Legal Pathways to Widespread Carbon Capture and Sequestration

by Wendy B. Jacobs and Michael Craig

Wendy B. Jacobs is Clinical Professor of Law and Clinic Director of the Emmett Environmental Law and Policy Clinic at Harvard Law School. Michael Craig is a Ph.D. candidate in the Engineering and Public Policy department at Carnegie Mellon University.

Summary

Despite competing views about climate change policy, the time is ripe to drive carbon capture and sequestration (CCS) forward. National and state investment in and support of CCS are completely consistent with the Donald Trump Administration's goals to invest in infrastructure projects, continue U.S. reliance on fossil fuels, and create jobs. This Article, excerpted from Michael B. Gerrard & John C. Dernbach, eds., *Legal Pathways to Deep Decarbonization in the United States* (forthcoming in 2018 from ELI), addresses the use of CCS to achieve significant reductions in emissions of carbon dioxide to the atmosphere by 2050, and explains why its widespread adoption in the United States has not yet occurred. The authors describe the potential of CCS for achieving deep decarbonization of the U.S. power sector, explain the key components of CCS, and identify and recommend several federal and state legal reforms necessary to drive it forward.

I. Introduction

According to the Deep Decarbonization Pathways Project (DDPP)[1] and the United States Mid-Century Strategy for Deep Decarbonization issued by the White House in November 2016,[2] carbon capture and sequestration (CCS) can play a major role in reducing greenhouse gas (GHG) emissions in the United States by 80% by 2050. CCS technology has been the subject of years of study and is in use as of July 2017 at 17 large-scale industrial and power generating facilities in the United States and elsewhere, with another three facilities expected to come online by 2018.[3] Studies have confirmed that most major point sources of carbon dioxide emissions in the United States are situated within a manageable distance from areas that could host pipelines and sequestration facilities.[4]

1. *See* James H. Williams et al., Energy and Environmental Economics, Inc. et al., US 2050 Report: Pathways to Deep Decarbonization in the United States 16-17 (2014) (describing four scenarios in which greenhouse gas (GHG) emissions are decreased by 80% in the United States by 2050, two of which include carbon capture and sequestration (CCS); the other two scenarios focus on renewable and nuclear energy. Of the two scenarios that include CCS, under the Mixed Scenario, CCS would be deployed at new NGCC units, which would account for roughly 13% of electricity generation in 2050 (36, fig. 29). Under the High CCS Scenario, CCS would be deployed first at new coal-fired plants and later at new NGCC plants, which would collectively account for nearly 60% of electricity generation in 2050 (*id.*)).
2. *See* The White House, United States Mid-Century Strategy for Deep Decarbonization (2016).
3. *See* Global CCS Institute, *Projects Database—Large-Scale CCS Facilities* (showing 17 operational plants globally), https://www.globalccsinstitute.com/projects/large-scale-ccs-projects (last visited Sept. 23, 2017). The three facilities expected to come online by 2018 are the Gorgon Carbon Dioxide Injection Project in Australia, and two projects in Alberta, Canada, associated with the Alberta Carbon Trunk Line. *See* Global CCS Institute, *Projects Database—Gorgon Carbon Dioxide Injection*, https://www.globalccsinstitute.com/projects/gorgon-carbon-dioxide-injection-project (last updated June 20, 2017), Global CCS Institute, *Projects Database—Alberta Carbon Trunk Line ("ACTL") With North West Redwater Partnership's Sturgeon Refinery CO_2 Stream*, https://www.globalccsinstitute.com/projects/alberta-carbon-trunk-line-actl-north-west-sturgeon-refinery-co2-stream (last updated Aug. 22, 2017), and Global CCS Institute, *Projects Database—Alberta Carbon Trunk Line ("ACTL") With Agrium CO_2 Stream*, https://www.globalccsinstitute.com/projects/alberta-carbon-trunk-line-actl-agrium-co2-stream (last updated Aug. 22, 2017). The Kemper County integrated gasification combined-cycle (IGCC) project was expected to be operational in 2017, but operations and startup activities were suspended in June 2017. *See* Southern Co. & Mississippi Power Co., SEC Form 8-K, Current Report 4 (June 28, 2017), https://d18rn0p25nwr6d.cloudfront.net/CIK-0000092122/98f6dd3e-1d59-4284-be58-88702a3702e1.pdf. *See also* Ryan L. Nave, *Mississippi Power Co. to Suspend Kemper Coal Operations*, Miss. Today, June 28, 2017, https://mississippitoday.org/2017/06/28/mississippi-power-co-to-suspend-kemper-coal-operations/.
4. *See* U.S. Environmental Protection Agency (EPA) Regulatory Impact Analysis for the Final Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units 5-17, n.21 (2015) (EPA-452/R-15-005); *see* James J. Dooley, Carbon Dioxide Capture and Geologic Storage 29 (2006) (noting that 95% of the 500 largest existing carbon dioxide point sources are located within 50 miles of a possible geologic sequestration reservoir); James Katzer, The Future of Coal 58 (2007); James J. Dooley et al., *A CO_2-Storage Supply Curve for North Amer-*

