

# THE WAY FORWARD: A LEGAL AND COMMERCIAL PRIMER ON CARBON CAPTURE, UTILIZATION, AND SEQUESTRATION\*

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Recent amendments to section 45Q of the Internal Revenue Code of 1986, as amended (Section 45Q), have created new opportunities for energy infrastructure stakeholders seeking to employ carbon capture, utilization, and storage (CCUS) technology in the United States.<sup>1</sup> CCUS is generally a process in which carbon dioxide (CO<sub>2</sub>) is captured at its source rather than released into the atmosphere. The application of this technology allows CO<sub>2</sub> emissions generated from the operation of industrial manufacturing, power, or processing plants to be captured at the plants' exhaust stack instead of discharged into the atmosphere. Separate, but similar, technologies are in development to capture and remove CO<sub>2</sub> directly from the ambient air rather than from the exhaust stack of an industrial source. As that technology develops, CCUS projects may start to incorporate direct air capture technology to harvest CO<sub>2</sub> for use, storage, or both in the same fashion as they use CO<sub>2</sub> captured from industrial processes.<sup>2</sup> The captured CO<sub>2</sub> may be utilized to create, or enhance the production of, other forms of energy or products. Alternatively, the CO<sub>2</sub> may be permanently sequestered in an underground reservoir or formation.

In evaluating the scope of the opportunities for CCUS projects, it is interesting to note that the Energy Information Administration (EIA) reported that the United States reached a record high consumption of 101.3 quadrillion Btu from all energy sources in 2018.<sup>3</sup> Such energy consumption is 4% greater than the U.S. energy consumption in 2017 and 0.3% above the previous record set in 2007.<sup>4</sup> The EIA estimates that in 2017 over 1,500 million tons of CO<sub>2</sub> were re-

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1. Note: The process of capturing CO<sub>2</sub> emissions from an industrial source or removing it from the air has also been referred to as Carbon Capture Sequestration and Storage (CCSS) and Carbon Capture and Storage (CCS). For purposes of this paper, the authors have chosen to refer to this process as CCUS, as defined above, which highlights that captured CO<sub>2</sub> has a large number of beneficial uses. As used herein, CCUS is intended to refer to any industrial process that incorporates the capture, removal, use, or storage of CO<sub>2</sub>.

2. In August 2020, Oxy Low Carbon Ventures, LLC (a subsidiary of Oxy) and Runsheen Capital Management announced a newly formed development company named "1PointFive." The company will develop and operate a large-scale direct air capture facility in the Permian Basin. The facility is slated to become the largest direct air capture facility in the world and aims to capture up to 1 million metric tons of CO<sub>2</sub> from the atmosphere each year. The project's executive management hopes that its efforts will help meet the targets set by the Paris Climate Agreement and Intergovernmental Panel on Climate Change while also creating a sustainable low-carbon economy. "We have an ambitious goal for 1PointFive—to help the world limit global temperature rise to 1.5 degrees—but we also have a powerful and practical vision for what needs to be done." Carbon Engineering, *Oxy Low Carbon Ventures, Runsheen Capital Management Create Development Company 1PointFive to Deploy Carbon Engineering's Direct Air Capture Technology*, GLOBE NEWSWIRE (Aug. 19, 2020), <https://www.globenewswire.com/news-release/2020/08/19/2080502/0/en/Oxy-Low-Carbon-Ventures-Rusheen-Capital-Management-create-development-company-1PointFive-to-deploy-Carbon-Engineering-s-Direct-Air-Capture-technology.html>.

3. *In 2018, the United States Consumed More Energy than Ever Before*, U.S. ENERGY INFO. ADMIN.: TODAY IN ENERGY (Apr. 16, 2019), <http://eia.gov/todayinenergy/detail.php?id=39092>.

4. *Id.*

leased into the atmosphere by coal and natural gas fired plants in their efforts to meet energy demands.<sup>5</sup> According to the EIA, approximately 76% of the total greenhouse gas emissions in the United States in 2018 were from burning fossil fuels.<sup>6</sup>

CCUS technology will allow energy infrastructure companies to capture this CO<sub>2</sub> instead of releasing it into the atmosphere. As companies capture, separate, and store these volumes of CO<sub>2</sub>, they will be supplying a new marketplace for CO<sub>2</sub> as a valuable commodity—one which their operations already produce in bulk as a byproduct. This captured CO<sub>2</sub> can be sold downstream to other CCUS project participants for utilization or monetized through storage using Section 45Q tax credits, as discussed below.<sup>7</sup>

This paper will examine the following: (I) the Section 45Q federal income tax credit, (II) CCUS methods, applications, and select infrastructure, (III) the real property rights and related legal considerations for CCUS projects, and (IV) certain commercial and legal considerations surrounding the common arrangements necessary to conduct these operations.

## I. THE SECTION 45Q FEDERAL INCOME TAX CREDIT<sup>8</sup>

Section 45Q, enacted in 2008 and expanded by the Bipartisan Budget Act of 2018, is intended to incentivize the reduction of carbon oxide emissions and the efficient use of carbon oxide, including for enhanced oil recovery (EOR). Section 45Q allows a federal income tax credit based upon the metric tons of qualified carbon oxide<sup>9</sup> that the taxpayer captures using carbon capture equipment, and which is (1) disposed of through secure geological storage, (2) used as a tertiary injectant for EOR, or (3) utilized through photosynthesis, conversion to

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5. *Making Carbon a Commodity: The Potential of Carbon Capture RD&D*, CARBON UTILIZATION RES. COUNCIL AND CLEARPATH FOUND., i (July 25, 2018), <http://www.curc.net/webfiles/Making%20Carbon%20a%20Commodity/180724%20Making%20Carbon%20a%20Commodity%20FINAL%20with%20color.pdf>; *Annual Energy Outlook 2018 with Projections to 2050*, U.S. ENERGY INFO. ADMIN., tbl.8 (Feb. 6, 2018), <https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf>.

6. *Energy and the Environment Explained*, U.S. ENERGY INFO. ADMIN., <https://www.eia.gov/energyexplained/energy-and-the-environment/where-greenhouse-gases-come-from.php> (last visited July 13, 2020).

7. There are more than 4,500 miles of pipeline transport for CO<sub>2</sub> in the United States existing and in service today. Matthew Wallace et al., *A Review of the CO<sub>2</sub> Pipeline Infrastructure in the U.S.*, U.S. DEP'T OF ENERGY | NAT'L ENERGY TECH. LAB'Y, 3 (April 21, 2015), [https://www.energy.gov/sites/prod/files/2015/04/t22/QR%20Analysis%20-%20A%20Review%20of%20the%20CO2%20Pipeline%20Infrastructure%20in%20the%20U.S.\\_0.pdf](https://www.energy.gov/sites/prod/files/2015/04/t22/QR%20Analysis%20-%20A%20Review%20of%20the%20CO2%20Pipeline%20Infrastructure%20in%20the%20U.S._0.pdf).

8. Since this article was written, the Consolidated Appropriations Act, 2021 extended the start of construction date for qualified facilities under Section 45Q by two years. Accordingly, start of construction for a qualified facility now must occur prior to January 1, 2026. More information on the amendment to Section 45Q is available at <https://bracewell.com/insights/changes-renewable-and-carbon-capture-tax-credits-under-consolidated-appropriations-act>. Also, the Department of the Treasury issued final regulations under Section 45Q (the "Final Regulations"), amending and clarifying the Proposed Regulations. More information on the Final Regulations is available at <https://bracewell.com/insights/treasury-releases-final-regulations-carbon-capture-credits>.

9. Note: Under Section 45Q, "qualified carbon oxide" includes carbon dioxide and other carbon oxides that meet the specifications set forth in the regulations.

a material or chemical compound, or any other purpose for which a commercial market exists, as determined by the Secretary of the Treasury. This portion of the paper will review (A) the eligibility requirements for Section 45Q credits and (B) the recapture of Section 45Q credits.

#### *A. Eligibility for Section 45Q Credits*

The Section 45Q credit is available for carbon capture projects for which construction begins before January 1, 2024 and continues for twelve years after a qualifying project is placed in service. For projects placed in service after February 8, 2018, the amount of the credit increases each year to a maximum of \$50 per metric ton of qualified carbon oxide placed in secure geological storage and a maximum of \$35 per metric ton if such carbon oxide is injected or utilized, in each case, with an inflation adjustment after 2026.

Section 45Q(f)(3) provides that, in the case of a project placed in service after February 8, 2018, Section 45Q credits may be claimed by a taxpayer that owns carbon capture equipment and either (1) physically ensures the capture, disposal, injection, or utilization of the qualified carbon oxide, or (2) contractually ensures the performance of these activities (the “Eligibility Rule”). The proposed regulations under Section 45Q (the “Proposed Regulations”) provide that, to contractually ensure performance of the capture and disposal, injection, or utilization of qualified carbon oxide, a taxpayer must enter into a binding written contract with the party that physically performs such activities. The contract must include commercially reasonable terms, must be enforceable against both parties under state law, and may not limit damages to a specific amount. The regulations promulgated by the Department of the Treasury also require the contract to include enforcement mechanisms to ensure the counterparty’s obligation to perform. While no specific mechanism is required, the Proposed Regulations do provide that such contracts may include provisions relating to long-term liability, indemnification, penalties for breach of contract, and liquidated damages. Finally, a taxpayer is not considered to elect to transfer all or any portion of allowable Section 45Q credits to a contracting party solely because it contracted for services related to such carbon oxide. Such credits may be transferred only through the Transfer Election, described below.

Section 45Q(f)(4) requires the Secretary of the Treasury, in consultation with the Environmental Protection Agency (EPA), the Secretary of Energy, and the Secretary of the Interior to establish regulations for determining adequate security measures for geological storage to ensure that qualified carbon oxide does not escape into the atmosphere. The Proposed Regulations provide that a taxpayer will be deemed to store captured qualified carbon oxide in secure geological storage if such storage is in compliance with the EPA’s rules for monitoring, reporting, and verifying carbon capture and sequestration found in subpart RR of 40 C.F.R. pt. 98 (Subpart RR).

In response to feedback from several commentators, the Proposed Regulations permit taxpayers using captured qualified carbon oxide as a tertiary injectant for EOR to rely on the CSA/ANSI ISO 27916:19 standard (the “ISO Standard”) as an alternative to Subpart RR. A taxpayer that reports volumes of carbon oxide to the EPA pursuant to Subpart RR may self-certify the volume of carbon oxide claimed for purposes of Section 45Q. Alternatively, if a taxpayer determines volumes pursuant to the ISO Standard, the taxpayer’s documentation must be certified by a qualified independent engineer or geologist as accurate and complete.

Section 45Q permits a taxpayer eligible to claim Section 45Q credits under the Eligibility Rule to elect to allow the party that disposes of, injects, or utilizes the qualified carbon oxide to claim the credit (the “Transfer Election”). The Transfer Election, along with the allocation of credits to tax equity investors through partnerships, allows taxpayers without sufficient tax liability to benefit from the credits to monetize Section 45Q credits and reduce overall project costs.

#### *B. Recapture of Section 45Q Credits*

Section 45Q(f)(4) requires the Secretary of the Treasury to promulgate regulations addressing the recapture of Section 45Q credits if qualified carbon oxide ceases to be captured and disposed of or injected in a manner consistent with the requirements of Section 45Q. Prior to the Proposed Regulations, the absence of guidance regarding recapture of Section 45Q credits created uncertainty regarding the scope of the recapture risk which, in turn, deterred investment in CCUS projects. The Proposed Regulations, however, provide greater clarity by defining how the recapture is computed and borne and the length of the recapture period.

