CCS and EOR

Carbon capture and sequestration (or storage) ("CCS") is a process that involves capturing man-made CO2 at its source and storing it permanently underground. (CCS is sometimes referred to as carbon capture, utilization, and storage ("CCUS")).[3] CCS has the potential to reduce the amount of CO2 emitted into the atmosphere from the burning of fossil fuels at power plants and other large industrial facilities. An integrated CCS system includes three main steps: (1) capturing and separating CO2 from other gases; (2) purifying, compressing, and transporting the captured CO2 to the sequestration site; and (3) injecting the CO2 into subsurface geological reservoirs.[4] Direct air capture is also an emerging technology that can remove atmospheric CO2, directly reducing its concentration.[5]

CO2 use in EOR involves injecting CO2 into oil wells to maximize the amount of oil recovered.[6] Using CO2 produced from other industrial sources replaces the use of CO2 from natural reservoirs, which is typical,[7] and depending on the setting and project type, more CO2 can be injected and stored than is used in consuming the final oil product.[8] As of now, EOR is the second most popular industrial use for CO2 and the purpose for which the vast majority of U.S. CO2

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1. Renee Cho, *Capturing Carbon's Potential: These Companies Are Turning CO2 Into Profits*, State of the Planet, COLUMBIA CLIMATE SCHOOL (May 29, 2019), https://news.climate.columbia.edu/2019/05/29/co2-utilization-profits/.

2. LABOR ENERGY P'SHIP, BUILDING TO NET-ZERO, A U.S. POLICY BLUEPRINT FOR GIGATON-SCALE CO2 TRANSPORT AND STORAGE INFRASTRUCTURE, 18 (June 20, 2021), https://www.eenews.net/assets/2021/06/30/document_ew_10.pdf.

3. PETER FOLGER, CONGRESSIONAL RESEARCH SERVICE, CARBON CAPTURE AND SEQUESTRATION (CCS) IN THE UNITED STATES (Aug. 9, 2018). We will use CCS and CCUS interchangeably in this Article.

4. *Id*. at 1.

5. *Id*.

6. Cameron Hepburn, Ella Adlen, John Beddington, Emily Carter, Sabine Fuss, Niall Mac Dowell, Jan C. Minx, Pete Smith & Charlotte Williams, *The Technological and Economic Prospects for CO2 Utilization and Removal*, 575 NATURE 87 (2019), https://www.nature.com/articles/s41586-019-1681-6.

7. *Enhanced Oil Recovery*, Office of Fossil Energy and Carbon Management, ENERGY.GOV, https://www.energy.gov/fe/science-innovation/oil-gas-research/enhanced-oil-recovery.

8. Hepburn et al., *supra* note 6; Christophe McGlade, *Can CO2-EOR really provide carbon-negative oil?*, IEA (Apr. 11, 2019), https://www.iea.org/commentaries/can-co2-eor-really-provide-carbon-negative-oil.

pipelines are used.[9] The total potential for CO2 injected for EOR in the US has been estimated at around 200 to 262 million metric tons per annum.[10] With more than 90% of the world's oil reservoirs potentially suitable for CO2 EOR, and a mature business model in the United States, there is good potential for CO2 EOR growth.[11]

However, in addition to the popular emphasis on climate change and the corresponding need to reduce emissions and remove greenhouse gases from the atmosphere, the concept of carbon utilization has gained interest within Congress and in the private sector as a means for capturing CO2 and converting it into commercially viable products. Therefore, CCS and direct air capture have the potential to significantly expand the market for CO2 not only as a means to combat climate change, but also as a profitable means of collecting CO2 for commercial use offsetting the significant costs associated with CCS.

B. Other Commercial Uses

CO2 is being heavily used for EOR, but it can also be used to manufacture many products. The current most popular industrial use of CO2 is to make urea for use in fertilizer.[12] It can also be used for food and beverage manufacturing, pulp and paper manufacturing, metal fabrication,[13] plastic manufacturing, carbon materials (graphene, carbon nanotubes, carbon fiber), textile dying, fishmeal, and concrete strengthening.[14] CO2 can also be used to create methanol as a new source of raw materials for use in fuel, concrete, and food production. Indeed, compared to the traditional method of methanol production, this way of making methanol reduces carbon emissions by 90%.[15] Researchers have also even devel-

9. IEA, *Putting CO2 to Use*, Technology Report (Sept. 2019), https://www.iea.org/reports/putting-co2-to-use; LABOR ENERGY P'SHIP, *supra* note 2 at 10.

10. KENNETH B. MEDLOCK, III AND KEILY MILLER, EXPANDING CARBON CAPTURE IN TEXAS, Center for Energy Studies: Rice University's Baker Institute for Public Policy, 21 (Jan. 21), https://www.bakerinstitute.org/media/files/files/8e661418/expanding-ccus-in-texas.pdf (citing Brown, Jeffrey D. and Ung, Poh Boon, *Supply and Demand Analysis for Capture and Storage of Anthropogenic Carbon Dioxide in the Central U.S.*, in MEETING THE DUAL CHALLENGE: A ROADMAP TO AT-SCALE DEPLOYMENT OF CARBON CAPTURE, USE AND STORAGE (Dec. 12, 2019), https://dualchallenge.npc.org/; ABRAMSON, MCFARLANE AND BROWN, TRANSPORT INFRASTRUCTURE FOR CARBON CAPTURE AND STORAGE, Great Plains Institute and Regional Carbon Capture Deployment Initiative, 34 (June 2020), https://www.betterenergy.org/wp-content/uploads/2020/06/GPI_RegionalCO2Whitepaper.pdf).

11. Hepburn et al., *supra* note 6.

12. IEA, *Putting CO2 to Use*, Technology Report (Sept. 2019), https://www.iea.org/reports/putting-co2-to-use.

13. *Carbon Dioxide Capture and Sequestration: Overview*, UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, https://19january2017snapshot.epa.gov/climatechange/carbon-dioxide-capture-and-sequestration-overview_.html.

14. CARBON CAPTURE COALITION, THE USEIT ACT (UTILIZING SIGNIFICANT EMISSIONS THROUGH INNOVATIVE TECHNOLOGIES): CREATING ECONOMIC, JOBS AND ENVIRONMENTAL BENEFITS THROUGH CARBON CAPTURE AND UTILIZATION, https://carboncapturecoalition.org/wp-content/uploads/2018/10/USEITAct_OnePager_10_8_18_formatted.pdf); Cho, *supra* note 1.

15. Anthony King, *Waste CO2 to be Turned into Ingredients for Fuel, Plastics and Even Food*, PHYS.ORG, (Nov. 19, 2018), https://phys.org/news/2018-11-co2-ingredients-fuel-plastics-food.html.

oped a process to turn waste CO2 into polyethylene, one of the most widely produced plastics in the world and for which there is a substantial existing market.[16] The list of potential uses will only continue to grow since there is an increasing push to find methods to fix and convert CO2 and captured CO2 could theoretically be used to make any fuel or chemical that is currently based on petroleum.[17]

Using CO2 in concrete is particularly interesting as a commercial use of CO2 because concrete is the most widely used construction material globally, with US production alone in 2019 totaling 370 million cubic yards, offering a large, widespread, and growing market for CO2 streams.[18] This presents an opportunity to reduce emissions from concrete (in addition to the initial CO2 source). Reducing concrete emissions would be significant because if global concrete emissions were from a country, the country would rank third for global CO2 emissions.[19] While storage in concrete is shorter and less secure than geological storage, it does offer a short-term, widely-available solution to store CO2 and monetize CO2 streams. Multiple companies have found various solutions to manufacture low-emissions concrete using CO2 as an input.[20] The popular "carbon curing" approach also makes the concrete cure faster and increases the concrete's water resistance and strength.[21]

Commercial uses of CO2 creates opportunities to offset emissions, which opportunities will expand further as energy-efficient processes to convert CO2 are found.[22] Other major opportunities for using CO2 in ubiquitous commercial uses include using CO2 to produce the organic chemicals used in solvents, synthetic, rubber, plastics, etc.[23] Additionally, while these technologies are in their early stages, CO2 could be used to create synthetic fuels and batteries, or be used instead of steam for energy efficiency.[24]

With uncertainty and lack of uniformity in state and local regulation, the CO2 legal landscape is widely variable and, as explained more fully below, there are distinctions between state laws (and, sometimes, lack thereof) that can influence where it makes sense to invest in CO2 sequestration projects and pipelines. Nonetheless, since 2009, the barriers to sequestration and related infrastructure projects have become more market-driven rather than regulatory-driven. Recent volatility in oil and gas commodity prices and increasing investor awareness of

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16. Leigh Krietsch Boerner, *New Catalyst Turns Waste CO2 into Valuable Commodity Chemical*, 97 CHEMICAL & ENGINEERING NEWS 46 (Nov. 22, 2019).

17. Cho, *supra* note 1.

18. Jane Margolies, *Concrete, a Centuries-Old Material, Gets a New Recipe*, THE NEW YORK TIMES (Aug. 11, 2020), https://www.nytimes.com/2020/08/11/business/concrete-cement-manufacturing-green-emissions.html.

19. *Id*.

20. *Id*.

21. Krysta Biniek, Ryan Davies, and Kimberly Henderson, *Why Commercial Use Could be the Future of Carbon Capture*, MCKINSEY & COMPANY (Jan. 12, 2018), https://www.mckinsey.com/business-functions/sustainability/our-insights/why-commercial-use-could-be-the-future-of-carbon-capture#.

22. Cho, *supra* note 1.

23. *Id*.

24. *Id*.

environmental and social governance ("ESG") issues, along with interest in facilitating the carbon transition, appear to be primary motivators of investment capital flows in this area. As a result, sequestration projects will develop if the market supports them, notwithstanding the relative lack of regulations and/or uniformity in regulations. Additionally, with improved and expanded federal tax incentives, investors may find that the tax benefits and various credit revenue streams will outweigh such uncertainties and continue to stimulate investment in these projects. In this climate, the current lack of a uniform regulatory framework may also present an opportunity to clarify policy priorities and move towards a regulatory framework that would further facilitate these projects.