Widespread adoption of CCS in the United States has not occurred for four major reasons. First and foremost is cost: both the high cost of capturing and compressing carbon dioxide at power plants, and the uncertain extent of potential liability and cost associated with sequestration. Federal and state legal reforms can overcome this hindrance, as spelled out in this Article. The second major obstacle is the absence of a strong national legislative or policy driver. A national price or cap on carbon dioxide emissions would drive the technology forward in applications across multiple industrial sectors in the United States.

The third hurdle to widespread adoption of CCS has been the persistently low price of natural gas combined with the current federal regulatory regime, which together incentivize near-term construction of natural gas plants with no CCS. Given the low price of natural gas and the absence of any national requirement (direct or indirect) that natural gas combined-cycle (NGCC) plants use CCS, construction of NGCC plants to replace coal-fired plants as baseload generators has been occurring and will continue.[5] Absent prompt legal reforms, as suggested here, these NGCC plants will be operational and emitting significant quantities of carbon dioxide for decades to come, undermining the ability of CCS to serve as a major contributor to carbon dioxide emissions reductions in the United States. Retrofitting these plants later will be more expensive and inefficient.[6]

Fourth, the existing pipeline infrastructure for transporting captured carbon dioxide from its source to suitable sequestration facilities is insufficient in location and size to carry the quantity of carbon dioxide that a national driver for capture would generate. Low oil prices pose a significant challenge to private investment in such pipelines, making it uneconomic to transport carbon dioxide to existing oil fields for use to enhance oil recovery.[7] Pipeline expansion is stymied not only by cost, but also by public opposition and a lack of coordinated regional approaches. These barriers can be addressed and overcome as suggested below.

Thus, significant legal reforms that include a combination of financial incentives, mandates, and other forms of government support are needed to drive full-scale diffusion of CCS technology in the United States.[8] This Article recommends a variety of legal reforms to expand CCS deployment on coal-fired and NGCC plants in line with DDPP projections. The recommended reforms would not only require the use of CCS at coal-fired and NGCC plants, but would also facilitate the sale of and help create markets for the higher-cost electricity generated by plants equipped with CCS, and would provide substantial investment in CCS and its associated infrastructure.

Assuming the continued absence of federal legislation that imposes a national cap or price on carbon dioxide emissions, this Article suggests: (1) issuance of presidential and gubernatorial Executive Orders to create federal and state markets for purchase of power generated by CCS-equipped power plants; (2) enactment of federal and state legislation to provide financial incentives to spur capture of carbon dioxide; (3) tightening of federal and state regulatory requirements for new and existing sources to directly or indirectly require widespread use of CCS; (4) action by federal and state actors to streamline permitting and improve interagency coordination; (5) expansion of public-private partnerships to build out the existing pipeline infrastructure (perhaps providing eminent domain authority to install the pipelines needed to transport captured carbon dioxide from early adopters of CCS to the proposed federal sequestration sites); and (6) use of federal funds to build and operate several sequestration facilities on federally owned lands located near existing or proposed large sources of captured carbon dioxide with the federal government retaining the long-term liability associated with permanent sequestration of the captured carbon dioxide.

Together with other federal and state financial and regulatory incentives described below, these suggested legal reforms could overcome the chief obstacles to CCS deployment in the United States and help achieve the economy-wide 80% GHG emissions reductions needed to deeply decarbonize the United States by 2050. The suggestions in this Article build on lessons learned from the efforts to date

ica and Its Implications for the Deployment of Carbon Dioxide Capture and Storage Systems, *in* Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies 593 (Edward S. Rubin et al. eds., Elsevier 2004).