First, the Proposed Regulations provide that a taxpayer is subject to recapture only to the extent the amount of qualified carbon oxide leaked into the atmosphere in a taxable year exceeds the amount disposed of or injected in the same taxable year (the “Net CO Decrease”). This determination is made separately for each project. The amount of the recapture is the product of the Net CO Decrease and the appropriate credit rate, using the last-in-first-out (LIFO) method. In other words, the leakage is deemed attributable to the first prior taxable year, then subsequent prior taxable years, in order, for up to five taxable years. If there is no Net CO Decrease, there is no recapture amount, although the amount of carbon oxide leaked into the atmosphere would offset the amount of qualified carbon oxide disposed of, or injected, in such year for purposes of computing the Section 45Q credit.

Second, the recapture period begins on the date on which qualified carbon oxide is first disposed into secure geological storage or used as a tertiary injectant. Such period ends upon the earlier of (1) five years after the last taxable year in which the taxpayer claimed a Section 45Q credit for the applicable pro-

ject or (2) the date monitoring ends for such project. Any recaptured amount must be added to the amount of tax due in the taxable year in which the recapture event occurs.<sup>10</sup>

## II. CCUS METHODS, APPLICATIONS, AND SELECT INFRASTRUCTURE

An integrated CCUS system has three functions: “(1) capturing CO<sub>2</sub> and separating it from other gases; (2) purifying, compressing, and transporting the captured CO<sub>2</sub> to a sequestration site (or site where it can be utilized); and (3) injecting the CO<sub>2</sub> into underground reservoirs.”<sup>11</sup> The first of these functions, capturing the CO<sub>2</sub>, is the most challenging.<sup>12</sup> Carbon capture facilities are expensive to construct, and operating them requires a substantial amount of energy.<sup>13</sup> This section of the paper will review (A) select capture methods used for CCUS and (B) primary disposal and sequestration processes and select CO<sub>2</sub> infrastructure.

### A. Select Capture Methods used for CCUS

There are several methods for capturing carbon at large-scale industrial facilities or power plants, including (1) post-combustion capture, (2) pre-combustion capture, and (3) oxy-fuel combustion capture.<sup>14</sup> The oxy-fuel combustion capture method has been limited primarily to research and development settings and will not be substantively discussed in this paper. However, it is worth noting, there are several pilot projects across the United States that have implemented oxy-fuel combustion technology in EOR operations.<sup>15</sup>

Presently, the power plants that have implemented post-combustion capture systems in the United States have the potential to “operate at an 85–95% capture efficiency—meaning that 85%–95% of all the CO<sub>2</sub> produced during the combustion process could be captured” before release into the atmosphere.<sup>16</sup>

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10. Michael Gerrard et. al., *The Future of Carbon Capture, Use and Storage Projects: Tax Credits, Measurement Standards and Transaction Structures*, BRACEWELL (June 24, 2020), <https://bracewell.com/insights/future-carbon-capture-use-and-storage-projects-tax-credits-measurement-standards-and>; Martha Kammoun & Elizabeth L. McGinley, *Treasury and the IRS Fuel Taxpayer’s Confidence Regarding Section 45Q Credits following Call for Suspension of the Credits*, BRACEWELL (June 15, 2020), <https://bracewell.com/insights/treasury-and-irs-fuel-taxpayers-confidence-regarding-section-45q-credits-following-call>; Elizabeth L. McGinley & Steven J. Lorch, *Treasury Releases Long-Awaited Proposed Regulations under Section 45Q*, BRACEWELL (June 8, 2020), <https://bracewell.com/insights/treasury-releases-long-awaited-proposed-regulations-under-section-45q>.

11. PETER FOLGER, CARBON CAPTURE AND SEQUESTRATION (CCS) IN THE UNITED STATES 1 (2018), <https://fas.org/sgp/crs/misc/R44902.pdf>.

12. *Id.*

13. *Id.*

14. *Id.* at 3.

15. *Id.* at 5. According to Oxy’s website, the company has partnered with a company named “Net Power,” which according to its website, is utilizing the oxy-fuel combustion method to capture and separate CO<sub>2</sub>. The company’s plant has recently completed construction in La Porte, Texas and plans to become operational in 2020–2021.

16. *Id.* at 3.

Under the post-combustion capture method, CO<sub>2</sub> is extracted from the mixture of gasses released from a facility's exhaust stack.<sup>17</sup> A vessel called an "absorber" captures the mixture of gasses, called "flue gas," and then scrubs the flue gas with an amine solution, which generally captures 85%–95% of the CO<sub>2</sub> emissions generated by the facility.<sup>18</sup> The solvent is then pumped to a second vessel called a regenerator.<sup>19</sup> Once the solution has been successfully separated into the regenerator, steam is introduced to the solution to create a stream of concentrated CO<sub>2</sub>, which is then compressed and transported by pipeline to either storage, disposal, or utilization facilities.<sup>20</sup> One example of this technology is the Petra Nova plant located outside Houston, Texas. The plant is fitted with equipment that captures the CO<sub>2</sub> emissions from its operations and then transports the captured CO<sub>2</sub> to a nearby oil field for EOR operations.<sup>21</sup> In July of 2020, after capturing an estimated 3.9 million tons of CO<sub>2</sub>, the operator of the Petra Nova project announced it planned to cease its capture operations at the plant until economics improve.<sup>22</sup>

Due to the historic drop in oil prices brought on by COVID-19 demand shock, coupled with increases in supply of OPEC<sup>+</sup> nations, the Petra Nova plant has struggled to maintain its profitability. This highlights some of the challenges faced by stakeholders for projects using CCUS technology for EOR. CCUS EOR projects may be subject to commodity price exposure and other project specific operational challenges.<sup>23</sup> As one commentator remarked, "fossil fuel companies cannot afford carbon capture in the short-term, but they know they need it to survive in the [long-term]."<sup>24</sup> However, technological innovations continue to show promise for CCUS technology; Exxon recently demonstrated

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17. *Id.* at 5.

18. *Id.* at 3.

19. *Id.*

20. *Id.*

21. The Petra Nova coal-fired power plant outside Houston, Texas, generates and captures between 1.4 and 1.6 million tons of CO<sub>2</sub> each year. *Id.* at i, 12. Since its carbon capture facilities became operational, the plant estimates that it has captured about 90% of the CO<sub>2</sub> emissions contained in its exhaust gas, which the plant then sells to E&P companies for EOR operations. *Id.* at i, 12. Specifically, the plant transports the CO<sub>2</sub> by pipeline to the West Ranch oil field where it is deployed for EOR operations. *Carbon Capture and the future of coal power*, PETRA NOVA, NRG, <https://www.nrg.com/case-studies/petra-nova.html> (last visited Oct. 18, 2020). The operator of the West Ranch oil field has successfully increased production from about 300 bpd pre-EOR to over 4,000 bpd after EOR measures were implemented. Because the owners of the Petra Nova plant also own an interest in the oil field's production, the increased production revenues resulting from CO<sub>2</sub> EOR help to offset their initial capital investment. Post-combustion projects implemented today may also qualify for tax credits under Section 45Q. Bracewell represented the operator of the oil and gas field in a joint venture transaction with the owner of the power plant. Bracewell also negotiated the management services agreement along with the CO<sub>2</sub> supply and transportation agreements which govern the CO<sub>2</sub> operations for this project.

22. Charles Kennedy, *Biggest U.S. Coal Carbon Capture Project Halted After Oil Price Crash*, OILPRICE.COM (July 29, 2020, 9:30 AM), <https://oilprice.com/Latest-Energy-News/World-News/Biggest-US-Coal-Carbon-Capture-Project-Halted-After-Oil-Price-Crash.html>.

23. Chris Tomlinson, *Oil industry could lose by gambling on carbon capture*, HOUSTON CHRONICLE (July 31, 2020), <https://www.houstonchronicle.com/business/columnists/tomlinson/article/Oil-industry-could-lose-by-gambling-on-carbon-15446419.php>.

24. *Id.*

a significant break-through in the capture and separation process by applying a new patent-pending technique to capture flue gas.<sup>25</sup> This new process captured CO<sub>2</sub> emissions up to six-times more effectively than conventional amine-based carbon capture technology, as described above.<sup>26</sup> Exxon's vice president of research and development summarized the significance of Exxon's development as follows: "This innovative hybrid porous material has so far proven to be more effective, requires less heating and cooling, and captures more CO<sub>2</sub> than current materials."<sup>27</sup>

Alternatively, the pre-combustion capture method involves introducing the fuel source to a stream of air or steam, which produces a separate stream of CO<sub>2</sub> that can be transported for storage, disposal, or utilization.<sup>28</sup> This approach is available to coal-powered plants today using existing CCUS technology.<sup>29</sup> Generally, the coal-powered plants use a process called "gasification" or "partial oxidation," which involves introducing the coal to a combination of steam and oxygen under high temperatures and pressures, resulting in a synthetic fuel consisting of mainly carbon monoxide and hydrogen.<sup>30</sup> The synthetic gas is then treated to remove impurities and introduced to steam.<sup>31</sup> When steam is applied to the carbon monoxide, the carbon monoxide is converted to CO<sub>2</sub> to result in a mixture of CO<sub>2</sub> and hydrogen.<sup>32</sup> The mixture is then exposed to a solvent that captures the CO<sub>2</sub> and produces a stream of hydrogen that can be burned in a combined-cycle power plant to generate electricity.<sup>33</sup> Meanwhile, the captured CO<sub>2</sub> may be sold for EOR or utilization purposes or sequestered. An example of this technology is found at the Great Plains plant in North Dakota. The Great Plains project applies the above noted gasification process to lignite coal to create both synthetic natural gas that is then sold in the natural gas market and CO<sub>2</sub> which is sold to E&P companies for EOR operations.<sup>34</sup>

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25. *Exxon Mobil Uncovers New Carbon Capture Technique for Power Plants*, HART ENERGY (July 24, 2020, 8:23 AM), <https://www.hartenergy.com/news/exxon-mobil-uncovers-new-carbon-capture-technique-power-plants-188770>.

26. *Id.*

27. *Id.*

28. FOLGER, *supra* note 11, at 4.

29. *Id.*

30. *Id.*

31. *Id.*

32. *Id.*

33. *Id.* At the time of this article, additional tax incentives are being developed for hydrogen production. Bracewell has been instrumental in developing the incentives for hydrogen production. Stakeholders seeking to learn more about hydrogen production incentives should contact Bracewell.

34. The pre-combustion process used at the Great Plains plant is important to stakeholders for purposes of this paper because it provides an example of the opportunity for operators engaged in coal mining operations to realize the advantages of CCUS technology, as well as the opportunity to partner with other energy infrastructure stakeholders that were previously viewed as competitors.