III. CURRENT CO2 PIPELINE INFRASTRUCTURE

The market for CO2 has the potential to increase dramatically, and with it, the market for CO2 pipeline projects. The U.S. is already home to several commercial and demonstration facilities, collectively capturing more than 25 million tons per annum ("Mtpa") of CO2; as a result, the U.S. is currently the global leader in CCS deployment.[25] As of June 2021, there were twelve commercial and seven demonstration carbon capture facilities in operation in the U.S.[26] There are 22 CCUS projects in the US in development, eight of which are pure sequestration projects and the rest EOR.[27] The deployment of direct air capture projects is beginning to ramp up as well.[28]

Most notably, in 2017, the NRG Petra Nova project in Texas was completed and captures ninety percent of the CO2 from a 240 MW slipstream of flue gas of its existing WA Parish plant, or roughly 1.6 million tons of CO2 per year.[29] The CO2 is then transported to an oil field nearby for EOR use.[30] This is the first industrial-scale, coal-fired, electricity-generating plant with CCS to operate in the United States.[31] Unfortunately the project was mothballed in 2020 due to a decline in oil prices during the pandemic, although NRG is currently evaluating its viability based on market changes in 2021.[32]

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25. Brad Page, *U.S. Leads New Wave of Carbon Capture and Storage Deployment*, THE HILL (Jan. 5, 2020), https://thehill.com/opinion/energy-environment/476783-us-leads-new-wave-of-carbon-capture-and-storage-deployment.

26. LABOR ENERGY P'SHIP, *supra* note 2 at 10.

27. LABOR ENERGY P'SHIP, *supra* note 2 at 12.

28. *Id*.

29. Folger, *supra* note 3 at 12.

30. *Id*.

31. *Id*. at 12-13.

32. Florian Martin, *Low Oil Prices Lead to Shutdown of Much-Hyped Carbon Capture System Outside Houston*, HOUSTON PUBLIC MEDIA (Aug. 3, 2020), https://www.houstonpublicmedia.org/articles/news/energy-environment/2020/08/03/379125/low-oil-prices-lead-to-shutdown-of-much-hyped-carbon-capture-system-outside-houston/; NRG Energy, Inc., *Petra Nova Status Update*, NRG (Aug. 26, 2020), https://www.nrg.com/about/newsroom/2020/petra-nova-status-update.html; Edward Klump, '*Falling Apart.' World's Largest CCS Plan Hits Snag*, E&E NEWS (June, 22, 2021), https://subscriber.politicopro.com/article/eenews/1063735475.

Also in 2017, Archer Daniels Midland launched its ADM Illinois Industrial Carbon Capture & Storage Project.[33] With this project, the sponsor began capturing CO2 from an ethanol production facility and sequestering it in a nearby deep saline formation. The project can capture up to 1.1 million tons of CO2 per year.[34]

There are also a number of additional proposed and pending projects. For example, an ammonia plant with near-zero CO2 emissions using a repurposed integrated gasification combined cycle plant with CCS was announced in Indiana.[35] The facility is expected to capture 1.5 to 1.75 Mtpa CO2 for geological storage in the Wabash CarbonSAFE CO2 storage hub.[36] Occidental Petroleum also announced the first large-scale direct air capture facility in Texas, which will capture more than one Mtpa of CO2 from the atmosphere.[37] The number of projects is only likely to grow as large firms such as BP, Shell, Equinor, Repsol, Eni, Occidental Petroleum, Entergy, Total, Dominion Energy, and NRG among others have all made net zero announcements and large banks and investors are increasingly reviewing the climate impacts of their investments.[38]

In addition to wholly private sector development, the U.S. Department of Energy ("DOE"), as directed by Congress, also plays a significant role in the growth of CCS by implementing test projects and engaging in R&D. As of January 2020, nine DOE-supported projects in the United States have injected large volumes of CO2 into underground formations as demonstrations of potential commercial-scale storage.[39] Four of these projects are actively injecting and storing CO2.[40] One of those four is in an underground saline reservoir that stores CO2 and simply demonstrates geologic sequestration, while the other three are in oil and gas reservoirs as part of EOR.[41]

The DOE has created the Regional Carbon Sequestration Partnership ("RCSP"), launched the Clean Coal Power Initiative, initiated its National Energy Technology Laboratory ("NETL") to implement a program titled "Carbon Capture and Sequestration from Industrial Sources and Innovative Concepts for Beneficial CO2 Use," and is using its Fossil Energy program to develop technologies that can capture and permanently store greenhouse gases.[42] Congress has

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33. *ADM Begins Operations for Second Carbon Capture and Storage Project*, ADM (Apr. 7, 2017), https://www.adm.com/news/news-releases/adm-begins-operations-for-second-carbon-capture-and-storage-project-1.

34. *Id*.

35. Page, *supra* note 25.

36. *Id*.

37. *Id*.

38. Medlock and Miller, *supra* note 10 at 30.

39. Angela C. Jones, *Injection and Geologic Sequestration of Carbon Dioxide: Federal Role and Issues for Congress*, CONGRESSIONAL RESEARCH SERVICE (Jan. 24, 2020), https://crsreports.congress.gov/product/pdf/R/R46192#:~:text=4%20EOR%20involves%20injecting%20CO2,of%20drinking%20water%20(USDWs).

40. *Id*.

41. LABOR ENERGY P'SHIP, *supra* note 2 at 10.

42. *Carbon Dioxide Capture and Sequestration: Federal Research and Regulations*, Climate Change, UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, https://19january2017snapshot.epa.gov/climatechange/carbon-dioxide-capture-and-sequestration-federal-research-and-regulations_.html.

made appropriations to support the DOE's carbon storage work, and, beginning in 2005, has proposed and enacted legislation directing the DOE to establish programs in this area.[43] Such programs include the Energy Policy Act of 2005 ("EPAct"),[44] which directed the DOE to carry out a 10-year carbon capture R&D program to develop technologies for use in new and existing coal combustion facilities. Under the EPAct, Congress directed the DOE, "in accordance with the carbon dioxide capture program, to promote a robust carbon sequestration program" and continue R&D work through carbon sequestration partnerships.[45] Another Congressional initiative was Section 354 of the EPAct, which directed the EPA to establish a demonstration program for CO2 injection for EOR purposes while increasing CO2 sequestration.[46] The Energy Independence and Security Act of 2007[47] amended Section 963 of the EPAct and increased the DOE's work on carbon sequestration R&D and demonstration.[48] Finally, Congress directed the DOE to conduct fundamental science and engineering research in CCS and to conduct training and research on geologic sequestration.[49]

In 2009, there were about 3,600 miles of CO2 pipeline in the U.S.[50] Today, there are approximately 5,000 miles of CO2 pipelines.[51] The U.S. regions with large-scale CO2 pipelines currently operating are the Permian Basin (West Texas, New Mexico, and Southern Colorado) with around 2,600 miles, the Gulf Coast (Mississippi, Louisiana, and East Texas) with 740 miles, the Rocky Mountains (Northern Colorado, Wyoming, and Montana) with 730 miles, the Mid-Continent (Oklahoma and Kansas) with 480 miles, and then a region containing the states of North Dakota and Michigan along with a section of Canada with 215 miles of pipeline.[52] The growth of CO2 pipelines is set to accelerate given the market and federal incentives at play. Recently, in March 2021, Valero announced it was partnering with BlackRock Global Energy & Power Infrastructure Fund and Navigator Energy Services to develop an industrial-scale CCS pipeline system which should span more than 1,200 miles in its initial phase.[53]

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43. Jones, *supra* note 39 at 6.
44. Energy Policy Act, Pub. L. No. 109-58 § 963, 119 Stat. 594 (2005).
45. Jones, *supra* note 39 at 6.
46. *Id*. at 6.
47. Energy Independence and Security Act of 2007 Pub. L. No. 110-140, 121 Stat. 1492 (2007).
48. Jones, *supra* note 39 at 6.
49. *Id.* at 6.
50. Robert Nordhaus and Emily Pitlick, *Carbon Dioxide Pipeline Regulation,* 30 THE ENERGY LAW JOURNAL 85 (Apr. 1, 2009).
51. Lee Beck, *Carbon Capture and Storage in the USA: The Role of US Innovation Leadership in Climate-Technology Commercialization*, 4 CLEAN ENERGY 9 (Dec. 24, 2019), https://academic.oup.com/ce/article/4/1/2/5686277.
52. MATTHEW WALLACE, LESSLY GOUDARZI, KARA CALLAHAN & ROBERT WALLACE, A REVIEW OF THE CO2 PIPELINE INFRASTRUCTURE IN THE U.S., U.S. Department of Energy, National Energy Technology Laboratory, Office of Fossil Energy, 31-32 (Apr. 21, 2015), https://www.energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20-%20A%20Review%20of%20the%20CO2%20Pipeline%20Infrastructure%20in%20the%20U.S_0.pdf.
53. *Valero and BlackRock Partner with Navigator to announce Large-Scale Carbon Capture and Storage Project,* BUSINESSWIRE (Mar. 16, 2021), https://www.businesswire.com/news/home/20210316005599/en/Valero-and-BlackRock-Partner-with-Navigator-to-Announce-Large-Scale-Carbon-Capture-and-Storage-Project.

IV. FEDERAL REGULATIONS AND INCENTIVES

A. Federal Regulatory Framework

The current federal regulatory framework for CO2 sequestration and transportation exists under a variety of authorities that have been patched together over the past decade. In 2007, the U.S. Supreme Court held CO2 is an air pollutant under the Clean Air Act in *Massachusetts v. EPA*.[54] Following the Supreme Court's decision in *Massachusetts v. EPA*, the EPA issued a series of regulations through its authority under the Clean Air Act ("CAA") to reduce GHG emissions from both mobile and stationary sources.[55] To date however, there are few EPA regulations affecting CO2. In addition, carbon dioxide has been conditionally excluded as a hazardous waste under the Resource Conservation and Recovery Act.[56] However, as demonstrated below, CO2 regulations have thus far been promulgated by administrative agencies. It remains possible that Congress could regulate CO2 as a commodity, deriving the power to regulate from the Commerce Clause of the U.S. Constitution. Nonetheless, Congress does not presently regulate CO2.