5. *See* U.S. Energy Information Administration (EIA), *Natural Gas Expected to Surpass Coal in Mix of Fuel Used for U.S. Power Generation in 2016*, Today in Energy, Mar. 16, 2016, http://www.eia.gov/todayinenergy/detail.cfm?id=25392; EIA, Annual Energy Outlook 2017 tbl. 8 (2017), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=8-AEO2017&cases=ref2017&sourcekey=0; Ira Shavel et al., The Brattle Group, Exploring Natural Gas and Renewables in ERCOT—Part IV 15 (2016) (projecting that low natural gas prices could cause the retirement of more than 60% of the Electric Reliability Council of Texas' (ERCOT's) coal-producing plants by 2022), https://static.texastribune.org/media/documents/FINAL_Brattle_TCEC_12_May_2016_with_appendix.pdf.

6. The National Energy Technology Laboratory (NETL) estimates that the capture cost of a retrofitted NGCC plant is $9/ton of captured carbon dioxide higher than that of a new NGCC plant built with capture equipment. Kristin Gerdes, NETL, NETL Studies on the Economic Feasibility of CO_2 Capture Retrofits for the U.S. Power Plant Fleet 10 (2014), https://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/NETL-Retrofits-Overview-2014-01-09-rev2.pdf.

7. *See* U.S. Department of Energy (DOE), Siting and Regulating Carbon Capture, Utilization, and Storage Infrastructure Workshop Report 8 (2017) [hereinafter DOE Workshop Report].

8. Technology diffusion brings costs down. Margaret R. Taylor et al., *Regulation as the Mother of Innovation: The Case of SO_2 Control*, 27 Law & Pol'y 348-78 (2005) (using the history of sulfur dioxide control to show that increased diffusion of technology results in significant and predictable operating cost reductions in existing systems, as well as notable efficiency improvements and capital cost reductions in new systems).

in the United States to build or retrofit power plants with CCS. One key lesson is that trying to integrate all aspects of CCS into a single project is financially challenging in the current economic environment of low natural gas and oil prices.

To drive CCS forward, this Article suggests disaggregating the three components of CCS—carbon dioxide capture, carbon dioxide transportation, and carbon dioxide sequestration—for separate albeit coordinated legal and financial treatment. Part II of the Article deals with reforms needed to spur capture of carbon dioxide; Part III addresses construction of the needed pipelines; and Part IV looks at the sequestration stage. For the earliest projects, it is recommended that the federal government not only provide more funding and support for carbon dioxide capture, but also make some federal land available for sequestration and assume postclosure liability for some sequestration sites in order to help subsidize widespread deployment and diffusion of CCS.

II. Legal Reforms Needed to Spur Widespread Capture of Carbon Dioxide

If the DDPP projections of CCS deployment in the High CCS and Mixed Scenarios in the United States are to be realized, legal reforms will be needed to subsidize application of CCS to NGCC plants, to facilitate the creation of markets to provide a long-term revenue stream for plants that capture carbon dioxide, and to tighten regulatory requirements for carbon dioxide capture. These include revamped renewable portfolio standards (RPS), allowances in ratemaking proceedings, contracts for differences or other schemes to compensate CCS facilities per unit of electricity they generate, and tightening performance standards for new and existing plants.

A. Federal and State Governments Can Create Markets for Electricity Generated by CCS-Equipped Facilities

Establishing markets specifically for electricity generated by CCS-equipped facilities would encourage CCS deployment by increasing certainty that a market will exist for their electricity once operational, thereby reducing project risk. Federal and state governments can create markets for electricity generated by CCS-equipped facilities in several ways. Presidential and gubernatorial Executive Orders can mandate that federal and state governments, respectively, buy electricity generated by CCS-equipped facilities. State governments can add a requirement for the purchase of electricity generated by CCS-equipped facilities to renewable portfolio standards. State public utility commissions and other actors can also stabilize prices for electricity generated by CCS-equipped facilities, such as through ratemaking proceedings and contracts for differences.

1. Presidential and Gubernatorial Executive Orders Can Require Governments to Procure Electricity Generated by CCS-Equipped Facilities

One way to create a market for the higher-cost electricity produced by plants that utilize CCS is for the federal and state governments themselves to buy that electricity. This can be done via power purchase agreements (PPAs). These contracts are not only important for providing a reliable revenue stream for electricity generators, but they also provide an asset that supports the ability of the generator to obtain debt and equity financing. PPAs thus help generators "afford" to invest in CCS—even if it is not yet mandatory.