### *B. Primary Disposal and Sequestration Processes and Select CO<sub>2</sub> Infrastructure*

As noted above, a CCUS system must not only capture and separate CO<sub>2</sub> but also either store, dispose of, or utilize the captured CO<sub>2</sub> to prevent its release into the atmosphere. All of these methods require the CO<sub>2</sub> to be captured before release into the atmosphere in order to eliminate or decrease harmful CO<sub>2</sub> emissions that would have otherwise occurred. This portion of the paper will examine: (1) the application of CO<sub>2</sub> for EOR operations, (2) CO<sub>2</sub> EOR as an environmental mitigation strategy, (3) the application of CO<sub>2</sub> for sequestration projects, and (4) a review of select CO<sub>2</sub> infrastructure.

#### 1. Application of CO<sub>2</sub> for EOR Operations

Today, the most common commercial use for CO<sub>2</sub> is its application for EOR operations in the oil and gas industry. An oil field's development occurs in several phases. Once the field is initially brought online, the natural pressure from the reservoir pushes the oil to the surface ("primary recovery"). However, as the oil is produced, the reservoir's natural pressure decreases, and recovery becomes more difficult. As operators lose pressure from their reservoir, they deploy a process called "secondary recovery." During secondary recovery, operators inject substances (mostly water) into the reservoir to help maintain the pressure so that oil continues to flow to the surface. Although this process is called secondary recovery, as noted below, advances in horizontal drilling and hydraulic fracturing now allow many operators to use these methods as part of their initial development process. Much like primary recovery, the increased pressure achieved after the deployment of secondary recovery operations eventually dissipates, and in some instances (dependent upon reservoir and field characteristics), this pressure may be restored with the injection of gas (including CO<sub>2</sub>) into the applicable reservoir or field. This process is known as "tertiary recovery."

Despite developments in hydraulic fracturing and other enhanced recovery techniques, it is estimated that between 70%–85% of the oil originally in place at the time of discovery will remain stranded in the reservoir.<sup>35</sup> One solution is to pump pressurized CO<sub>2</sub> into the depleted reservoir. As a result, a new fluid is formed with lower viscosity and surface tension, and the remaining oil deposits are more easily displaced.<sup>36</sup> In other words, the CO<sub>2</sub> scours the geological

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35. L. STEPHEN MELZER, CARBON DIOXIDE ENHANCED OIL RECOVERY (CO<sub>2</sub> EOR): FACTORS INVOLVED IN ADDING CARBON CAPTURE, UTILIZATION AND STORAGE (CCUS) TO ENHANCED OIL RECOVERY 3 (Feb. 2012), [https://carboncapturecoalition.org/wp-content/uploads/2018/01/Melzer\\_CO2EOR\\_CCUS\\_Feb2012.pdf](https://carboncapturecoalition.org/wp-content/uploads/2018/01/Melzer_CO2EOR_CCUS_Feb2012.pdf).

36. JAMES P. MEYER, SUMMARY OF CARBON DIOXIDE ENHANCED OIL RECOVERY (CO<sub>2</sub> EOR) INJECTION WELL TECHNOLOGY 1, <https://www.api.org/~media/Files/EHS/climate-change/Summary-carbon-dioxide-enhanced-oil-recovery-well-tech.pdf>.

structure for more oil.<sup>37</sup> Once the oil is found, the CO<sub>2</sub> “mixes with the oil and mobilizes more of it—like turpentine cleaning paint—and then allows it to be pumped to the surface.”<sup>38</sup> In fact, Occidental Petroleum Corp. (Oxy) estimates that in some cases only 11% of the oil in place upon discovery is ultimately produced from its shale reserves.<sup>39</sup> Generally, the oil is left behind because “either it [was not] contacted by the injected fluid, or because of the capillary forces that exist between oil, water[,] and the porous rock in the contacted portions that trap and retain [the oil].”<sup>40</sup> As noted below, many operators believe that these remaining deposits can be recovered using the injection of pressurized CO<sub>2</sub>.

The application of CO<sub>2</sub> for EOR operations is not new. In fact, the first commercial CO<sub>2</sub> EOR projects date back to the early 1970s.<sup>41</sup> However, as noted below, the prevalence of these technologies have been constrained by a number of market factors, including the limited supplies of CO<sub>2</sub>. Many of the projects conducted to date have demonstrated dramatic increases in ultimate recovery. One case study, which analyzed CO<sub>2</sub> EOR operations conducted in Gaines County, Texas concluded that “over 10,000 bopd can be shown to be coming from the [flood] interval, a zone that would have produced no oil under primary or water flood phases.”<sup>42</sup> A study on the subject found that CO<sub>2</sub> EOR “has increased recovery from some oil reservoirs by an additional 4 to 15 percentage points over primary and secondary recovery efforts.”<sup>43</sup> The study noted that other pilot projects have reported “incremental recovery of as much as 22 percent” and further notes recent innovations could “push total recovery in some reservoirs to more than 60 percent.”<sup>44</sup> According to Oxy’s website, “CO<sub>2</sub>

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37. David Biello, *Enhanced Oil Recovery: How to Make Money from Carbon Capture and Storage Today*, SCI. AM. (Apr. 9, 2009), <https://www.scientificamerican.com/article/enhanced-oil-recovery/>.

38. *Id.*

39. Ed Crooks, *Chief Aims for Occidental Petroleum to be “Carbon Neutral,”* FIN. TIMES (Mar. 19, 2019), <https://www.ft.com/content/74c859da-4a90-11e9-bbc9-6917dce3dc62>.

40. MEYER, *supra* note 36, at 1.

41. The first documented commercial project using CO<sub>2</sub> for EOR was the SACROC Unit located in Scurry County, Texas. *Id.* The project was initiated in 1972 and, as of 2016, continued to produce about 29,300 barrels of oil per day. *CO<sub>2</sub>: Overview*, KINDERMORGAN, <https://www.kindermorgan.com/pages/business/co2/eor/sacroc.aspx> (last visited Oct. 19, 2020). Another example of a successful CO<sub>2</sub> EOR project was Shell’s Denver Unit in the Wasson Field, where it is estimated that injected CO<sub>2</sub> led to the incremental recovery of more than 120 million barrels of oil from 1983 through 2008. *Carbon Dioxide Enhanced Oil Recovery: Untapped Domestic Energy Supply and Long Term Carbon Storage Solution*, NAT’L ENERGY TECH. LAB. (Mar. 2010), [https://www.netl.doe.gov/sites/default/files/netl-file/CO2\\_EOR\\_Primer.pdf](https://www.netl.doe.gov/sites/default/files/netl-file/CO2_EOR_Primer.pdf). It should be noted that today Kinder Morgan’s SACROC and GLSA EOR projects use CO<sub>2</sub> produced from naturally-occurring underground deposits. Therefore, these projects would not be eligible for Section 45Q credits. However, the initial CO<sub>2</sub> flood was conducted with CO<sub>2</sub> that had been separated from produced natural gas and it wasn’t until the early 1980’s that operators began piping CO<sub>2</sub> from natural sources. MELZER, *supra* note 35, at 3.

42. ROBERT C. TRENTHAM ET AL., CASE STUDIES OF THE ROZ CO<sub>2</sub> FLOOD AND THE COMBINED ROZ/MPZ CO<sub>2</sub> FLOOD AT THE GOLDSMITH LANDRETH UNIT, ECTOR COUNTY, TEXAS. USING “NEXT GENERATION” CO<sub>2</sub> EOR TECHNOLOGIES TO OPTIMIZE THE RESIDUAL OIL ZONE CO<sub>2</sub> FLOOD ii (2015).

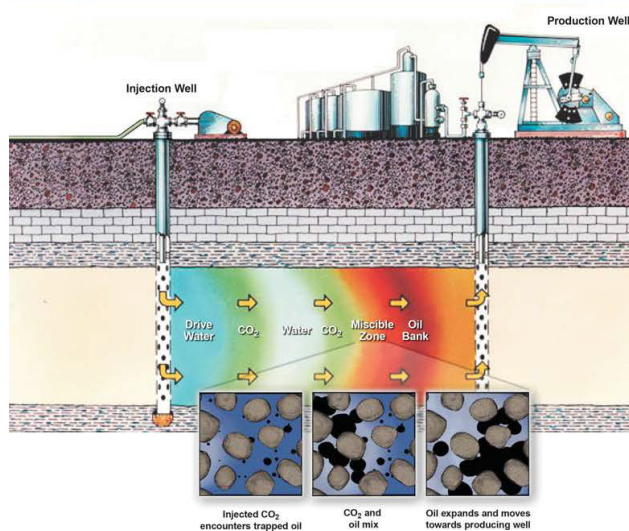
43. MELZER, *supra* note 35, at 14.

44. *Id.*

EOR can increase ultimate oil and associated gas recovery by 10 to 25 percent in the fields where it is employed.”<sup>45</sup>

Although CO<sub>2</sub> EOR reached its billionth barrel of production in 2005, the technology remains in its infancy with respect to shale development.<sup>46</sup> Several operators have conducted pilot programs testing EOR technology to varying degrees of success for unconventional development in the Bakken, Eagle Ford, and Permian Basin.<sup>47</sup> However, the experts agree that the application and success of CO<sub>2</sub> EOR for unconventional development is highly dependent upon the geology, and some fields will be more suitable than others.

The figure below illustrates how CO<sub>2</sub> mixes with oil molecules to increase recovery in EOR operations for conventional development.<sup>48</sup>



45. *Enhanced Oil-Recovery*, OXY <https://www.oxy.com/OurBusinesses/OilandGas/Technology/Enhanced-Oil-Recovery/Pages/default.aspx> (last visited Nov. 18, 2019).

46. MELZER, *supra* note 35, at 5; *see also* Nissa Darbonne, *Shale EOR: Found Oil*, HART ENERGY (Dec. 12, 2019, 11:00 AM), <https://www.hartenergy.com/exclusives/found-oil-184325>.

47. Darbonne, *supra* note 46. EOG’s pilot program in the Eagle Ford has provided the most promising results to date. Using a proprietary huff-n-puff injection method and EOR solution, EOG was able to “yield up to 80% more oil in the Eagle Ford from its gas injection process.” Mary Holcomb, *EOG Boosts Production With EOR Program in Eagle Ford*, HART ENERGY (Oct. 21, 2019, 4:30 AM), <https://www.hartenergy.com/exclusives/eog-boosts-production-eor-program-eagle-ford-183524>. The solution EOG utilized in its injection process has been kept confidential, so the use and extent of anthropogenic CO<sub>2</sub> used in these operations remains unclear. Brian Walzel, *The Next Frontier: EOR in Unconventional Resources*, HART ENERGY (Aug. 8, 2017, 1:20 PM), <https://www.hartenergy.com/exclusives/next-frontier-eor-unconventional-resources-30199>. The project has been publicly described as both a natural gas EOR project and a CO<sub>2</sub> EOR project. *See generally*, Holcomb, *supra*; Stephen Rassenfoss, *Shale EOR Works, But Will it Make a Difference?*, J. PETROLEUM TECH. (Oct. 1, 2017), <https://pubs.spe.org/en/jpt/jpt-article-detail/?art=3391>. Nevertheless, the program’s success has provided promise for the application of CO<sub>2</sub> EOR in shale resource plays.

48. *Carbon Dioxide Enhanced Oil Recovery: Untapped Domestic Energy Supply and Long Term Carbon Storage Solution*, *supra* note 40, at 5.