Beginning in December 2010, the EPA finalized its requirements for geological CO2 sequestration, designed to protect underground sources of drinking water ("USDW")[57] with the development of a new class of wells, Class VI, under the authority of the Safe Drinking Water Act's ("SDWA") Underground Injection Control ("UIC") Program.[58] These requirements, also known as the Class VI rule, contain specific criteria for Class VI wells, including (i) site characterization requirements, (ii) injection well construction requirements including long-term CO2 compatible materials, (iii) injection well operation requirements, (iv) monitoring requirements addressing well integrity, CO2 injection and storage, and ground water quality, (v) financial responsibility requirements to assure funds are available for the duration of a project, and (vi) reporting and record-keeping requirements to evaluate the operations and confirm USDW protection.[59] The SDWA currently serves as the major federal authority for regulating injection of CO2 for geologic sequestration and carbon storage in general.[60] However, the purpose of the Act is to prevent the endangerment of public water supplies and sources from injection activities.[61] Indeed, the EPA has identified specific policy areas related to geologic sequestration that it is not authorized to

54. Massachusetts v. EPA, 549 U.S. 497 (2007).

55. Linda Tsang, *U.S. Climate Change Regulation and Litigation: Selected Legal Issues*, CONGRESSIONAL RESEARCH SERVICE (Apr. 3, 2017), https://fas.org/sgp/crs/misc/R44807.pdf.

56. Hazardous Waste Management System: Conditional Exclusion for Carbon Dioxide (CO2), 79 Fed. Reg. 350 (Jan. 3, 2014).

57. *Underground Injection Control (UIC): Class VI- Wells Used for Geologic Sequestration of CO2*, UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, https://www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-co2 (Last visited July 2, 2020).

58. *Id.*

59. *Id.*

60. Jones, *supra* note 39.

61. *Id.*

regulate, including (but not limited to) the capture and transport of CO_2, managing human health and environmental risks other than drinking water endangerment, determining property rights, and the transfer of liability from one entity to another.[62] In the preamble to the proposed UIC Class VI Rule, the EPA states: "[w]hile the SDWA provides EPA with the authority to develop regulations to protect USDWs from endangerment, it does not provide authority to develop regulations for all areas related to GS [geologic sequestration]."[63]

Under the authority of the CAA, the EPA promulgated GHG reporting requirements ("GHGRP") for suppliers of CO_2 to be used in underground injection and for geologic sequestration.[64] Under these requirements, facilities that inject CO_2 for long-term sequestration and any facilities that inject CO_2 underground fall within the GHGRP and must develop and implement a monitoring, reporting, and verification plan.[65] Moreover, reporting requirements apply to both Class VI wells and Class II wells that inject CO_2.[66] These requirements will provide the EPA with information that can be used to monitor the growth and effectiveness of CCS as a GHG mitigation technology and consider further policies.[67]

While the Federal Energy Regulatory Commission ("FERC") regulates the sale and transportation of natural gas under the Natural Gas Act, Chapter 15B §717(b), FERC rejected oversight of CO_2 transportation pipelines in response to a 1979 inquiry by the Cortez Pipeline Company.[68] FERC responded to the inquiry by ruling that high-purity CO_2, used for CO_2-EOR in this inquiry, cannot be considered natural gas at the compositional level, and thus is not subject to FERC regulation.[69] Since FERC has rejected oversight of CO_2 pipelines, the eminent domain authority for FERC-approved natural gas interstate pipelines is not available to CO_2 pipelines.[70]

The Interstate Commerce Commission ("ICC") also determined it does not have oversight of CO_2 transportation pipelines in 1981 in response to a similar petition by the Cortez Pipeline Company.[71] The ICC concluded that CO_2 is transported as a gas (although it is frequently transported in a supercritical liquid phase) and thus was exempt from ICC oversight.[72]

Following these decisions by FERC and ICC, the U.S. Government Accountability Office ("GAO") determined that the U.S. Department of Transportation's

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62. *Id.* at 16.
63. *Id*.
64. *Id.*
65. 40 C.F.R. § 98.448 (2020).
66. 40 C.F.R. pt. 98 subpart RR (Subpart RR); 40 C.F.R. pt. 98 (Subpart UU).
67. *Carbon Dioxide Capture and Sequestration: Federal Research and Regulations*, Climate Change, UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, https://archive.epa.gov/epa/climatechange/carbon-dioxide-capture-and-sequestration-federal-research-and-regulations.html.
68. Wallace et. al., *supra* note 52 at 31.
69. *Id*.
70. Natural Gas Act, 15 U.S.C. §717.
71. Wallace et. al., *supra* note 52 at 31.
72. *Id*.

("DOT") Surface Transportation Board ("STB") has oversight over CO2 transportation pipelines, despite the STB being primarily responsible for regulating the interstate transportation of commodities "other than water, oil, or gas" by rail or pipeline.[73] However, the STB has not heard a case involving the transportation of CO2, so its oversight status remains as of yet unfulfilled.[74]

CO2 transportation pipelines are also subject to federal safety regulations by the U.S. DOT's Pipeline and Hazardous Materials Safety Administration ("PHMSA").[75] PHMSA regulates interstate pipeline safety, but state agencies regulate and inspect intrastate pipelines.[76] Although DOT does not consider CO2 a hazardous material, CO2 transportation pipelines are regulated under 49 CFR Part 195, Transportation of Hazardous Liquids by Pipeline, since transportation pipelines often carry highly-pressurized liquid-phase CO2.[77] However, smaller CO2 distribution lines transporting CO2 from the trunk-line to individual wells are generally not subject to PHMSA safety standards.[78]

Significantly, new CO2 transportation pipelines do not need federal siting authority, but the federal government also has no power of eminent domain regarding CO2 pipelines unless the pipeline is built on federal lands.[79] Siting and eminent domain issues for CO2 pipelines are regulated individually by the states.[80] The patchwork of rules and authorities for eminent domain and permitting in the absence of a federal framework creates complexity and challenges for CO2 pipeline developers.[81]

B. Tax Incentives

While there is no uniform federal regulatory framework, there are federal tax credits available, which are intended to incentivize investment in and development of CO2 sequestration projects and pipelines. Initially enacted in 2008, the Section 45Q Tax Credit[82] provides a credit per metric-ton of carbon oxide that is captured either from an industrial source by carbon capture equipment, where the carbon oxide would otherwise be released into the atmosphere, or through direct air capture.[83] The tax credits are available for carbon captured and sequestered, disposed of, or otherwise utilized in a manner that permanently removes the carbon oxide from the atmosphere, and are available during the 12-year period beginning with the year in which the carbon capture equipment is placed in service. The Internal Revenue Service ("IRS") recently issued guidance and final regulations that give much needed certainty on the requirements for investors

73. Wallace et. al., *supra* note 52 at 31-32.
74. Wallace et. al., *supra* note 52 at 32.
75. *Id*.
76. *Id*.
77. *Id*.
78. *Id*.
79. *Id*.
80. *Id*.
81. LABOR ENERGY P'SHIP, *supra* note 2 at 27, 29.
82. I.R.C. § 45Q.
83. I.R.C. § 45Q.

interested in financing carbon capture and sequestration projects to obtain the tax credits.

In February 2020, the IRS issued Revenue Procedure 2020-12, which provides a safe harbor partnership "flip" structure, already widespread in the wind and solar sectors, for carbon capture projects.[84] Under these structures, a tax equity investor, typically a large bank or corporation who can more efficiently use the tax credits, makes an equity investment in a project and is allocated the tax credits while their partner, a developer with limited tax appetite, is allocated a larger share of the cash flows of the project. Upon receiving a negotiated rate of return, the partnership "flips" and the tax equity investor receives a lower percentage of the tax allocations.

In February 2020, the IRS also provided guidance on when construction has begun for a qualified facility or carbon capture equipment,[85] which is a vital component of qualifying for the tax credits, as developers must generally "begin" construction before January 2026 in order to qualify for the tax credits.[86]

Significantly, in January 2021 the IRS issued final regulations for Section 45Q.[87] The final regulations describe how the owner of the carbon capture equipment, who is generally entitled to claim the tax credit, may contract with others to dispose of, inject, or use the carbon oxides and, in certain scenarios, may elect to allow that contractor to claim all or a portion of the credit.[88] The final regulations provide the compliance requirements for taxpayers to demonstrate secure geological storage for projects disposing of carbon oxide through sequestration or injecting carbon oxide in an EOR operation or, if the carbon oxide is utilized, through the fixation, chemical conversion or use of carbon oxide in other commercial products.[89] The final regulations also outline the situations in which the IRS can "recapture" credits if the carbon oxides escape.[90] The IRS recapture period for credits claimed in any given tax year lasts for up to three years.[91] If the loss of containment is not due to the selection, operation, or maintenance of the facility (*e.g.,* as in the case of volcanic activity or terrorist attacks), the IRS generally cannot recapture the credits.[92]

Finally, the IRS released a revenue ruling in July 2021 that clarified the scope of carbon capture equipment, the starting date for the tax credits, and the date the carbon capture equipment is considered placed-in-service for retrofitted carbon capture projects.[93]

84. *See* Rev. Proc. 2020-12, 2020-11 I.R.B.
85. *See* I.R.S. Notice 2020-12, 2020-11 I.R.B.
86. I.R.C. § 45Q(d)(1).
87. T.D. 9944, Treas. Dec. Int. Rev. (2021).
88. Treas. Reg. § 1.45Q-1(h).
89. Treas. Reg. § 1.45Q-3; Treas. Reg. § 1.45Q-4.
90. Treas. Reg. § 1.45Q-5.
91. Treas. Reg. §§ 1.45Q-5(f).
92. Treas. Reg. §§ 1.45Q-5(i).
93 Rev. Rul. 2021-13, 2021-20 I.R.B. This revenue ruling specifically addresses a facility with an existing acid gas removal unit.

The certainty provided in this detailed guidance and the limited recapture period will likely spur interest in carbon capture projects to generate these credits.