Presidential Executive Order No. 13693 requires, among other things, that federal agencies increase the amount of clean energy used in their buildings to 25% relative to total energy use (electric and thermal) by fiscal year 2025.[9] Clean energy is defined to include both renewable electric energy and alternative energy.[10] CCS is but one of several types of qualifying alternative energy. The Executive Order could be revised and reissued to (1) direct agencies to purchase a minimum amount of CCS-produced energy, thereby creating a more stable market for it; and (2) significantly raise the minimum total amount of clean energy to be purchased by the federal government by 2050.

Similar orders can be issued by governors and mayors[11] where the grid includes plants that are or can be equipped with CCS.

2. States Can Expand Their RPS to Include Low-Carbon Electricity Generated by Plants Equipped to Capture Carbon Dioxide

Currently, 29 states and the District of Columbia require utilities to purchase a percentage of their electricity from renewable energy sources. These laws, typically known as RPS, could be expanded to become clean energy standards (CES) mandating not just the purchase of renewable energy, but also energy produced by coal-fired and NGCC plants equipped to capture carbon dioxide. In this way, states could help drive CCS forward by creating a market for such higher-cost electricity just as some states have already done for solar electricity through carve-outs to their RPS.[12] Indeed, six states have created carve-outs in their CES for electricity generated by CCS-equipped

9. Exec. Order No. 13693, 80 Fed. Reg. 15871, 15872 (Mar. 19, 2015).
10. *Id.* at 15882.
11. For instance, in 2017, Chicago committed to powering government buildings with 100% renewable energy. *See* Fran Spielman, *900 Chicago Government Buildings to Switch to Renewable Energy*, Chi. Sun Times, Apr. 7, 2017, http://chicago.suntimes.com/chicago-politics/900-chicago-government-buildings-to-switch-to-renewable-energy/. This commitment could be modified to require a certain portion of electricity for government buildings to come from CCS-equipped power plants.
12. *See* Database of State Incentives for Renewables and Efficiency, *RPS Carveout Map*, http://www.dsireusa.org/resources/detailed-summary-maps/rps-carveout-map/ (last visited Sept. 23, 2017).

power plants and other low-carbon technologies, thereby creating a market for low-carbon technologies, including CCS.[13] If adopted by more states, these changes would significantly expand the market for electricity generated by CCS-equipped power plants and provide an additional revenue stream to CCS-equipped power plants.[14]

3. State Public Utility Commissions, Private Parties, and the Federal Government Can Help Stabilize and Subsidize Prices for CCS-Generated Electricity

In addition to creating markets for the higher-priced electricity generated at CCS-equipped plants, governments and private parties can help stabilize prices by a variety of mechanisms, including PPAs and contracts for differences (CfDs) in order to support sales of CCS-generated electricity.

A CfD is a bilateral agreement between an electricity generator and another party, such as a public utility, large private electricity consumer, or government entity.[15] CfDs contain a predetermined price (the strike price) that operates against a reference wholesale market price. If the strike price is higher than the reference wholesale market price, then the generator receives the difference between the two prices. If the strike price is lower than the reference wholesale market price, then the generator has to pay back the difference. The CfD is a type of hedge that helps to reduce the exposure of both parties to energy price fluctuations, creating more certainty around future pricing. In the United Kingdom, the national government auctions CfDs to low-carbon sources of energy in order to provide long-term price stability and help these projects obtain a lower cost of capital.[16]

In the United States, there is already some precedent for the use of CfDs (sometimes referred to as "synthetic" PPAs) between a generator and another party (known as an off-taker) in which there is no physical exchange of power between the generator and the off-taker. The generator sells electricity into the open market, and the other party buys its electricity on the open market. Since both parties can benefit from a hedge, they will enter into a CfD for either the power produced by the project or for future revenue from the project.[17]