## 2. EOR as a Climate Change Mitigation Strategy for the Fossil Fuels Industry

The Texas legislature and Texas Supreme Court have each acknowledged the importance of the role that secondary recovery operations play in enabling responsible operation and preventing waste. One Texas Supreme Court case noted:

Secondary recovery operations are carried on to increase the ultimate recovery of oil and gas, and it is established that pressure maintenance projects result in more recovery than was obtained by primary methods. It cannot be disputed that such operations should be encouraged, for as the pressure behind the primary production dissipates, the greater is the public necessity for applying secondary recovery forces.<sup>49</sup>

The examples discussed above indicate the deployment of CCUS technology for EOR operations would increase efficiency in recovery and prevent waste in the same manner as secondary recovery.

In the last several years, the upstream and midstream sectors have seen an increased scrutiny placed on the overall environmental and climate change impacts of their businesses.<sup>50</sup> In Colorado for instance, the Colorado Oil and Gas Conservation Commission expanded the factors considered for approval of a drilling permit to include public safety and welfare.<sup>51</sup> Further, under the National Environmental Policy Act and analogous state laws, federal and state agencies permitting oil and gas projects have expanded their consideration of environmental impacts to include, in some cases, consumption (i.e. burning) of the fossil fuels produced or transported by the project being permitted. Opponents of fossil fuels, like non-governmental organizations pushing the “Keep It In the Ground” initiative, have seized upon these environmental reviews to delay, and in some cases prevent, projects from coming to fruition. As a result, the need and importance of CCUS technology only increases as regulatory agencies continue to place more focus on the environmental impact of development.

The use of CCUS technology can mitigate the climate change impacts associated with oil and gas development, meaning state regulators will no longer be forced to make a binary choice with respect to allowing oil and gas development that is often vital to their area’s economy and their constituents’ concerns for climate change. Similarly, CCUS technology may also help mitigate investors’ environmental and social governance (ESG) concerns surrounding the production and development of hydrocarbons. As noted above, according to the EIA, approximately 76% of U.S. energy-related CO<sub>2</sub> emissions came from

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49. R.R. Comm’n of Tex. v. Manziel, 361 S.W.2d 560, 568 (Tex. 1962).

50. See generally, Tara K. Righetti et al., *The New Oil and Gas Governance*, 130 YALE L.J. F. 51, 51–77 (2020).

51. *Id.* at 60.

burning fossil fuels.<sup>52</sup> Given that the residential and commercial sectors have lower CO<sub>2</sub> emissions than the industrial sector, a widespread curtailment or reduction of the CO<sub>2</sub> emissions from industrial sources (through CCUS, EOR, and other methods) would have a meaningful impact on the amount of CO<sub>2</sub> emissions released into the atmosphere. One article prepared by the IEA recently provided the following example:

Today, between 300kg CO<sub>2</sub> and 600kg CO<sub>2</sub> is injected in EOR processes per barrel of oil produced in the United States (although this does vary between fields and across the life of projects). Given that a barrel of oil releases around 400kg CO<sub>2</sub> when combusted, and around 100kg CO<sub>2</sub> on average during the production, processing and transport of the oil, [anthropogenic CO<sub>2</sub> injection in EOR] opens up the possibility for the full lifecycle emissions intensity of oil to be neutral or even ‘carbon-negative.’<sup>53</sup>

A majority of the CO<sub>2</sub> used for EOR operations has been sourced from naturally-occurring deposits up to this point.<sup>54</sup> But, recent federal legislation has now incentivized the use of anthropogenic CO<sub>2</sub>.<sup>55</sup> The factors discussed above suggest that the use of CCUS technology is not only beneficial for purposes of recovery but may one day be called for by state regulators in order to mitigate waste and environmental impact.<sup>56</sup>

In fact, many oil companies have already embraced that CCUS is necessary for oil companies to survive in the face of climate and environmental concerns. Since 2019, Repsol, Lundin Petroleum, British Petroleum, Oxy, and Shell have pledged to become carbon neutral. Vicki Hollub, CEO of Oxy, has remarked that the use of this technology has been well-established for conventional oil wells, but recent amendments to Section 45Q now make CCUS projects economic in the context of horizontal shale wells.<sup>57</sup> Hollub cited CCUS technology as something that “has to happen” in order for the mandates under the Paris Climate Agreement to be achieved.<sup>58</sup> Hollub’s remarks indicate that CCUS is not only an investment strategy, but a lifeline. “We want to be the company

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52. See *supra* note 7 and accompanying text.

53. Christophe McGlade, *Can CO<sub>2</sub>-EOR really provide carbon-negative oil?*, INT’L ENERGY AGENCY (Apr. 11, 2019), <https://www.iea.org/commentaries/can-co2-eor-really-provide-carbon-negative-oil>.

54. *Id.*

55. Generally, the term anthropogenic CO<sub>2</sub> refers to man-made CO<sub>2</sub>. However, some states, such as Texas, have defined this term by statute. See *generally*, TEX. WATER CODE § 27.002. The Texas Water Code defines “anthropogenic carbon dioxide” as CO<sub>2</sub> that otherwise would have been released into the atmosphere but instead has been captured from a fluid stream or an emissions source (such as a power plant or industrial site). *Id.*

56. See *generally*, Righetti et al., *supra* note 50.

57. Crooks, *supra* note 39.

58. *Id.* While the United States withdrew from the Paris Climate Agreement in 2017, stakeholders with international asset portfolios still must consider the agreement’s impact on their operations in countries that are party to the agreement. However, Section 45Q credits will only be applicable for qualified carbon oxide captured within the United States.

that's producing the last barrel of oil. And that barrel of oil has to be from [CO<sub>2</sub>] enhanced oil recovery, because that's the lowest emission barrel possible."<sup>59</sup> According to recent data, Oxy injected more than 2.6 Bcf, or approximately 136,800 metric tons, of both CO<sub>2</sub> from naturally-occurring sources and anthropogenic CO<sub>2</sub> per day in connection with its thirty-four active EOR projects in the Permian Basin in 2019.<sup>60</sup>

### 3. Application of CO<sub>2</sub> for Sequestration Projects

According to the Energy Department, deep saline formations could potentially store up to 12 trillion metric tons of carbon dioxide.<sup>61</sup> The injection process for sequestration of CO<sub>2</sub> is similar to the injection process for EOR operations. However, unlike EOR operations, sequestration does not entail the extraction of hydrocarbons. In other words, "storing CO<sub>2</sub> in deep saline reservoirs does not have the potential to enhance the production of oil and gas or to offset costs of [CCUS] with revenues from the produced oil and gas."<sup>62</sup> However, oil producers, service companies, and midstream operators are the most logical groups to play a role in the sequestration process since they have the technical expertise and experience required to physically move the CO<sub>2</sub> and conduct the operations necessary to store captured CO<sub>2</sub> in these deep saline formations. One study notes:

Most industrial and power plant operators lack the knowledge and ability to execute a large-scale CO<sub>2</sub> injection and monitoring program. To receive the expanded tax credits, they will likely partner with CO<sub>2</sub> services companies. Potential partners may include traditional oil and gas companies with CO<sub>2</sub> EOR experience (e.g., Oxy, Denbury), traditional oil and gas service companies (e.g., Schlumberger, Baker Hughes), or new entities willing to shoulder the operational and post-operational responsibilities. They may also include CO<sub>2</sub> pipeline companies (e.g., Kinder-Morgan).<sup>63</sup>

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59. *Id.*

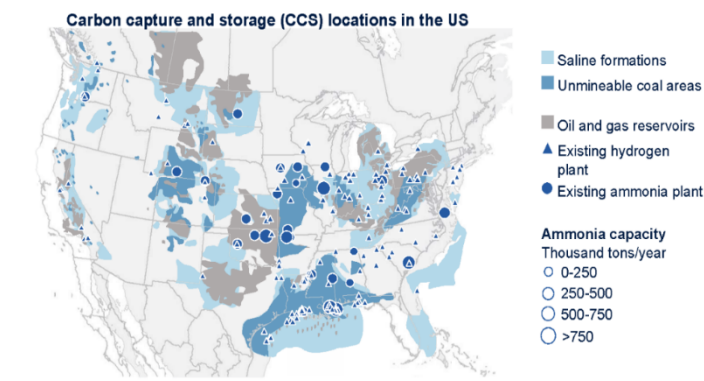
60. Vincent A. Alspach, Comment in response to Notice 2019-32 Regarding the Section 45Q Credit for Carbon Oxide Sequestration (July 2, 2019), <https://beta.regulations.gov/document/IRS-2019-0026-0031>.

61. Allyson Versprille, *Carbon-Capture Projects Face Uncertain Future Amid IRS Delays*, BLOOMBERG TAX (Feb. 11, 2020, 3:38 PM), <https://news.bloombergtax.com/daily-tax-report/carbon-capture-projects-face-uncertain-future-amid-irs-delays> (citing *Carbon Storage R&D*, OFF. OF FOSSIL ENERGY, <https://www.energy.gov/fe/science-innovation/carbon-capture-and-storage-research/carbon-storage-rd> (last visited Nov. 4, 2020)).

62. FOLGER, *supra* note 11, at 9.

63. *Advancing Large Scale Carbon Management: Expansion of the 45Q Tax Credit*, ENERGY FUTURES INITIATIVE, 20 (May 2018), [https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5d2ce5a6d73552000171a460/1563223469397/EFL\\_Advancing%2BLarge%2BScale%2BCarbon%2BManagement-%2BExpansion%2Bof%2Bthe%2B45Q%2BTax%2BCredit\\_2018.pdf](https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5d2ce5a6d73552000171a460/1563223469397/EFL_Advancing%2BLarge%2BScale%2BCarbon%2BManagement-%2BExpansion%2Bof%2Bthe%2B45Q%2BTax%2BCredit_2018.pdf).

These findings support the potential for new synergies, partnership, and consolidation among energy infrastructure companies. The figure below shows a number of potential formations suitable for deep saline sequestration in the United States.<sup>64</sup>



#### 4. Review of Select CO<sub>2</sub> Infrastructure

Recent statistics indicate there are at least fifty CO<sub>2</sub> transportation pipelines in the United States comprising 4,500 miles of pipeline.<sup>65</sup> The three largest CO<sub>2</sub> pipelines converge at the Denver City CO<sub>2</sub> hub where the CO<sub>2</sub> is subsequently delivered to purchasers through a smaller network of pipelines for various industrial uses.<sup>66</sup> As of 2015, 80% of the CO<sub>2</sub> utilized in EOR operations were from naturally-occurring sources.<sup>67</sup> However, experts have cited depletion, scarcity, and remoteness of source fields as constraining factors for large scale investment of CO<sub>2</sub> EOR.<sup>68</sup> A 2015 Department of Energy study indicated the existing pipeline system could serve as the “building block for linking the capture of CO<sub>2</sub> from industrial [sources] with its productive use in oilfields (with CO<sub>2</sub> enhanced oil recovery [CO<sub>2</sub>-EOR]) and its safe storage in saline formations.”<sup>69</sup> The study also indicated an additional 600 miles of high-volume CO<sub>2</sub> pipeline were in planning and development stages at the time of its publication.<sup>70</sup>

The methods discussed above are not only examples of successful implementation of CCUS technology but also examples of the potential synergies that can be realized amongst energy infrastructure companies. These CCUS

64. Karine Boissy-Rousseau, President, Hydrogen Energy & Mobility, Air Liquide North America, Air Liquide Presentation: H<sub>2</sub> Energy At the heart of the energy transition (June 15, 2020) (presentation slides on file with author).