V. STATE REGULATORY FRAMEWORK

As no federal system governs CO2 pipeline siting, it is subject to individual state regulation. There are many factors to consider when determining the states in which to invest in CO2 sequestration and pipeline projects (for example the location of CO2 sources and sinks or state incentives, *see infra* at Section F), but in our view, the right to exercise eminent domain, or lack thereof, is probably the most significant and determinative. Most states do not permit eminent domain for CO2 pipelines, and variability in the rights, requirements, and processes exist across the states that do. For example, some states require certification processes in order to use eminent domain,[94] and some give common carriers[95] or public utilities[96] eminent domain rights, statuses which may come with further regulations.

A. General State Eminent Domain Requirements

In general, the states that allow eminent domain for CO2 pipelines seem to follow a similar process under the state's eminent domain title.[97] The condemnor must be unable to agree with the landowner on a sale of the land.[98] The condemnor must then file a petition in county court including the purpose for its taking, the legal basis for the taking, information on the land to be condemned and the

94. 220 ILL. COMP. STAT 75/20(a) (2020); KY. REV. STAT. ANN. § 154.27-100(2) (2021); LA. STAT. ANN. § 30:4(17)(a) (2020).

95. ARK. CODE ANN. § 23-15-101(a) (2019); COLO. REV. STAT. ANN. §§ 38-4-102, 40-9-102 (2021); MICH. COMP. LAWS § 483.5 (2021); MONT. CODE. ANN. § 69-13-101 (2019); N.D. CENT. CODE § 49-19-01 (2019); OKLA. STAT. tit. 52, § 24 (2020); S.D. CODIFIED LAWS § 49-7-11 (2021); TEX. NAT. RES. CODE ANN. § 111.002(6) (2021).

96. COLO. REV. STAT. ANN. § 40-1-103(1)(a)(I) (2021); WYO. STAT. ANN. § 37-1-101(a)(vi)(G)(II)) (2020) (carving out EOR pipelines from public utility status, although other CO2 pipelines may be considered public utilities if they transport gas "for the public").

97. LA. STAT. ANN. §§ 19:2.1(A), 30:1108(2)(C) (2020); MISS. CODE ANN. § 11-27-1 (2019); MONT. CODE. ANN. § 70-30 (2020). Proceedings and rules of practice are detailed in the Montana Rules of Civil Procedure and the Montana Rules of Evidence. MONT. CODE. ANN. § 70-30-201 (2020); N.M. STAT. ANN. §§ 42A-1-1 to -33 (2021); N.M. STAT. ANN. § 70-3-5 (2021); N.D. CENT. CODE § 49-19-12 (2019); OKLA. STAT. tit. 52 § 46.3 (2020); TEX. PROP. CODE § 21.011 (2019).

98. ARK. CODE ANN. § 18-15-1202(a)(1) (2019); KY. REV. STAT. ANN. § 154.27-100(2) (2020); KY. REV. STAT. ANN. § 416.550 (2020). Note that some states, such as Mississippi, New Mexico, North Dakota, Texas, and Wyoming require more specific procedures such as written offers and appraisals being made available to the landowner prior to commencing an eminent domain suit. MISS. CODE ANN. § 11-27-7 (2019); N.M. STAT. ANN. § 42A-1-4 (2021); N.D. CENT. CODE § 32-15-06.1 (2019); TEX. PROP. CODE §§ 21.0111, 21.0113 (2019); WYO. STAT. ANN. § 1-26-509 (2020). Some states also allow the condemnor to enter the land for surveys and sampling before they are granted any rights to the land, though they may need landowner or court approval and can be liable for damages. CAL. CIV. PROC. CODE § 1245.010, -.020, -.060 (2020); MISS. CODE ANN. § 11-27-39 (2019); N.M. STAT. ANN. §§ 42A-1-8 to -10, -12 (2021); N.D. CENT. CODE § 32-15-06 (2019); OKLA. STAT. tit. 66 §§ 7, 51 (2020); WYO. STAT. ANN. § 1-26-506; -507, -508 (2020). This right is important so that pipeline companies can evaluate whether areas of land will be suitable for their pipeline before entering a costly legal process.

landowner, and a request that the court will determine the amount of compensation.[99] The condemnor must also give notice to the landowner, and post notices in a newspaper of general circulation if normal notice procedures cannot be followed (for example, if the owner cannot be found).[100] The court typically decides whether the condemnor has eminent domain rights, while a jury or a few impartial local landowners may decide the amount of compensation.[101] The decision-makers usually must view the land themselves and determine an amount based on the fair market value of the land being taken.[102] After the court delivers a

99. ARK. CODE ANN. § 18-15-1202(a)(2) (2019); CAL. CIV. PROC. CODE § 1250.310 (2020); COLO. REV. STAT. ANN. § 38-1-101.5(1)(b), (2), -102(1) (2021); KAN. STAT. ANN. § 26-501(b), -502 (2020); KY. REV. STAT. ANN. § 416.570 (2021); LA. STAT. ANN. § 19:2.1(A), (A)(1) (2020); LA. STAT. ANN. § 30:1108(2)(C) (2020); MISS. CODE ANN. § 11-27-5 (2019); MONT. CODE. ANN. §§ 70-30-202, 203 (2019); N.M. STAT. ANN. § 42A-1-17 (2021); N.D. CENT. CODE § 32-15-18 (2019); OKLA. STAT. tit. 66 § 53(A) (2020); S.D. CODIFIED LAWS § 21-35-1, -2 (2019); TENN. CODE. ANN. § 29-16-104 (2019); TEX. PROP. CODE ANN. § 21.012 (2019); UTAH CODE ANN. § 78B-6-507 (2019); WYO. STAT. ANN. § 1-26-512 (2020). California and Colorado require additional proof regarding the optimality of the planned route of the pipeline in order to be granted eminent domain rights. CAL. CIV. PROC. CODE § 1240.030(b) (2020); COLO. REV. STAT. ANN. § 38-1-101.5(1)(a), (c) (2021).

100. ARK. CODE ANN. § 18-15-1202(c) (2020); CAL. CIV. PROC. CODE § 1250.120 (2020); COLO. REV. STAT. ANN. § 38-1-103 (2021); 735 ILL. COMP. STAT. 30/10-5-25 (2020); KAN. STAT. ANN. §§ 26-503, -506 (2020); MONT. CODE. ANN. § 70-30-202 (2019); N.M. STAT. ANN. § 42A-1-14 (2021); OKLA. STAT. tit. 66 §53(B) (2020); S.D. CODIFIED LAWS § 21-35-9, -10 (2019); TENN. CODE. ANN. § 29-16-105 (2020); TEX. PROP. CODE ANN. §§ 21.012(c); 21.016 (2019).

101. ARK. CODE ANN. § 18-15-1204 (2020); CAL. PUB. UTIL. CODE. § 625(a)(3) (2020) (commissioner or administrative law judge); COLO. REV. STAT. ANN. §§ 38-1-101(2)(a), 106, -107 (2021); KAN. STAT. ANN. § 26-504 (2020); KY. REV. STAT. ANN. §§ 416.610(4), 416.580(1) (2021); LA. STAT. ANN. §§ 19:4, 19:8, 19:9 (B), 30:1108(C) (2020); MICH. COMP. LAWS § 213.62 (2020); MONT. CODE. ANN. § 70-30-206, -207 (2019); N.M. STAT. ANN. § 42A-1-19(A) (2021); N.D. CENT. CODE § 32-15-13, -21, -22 (2019); OKLA. STAT. tit, 66 §§53, 55 (2020); S.D. CODIFIED LAWS § 21-35-10.1, -13, -15 (2019); TENN. CODE ANN. § 29-16-108 to 110, -113 (2020); TEX. PROP. CODE ANN. § 21.014 (2019); UTAH CODE ANN. § 78B-6-511 (2020). The states also have varying provisions regarding awarding attorney's fees, *see* CAL. CIV. PROC. CODE § 1250.410, 1268.610 (2020); LA. STAT. ANN. § 19:8(A) (2020); MISS. CODE ANN. § 11-27-37 (2019); N.D. CENT. CODE § 32-15-28, -32, -35 (2019); OKLA. STAT. tit. 66 § 55(D) (2020); MONT. CODE. ANN. § 70-30-206(b)(4) (2019); N.M. STAT. ANN. § 42A-1-32 (2021); N.D. CENT. CODE § 32-15-32 (2019); TEX. PROP. CODE ANN. § 21.047 (2019); and whether parcels must be handled in combined or separate trials and opportunities for alternative dispute resolution, *see* CAL. CIV. PROC. CODE § 1250.240, .420, 1273.010 – 1273.050 (2020); COLO. REV. STAT. ANN. § 38-1-104 (2021); 735 ILL. COMP. STAT. 30/10-5-30 (2020); MISS. CODE ANN. § 11-27-13 (2019); MONT. CODE. ANN. § 70-30-301(1), (3)(b) (2019); N.M. STAT. ANN. § 42A-1-19(B) (2021); N.D. CENT. CODE § 32-15-19 (2019); S.D. CODIFIED LAWS § 21-35-18 (2021); UTAH CODE ANN. § 78B-6-507 (2020); WYO. STAT. ANN. § 1-26-509(h) (2020).

102. 735 ILL. COMP. STAT. 30/10-5-5 (2019); KAN. STAT. ANN. § 26-506 (2019); KY. REV. STAT. ANN. § 416.580(1) (2019); MICH. COMP. LAWS § 213.70 (2019); MISS. CODE ANN. § 11-27-19 (2019); MONT. CODE. ANN. §§ 70-30-301, -302, -313 (2019); S.D. CODIFIED LAWS § 21-35-16 (2019); TEX. PROP. CODE ANN. §§ 21.041, 21.042 (2019); WYO. STAT. ANN. §§ 1-26-702 to 714 (2020).

verdict and the condemnor pays compensation, the condemnor is given title to the property.[103] The parties may appeal.[104]

B. Specific State Requirements for Exercising Eminent Domain for CO2 Pipelines

In this section, we will describe the specific requirements in certain states that allow eminent domain for CO2 pipelines. This section reviews the major rules determining whether eminent domain is available to particular parties looking to construct CO2 pipelines. These include the types of entities and projects eminent domain is granted for, including permitted uses and common carrier or public utility status and regulations. Note that companies and projects otherwise eligible for eminent domain, will still need to comply with the applicable procedural process, including something akin to the general procedural process described above and any other specific procedural requirements in that state. These requirements are beyond the scope of this article, which focuses on substantive access to eminent domain rights.