To help subsidize the higher cost of electricity generated by CCS-equipped plants, federal or state governments could enter into CfDs with such plants (although legislation may be required for this). As CCS costs decline (e.g., as costs decline or oil prices and consequent enhanced oil recovery (EOR) revenues increase), private companies may also profitably enter into CfDs. The federal government could run a reverse auction to allow companies to reveal the strike price they would accept or set the strike price around the levelized cost of electricity for an NGCC plant with carbon dioxide capture. The generator would consequently earn revenues from selling its electricity into the wholesale power market at the wholesale power price and would be paid the difference between the wholesale power price and the strike price. Effectively, this subsidizes the cost of carbon dioxide capture to enable generators to compete in the marketplace, even with their higher cost of electricity generation. For every gigawatt (GW) of installed capacity of coal-fired or NGCC plants with CCS supported through such a CfD, costs would be on the order of $200-$800 million per year.[18]

There has been some discussion recently of the potential use of CfDs offered by the federal government to stabilize and set a floor for the sale price of captured carbon dioxide to address the volatile price of oil and encourage the use of

13. Illinois, 20 Ill. Comp. Stat. 3855/1-75(d)(1) (requiring electric utilities to procure at least 5% of their total energy supply from "clean coal" facilities); *id*. 3855/1-10 (plants that capture and sequester between 50% and 90% of carbon dioxide, depending on the date of construction, qualify as "clean coal" facilities); Massachusetts, Mass. Regs. Code tit. 225, §16.04 (naming gasification facilities with carbon capture technologies as one of five eligible alternative energy sources); Michigan, Mich. Comp. Laws §460.1003(c)(iii) (naming plants that capture and sequester 85% or more of carbon emissions as eligible "advanced cleaner energy sources"); Ohio, Ohio Rev. Code §4928.01(34)(c) (naming plants using "clean coal technology that includes the design capability to control or prevent the emission of carbon dioxide" as eligible alternative energy sources); and Indiana, which has voluntary procurement standards, Ind. Code 8-1-37-4(17) (defining eligible clean power sources as including those described in *id*. 8-1-8.8-2, which includes "advanced technologies that reduce regulated air emissions from or increase the efficiency of existing energy production or generating plants that are fueled primarily by coal or gases from coal from the geological formation known as the Illinois Basin"); Utah, Utah Code Ann. §54-17-602(1)(a) (providing for 20% of Utah's adjusted electricity sales to be from qualifying electricity or renewable energy certificates by 2025).
14. New York has announced a similar plan in order to support and subsidize nuclear energy. *See* Press Release, Gov. Andrew M. Cuomo, Governor Cuomo Announces Establishment of Clean Energy Standard That Mandates 50 Percent Renewables by 2030 (Aug. 1, 2016), https://www.governor.ny.gov/news/governor-cuomo-announces-establishment-clean-energy-standard-mandates-50-percent-renewables; *see also* Patrick McGeehan, *New York State Aiding Nuclear Plants With Millions in Subsidies*, N.Y. Times, Aug. 1, 2016, http://www.nytimes.com/2016/08/02/nyregion/new-york-state-aiding-nuclear-plants-with-millions-in-subsidies.html.
15. *See generally* U.K. Department of Energy and Climate Change, Electricity Market Reform Contracts for Difference (2014), https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/301464/cfd_implementation_plan.pdf.
16. *See* Department for Business, Energy, and Industrial Strategy, *Electricity Market Reform: Contracts for Difference (Collection)*, https://www.gov.uk/government/collections/electricity-market-reform-contracts-for-difference (last visited Sept. 23, 2017).
17. *See generally* Hughes v. Talen Energy Mktg., LLC, 136 S. Ct. 1288, 1299 n.12, 46 ELR 20078 (2016).
18. Annual costs would vary based on the wholesale electricity price. Here, we estimate the CfD cost using average wholesale electricity prices in 2016 and the levelized cost of electricity (LCOE) for NGCC and coal-fired plants equipped with CCS. This method likely underestimates the actual cost of the CfD, given that the LCOE represents break-even payments rather than a commercial return on investment. Nonetheless, monthly average weighted-average wholesale electricity prices in PJM ranged from $23-$33/megawatt hour (MWh) from January to December in 2016. *See* PJM, *Hourly Real-Time & Day-Ahead LMP* (data derived from monthly spreadsheets of weighted-average locational marginal price data for 2016), http://www.pjm.com/markets-and-operations/energy/real-time/monthlylmp.aspx (last visited Sept. 23, 2017). This assumes an LCOE for coal-fired CCS-equipped units of $90-$150/MWh and for NGCC CCS-equipped units of $60-$120. According to Edward Rubin et al., annual CfD payments for one GW of coal-fired CCS-equipped units operating at a capacity factor of 0.7 would equal $350-$780 million per year and for one GW of NGCC CCS-equipped units would equal $170-$590 million per year. Edward S. Rubin et al., *The Cost of CO_2 Capture and Storage*, 40 Int'l J. Greenhouse Gas Control 388, tbl. 14 (2015).