65. Wallace et al., *supra* note 7, at 3.

66. *Id.* at 2.

67. *Id.*

68. MELZER, *supra* note 35, at 6.

69. Wallace et al., *supra* note 7, at 2.

70. *Id.*

technologies allow coal, oil, gas, midstream, chemical, and power producers to create new value centers and, in some instances, revenue sources from their existing operations through capture and disposal technologies. They will also simultaneously improve the efficiency of their existing operations from an economic and environmental perspective to create a marketplace where these sectors will no longer be required to fight one another for market share, but will work with each other as partners and customers of one another.<sup>71</sup> The remaining portions of this paper will review the real property rights and related legal considerations for EOR and sequestration operations as well as some of the principle considerations for commercial arrangements in CCUS projects.

### III. REAL PROPERTY RIGHTS AND RELATED LEGAL CONSIDERATIONS FOR EOR AND SEQUESTRATION OPERATIONS

In order to conduct an EOR or sequestration project, the operator must have the real property rights to possess the premises where CO<sub>2</sub> will be injected. Both types of projects entail the injection of CO<sub>2</sub> into subsurface geological structures of the property where operations are conducted. Consequently, both require the operator to have the right to access and possess the subsurface geological structures. For this reason, many of the real property rights and land-related legal considerations for either type of project will be the same. This portion of the paper will explore the relevant legal considerations regarding ownership of subsurface geological pore space and the notable differences between these types of projects.

#### *A. Ownership of Subsurface Geological Pore Space in the United States*

Within the United States, the right to inject and store gaseous substances in an underground reservoir generally belongs to the surface owner of the premises on which the reservoir is situated.<sup>72</sup> Those familiar with mineral ownership rights may struggle to reconcile the fact that the right to inject gaseous substances thousands of feet beneath the surface belongs to the surface owner with

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71. See 26 U.S.C. § 45Q (2018).

72. See generally Marie Durrant, *Preparing for the Flood: CO<sub>2</sub> Enhanced Oil Recovery*, 59 ROCKY MTN. MIN. L. INST. 11-1 (2013); Owen L. Anderson, *Geologic CO<sub>2</sub> Sequestration: Who Owns the Pore Space?*, 9 WYO. L. REV. 97 (2009). In some instances, the mineral substances themselves will be used, commingled, or disrupted in the course of injection operations. For instance, many underground storage facilities are located within depleted salt-dome reservoirs. When injection operations target a strata that is either composed of a mineral substance (like a salt dome) or may contain marketable mineral substances, the mineral interest owners should consent to operations. If the property is subject to a valid mineral lease, appropriate consent and access rights should be obtained from both the mineral lessor and mineral lessee. See generally, *Mapco, Inc. v. Carter*, 808 S.W.2d 262 (Tex. App.—Beaumont 1991), *rev'd on other grounds*, 817 S.W.2d 686 (Tex. 1991). Additionally, when minerals are actively being extracted from the reservoir in connection with EOR operations, the lessee of the mineral lease will have royalty obligations on the native mineral substances removed from the reservoir. The lease's royalty provision will determine the calculation and scope of the royalty obligations owed to the mineral lessor by the mineral lessee for produced mineral substances.



the fact that the right to recover the same substances belongs to the mineral interest owner. However, a closer analysis of the rights associated with mineral ownership makes it clear that the rights associated with the mineral estate are limited to rights regarding physical molecules of the mineral substances that are naturally occurring on or under the subject property (e.g., “native gas”) and, in most cases, do not extend to the subsurface geological structures which encase such mineral substances.

The owner of real property generally holds its interest in fee simple absolute unless otherwise provided by either the terms of conveyance or a reservation of rights.<sup>73</sup> A separate and distinct mineral estate is not recognized until the real property interest owner has severed or reserved the mineral estate from the remainder of the real property estate.<sup>74</sup> Consequently, in instances where no severance has occurred, the right to inject gaseous substances remains with the landowner. Depending on the jurisdiction, once severed, the mineral estate owner is recognized to hold either an ownership interest in the physical molecules of the mineral substances (e.g., oil, gas, salt, etc.) in place under the given property or an easement-like right that gives the owner the right to access the surface (and subsurface) of the subject property to recover and produce such minerals from the given property. However, the ownership interest associated with the mineral estate does not extend to the ownership of geological structures beneath the surface, unless expressly provided by the language of the conveyance.<sup>75</sup> As many practitioners know, the mineral estate has been recognized as the dominant estate and inherently includes the right to use the surface of the given tract of land as is reasonably necessary to develop the mineral estate of that tract. However, there is a distinction between accessing the surface estate for extraction of the minerals and possessing subsurface geological structures through the injection of foreign gas from outside the property for storage and/or enhanced recovery purposes. Thus, in many situations, someone who seeks to inject substances (like CO<sub>2</sub> for EOR purposes) will need to obtain rights to both the mineral and surface estate.

The most common severance of the mineral estate from the full fee simple interest occurs in the form of a mineral deed. Typically, the mineral deed conveys all right, title, and interest, in and to the oil, gas, and other minerals in on and under the subject tract to the applicable grantee. However, in other instances, the severance of the estates may derive from an owner who reserves the mineral estate and conveys the surface estate (or portions thereof). In either instance, it is important to appreciate that the mineral and surface estates (or por-

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73. Durrant, *supra* note 72, at 7.

74. Springer Ranch, Ltd. v. Jones, 421 S.W.3d 273, 282 (Tex. App.—San Antonio 2013, no pet.); see Moser v. U.S. Steel Corp., 676 S.W.2d 99, 101 (Tex. 1984).

75. Humble Oil & Ref. Co. v. West, 508 S.W.2d 812, 815 (Tex. 1974) (citing Emeny v. United States, 412 F.2d 1319, 1323 (Ct. Cl. 1969)).

tions thereof) are each freely alienable.<sup>76</sup> In other words, a surface owner, who does not own an interest in the mineral estate, may have reserved rights typically associated with the mineral estate (e.g., the right to enter into a mineral lease or the right to collect a bonus upon execution of such lease), and *vice versa*, a mineral owner, who does not own an interest in the surface estate, may have been granted rights typically associated with the surface estate (e.g., the right to inject substances into geological structures).<sup>77</sup> Therefore, it is imperative to review the instruments in the chain of title to the property in question carefully to understand if, and how, the rights associated with the mineral estate of that tract have been severed and to ensure that neither the applicable mineral conveyance nor reservation is so broad as to include ownership of the geological structures beneath the surface, or so narrow that the surface estate reserved or conveyed in the instrument is limited to just the soil on the surface of the land.<sup>78</sup>

In many cases, the acquisition of the right to store gas is separate and distinct from the need to obtain a subsurface easement from the mineral estate owner as well as any mineral lessee (unless, for example, no severance has occurred and there is no active mineral lease on the subject property).<sup>79</sup> In the vast majority of cases, a surface use agreement with the surface owner is required to inject gas into the premises, and this agreement accounts for the injector's rights to possession and use of the subsurface geological structures included in the surface estate of the applicable tract. However, this agreement will not account for the use or displacement of native mineral substances potentially resulting from the injection of foreign gas into such structures. Consequently, a subsurface easement with the mineral owner or respective mineral lessee (in an instance where an active mineral lease encumbers the property) is required to account for the native mineral substances that may exist in the subsurface structures which are ultimately injected into, as well as any mineral substances that are displaced as a result of drilling to reach, the geological structure into which the foreign gas is being injected. Accordingly, it is necessary to understand the distinction between the rights and obligations associated with the surface and mineral estates in order to ensure that injection operations do not expose the injection operator to trespass or conversion claims from either the surface or mineral estate owners or other unaccounted for obligations.

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76. At least one state has declared that pore space belongs to the surface owner and may not be severed. *See generally*, N.D. CENT. CODE ANN. §§ 47-31-0 to -05 (West 2020).

77. Owen Anderson & R. Lee Gresham, *Legal and Commercial Models for Pore-Space Access and Use for Geologic CO<sub>2</sub> Sequestration*, ROCKY MTN. MIN. L. INST. Paper No. 9, \*9-10 (2015).

78. *Id.*

79. In such an instance, the landowner would be the only party with whom an agreement must be entered into because both the subsurface geological structures and the mineral substances which are encased in such structures belong to the same landowner.

### *B. Legal Distinctions between EOR and Sequestration Projects*

The primary difference between the two types of projects is that the EOR operations inherently entail the injection of CO<sub>2</sub> to enhance the extraction of native mineral substances from the subject property, while sequestration operations are limited to the permanent injection of CO<sub>2</sub> into the reservoir selected for storage. Extraction of native mineral substances will require the operator to obtain the right to extract mineral substances from the mineral owner, either in the form of an oil and gas lease or an outright purchase of the mineral estate. Practically speaking, CO<sub>2</sub> EOR almost always takes place in fields with existing production and leases.<sup>80</sup> For this reason, an oil and gas lease is required to conduct EOR operations. As a lessee under an oil and gas lease, the injecting party will have obligations under implied covenants that are owed to its lessor as well as an obligation to compensate the mineral owner for its share of the produced mineral substances.

One unique consideration with respect to mineral owners conducting EOR operations is the payment of royalties. Within this context, there are two principal issues to consider: (1) whether the mineral owner is entitled to the payment of royalties on *injected* substances (rather than native substances) and (2) the calculation of royalty payments on produced EOR volumes. On the first issue, many courts, including the Texas Supreme Court, recognize extraneous (e.g., non-native) gas as personal property once it has been severed from the realty (e.g., after it is initially produced prior to injection).<sup>81</sup> In these jurisdictions, the injecting party will retain ownership of extraneous gas that is injected into a reservoir and typically will not owe a mineral lessor a royalty on such injected gas.<sup>82</sup> This principle regarding the retention of ownership of injected gas has also generally been applied in the storage and sequestration context.<sup>83</sup> With respect to the calculation of royalty payments on produced native mineral substances after injection of CO<sub>2</sub>, the Texas Supreme Court has recognized that “royalty owners and working interest owners are, of course, free to agree on what royalty is due, the basis on which it is to be calculated, and how expenses are to be allocated.”<sup>84</sup> As such, the applicable oil and gas lease will govern the payment of royalties on produced native mineral substances in the context of EOR operations and should be tailored to account for EOR operations.

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80. Durrant, *supra* note 72, at 4.

81. Humble Oil & Ref. Co. v. West, 508 S.W.2d 812, 817 (Tex. 1974) (citing Lone Star Gas Co. v. Murchison, 353 S.W.2d 870 (Tex. App.—Dallas 1962, writ ref’d n.r.e)).

82. *Id.*

83. *Id.* Note: This common law ownership theory may be changed by the local jurisdiction’s sequestration statutes. At least one state’s regulations governing sequestration provides that the ownership rights to sequestered CO<sub>2</sub> transfers to the state upon 10 years after the completion of operations. See LA. STAT. ANN. § 30:1109 (2019).

84. French v. Occidental Permian Ltd., 440 S.W.3d 1, 8 (Tex. 2014).

Another issue that EOR operators should be mindful of when evaluating an EOR project is the need for unitization of the project area (including the execution of a unit agreement and unit operating agreement). EOR projects are generally conducted across an entire source of supply (e.g., a field or reservoir). Accordingly, unitization of all (or a majority) of the interests in the tracts covering such area is necessary to account for the rights belonging to other working and royalty interest owners across the project area.<sup>85</sup> Since operations will occur across the common source of supply underlying such a large area, the operator should control such operations to limit liability exposure and maximize recovery from operations.<sup>86</sup> Once the project area has been unitized, the unit agreement will provide for the commitment of the real property interests of the parties in the project area for development. The working interest owners will also enter into a unit operating agreement to govern operations within the unit. The rights and obligations granted in these agreements deliver a number of economical and operational benefits to the owners of interests in these projects.