1. Permitted Uses

Most states that provide eminent domain for CO2 pipelines permit the use of eminent domain for pipelines more broadly without limiting the use of eminent domain based on a specific end use.[105] However, Mississippi[106] only permits eminent domain for CO2 pipelines for EOR use, not storage or other commercial

103. CAL. CIV. PROC. CODE § 1268.210 (2020); COLO. REV. STAT. ANN. § 38-1-108 (2021); KAN. STAT. ANN. § 26-507 (2019); KY. REV. STAT. ANN. § 416.620(6) (2021); MICH. COMP. LAWS § 213.57 (2021); MISS. CODE ANN. § 11-27-27 (2019); MONT. CODE. ANN. § 70-30-311 (2019); N.M. STAT. ANN. § 42A-1-27 (2021); N.D. CENT. CODE § 32-15-27 (2019); S.D. CODIFIED LAWS § 21-35-25 (2019); TENN. CODE ANN. § 29-16-122 (2019); UTAH CODE ANN. §§ 78B-6-515, 516 (2020). Importantly, California, New Mexico, and Texas allow the condemnor to acquire use of the property before the eminent domain case is finalized with the courts if the condemnor can show why it is necessary they begin their project rather than wait and make a deposit in the amount of expected compensation. ARK. CODE ANN. § 18-15-1206 (2019); CAL. CIV. PROC. CODE § 1255.410 (2020); 735 ILL. COMP. STAT. 30/20-5-5 (2019); MICH. COMP. LAWS § 213.59(1)-(2) (2019); N.M. STAT. ANN. § 42A-1-22 (2021); TEX. PROP. CODE ANN. § 21.021 (2019); UTAH CODE ANN. § 78B-6-510 (2020).

104. ARK. CODE ANN. § 18-15-103(10) (2020); COLO. REV. STAT. ANN. § 38-1-110 (2021); 735 ILL. COMP. STAT. 30/10-5-70; KAN. STAT. ANN. §§ 26-504 (2019); MISS. CODE ANN. § 11-27-29 (2019); MONT. CODE. ANN. § 70-30-304 (2019); OKLA. STAT. tit. 66 § 56 (2020); S.D. CODIFIED LAWS § 21-35-20 (2019); TENN. CODE ANN. § 29-16-118 (2019); TEX. PROP. CODE ANN. § 21.018 (2019).

105. CAL. PUB. UTIL. CODE. § 615 (2020); COLO. REV. STAT. ANN. §§ 38-2-101, 38-5-105; 38-1-202 (2021) (listing all statutes under which pipeline companies are granted eminent domain); 220 ILL. COMP. STAT. 75/5 (2019) (mentioning sequestration and EOR, though leaving eminent domain open to broader carbon management purposes in the public interest); IND. CODE § 14-39-1-7 (2019); KY. REV. STAT. ANN. § 154.27-100(2) (2021); MICH. COMP. LAWS §§ 483.2(1)(a), 483.1(1)(a) (2021); MONT. CODE. ANN. §§ 69-13-101,-101(3)(a), -102, -104 (2019); N.M. STAT. ANN. § 70-3-5 (2021); N.D. CENT. CODE § 49-19-09 (2019); S.D. CODIFIED LAWS § 49-7-11 (2019); TENN. CODE ANN. § 65-28-101 (2019); TEX. NAT. RES. CODE ANN. §§ 111.002(6), 111.019, 111.020, 111.022 (2019); WYO. STAT. ANN. § 1-26-814 (2020).

106. MISS. CODE ANN. § 11-27-47 (2019).

purposes. Louisiana allows eminent domain for CO2 pipelines for EOR purposes,[107] but also permits eminent domain for those built by CO2 storage operators.[108]

Whether eminent domain is available to CO2 pipelines in Oklahoma is less clear. Oklahoma regulates oil and intrastate natural gas pipelines as common carriers with the right to eminent domain.[109] Those constructing CO2 pipelines may be able to use this regime; however, since Oklahoma does not have specific CO2 pipeline legislation, it is unclear whether Oklahoma law considers pipeline operators common purchasers or carriers like they do natural gas pipeline operators.[110] It is possible that the definition of common carrier may be broad enough on its own to include CO2 pipelines since it declares that "[e]veryone who offers to the public to carry persons, property or messages is a common carrier of whatever he thus offers to carry."[111] If CO2 qualifies as property and if pipeline services are considered offered to the public, pipeline operators could exercise eminent domain, but would also be subject to Oklahoma common carrier regulations.[112] However, to date, it is unclear how Oklahoma law would treat CO2 pipeline operators.

2. Common Carrier and Public Utility Status

Montana, North Dakota, Oklahoma, and Texas grant eminent domain for CO2 pipelines only under their common carrier statutes.[113] In Colorado, on the other hand, multiple statutes grant pipeline companies the right of eminent domain,[114] including under the common carrier article[115] and the corporations title.[116] In Colorado, pipeline companies generally are common carriers,[117] and Colorado considers common carriers and pipeline corporations to be public utilities.[118]

Common carrier status, while giving companies access to eminent domain, does subject companies operating the pipelines to more regulation and oversight. Common carriers are usually regulated by the public service commission of the state and must follow the regulations in the common carrier chapter or title of

107. LA. STAT. ANN. § 19:2(10) (2019).
108. LA. STAT. ANN. § 30:1108(a)(1) (2019).
109. OKLA. STAT. tit. 52 §§ 3, 23, 24 (2020).
110. OKLA. STAT. tit. 52 §§ 23, 24 (2020).
111. OKLA. STAT. tit. 13 § 4 (2020).
112. OKLA. STAT. tit. 13 (2020).
113. ARK. CODE ANN. § 23-15-101(a) (2020); COLO. REV. STAT. ANN. §§ 38-4-102, 40-9-102(1) (2020); MICH. COMP. LAWS § 483.5 (2021); MONT. CODE. ANN. §§ 69-13-101 (2019); N.D. CENT. CODE § 49-19-01 (2019); OKLA. STAT. tit. 52 § 24 (2020); S.D. CODIFIED LAWS § 49-7-11 (2019); TEX. NAT. RES. CODE ANN. § 111.002(6) (2019).
114. COLO. REV. STAT. ANN. § 38-2-101 (2020); COLO. REV. STAT. ANN. § 38-5-105 (2020); COLO. REV. STAT. ANN. § 38-1-202(2)(b) (2020) (listing all statutes under which pipeline companies are granted eminent domain).
115. COLO. REV. STAT. ANN. § 38-4-102 (2020).
116. COLO. REV. STAT. ANN. § 7-43-102; 38-4-105 (2020).
117. COLO. REV. STAT. ANN. § 40-9-102(1) (2020).
118. COLO. REV. STAT. ANN. § 40-1-103(1)(a)(I) (2020).

that state.[119] These regulations include charging reasonable and uniform rates, which are often publicly available, without discrimination, and following rate-making procedures.[120] Additionally, common carriers or public utilities are required to pay just compensation for rights of way (including when exercising eminent domain),[121] file monthly reports,[122] and be subject to inspection.[123]

Some states legislate that certain entities are considered common carriers, while other states have particular requirements that must be satisfied for the entity to be considered a common carrier. Recently, the Texas Supreme Court in *Denbury Green Pipeline-Texas LLC v. Texas Rice Land Partners, Ltd.*[124] determined that companies can no longer simply "check the common carrier box," but must provide some proof that they are a common carrier if a landowner challenges that status.[125] In order to demonstrate common carrier status, "the company must present reasonable proof of a future customer, thus demonstrating that the pipeline will indeed transport 'to or for the public for hire' and is not 'limited in [its] use to the wells, stations, plants, and refineries of the owner.'"[126] Thus, in order to be able to use eminent domain, companies will need to show the pipeline is not just for the owner's use. However, the bar is low since the requirement to be found a common carrier is just to show "reasonable probability that, at some point . . . the [carbon dioxide pipeline]…would serve the public" and reasonable proximity to other CO2 shippers or providing contracts to carry CO2 for non-affiliates should suffice.[127]

In California, any pipeline corporation considered a public utility may condemn any property necessary for the construction and maintenance of its pipeline using eminent domain; however, if it offers competitive services, it must show the condemnation is in the public interest.[128] Under California law, pipeline corporations are considered public utilities if "the service is performed for, or the commodity is delivered to, the public or any portion thereof."[129]

There is some concern that CO2 pipelines might not meet the public use or benefit requirement if CO2 is determined to be a "waste."[130] This is particularly

119. MONT. CODE. ANN. §§ 69-13-101(b), -102 (2019); N.D. CENT. CODE § 49-19-01 (2019). In Wyoming, the Public Service Commission may regulate CO2 pipelines for non-EOR uses if the pipeline was considered to transport gas "for the public." WYO. STAT. ANN. § 37-1-101(a)(vi)(G) (2020).

120. COLO. REV. STAT. ANN. §§ 38-4-105 (2020); MONT. CODE. ANN. §§ 69-13-201, -303 (2019); N.D. CENT. CODE §§ 49-19-13, -17, -19, -20 (2019); TEX. NAT. RES. CODE ANN. §§ 111.014, -.015, -.017 (2019).

121. COLO. REV. STAT. ANN. § 38-4-107 (2020).

122. MONT. CODE. ANN. § 69-13-301 (2019).

123. N.D. CENT. CODE §§ 49-02-14; 49-19-02 (2019).

124. Denbury Green Pipeline-Texas, LLC v. Texas Rice Land Partners, LTD., No. 15-0225, 909 (Tex. 2016), http://www.txcourts.gov/media/1436866/150225.pdf.

125. *Id*.

126. *Id*. at 912.

127. John McFarland, *Landowners Lose in Denbury v. Texas Rice Land Partners*, OIL AND GAS LAWYER BLOG, GRAVES DOUGHERTY HEARON & MOODY (Jan. 9, 2017), https://www.oilandgaslawyer-blog.com/landowners-lose-denbury-v-texas-rice-land-partners/.