captured carbon dioxide for EOR.[19] Much of the existing carbon dioxide pipeline infrastructure was built when the price of oil topped $70 per barrel and there was a profit to be made shipping carbon dioxide to existing oil fields for EOR.[20] In 2016, the U.S. Congress directed the U.S. Department of Energy (DOE) to analyze the potential for CfDs to bolster CCS and to be revenue-neutral for the U.S. Department of the Treasury (the federal government would pay the difference when the price of oil falls below the strike price; the project would return the excess to the Treasury when the price of oil exceeds the strike price).[21]

B. Congress and the States Can Also Provide a Variety of More Traditional Financial Incentives to Spur Capture of Carbon Dioxide

In addition to creating markets for electricity generated by CCS-equipped facilities, as described in the prior section, federal and state legislatures can promote CCS deployment by providing new and expanding existing financial incentives. Current incentives that could be expanded include federal tax credits for "clean coal" investment, investment tax credits (ITCs) for carbon dioxide used in EOR operations, and loan guarantees. New incentives could also be offered to CCS-equipped facilities, such as a production tax credit (PTC) for generated electricity and tax incentives at the state level.

1. Congress Can Allocate Additional Funds and Expand Eligibility for Federal Tax Credits

Congress enacted federal tax credits for "clean coal" investment (including CCS) in 2005 in §§48A and 48B of the Internal Revenue Code. These tax credits are competitively awarded based on a joint review by DOE and the Treasury.[22] Section 48A allows up to a 30% tax credit for qualifying advanced coal projects generating electricity that also capture and sequester 65% or more of their carbon dioxide emissions.[23]

Section 48B allows up to a 30% tax credit to qualifying gasification projects for electricity generation or industrial applications that capture and sequester at least 75% of their carbon dioxide emissions.[24] Credits allocated under §§48A and 48B come with five- and seven-year in-service deadlines, respectively, meaning once tax credits are allocated to a project, then the project developer has five or seven years to place the project in service.[25] While hundreds of millions have been allocated under both credits, in-service deadlines and CCS project cancellations have resulted in forfeiture of hundreds of millions as well.[26] Consequently, to what extent successful projects have obtained and kept credits under §§48A and 48B is unclear.[27]

To more effectively promote CCS, Congress can expand both programs in key ways by (1) explicitly extending them to NGCC plants that capture carbon dioxide[28]; (2) enlarging the five-year time frame; and (3) appropriating additional funds on the order of $16 billion and $5 billion to the §§48A and 48B tax credits, respectively, to support early mover projects.[29]

Since 2008, ITCs of $20 per metric ton of captured and sequestered carbon dioxide or $10 per metric ton of captured carbon dioxide used for EOR operations have been available under §45Q.[30] To qualify, carbon dioxide must be captured from an industrial source and measured at the source of capture. This credit is only available for the first 75 million metric tons of carbon dioxide that are captured,[31] one-half of which had already been claimed by February 2014.[32] Congress could raise the cap to incentivize additional capture and sequestration[33]; indeed, in July 2017, a bipartisan