Unitization limits free-riding and ensures that responsibility for capital and operating expenses as well as entitlement to resulting revenues from operations are properly allocated amongst the working interest owners.<sup>87</sup> Unitization also allows for the implementation of a unified development scheme across the common source of supply that maximizes the effectiveness of operations. Additional advantages of unitization include the following: (1) the ability for unit operations to maintain all leasehold interests covering the project area, (2) the avoidance of duplicative infrastructure costs for surface facilities, roads, and other infrastructure, and (3) the increased certainty for potential investors/project participants regarding cost allocation and lease maintenance.

Unitization may be effectuated through either voluntary agreement or, in many jurisdictions, compulsory unitization statutes.<sup>88</sup> The state's regulatory body is ultimately responsible for the permitting and governance of unitization operations under either approach. Authorization to unitize the leased premises may be provided under the express terms of the applicable oil and gas lease. In the absence of such provision, a separate agreement is required between the operator and the applicable interest owner to effectuate unitization, unless the applicable state has a compulsory unitization statute. States with such statutes may compel the joinder of holdout mineral or leasehold interests to maximize production and minimize waste.<sup>89</sup> These statutes may also require certain consent thresholds from working and royalty interest owners in the proposed unit

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85. For more insights on unitization, see Austin T. Lee, *Pooling and Unitization*, BRACEWELL, 10 (Apr. 26, 2017), <https://bracewell.com/news/pooling-and-unitization>.

86. *Id.* at 11.

87. *Id.*

88. *Id.*

89. *Id.* at 10.

area before the unit is approved by the state's applicable regulatory agency.<sup>90</sup> The statutes also typically require the operator to show good faith efforts were made to reach a voluntary agreement with the applicable interest owner before compulsory unitization will be ordered. Operators in states lacking a compulsory unitization provision, such as Texas, must obtain the voluntary consent of working and royalty interest owners owning an interest within the unit area to effectuate a unitization.<sup>91</sup>

Once unitization has been approved by the state regulatory agency, some jurisdictions will take the public benefit of increased recovery into consideration in the face of common law trespass claims against the members of the unit. Texas courts have consistently declined to provide injunctive relief, in this context, to trespass claims for injected substances that have traversed unit boundaries into nonunitized neighboring tracts and formations.<sup>92</sup> These decisions have effectively replaced the common law trespass standards with a more lenient standard for unit operations in units approved by the Texas Railroad Commission.<sup>93</sup> Further, "the courts in Texas have been willing to limit relief to damages and have required a showing that the conduct is not only intentional but also unreasonable before such a claim can become actionable."<sup>94</sup> In Oklahoma, several courts have held operators liable for nuisance claims, despite a state approved unit agreement, after injected substances migrated beyond unit boundaries.<sup>95</sup> In these instances, the landowner was ultimately awarded damages after proving interference resulting from the encroachment of injected substances into nonunitized tracts or formations.<sup>96</sup>

A similar regulatory framework has emerged for CO<sub>2</sub> sequestration operations. In the last fifteen years, a number of states have passed new legislation to

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90. See Kate Goodrich, *Texas Takes a Different View Towards Compulsory Unitization Legislation*, TEX. J. OIL GAS & ENERGY L. (Mar. 24, 2017), <http://tjogel.org/texas-takes-a-different-view-towards-compulsory-unitization-legislation/>, for a discussion of state unitization statutes, observing the following:

To date, 29 oil-producing states have statutes that govern unitization, and of those, 25 require authorization by both owners of the 'working interest group' (those responsible for costs) and the 'royalty group' (owners entitled to royalties). The percentage of parties' approval required to unitize varies between states, but usually it is the same percentage within a particular state as to both the working interest group and the royalty group. It ranges from as low as 51 percent (e.g. Illinois and Kentucky) to as high as 80 percent (e.g. Colorado). Sixteen states require 75 percent approval for at least one group.

91. Durrant, *supra* note 72, at 4. For a complete summary of unitization laws by state, see Marie C. Baca, *State Laws can Compel Landowners to Accept Gas and Oil Drilling*, PROPUBLICA (May 19, 2011), <https://projects.propublica.org/tables/forced-pooling.html>.

92. Lee, *supra* note 85, at 11 (citing R.R. Comm'n of Tex. v. Manziel, 361 S.W. 2d 560 (Tex. 1962)).

93. *Id.*

94. *Id.* at 12.

95. Durrant, *supra* note 72, at 8 (citing Boyce v. Dundee Healdton Sand Unit, 560 P.2d 234, 238 (Okla. Civ. App. 1975)); see also Fairfax Oil Co. v. Bolinger, 97 P.2d 574, 576 (Okla. 1939); Greyhound Leasing & Fin. Corp. v. Joiner City Unit, 444 F.2d 439, 441-44 (10th Cir. 1971); Gulf Oil Corp. v. Hughes, 371 P.2d 81, 83 (Okla. 1962).

96. See generally, *Bolinger*, 97 P.2d at 57; *Greyhound Leasing*, 444 F.2d 439; *Hughes*, 371 P.2d 81.

govern CO<sub>2</sub> sequestration projects.<sup>97</sup> Most of these statutes require the injector/storer of CO<sub>2</sub> to apply to the state's applicable regulatory agency for a permit for a sequestration project. Prior to the approval of such an application, the applicable state agency will typically be required to determine one or more of the following findings: (1) the target reservoir intended for sequestration is suitable for storage purposes, (2) the reservoir sought for sequestration is either not producing native mineral substances or the injector/storer has obtained consent from a certain threshold of owners in interest of the reservoir where the storage is being contemplated, and/or (3) operations will not interfere with underground water resources.<sup>98</sup> Once CO<sub>2</sub> sequestration operations have been permitted, the state regulatory agency will often have the power to issue additional protective orders to prevent interference from mineral estate development. Some of these statutes have also established the right to use eminent domain to condemn portions of the surface, mineral, and subsurface estates (though these specific powers vary depending upon jurisdiction) as is reasonably necessary for the construction of sequestration facilities.<sup>99</sup> To the extent the injector/storer cannot acquire title to all of the relevant rights to the surface, mineral, and subsurface estates through eminent domain or through voluntary agreement, it will need to reach agreements similar to those used for unitization in the EOR context to account for the rights belonging to other interest owners across the project area.

EOR and CO<sub>2</sub> sequestration projects also contain a notable difference with respect to permitting. Section 1421 of the Safe Drinking Water Act (SDWA) prohibits underground injection wells except when authorized by a rule or permit.<sup>100</sup> Under the EPA's Underground Injection Control (UIC) program, there are six classes of injection wells permitted by the EPA. The UIC program designates EOR wells as Class II injection wells and sequestration wells as Class VI injection wells.<sup>101</sup>

The EPA estimates that more than 175,000 Class II wells have been permitted in the United States.<sup>102</sup> Pursuant to Section 1425 of the SDWA, the EPA may delegate the primary implementation and enforcement authority (also known as primacy) for the approval and oversight of Class II wells to state governments.<sup>103</sup> In order to obtain primacy, a state must develop a permitting

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97. For a complete summary of state's sequestration statutes, see Anderson & Gresham, *supra* note 77, at 9–10.

98. See generally, LA. STAT. ANN. § 30:1108 (2019).

99. *Id.*

100. ANGELA C. JONES, CONG. RES. SERV., INJECTION AND GEOLOGIC SEQUESTRATION OF CARBON DIOXIDE: FEDERAL ROLE AND ISSUES FOR CONGRESS 7–8 (2020).

101. Durrant, *supra* note 72, at 21.

102. JONES, *supra* note 99, at 9.

103. U.S. ENV'T. PROTECTION AGENCY, GEOLOGIC SEQUESTRATION OF CARBON DIOXIDE: UNDERGROUND INJECTION CONTROL (UIC) PROGRAM CLASS VI PRIMACY MANUAL FOR STATE DIRECTORS 5 (2014) [hereinafter Primacy Manual].

program that is at least as stringent as the requirements of the federal regulations and submit an application for oversight authority with the EPA. A total of forty states have received primacy from the EPA for Class II wells.<sup>104</sup> The State of Texas has obtained primacy and now has an estimated 30,000 active Class II wells governed by the Texas Railroad Commission.<sup>105</sup> While requirements for a Class II well may vary among states, the federal regulations provide a baseline of the requirements an applicant may expect when permitting a Class II well. Approval for these wells will often require (1) a finding that the injection well will not injure any freshwater strata in the area, (2) certain casing and cementing requirements to prevent the migration of injected substances into underground sources of drinking water (USDWs), (3) annual monitoring, testing, and record keeping obligations, and (4) financial assurances that the applicant will properly plug and abandon the well.<sup>106</sup> Findings regarding the impact that injection wells will have on USDWs require coordination among the applicant, the state's department of natural resources, and the state's department of environmental protection. For example, in Texas, the Commission on Environmental Quality must issue a finding that the proposed injection well will not injure any freshwater strata in the area of operations before the Railroad Commission may issue a Class II permit.<sup>107</sup>

Class VI well permitting entails an even more rigorous process tied to sequestration-related risks. For instance, the injection streams used for Class VI wells often contain higher pressures and volumes than the streams used for Class II wells. Consequently, Class VI wells can pose a higher risk of the injected substances migrating or escaping from the reservoir in which they are injected. The migration or escape of the injected substances presents a risk of contamination to USDWs, injury of nearby oil and gas operations, or a seismic event, each of which must be adequately addressed during the permitting process. Another notable difference in Class VI wells is that the injected substances are intended to be permanently stored compared to Class II wells which often extract a majority of the injected substances through the recovery process.<sup>108</sup> Accordingly, the EPA's regulations governing Class VI wells con-

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104. JONES, *supra* note 99, at 10.

105. David Hill, *UIC Permit Applications: Technical Review & Public Notification*, RAILROAD COMMISSION OF TEX., 11, <https://www.rrc.state.tx.us/media/29144/uic-permit-applications-technical-review-public-notification.pdf> (last visited Oct. 22, 2020).

106. JONES, *supra* note 99, at 28.

107. 3 ERNEST E. SMITH & JACQUELINE LANG WEAVER, TEXAS LAW OF OIL AND GAS §14.10 (2d ed. 1998); *see* 16 TEX. ADMIN. CODE §3.30(e)(7) (Tex. R.R. Comm'n, Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)).