128. CAL. PUB. UTIL. CODE. §§ 615, 625(a)(1)(A), (b), (f) (2020) (requiring the exercise of eminent domain under Title 7 of the Code of Civil Procedure beginning at section 1230.010).

129. CAL. PUB. UTIL. CODE. § 216(a)(1) (2020).

130. Medlock and Miller, *supra* note 10 at 16.

concerning in Texas under the *Denbury* ruling discussed above that could suggest customers would need to retain ownership of their CO2 in the pipeline and then sell it, which may be at odds with the concept of the customer having simply disposed of it at this phase.[131] Additionally, "waste" disposal may not seem to offer a direct public benefit that aligns with the statutory justification for eminent domain.[132] Since the Texas Supreme Court has also ruled that landowners can challenge a company's common carrier self-designation, a motivated landowner could challenge and potentially prevent common carrier eminent domain for CO2 pipelines.[133]

In states that consider pipelines to be public utilities, being a public utility has similar implications to being a common carrier. For example, in California a public utility is subject to the regulations of the public utilities commission[134] and must follow all orders, decisions, directions, or rules of the commission.[135] Public utilities also must pay an annual fee,[136] provide information and reports,[137] charge just and reasonable rates,[138] make rate filings,[139] and be subject to rate investigations by the commission.[140]

C. Other Considerations for CO2 Pipeline Siting

While the right to exercise eminent domain rights is a significant factor in determining where to site CO2 pipelines, it is not the only consideration. There are also other state-specific factors when selecting where to site a CO2 pipeline. Obviously, one must consider the location of CO2 sources and sinks. It is also important to consider the state laws that will be applicable to the pipelines and other infrastructure that will service CO2 sequestration projects when determining whether and where to invest in CO2 sequestration projects. That is because the feasibility and practicality of building the necessary infrastructure to service those projects will dictate their viability and potential profitability. While the locations of CO2 sources and sinks are likely fixed, when thinking about developing and investing in either CO2 sequestration projects or their supporting infrastructure, it is paramount to consider all sides of the equation, as state-law roadblocks to CO2 pipelines could render an otherwise potentially profitable CO2 project ultimately worthless, and pipelines to not-yet-existing CO2 sources may never come to fruition.

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131. *Id*.
132. Tracy Hester and Elizabeth George, *The Top Five Legal Barriers to Carbon Capture and Sequestration in Texas*, FORBES (Nov. 19, 2019), https://www.forbes.com/sites/uhenergy/2019/11/19/the-top-five-legal-barriers-to-carbon-capture-and-sequestration-in-texas/?sh=38fc87887508.
133. *Id*.
134. CAL. PUB. UTIL. CODE. § 216(b) (2020).
135. CAL. PUB. UTIL. CODE. § 702 (2020).
136. CAL. PUB. UTIL. CODE. § 431 (2020).
137. CAL. PUB. UTIL. CODE. §§ 434, 581-82, 584 (2020).
138. CAL. PUB. UTIL. CODE. § 451 (2020).
139. CAL. PUB. UTIL. CODE. § 486 (2020).
140. CAL. PUB. UTIL. CODE. § 703 (2020); other rights and obligations applying to public utilities can be found in §§ 451-651.

1. Other State Regulations and Incentives

In addition to eminent domain, individual states have various incentives and regulations for CCS projects that may make projects more or less attractive in that state. First, this section will focus on state permitting and enforcement regimes, in particular for non-EOR sequestration and long-term liability rules. These are particularly important as progress regarding siting, permitting and long-term liability for geologically stored CO2 has been identified as a key impediment slowing carbon capture development.[141] Then, this section will provide an overview of other relevant state laws such as those regulating EOR and sequestration as well as financial incentives for CCS.[142]

a. State Permitting and Enforcement Regimes for Non-EOR Sequestration

The UIC Class II well permit that is used by the EPA for EOR has been in existence for three decades.[143] Consequently, all states except Arizona, Florida, Hawaii, Idaho, Iowa, Minnesota, Virginia, New York and Pennsylvania have developed their own local permitting and enforcement regimes to get these wells approved and, therefore, have primacy over the EPA in handling Class II permits.[144] Thus, the proper siting authority in most states for Class II EOR wells is the state rather than the EPA, a situation that leads to more seamless permitting for these wells. As of 2019, there are 157,667 permitted Class II wells in the United States.[145]

The most recent category of UIC well with regulations promulgated in 2010, Class VI wells, are specifically designed for carbon dioxide sequestration purposes.[146] Class VI wells are the appropriate well for non-EOR sequestration of carbon dioxide.[147] The requirements for these wells are more demanding upfront

141. LABOR ENERGY P'SHIP, *supra* note 2 at 10.

142. ENVTL. PROT. AGENCY, DOCKET ID NO. EPA–HQ–OAR–2013–0495, COMMENT LETTER ON THE ENVIRONMENTAL PROTECTION AGENCY'S PROPOSED REVIEW OF STANDARDS OF PERFORMANCE FOR GREENHOUSE GAS EMISSIONS FROM NEW, MODIFIED, AND RECONSTRUCTED STATIONARY SOURCES: ELECTRIC UTILITY GENERATING UNITS, 83 FED. REG. 65, 424 (DEC. 20, 2018) (March 18, 2019), https://oag.ca.gov/system/files/attachments/press_releases/Appendix%20B%20CCS%20in%20State%20Statutes%20%26%20Regulations.pdf.

143. UNITED STATES ENVTL. PROT. AGENCY, Introduction to the Underground Injection Control Program, https://www.epa.gov/sites/production/files/2018-06/documents/introduction_to_training_course_and_uic_overview_2018_-_nathan_wiser.pdf.

144. *Primary Enforcement Authority for the Underground Injection Control Program*, Underground Injection Control (UIC), UNITED STATES ENVTL. PROT. AGENCY, https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program.

145. *UIC Injection Well Inventory*, Underground Injection Control (UIC), UNITED STATES ENVTL. PROT. AGENCY, https://www.epa.gov/uic/uic-injection-well-inventory (including both state and tribal lands).

146. ENVTL. PROT. AGENCY, *supra* note 143.

147. Molly Bayer and Brian Graves, Geologic Sequestration of CO_2 and Class VI Wells: UIC Inspector Training, United States Environmental Protection Agency (July 2019), https://www.epa.gov/sites/production/files/2019-08/documents/graves_-_class_vi_wells_2019.pdf; T.D. 9944, Treas. Dec. Int. Rev. 51-52 (2021) (for purposes of the 45Q tax credit).

and as an ongoing compliance matter in comparison to Class II wells.[148] To date only six permits have been issued, only two of which are active and not expired.[149] Of these existing permits the time it took the final permit to drill was about 3 years for the two active permits, and about 18 months for the four inactive permits.[150] For the two active permits, the process from initiating drilling to receiving an Authorization to Inject took an additional 2 to 3 years, for a total of about 6 years.[151] While the Class VI requirements present an added burden to non-EOR sequestration in general, a few states have pursued primacy, which may result in a more manageable process for non-EOR sequestration. Thus far, only North Dakota and Wyoming have primacy,[152] and Louisiana has applied.[153] This means that, currently, the only two states with authority to approve Class VI injection wells for non-EOR sequestration purposes are North Dakota and Wyoming. For non-EOR sequestration projects in the rest of the United States, the approval for Class VI wells must be obtained from the EPA. Thus, these states may have slower and more divided permitting pathways for non-EOR sequestration projects, and this will likely remain the case for some time as it may take a few years for states to be granted primacy after application.[154]

Additionally, states may need to sort out administrative matters to set up their permitting and enforcement regimes prior to applying. For example, the legislature of Texas, a major oil and gas producing state, only recently introduced a bill, which failed in committee, granting the Railroad Commission of Texas (the "Railroad Commission") sole authority over carbon sequestration wells.[155] Authority is currently split between the Railroad Commission and the Texas Commission on Environmental Quality complicating any pursuit of primacy.[156] Texas had also passed a bill providing permitting and compliance for carbon sequestration wells, just prior to the final Class VI regulations, but has not yet revised that

148. UNITED STATES ENVTL. PROT. AGENCY, GEOLOGIC SEQUESTRATION OF CARBON DIOXIDE: UNDERGROUND INJECTION CONTROL (UIC) PROGRAM CLASS VI IMPLEMENTATION MANUAL FOR UIC PROGRAM DIRECTORS (Jan 2019), https://www.epa.gov/sites/production/files/2018-01/documents/implementation_manual_508_010318.pdf; United States ENVTL. PROT. AGENCY, Underground Injection Control (UIC) Program: Class II Permit Application Completeness Review Checklist, https://www.epa.gov/sites/production/files/2019-08/documents/solution_2.2_-_class_ii_administrative_review_checklist_draft_final.pdf.

149. Bayer and Graves, *supra* note 147.

150. National Petroleum Council, *Policy, Regulatory and Legal Enablers*, *in* MEETING THE DUAL CHALLENGE: A ROADMAP TO AT-SCALE DEPLOYMENT OF CARBON CAPTURE, USE AND STORAGE 3-21 (Dec. 12, 2019), https://dualchallenge.npc.org/files/CCUS-Chap_3-122220.pdf. Note these inactive permits were for a project that ran out of time to use federal funding and was never fully completed. *Id*.

151. *Id*.

152. *Primary Enforcement Authority for the Underground Injection Control Program supra* note 144.

153. Hester and George, *supra* note 132.

154. MATTHEW GERACI, SYED JEHANGEER ALI, COURTNEY ROMOLT & REGINA ROSSMAN, THE ENVIRONMENTAL RISKS AND OVERSIGHT OF ENHANCED OIL RECOVERY IN THE UNITED STATES, Clean Water Action | Clean Water Fund, 48 (Aug. 2017), https://www.cleanwateraction.org/sites/default/files/docs/publications/The%20Environmental%20Risks%20and%20Oversight%20of%20Enhanced%20Oil%20Recovery%20in%20the%20United%20States%2008.17.17a.pdf.