19. DOE Workshop Report, *supra* note 7; Great Plains Institute, Putting the Puzzle Together: State & Federal Policy Drivers for Growing America's Carbon Capture & CO_2-EOR Industry 8, 9 (2016), *available at* http://www.betterenergy.org/sites/default/files/PolicyDriversCO2_EOR%20V1.1_0.pdf.
20. *See generally* DOE Workshop Report, *supra* note 7, at 36.
21. North American Energy Security and Infrastructure Act of 2016, S. 2012, 114th Cong. (2016), *amended by* S. Amdt. 3174, 114th Cong. (2016).
22. *See* Peter Folger & Molly F. Sherlock, Congressional Research Service, Clean Coal Loan Guarantees and Tax Incentives: Issues in Brief 7 (2014) (R43690).
23. 26 U.S.C. §48A(e)(1)(G). For funds reallocated from prior rounds, 70% of carbon dioxide must be captured and sequestered. *Id.*
24. *Id.* §48B(d)(1)(B).
25. *Id.* §48A(d)(2)(E). *See generally* Folger & Sherlock, *supra* note 22, at 7 ("For Section 48B credits allocated starting in 2009, there is a seven-year placed-in-service requirement.").
26. Reallocation of Section 48B Credits Under the Qualifying Gasification Project Program, I.R.S. Notice 2014-81, at 5, 2014-53 I.R.B. 1001 (stating that $309,337,000 of §48B tax credits previously allocated and forfeited were available for reallocation), https://www.irs.gov/pub/irs-drop/n-14-81.pdf; Round 2 of Section 48A Phase III Program Under the Qualifying Advanced Coal Project Program, I.R.S. Notice 2015-14, at 3, 2015-10 I.R.B. 722 (stating that $1,104,000,000 of §48A tax credits previously allocated and forfeited were available for reallocation), https://www.irs.gov/pub/irs-drop/n-15-14.pdf.
27. *See, e.g.*, Great Plains Institute, *supra* note 19, at 32.
28. The Internal Revenue Service has been considering expanding these tax credits and requested public comments on the current definition of qualifying energy property for purposes of §48 in October 2015. I.R.S. Notice 2015-70, Request for Comments on Definitions of Section 48 Property, 2015-43 I.R.B. 604.
29. Through the CCPI program, DOE committed (but ultimately did not pay) roughly $450 million to Summit Texas Clean Energy, a 250 MW (net power output) IGCC facility. The project also received $811 million in §48A investment tax credits. Press Release, Summit Power, Summit Secures Contracts for $2.5 Billion Plant (Dec. 8, 2015), http://www.summitpower.com/story/summit-secures-contracts-for-2-5-billion-plant/; *Summit Presses on With TCEP*, Mod. Power Sys., Feb. 19, 2016, http://www.modernpowersystems.com/features/featuresummit-presses-on-with-tcep-4816616/. If similar support through tax credits were to be provided to all CCS projects until 5 GW of CCS is deployed, roughly $16 billion would need to be allocated to §48A credits. *See* Great Plains Institute, *supra* note 19, at 34 (the State CO_2-EOR Deployment Working Group, which includes representatives from 14 states, federal agencies, and private and nonprofit firms, also recommends continued appropriations be made to the §§48A and 48B ITCs).
30. 26 U.S.C. §45Q.
31. *Id.* §45Q(e).
32. *See generally* Christa Marshall, *Strange Bedfellows Seek Tax Fix for Sequestration Projects*, E&E News, Feb. 4, 2016, http://www.eenews.net/stories/1060031779.
33. A single large-scale CCS-equipped coal-fired power plant captures roughly five million tons of carbon dioxide per year. *See* Rubin et al., *supra* note 18, at 382 tbl. 2. Assuming a 40-year life, that plant would capture roughly 200 million tons of carbon dioxide, or more than twice the current ITC cap. Thus, a significant increase in the ITC cap is needed to support even a

bill was introduced in the U.S. Senate "to improve, expand, and extend the [Section 45Q] credit for carbon dioxide sequestration."[34] Funding for the ITC could later be phased out as the installed capacity of CCS increases.

Another mechanism to help close cost gaps between NGCC with and without CCS is to expand the existing §45 PTC for renewable generation to include electricity that is produced by plants that use CCS.[35] To account for partial capture of carbon dioxide at some plants, the National Coal Council suggests that the PTC for CCS could be set to 2.3¢ for each kilowatt hour (kWh) generated while operating the capture system multiplied by the carbon dioxide capture percentage.[36] Thus, partial capture would receive a lower PTC payment than would "full" capture.[37] The PTC, like the ITC, could be phased out as the installed capacity of CCS increases.

Private activity bonds (PABs) are another option to help lower the cost of capital. These tax-exempt bonds are commonly used to provide access to lower-cost funding of infrastructure in the United States, such as airports and water and sewer facilities.[38] They have not been commonly used for CCS projects.[39] Congress or the states could enact legislation to encourage private investment in CCS technology via PABs.[40] Indeed, in April 2017, a bill was introduced in the Senate to extend PABs to the purchase of carbon dioxide capture equipment for CCS.[41]

decade of sequestration for several CCS-equipped power plants (e.g., to 500 million tons of carbon dioxide).