108. JONES, *supra* note 99, at 13–14 (The EPA recognizes that the primary purpose of Class II wells is enhanced recovery, while the primary purpose of Class VI wells is secure geologic sequestration. The regulations provide that, when injection operations are conducted with the primary purpose of geologic sequestration and there is an increased risk to USDWs, the operator must apply for a Class VI permit. However, the EPA also recognizes that Class II injection wells will likely result in some volumes of CO<sub>2</sub> being permanently trapped in the reservoir after EOR operations are concluded. The regulations provide

tain more stringent requirements than Class II wells for the permitting, siting, construction, operation, monitoring, plugging, post-injection site care, and site closure of injection wells used for permanent sequestration.<sup>109</sup> Class VI wells also require increased financial assurances to cover corrective action, well plugging, post-injection site care, and emergency responses, remedial responses, or both.<sup>110</sup>

Section 1422 of the SDWA authorizes the EPA to delegate primacy of Class VI wells to state governments, subject to certain statutory requirements.<sup>111</sup> A state seeking to establish primacy over Class VI wells must develop a Class VI regulatory program that is at least as stringent as the federal requirements and that is confirmed by EPA via an application process.<sup>112</sup> As of September 2020, North Dakota and Wyoming are the only states that have received primacy for Class VI wells.<sup>113</sup> Louisiana has also initiated discussions with the EPA and plans to pursue Class VI primacy.<sup>114</sup> In the absence of state primacy, approval for a Class VI well permit must be obtained directly from the EPA. As of January 2020, there have only been two Class VI permits issued in the United States, both of which were for projects located in Illinois.<sup>115</sup>

Please note this paper provides a general synopsis of the primary land-side legal considerations and an overview of permitting schemes required for CCUS operations. This analysis is further limited to the context of privately-owned lands and does not include consideration of issues that are specific to ownership rights on publicly-owned state or federal lands. Further, there are a number of intricacies regarding environmental and regulatory considerations that apply to these projects, a discussion of which is beyond the scope of this paper. Nonetheless, it is important that project participants appreciate the role that permitting and acquiring the necessary land rights plays in these projects. Both of the issues can have a substantial impact on project timing and ability of project participants to finance the applicable CCUS project. Further, these issues are especially important to consider when entering into commercial or financing arrangements with project stakeholders.

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that permanent storage is authorized by a Class II well permit without the need to apply for a Class VI permit, so long as the UIC program director determines that there is not an increased risk to USDWs.).

109. *Id.*

110. *Id.*

111. Primacy Manual, *supra* note 102, at 5.

112. *Id.* at 1.

113. Jessica Casey, *EPA Announces Wyoming's primacy for Class VI Underground Injection Control Programme*, WORLD COAL (Sept. 4, 2020, 12:30 PM), <https://www.worldcoal.com/coal/04092020/epa-announces-wyomings-primacy-for-class-vi-underground-injection-control-programme/>.

114. Wyoming Underground Injection Control Program; Class VI Primacy, 85 Fed. Reg. 20,621 (Apr. 14, 2020) (to be codified at 40 C.F.R. pt. 147); JONES, *supra* note 99, at 10.

115. JONES, *supra* note 99, at 11.



#### IV. CERTAIN COMMERCIAL AND LEGAL CONSIDERATIONS SURROUNDING THE COMMON ARRANGEMENTS NECESSARY TO CONDUCT THESE OPERATIONS

As noted above, CCUS projects involve an interdependent combination of processes and technologies that are used to produce, capture, and either or both utilize and store CO<sub>2</sub>. As such, any CCUS project will require a tailored set of contractual arrangements between the various project participants, which allow for the integration of these processes and address the various risks that each participant is exposed to by virtue of its participation in the project. This section of the paper will provide a general overview of the main considerations that will need to be addressed in negotiating some of the more common commercial arrangements involved in CCUS projects.

##### *A. Participants; Economic Drivers and Objectives for CCUS Projects*

A CCUS project will typically involve three or four principal participants who will enter into the commercial arrangements that tie together the various processes required to operate the project. These include some variations of the following: (1) an emitter of CO<sub>2</sub>, (2) a capturer of CO<sub>2</sub>,<sup>116</sup> (3) a transporter of CO<sub>2</sub>, and (4) a user or storer of CO<sub>2</sub>. Emitters of CO<sub>2</sub> in this context are owners of industrial facilities that emit CO<sub>2</sub> as part of their primary operations. Examples of common CO<sub>2</sub> emitters include gas processing plants, ammonia facilities, and a number of other industrial facilities. Capturers of CO<sub>2</sub> are typically the sponsors of the CCUS project. They own the carbon capture equipment which attaches to the emitter's facilities and will be the party that earns the tax credits that are available under Section 45Q. Transporters of CO<sub>2</sub> are necessary to ensure the delivery of captured CO<sub>2</sub> volumes to the ultimate end-user, the storage facility where those volumes are sequestered, or both. The most common method of CO<sub>2</sub> transportation is through a pipeline. Users of CO<sub>2</sub> come from a wide variety of industries. While the most common use of captured CO<sub>2</sub> today is for EOR, there are a number of other industries that use CO<sub>2</sub>, including producers of fertilizer, producers of chemical compounds (e.g., hydrogen), power generation companies, and producers of iron and steel, to name a few. Storers of CO<sub>2</sub> for sequestration projects are entities that own and maintain the underground storage facilities used to sequester CO<sub>2</sub>.

In many situations, one entity could take on multiple roles as part of a CCUS project. For example, an industrial facility may function as both an emitter and capturer of CO<sub>2</sub> if it desires to invest in the carbon capture equipment needed to remove CO<sub>2</sub> from its primary operations. Similarly, a capturer, user, or storer will often take on the role of transporter for all or a portion of the project and

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116. Note: CCUS projects that rely on direct air capture technology to capture CO<sub>2</sub> will not require the participation of an emitter. In these projects, the capturer uses technology that removes CO<sub>2</sub> directly from the air surrounding the facility rather than the emissions generated from an industrial plant thereby eliminating the need for an emitter.

build out the applicable transportation facilities as part of its primary role in the project. Additionally, there will be a number of different investors, partners, and capital providers for each of the participants involved in the project. Each of these stakeholders will have unique concerns and requirements that will influence the perspective that each of the project participants has in negotiating the required project-level commercial arrangements. While there will be a number of contractual agreements among the various stakeholders of a project, this paper will focus on the principle commercial arrangements needed to produce, capture, and supply CO<sub>2</sub> as it moves through the processes involved in a CCUS project.

As noted above, currently, the primary economic driver of CCUS projects is the tax credits available to the capturer under Section 45Q. In CO<sub>2</sub> utilization projects, there will also be a revenue stream generated from the sale of CO<sub>2</sub> to the user that will contribute to the economics of the project. Given the interdependent nature of the processes involved in any CCUS project, both whether or not the requirements under Section 45Q are met and the volume of CO<sub>2</sub> available to generate those credits will be influenced by factors controlled by each of the participants in the project. Thus, the primary objectives that participants will have in structuring these commercial arrangements will be backstopping the success of these economic drivers and with them the ability of the project to be financed by third-party investors and capital providers.

To accomplish these objectives, these commercial arrangements must require that the processes and facilities utilized by the project meet the requirements of Section 45Q so that tax credits can be earned. Additionally, the risk of tax credits being recaptured due to leakage of CO<sub>2</sub> during use or sequestration should be addressed. Finally, the parties should attempt to secure availability of a minimum level of CO<sub>2</sub> as necessary to meet the anticipated economic assumptions underlying the business case for the project.

#### *B. Structure of Commercial Contractual Arrangements for CCUS Projects*

CCUS projects will typically involve some variation of the following types of commercial agreements for the delivery, use, or storage of CO<sub>2</sub>. These include agreements whereby the emitter agrees to supply the capturer with CO<sub>2</sub> from the applicable industrial facility (which this paper will refer to as CO<sub>2</sub> Supply Agreements) and one of two types of “Offtake Agreements” between the capturer and the user or storer, which addresses the delivery of captured CO<sub>2</sub> for use or storage. Offtake Agreements may take the form of a CO<sub>2</sub> Purchase Agreement (if the capturer is selling the CO<sub>2</sub> to an end-user such as an oil and gas company that is conducting EOR operations) or a CO<sub>2</sub> Storage Agreement (if the capturer is simply delivering the CO<sub>2</sub> to the owner of a storage facility for sequestration).

The structure of these agreements generally follows that of supply or purchase agreements for the delivery or processing of natural gas, with several im-

portant additional nuances that address certain risks specific to CCUS projects. In each case, the provisions of the applicable agreement will need to be tailored to address the facts and circumstances involved with the project itself and the different participants who are parties to the agreement.

As with many gas supply and gas purchase agreements in the midstream space, these CO<sub>2</sub> Supply and Offtake Agreements will normally address the following general topics, among others:

- Required buildout of project facilities (in-service deadlines, facility specifications and requirements, permitting and approval requirements, and remedies for the failure to meet deadlines or the failure to build (or maintain) facilities in accordance with required specifications);
- Fees for CO<sub>2</sub> delivered or stored pursuant to the agreement;
- Service levels (“firm” vs. “interruptible”) for delivery obligations and capacity for storage;
- Force Majeure and change in law provisions which excuse performance of obligations in certain circumstances (scope of circumstances constituting a “Force Majeure” event or a change in law, termination rights for prolonged events, obligations to remedy or adjust the agreement);
- Required specifications for the quality, temperature, and pressure of the CO<sub>2</sub> delivered;
- Measurement of delivered CO<sub>2</sub> and testing of measurement equipment;
- Custody and control of CO<sub>2</sub> delivered under the agreement (at what point does it transfer);
- Division of responsibility and liability for CO<sub>2</sub> delivered under the agreement and for the facilities owned by each party;
- Confidentiality obligations with respect to information to which each party has access to pursuant to the agreement; and
- Obligations to maintain appropriate levels of insurance for the benefit of the other parties involved in the project.

One of the most material issues in any legal arrangement is the creditworthiness of the parties and their ability to stand behind their respective obligations under the agreement. While diligence regarding the financial and operational wherewithal of each of the participants in a CCUS project should occur prior to the commencement of the project, it is also important to provide contractual mechanics that seek to maintain the credit profile of the parties to each agreement (or that provide remedies in the event one party can no longer effectively stand behind its obligations).

In circumstances where a party to an agreement has limited resources (such as when a special purpose vehicle is used), a guarantee of that party’s obligations from more creditworthy affiliates or capital sponsors should be obtained. Alternatively, in these situations, related parties may grant a lien on certain

property to secure the obligations of one of the parties under the agreement in question. Depending on the collateral covered, that lien can serve as an effective substitute for providing a related party guarantee.

In addition to ensuring that sufficient financial resources are there to support each party's obligations, the agreement should define "events of default" to include instances where a party files for bankruptcy or otherwise demonstrates that it is in financial distress. These events of default should trigger remedies (such as indemnity and potentially contract termination) when they are not timely cured. Additionally, it is important to limit the ability of the parties to assign their interest in the agreement (and potentially the facilities used to perform that party's obligations under the agreement) to only assignees who either meet stated minimum credit rating standards or who can provide a guarantee from a party that meets those standards.

A full discussion of each of these topics is beyond the scope of this paper; however, the above outline of the general framework used for these agreements provides an important background for the discussion of some of the more nuanced considerations noted below. Further, as with any legal agreement, care should be taken to tailor the agreement to address the specific circumstances being encountered by the parties. The parties should also ensure that the terms of the agreement work in concert with other agreements that are binding on the parties or that otherwise impact the operation of the project. Next, this paper will discuss some of the important commercial considerations that are specific to CCUS projects.

### *C. CCUS Project Specific Considerations*

A number of commercial issues that participants in CCUS projects must consider flow from the fact that the success of the project will rely on the integrated performance of each of the participants and their respective processes and facilities. They all have to work together to capture and deliver sufficient volumes of CO<sub>2</sub> and to meet the requirements necessary to generate tax credits, which underlie the project's economics. As a result, recognition of the considerations and risks related to these interdependencies and appropriately addressing them in the participants' commercial arrangements is essential to the success of each project.