155. S.B. 450, 2021-2022 Leg., 87th Sess. (Tx. 2021), https://legiscan.com/TX/bill/SB450/2021.

156. Medlock and Miller, *supra* note 10 at 10); Hester and George, *supra* note 132.

statute in connection with seeking primacy.[157] Texas will likely need to pass additional legislation and amend the current statutes to successfully seek primacy from the EPA, including either granting a single agency authority over carbon sequestration wells or a clear articulation for multiple agencies to work together to apply for primacy.[158] The faster states take on primacy, the more quickly they can nimbly respond to interest in the market to complete these projects.

b. Long-term Liability

Laws providing for liability caps or the assumption by the state of long-term liability for CO2 storage sites provide certainty to investors in valuing their risk, particularly in light of novelty in the insurance market and unclear federal liability policy.[159] Illinois, Louisiana, Montana, North Dakota, and Texas have passed legislation providing transfer of long-term liability and site ownership to the state after injection. Louisiana, Montana, Wyoming, Texas, Oklahoma, and North Dakota all provide that initially the project operator is responsible until liability is transferred to the state.[160]

Legislation in Illinois and Texas (offshore only) provide for the state to assume liability for the period after well closure. However, Illinois's bill only applies to a specific carbon capture project.[161] Texas's law, HB 1769 signed September 1, 2009,[162] grants the Texas School Land Board authority to oversee offshore carbon dioxide storage sites and accept carbon dioxide for a fee, with scientific advisement and measurement, monitoring and verification from the Bureau of Economic Geology at the University of Texas at Austin.[163] The Texas School Land Board takes title and liability relating to the CO2 in the depository once permanent storage is verified and applicable regulations are complied with, but the board does not take liability with regards to the CO2 prior to storage in the repository or regarding any liability for the construction of the repository.[164]

Under bills in Louisiana and North Dakota, the state assumes title and liability after 10 years, provided a certificate of completion is received by the project and there is proof of well integrity since closure.[165] Montana assumes liability after

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157. S.B. 1387, 2009 Leg., 81st Sess, (Tx. 2009), https://capitol.texas.gov/tlodocs/81R/billtext/pdf/SB01387F.pdf#navpanes=0; 16 TEX. ADMIN. CODE § 5.201 et seq. (2019).

159. Medlock and Miller, *supra* note 10 at 11; Hester and George, *supra* note 132; LABOR ENERGY P'SHIP, supra note 2 at 31.

160. S.B. 498, 2009 Leg., 61st Sess. (Mt. 2009); WYO. STAT. ANN. § 34-1-153 (2020); TEX. HEALTH & SAFETY CODE § 382.508 (2009); OKLA. STAT. tit. 27-A § 3-5-105; LA. STAT. ANN. § 30:1103(10) (2021); N.D. CENT. CODE § 38-20-16 (2021).

161. Clean Coal FutureGen for Illinois Act, S.B. 1704, § 20, 25, 30 (2009). Interestingly this bill also provides for eminent domain powers for this specific project by declaring it in the public interest and for public use. *Id*. at § 45.

162. H.B. 1796, 2009 Leg., 81st Sess. (Tx. 2009), https://capitol.texas.gov/tlodocs/81R/billtext/pdf/HB01796F.pdf#navpanes=0.

163. TEX. HEALTH & SAFETY CODE § 382.503, -.505, -.506 (2009).

164. TEX. HEALTH & SAFETY CODE § 382.507, -.508 (2009).

165. H.B. 661, 2009 Leg., § 1109 (La. 2009); S.B. 2095, 2009 Leg., 61st Sess. § 38-20-16. § 38-20-17 (Nd. 2009).

30 years. [166] A certificate of completion may be issued 15 years after completion and if no leakage or movement of CO2 is demonstrated in the 15 years after the issuance of a certificate of completion, liability is transferred to the state.[167] Kansas has specifically rejected liability and any responsibility for CO2 injection wells or storage sites.[168]

c. Other State Regulations and Incentives

California provides a credit of nearly $200/ton for certain CCS projects in California under its Low Carbon Fuel Standard, which can be claimed by CCS projects outside of California as long as the resulting fuel is consumed in California.[169]

Kansas has created the authority for the corporation commission to create regulations for EOR and non-EOR CO2 sequestration. [170] Kansas also exempts CO2 capture, sequestration, utilization property from property taxation and provides for a deduction based on the costs of capture, sequestration, or utilization machinery.[171]

Louisiana exempts approved EOR projects from severance taxes until the project has reached payout.[172] After the EOR project reaches payout, severance tax on future production is reduced to 50% of that which would normally be due.[173] Louisiana also requires permits for CO2 injections for EOR operations[174] and has many regulations for the construction, design, safety, and operation of CO2 pipelines.[175] Louisiana permits eminent domain for CO2 sequestration sites.[176]

Montana has a regulatory system for carbon dioxide injection and EOR[177] and provides a 3% or lower tax rate for CO2 pipelines, sequestration, and EOR equipment.[178]

166. S.B. 498, 2009 Leg., 61st Sess. § 4 (Mt. 2009).

167. *Id*.

168. H.B. 2418, 2010 Leg., (Ks. 2010); KAN. STAT. ANN. § 55-1637(h) (2020).

169. LABOR ENERGY P'SHIP, *supra* note 2 at 30; *Carbon Capture and Sequestration Project Eligibility FAQ*, CALIFORNIA AIR RESOURCES BOARD, https://ww2.arb.ca.gov/resources/fact-sheets/carbon-capture-and-sequestration-project-eligibility-faq.

170. KAN. STAT. ANN. §§ 55-1636.

171. KAN. STAT. ANN. §§ 79-233; KAN. STAT. ANN. §§ 79-32, 256.

172. LA. REV. STAT. ANN. § 47:633.4(B)(1) (2019).

173. LA. REV. STAT. ANN. § 47:633.4(B)(2) (2019). Michigan similarly allows for reduced severance tax rate for approved EOR projects using CO2. MICH. COMP. LAWS § 205.303(4) (2019).

174. LA. ADMIN. CODE tit. 43, § XIX-403, -405, -407 (2018).

175. LA. ADMIN. CODE tit. 43, § XI, subpt. 4 (2018). Michigan also regulates CO2 pipelines and injection wells. MICH. ADMIN. CODE. 299.9204 (2021).

176. H.B. 661, 2009 Leg., (La. 2009); *Id*. at § 1108; LA. REV. STAT. ANN. § 19:2(12); *Id*. § 2(12).

177. S.B. 498, 2009 Leg., 61st Sess. (Mt. 2009) (with certain sections effective once primacy is granted); MONT. CODE. ANN. §§ 70-30-105, 75-5-103, 75-5-401, 77-3-430, 82-10-402, 82-11-101, 82-11-111, 82-11-118, 82-11-122, 82-11-123, 82-11-127, 82-11-136, 82-11-137, 82-11-161, 82-11-163, 82-11-181, 82-11-182, 82-11-184, 82-11-188.

178. MONT. CODE ANN. § 15-6-158 (2019).

North Dakota exempts CO2 pipeline property and equipment from taxes for the first ten full years following initial operation.[179] North Dakota has regulations for geologic storage of CO2.[180]

For EOR, Texas provides a reduced severance tax rate of 2.3 percent of the production's market value for 10 years after the Railroad Commission certifies the production response.[181] This lower tax rate can then be reduced by 50% for oil producers operating qualified EOR projects using CO2 produced through human activity ("anthropogenic CO2").[182] Components of clean energy projects are exempt from sales and use taxes if they capture, transport, prepare or inject carbon that is later sequestered including as part of an EOR project.[183] Texas has regulations for the use of anthropogenic CO2 in EOR projects as well as for geologic storage.[184] Additionally, while not a regulatory incentive, the cost of CO2 pipelines is lowest in the Permian Basin likely due to relatively simple terrain, low population, and strong competition among developers capable of putting in pipelines. [185]

Wyoming created a commission for research and technology transfer for EOR and has developed some permitting requirements for geological sequestration.[186] Additionally, through the Wyoming Pipeline Corridor Initiative it has authorized corridors on federal lands for CO2 pipelines.[187]

Kansas, Louisiana, Montana, North Dakota, Texas, and Wyoming have created funds built from fees and penalties to cover long-term monitoring and management of non-EOR CO2 injection and storage sites.[188]

North Dakota, Wyoming, and Montana have passed legislation allowing the unitization of carbon dioxide reservoirs.[189] Montana and North Dakota require that holders holding 60% of the surface apply for unitization,[190] while Wyoming requires 80% (or 75% in special circumstances).[191] Texas allows unitization for EOR/Class II wells but does not have unitization laws for pure sequestration.[192]

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179. N.D. CENT. CODE § 57-06-17.1 (2019).
180. N.D. CENT. CODE § 38-22 (2019).
181. TEX. TAX CODE ANN. § 202.054 (2019).
182. *Id*. § 202.0545.
183. *Id*. § 151.334; *See also* 34 TEX. ADMIN. CODE § 3.326(b) (2019).
184. 16 TEX. ADMIN. CODE § 5.301 et seq. (2019); TEX. WATER CODE §§ 27.002(19)-(25), 27.041-.051, 27.071-.073 (2019); TEX. NAT. RES. CODE ANN. §§ 91.801-802; 120.001-04 (2019).
185. U.S. DEPT OF ENERGY, DOE/NETL-2014/1681, A REVIEW OF THE CO2 PIPELINE INFRASTRUCTURE IN THE U.S. 1, 22 (April 21, 2015).
186. WYO. STAT. ANN. § 30-5-502, 30-8-101; WYO. STAT. ANN. § 35-11-313 to 318.
187. LABOR ENERGY P'SHIP, *supra* note 2 at 50.
188. HOLLY JAVEDAN, REGULATION FOR UNDERGROUND STORAGE OF CO2 PASSED BY U.S. STATES, Massachusetts Institute of Technology, 7, https://sequestration.mit.edu/pdf/US_State_Regulations_Underground_CO2_Storage.pdf; KAN. STAT. ANN. § 55-1638; H.B. 661, 2009 Leg., (La. 2009), § 1110; TEX. NAT. RES. CODE ANN. §§ 121.002(a), 121.003,(c),(d); TEX WATER CODE § 27.045(b); S.B. 498, 2009 Leg., 61st Sess. (Mt. 2009); MONT. CODE ANN. § 82-11-181 (2019); S.B. 2095, 2009 Leg., 61st Sess. (Nd. 2009) §38-20-15; WYO. STAT. ANN. § 35-11-318.
189. MONT. CODE ANN. § 82-11-101 (6); MONT. CODE ANN. § 82-11 Part 2; S.B. 2095, 2009 Leg., 61st Sess. (Nd. 2009).
190. MONT. CODE ANN. § 82-11-204; S.B. 2095, 2009 Leg., 61st Sess. (Nd. 2009).
191. WYO. STAT. ANN. §§ 35-11-314 through 35-11-317.
192. TEX. NAT. RES. CODE ANN. §§ 101.011 - .013 (2019); Hester and George, *supra* note 132.

The availability of compulsory unitization can prevent a single interest owner from blocking a project.[193] This provides some certainty for investments and can simplify a project allowing for one operating contract for the sequestration facility rather than requiring one with each owner.[194] Unitization can also improve production efficiency, avoid disputes among owners, and ensure each owner receives their proper royalties.[195]

Under existing law, it is often unclear who owns the empty pores where CO2 can be stored, the surface owner, or if applicable, a separate mineral estate owner.[196] The mineral estate owner has rights to the oil and gas that the owner extracts from such spaces, but may not have rights to the space left behind.[197] Despite the importance of having clarity on how to secure rights to carbon sequestration pore space, only Montana, Wyoming and North Dakota have laws addressing pore space ownership specific to CCS.[198] All three allocate the pore space to the surface owner. Montana and Wyoming allow the pore space to be severed and transferred separately, while North Dakota only allows leasing, not severance. In states without such legislation, it may be unclear who owns one of the most vital pieces of property for sequestration. This includes states like Texas where there are conflicting court decisions further muddying the analysis.[199]

2. The Location of CO2 Sources and Sinks

Existing carbon capture and storage infrastructure in the US is primarily used for EOR operations.[200] This infrastructure includes CO2 pipelines that connect natural sources of CO2 to EOR sites, or industrial CO2 sources (processing and gasification plants, fertilizer plants, hydrogen plants, ethanol plants etc.) to EOR projects.[201] When siting a CO2 pipeline, it is obviously important to consider the location of CO2 sources to supply the pipeline. These may be natural, or increasingly, industrial sources as the world seeks to lower emissions and various incentive programs including the 45Q Credit make such investments financially

[193] Hester and George, *supra* note 132.

194. Medlock and Miller, *supra* note 10 at 15; Hester and George, *supra* note 132.

195. Hester and George, *supra* note 132.

196. *Id*.

197. *Id*.

198. S.B. 498, 2009 Leg., 61st Sess. (Mt. 2009); H.B. 89, 2008 Leg., 49th Sess. (Wy. 2008); S.B. 2139, 2009 Leg., 61st Sess. (2009); Medlock and Miller, *supra* note 10 at 13.

199. Hester and George, *supra* note 132; MAPCO, Inc. v. Carter 437 U.S. 904 (1978) (finding the mineral estate owns underground formations); Emeny v. United States 412 F.2d 1219 (Fed. Cir. 1969) (holding the surface estate owns underground formations, though this right bows to reasonable use of a productive oil and gas lessee).

200. U.S. DEPT. OF ENERGY, SITING AND REGULATING CARBON CAPTURE, UTILIZATION AND STORAGE INFRASTRUCTURE: WORKSHOP REPORT, 1, 12 (January 2017), https://www.energy.gov/sites/prod/files/2017/01/f34/Workshop%20Report—Siting%20and%20Regulating%20Carbon%20Capture%2C%20Utilization%20and%20Storage%20Infrastructure.pdf); LABOR ENERGY P'SHIP, *supra* note 2 at 10.

201. U.S. DEPT. OF ENERGY, SITING AND REGULATING CARBON CAPTURE, UTILIZATION AND STORAGE INFRASTRUCTURE: WORKSHOP REPORT, 1, 10-11 (January 2017), https://www.energy.gov/sites/prod/files/2017/01/f34/Workshop%20Report—Siting%20and%20Regulating%20Carbon%20Capture%2C%20Utilization%20and%20Storage%20Infrastructure.pdf).

attractive. Regions with clusters of industrial facilities could be particularly attractive locations to build pipelines that could serve to transport the CO2 of multiple facilities taking advantage of economies of scale.[202] Some regions of promise include the Ohio River Valley with its emissions-heavy industrial and power generation facilities, Wyoming with its large power generation plants, and the Texas and Louisiana Gulf Coast with a wide variety of industrial and power generation plants.[203]

Additionally, viable locations for geological storage or EOR must be identified to determine the terminus of the pipeline. For geological storage, that may mean the location of a deep saline formation, or a depleted oil and gas reservoir.[204] For EOR, potential sites would include oil reservoirs, carbonate, or sandstone fields with declining production, but where there is substantial crude oil remaining, and CO2 flooding could help increase recovery.[205] Some existing locations with oil fields using EOR include the Permian Basin, New Mexico, West Texas, Oklahoma, Louisiana, Mississippi, East Texas, Wyoming, Utah, Colorado, Michigan,[206] Montana, and Wyoming.[207] Texas for example is estimated to have CO2 storage potential of nearly 1.4 trillion tons in saline formations and an additional 4.9 billion tons in enhanced oil recovery (EOR) operations.[208] Additionally it has been estimated that saline formations in the Outer Continental Shelf could store more than 2,000 gigatons of CO2.[209] For commercial CO2 purposes the location of product manufacturers that could use CO2 as an input would be relevant.

3. Future Laws and the Outlook for Legal Changes

There may be increasing barriers to pipeline siting due to the backlash against the use of eminent domain for pipelines during the natural gas boom. People may not consider CO2 pipelines as environmentally destructive as natural gas pipelines, but landowners, courts and governments may nonetheless increase resistance to corporations exercising eminent domain over private land. People may have a growing aversion to pipelines being sited through eminent domain after witnessing high-profile disputes and the many natural gas pipelines sited using eminent domain. Further, local areas may tighten their regulations to block

202. LABOR ENERGY P'SHIP, *supra* note 2 at 21.
203. *Id*. at 23.
204. *Id*. at 16.
205. U.S. DEPT. OF ENERGY, CARBON DIOXIDE ENHANCED OIL RECOVERY: UNTAPPED DOMESTIC ENERGY SUPPLY AND LONG TERM CARBON STORAGE SOLUTION. NATIONAL ENERGY AND TECHNOLOGY LAB, 1, 9 (March 2019), https://www.netl.doe.gov/sites/default/files/netl-file/CO2_EOR_Primer.pdf. Generally, CO2 flooding would be successful if the minimum miscibility pressure can be reached, and there is not geological complexity that would hinder CO2 from contacting the crude. *Id.*
206. U.S. DEPT OF ENERGY, DOE/NETL-2014/1681, A REVIEW OF THE CO2 PIPELINE INFRASTRUCTURE IN THE U.S., 1, 2, 4, 7, 8, 12 (April 21, 2015).
207. DENBURY, *Current Tertiary Operations* (Last visited: May, 22, 2020), https://www.denbury.com/operations/rocky-mountain-region/Tertiary-Operations-/default.aspx.
208. Medlock and Miller, *supra* note 10 at 5 (citing Abramson et al, "Transport Infrastructure for Carbon Capture and Storage," Great Plains Institute, 19, June 2020.)
209. LABOR ENERGY P'SHIP , *supra* note 2 at 17.

the use of eminent domain, as has been done in Kyle, Texas,[210] and may tighten the requirements to obtain common carrier status which is necessary to exercise eminent domain in many states. *See supra* at Section V(B)(2). The *Denbury* case is one such example.[211]

Competing with anti-pipeline and anti-eminent domain sentiment, however, is the urgency of lowering the levels of atmospheric CO2. CCS and direct air capture are critical technologies that may help reach this goal. A recent report finds that the capture, utilization, storage, and removal of CO2 could support a gigaton-scale reduction in CO2 by midcentury.[212] Thus, policies to combat climate change may continue to create tailwinds for CO2 pipeline developers. We will likely continue to see increasing incentives for geologic storage of anthropogenic carbon and EOR at both federal and state levels.[213] These incentives should present new opportunities for those seeking to build CO2 pipelines.

VI. CONCLUSION

This article responds to the increasing urgency of reducing our carbon footprint, a much stronger consensus over the last twelve years on the need to mitigate climate change, but also the rapidly developing regulatory and economic infrastructure for the use of CO2. In addition, investment capital flows are moving towards technologies and projects that are consistent with a global carbon transition, and these investors are providing capital to projects focused on reducing CO2. We have seen growth for traditional uses of CO2 such as EOR and carbonation, but also for rapidly expanding new uses that would increase the value of the CO2 gas stream. This combined with developments regarding tax incentives and eminent domain rights to connect the locations where the CO2 is generated with locations of CO2 sinks has called for a current overview of the market and regulatory framework for CO2 pipelines.

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210. Kyle, Texas, Code of Ordinances § 8-253 (2021).

211. Denbury Green Pipeline-Texas, LLC v. Texas Rice Land Partners, LTD., No. 15-0225 1, 14 (Tex. 2016), http://www.txcourts.gov/media/1436866/150225.pdf.

212. LABOR ENERGY P'SHIP, *supra* note 2 at 9.

213. *See* ENVTL. PROT. AGENCY, DOCKET ID NO. EPA–HQ–OAR–2013–0495, COMMENT LETTER ON THE ENVIRONMENTAL PROTECTION AGENCY'S PROPOSED REVIEW OF STANDARDS OF PERFORMANCE FOR GREENHOUSE GAS EMISSIONS FROM NEW, MODIFIED, AND RECONSTRUCTED STATIONARY SOURCES: ELECTRIC UTILITY GENERATING UNITS, 83 FED. REG. 65, 424 (DEC. 20, 2018) (March 18, 2019), https://oag.ca.gov/system/files/attachments/press_releases/Appendix%20B%20CCS%20in%20State%20Statutes%20%26%20Regulations.pdf.https://oag.ca.gov/system/files/attachments/press_releases/Appendix%20B%20CCS%20in%20State%20Statutes%20%26%20Regulations.pdf; I.R.C. § 45Q.