Further, it is important to note that these risks are shared by all of the project participants even if the issue creating the risk materializes from the interaction of processes between participants that are contractually "upstream" or "downstream" within the contractual chain. The consequences of delays or inability to perform based on these risks should be considered, and a clear allocation of these risks among the project participants should be provided for in these commercial arrangements.

### 1. Industry and Private-Party Considerations

CCUS projects entail risks associated with the industry in which the emitter operates as well as risks that are unique to that emitter's specific business. For projects where utilization of CO<sub>2</sub> is contemplated, similar risks related to the end-user of the CO<sub>2</sub> and its business also apply. These risks materialize in a variety of ways, including: operational risks (will the industrial facility be operating at the anticipated level of output?), reliability risks (will the facility generating CO<sub>2</sub> need to shut down for repairs or due to seasonal factors?), risks related to that particular participant's contractual counterparties and capital providers (is the emitter dependent on a key supplier or does it require additional investment capital to maintain production at a certain level?), and viability concerns driven by political developments (will increased regulations prevent a coal plant that is the source of the CO<sub>2</sub> from being able to operate for the entire life of the project?).

Generally, the commercial arrangements among the participants in the project will force each party to internalize these industry-specific and business-specific risks. For example, consider the risk of outages at an emitter's facilities. While it is normal to provide the owner of facilities relief from complying with certain obligations for planned outages that are necessary to maintain its facilities and those due to events beyond its reasonable control (e.g., force majeure events), unplanned curtailments in production and facility shutdowns should be treated differently. Events such as unplanned shutdowns of facilities or curtailments in production that persist for prolonged periods of time will often trigger termination rights, make-whole payment obligations, and other specific remedies for the other party.

### 2. General Compliance and Recapture Risk under Section 45Q

As noted above, Section 45Q sets forth a number of specific requirements and qualifications that must be met in order to earn the tax credits available for CCUS projects. These requirements relate to the equipment used for capturing CO<sub>2</sub>. Additionally, the parties will have to take steps to ensure that any tax credits that are earned are not recaptured due to leakage of CO<sub>2</sub> from the facilities of the parties using or sequestering CO<sub>2</sub> captured in project operations. The Section 45Q credit recapture risk is driven by the ability of the users of CO<sub>2</sub> or storers of CO<sub>2</sub> to prevent captured CO<sub>2</sub> from escaping from their facilities or processes. Thus, the applicable Offtake Agreements should obligate the user/storer to conduct its operations in a way that minimizes the risk of leakage from its facilities. Further, in any arrangement where CO<sub>2</sub> captured by the project is utilized for EOR operations or sequestered in underground storage reservoirs, the user/storer of such CO<sub>2</sub> should be allocated responsibility for obtaining and maintaining the necessary real property rights in the applicable reservoirs where the CO<sub>2</sub> is injected.

Addressing these recapture and compliance risks will require that the participants make representations and warranties about themselves, their facilities, and their processes that confirm that the applicable qualifications and requirements have been met. To the extent compliance with Section 45Q and other regulatory requirements is dependent on a participant taking future actions (such as the buildout or maintenance of its facilities), the participant must expressly obligate itself to meet those specific requirements. Finally, these representations, warranties, and obligations will need to be supported by customary indemnity obligations in favor of the applicable counterparty in the event that it suffers damages or third-party claims resulting from a breach of these specific obligations.

### 3. Minimum Volume Commitments

The volume of CO<sub>2</sub> captured and utilized or sequestered in CCUS project operations will correlate directly with the amount of the tax credits that the project can generate and, in utilization projects, the amount of fees paid by end-users of that CO<sub>2</sub>. As such, in many cases, project participants will seek commitments from the various participants that are “upstream” in the contractual chain to deliver or conduct activities expected to generate a minimum amount of CO<sub>2</sub> as necessary to achieve the economic assumptions underlying the business case for the project. In the event the participant obligated to deliver or generate the CO<sub>2</sub> does not meet its delivery or generation obligations called for under its agreement, it will be obligated to pay a deficiency payment for the undelivered volumes (or underutilization of its facilities).

Captors seek these minimum generation commitments from emitters based on anticipated production from an assumed level of operations at the emitter’s facilities. This provides capturers some certainty regarding the level of tax credits (or deficiency payments in lieu thereof) that they can generate. At the other end of the contractual chain, both capturers and users of CO<sub>2</sub> often agree to the delivery and acceptance of a specified minimum volume of CO<sub>2</sub>. This provides certainty to capturers regarding the revenue stream they can expect to receive from CO<sub>2</sub> offtakers. It also provides certainty to the user of CO<sub>2</sub> regarding the level of feedstock it will receive. Minimum volume commitments are also important in the CO<sub>2</sub> sequestration context as they function to provide the owner of the storage facility with a baseline set of fees it can anticipate receiving from the capturer. In turn, the storage facility owner will normally guarantee the capturer a level of “firm capacity” in the applicable storage facility that corresponds to the minimum volumes that the capturer can commit to deliver under these arrangements.

Structuring the various volume commitments made by each of the project participants requires a lot of coordination among the terms of the different agreements creating these commercial arrangements. The amounts of these volume commitments should be coordinated to ensure that sufficient volumes

of CO<sub>2</sub> will be available for delivery from one project process to another and should account for the expected production capabilities and capacities of the different facilities involved in the project. Additionally, the remedies available to a party for the failure of its counterparty to meet the minimum delivery requirements should be understood and adequate to address the consequences of that breach.

In the event the emitter fails to deliver the agreed minimum volume of CO<sub>2</sub> (or fails to conduct the agreed minimum level of activity at its facility that the capturer requires for the generation of CO<sub>2</sub>), it is likely that the capturer will not be able to meet its downstream minimum delivery requirements to either end-users or storers under its Offtake Agreements. The impacts of these downstream consequences should be considered in setting the level of both deficiency payments that the emitter will owe under its CO<sub>2</sub> Supply Agreement and the potential deficiency payments that the capturer may owe under its Offtake Agreement. Because alternative sources of CO<sub>2</sub> may not be readily available (especially those that can generate Section 45Q tax credits), minimum volume commitments and the corresponding monetary damages for underdeliveries of CO<sub>2</sub> volumes are often the principal mechanisms used to support anticipated project economics. These mechanisms also force participants to internalize the risks presented by the project-level processes and facilities that are within that participant's control.

It should be noted that CCUS projects that utilize EOR operations as the end-use for captured CO<sub>2</sub> may not need to rely on minimum volume commitments to the same extent as other CCUS projects. This is due to the fact that most EOR operations are sufficiently large in scale such that they will require an amount of CO<sub>2</sub> far beyond what can be captured and provided from a single industrial emitter. Thus, most EOR operations will have access to naturally sourced CO<sub>2</sub> and will be supplementing that supply with anthropogenic CO<sub>2</sub> from the CCUS project. While other project participants may seek minimum volume commitments (or minimum operation levels) from emitters to support the desired economics, EOR operators who are end-users of the captured CO<sub>2</sub> may be in a position to agree to take all the captured CO<sub>2</sub> generated by the project up to a certain requested amount without a strict minimum delivery requirement. This typically occurs where an EOR operator participates in the project through a joint venture with the capturer (or other participants) and thus locks in exposure to its portion of the economic benefits of the project at the joint venture level. In these situations, the EOR operator would still secure some contractual protections in its agreement with the capturer. These protections include the right to source CO<sub>2</sub> from alternative sources to the extent the project cannot supply the requested amount of CO<sub>2</sub> and the right to terminate its agreement with the capturer in the event that the project continually fails to deliver the requested amounts of CO<sub>2</sub>.

#### 4. Access and Information Rights

The highly-integrated nature of the various processes involved in a CCUS project requires that project participants provide each other access and inspection rights to most of the facilities involved in project operations. For example, in almost all cases, the capturer's equipment will need to be located onsite at the emitter's industrial facility. Access and use rights are needed to allow for the installation and operation of the carbon capture equipment on the emitter's premises and to account for issues such as joint use of those premises, ingress and egress to specific parts of the facility, restrictions on access, security, and emergency scenarios, and other issues.

Additionally, participants in the project will likely require inspection rights granting them the ability to inspect the facilities and processes controlled by the other project participants. These rights are necessary to allow each participant to confirm that the other project participants are complying with the requirements of Section 45Q as well as other applicable regulatory requirements. They also are needed to allow the project participants to monitor, and hopefully prevent, leakage of CO<sub>2</sub> that could result in recapture of Section 45Q credits.

In addition to granting inspection rights, participants in the project should be obligated to routinely provide other project participants with an agreed upon set of reports, certifications, and testing results as necessary to substantiate that participant's compliance with Section 45Q and other applicable regulatory requirements. Each project participant should have the right to audit these reports, certifications, and testing results over reasonable periods after they are obtained. Further, each project participant should have the right to test facilities and related equipment as needed to confirm compliance with these core regulatory or legal requirements.

In certain situations, governmental agencies, such as the Department of Energy, will enter into cost sharing or reimbursement agreements with owners of carbon capture projects that utilize emerging technology. These agreements benefit the governmental agencies by providing them with information about the effectiveness of promising new technologies that support policy initiatives. They also provide the project participants with economic support that lowers the risk associated with the project. Often, those cost sharing reimbursement agreements will require that the capturer gain access for the applicable governmental agency to monitor and evaluate the results of the project operations. In these cases, sufficient access rights will need to sync up with the requirements under the applicable cost sharing or reimbursement agreements.

Finally, appropriate confidentiality and non-disclosure obligations should accompany these access and inspection rights in order to safeguard information concerning each participant's business, operations, or facilities. Further, any party who is providing access to another party's facilities should be required to remediate (or otherwise account for) any damages resulting from the exercise of those access and related inspection rights.



### 5. Minimum Term Considerations

As noted above, Section 45Q credits are available with respect to a qualifying CCUS project for twelve years from the date that the applicable facility is placed in service. Tax credits earned in a given year generally are subject to recapture until five years after the last taxable year in which the taxpayer claimed a Section 45Q credit for the applicable project. Thus, the commercial arrangements among the participants in a CCUS project should be maintained for sufficient periods of time to allow the project to earn tax credits during the twelve-year eligibility period and to provide contractual protections and remedies regarding recapture and compliance risk for seventeen years following the in-service date of the applicable project facilities.

### IV. CONCLUSION

The recent amendments to Section 45Q have created meaningful economic incentives for energy infrastructure companies and other industrial manufacturers that wish to invest in CCUS technology. CCUS technology will help energy sectors realize synergies to foster a world where the byproducts emitted in the production of our energy are recycled and utilized to create more energy. A recent report on CCUS technologies observed that when “[v]iewed through this lens, the U.S. power sector’s annual production of [CO<sub>2</sub>] represents a potentially prolific economic opportunity: [CO<sub>2</sub>] can be captured from power plants and sold for oil production.”<sup>117</sup> The report further went on to determine, “[o]ur analysis finds that these recent developments could be the beginnings of a carbon capture revolution . . . .”<sup>118</sup>

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117. *Making Carbon a Commodity: The Potential of Carbon Capture RD&D*, *supra* note 5, at i.

118. *Id.* at ii.