34. S. 1535, 115th Cong. (2017) (the legislation would increase the tax credits available under §45Q to $50 per metric ton of sequestered carbon dioxide and to $35 per metric ton of carbon dioxide used in EOR and would also remove the 75 million metric ton cap and allow developers to claim a credit for up to 12 years). *See* Christa Marshall, *After Kemper Debacle, Senators See Promise in CCS Bill*, E&E News, July 13, 2017, https://www.eenews.net/eedaily/2017/07/13/stories/1060057308.

35. Currently, 26 U.S.C. §45 establishes a "renewable electricity production credit" of 1.5¢/kWh of electricity produced from a "qualified energy resource," which is defined to include wind, closed-loop biomass, open-loop biomass, geothermal energy, solar energy, small irrigation power, municipal solid waste, hydropower, and marine and hydrokinetic renewable energy. *Id.* §45(c)(1)(A)-(I).

36. National Coal Council, Leveling the Playing Field: Policy Parity for Carbon Capture and Storage Technologies 34 (2015) (2.3¢/kWh of electricity generated is the same credit as provided to renewable facilities under the §45 PTC), *available at* http://www.nationalcoalcouncil.org/studies/2015/Leveling-the-Playing-Field-for-Low-Carbon-Coal-Fall-2015.pdf.

37. "Full" capture is defined as 90% capture. *See* Rubin et al., *supra* note 18, at 379.

38. *E.g.*, Massachusetts Executive Office for Administration and Finance, *Private Activity Bonds*, http://www.mass.gov/anf/budget-taxes-and-procurement/cap-finance/private-activity-bonds.html (last visited Sept. 23, 2017).

39. The Petra Nova project was, however, able to take advantage of PABs due to a limited exemption in the federal tax code, authorizing the issuance of PABs to help finance projects in the Hurricane Ike disaster zone. *See* Diane Cardwell, *Senators Revive Financing Tactic From '70s for Carbon Emissions*, N.Y. Times, Nov. 18, 2015, https://www.nytimes.com/2015/11/19/business/energy-environment/senators-revive-financing-tactic-from-70s-for-carbon-emissions.html?mcubz=1.

40. *See Broad Industry, Labor, NGO Coalition Supports Bipartisan Private Activity Bond Legislation to Finance Deployment of Carbon Capture Infrastructure*, Nat'l Enhanced Oil Recovery Initiative, Apr. 5, 2017, http://neori.org/broad-industry-labor-ngo-coalition-supports-bipartisan-private-activity-bond-legislation-to-finance-deployment-of-carbon-capture-infrastructure/.

41. *See* S. 843, 115th Cong. (2017). As of July 2017, the bill has been introduced in the Senate and referred to the Committee on Finance.

2. State Legislatures Can Provide a Number of Tax Incentives to CCS

State legislatures have a number of tax tools they can implement to incentivize CCS. These include sales taxes that apply to the purchase of capture equipment, property taxes applicable to the power plant and the sequestration site,[42] and income taxes. While these will not alone close the gap in cost between plants operating with and without CCS, they are useful tools for narrowing that cost gap.[43]

3. State Public Utility Commissions Can Help Subsidize CCS Via Ratemaking Proceedings

In regulated markets, it is the state utility regulator that makes decisions about retail electricity rates and to what extent a plant can pass costs along to the ratepayers. At present, plants using CCS cannot achieve a commercial rate of return. Without a mandate to use CCS, the gap between cost and return needs to be closed. State ratemakers can pass at least some of the increased cost of CCS on to ratepayers. Doing so would speed the deployment of CCS by vertically integrated utilities.

The Mississippi Public Service Commission (PSC) twice tried to include the cost of CCS in rates charged by Mississippi Power to support its Kemper County plant.[44] However, the Mississippi Supreme Court struck down the rate increases both times on procedural grounds. The first time, it concluded that the PSC had not supported its decision with sufficient evidence that the plant would benefit the ratepayers[45]; the second time, it held that the PSC violated the state constitution in failing to notify ratepayers that it was reviewing a request to raise rates.[46]

In West Virginia, the State Corporation Commission denied American Electric Power's (AEP's) two requests for rate increases to cover a portion of the CCS expense. The Commission reasoned that there was too much "policy uncertainty" involved.[47] AEP subsequently cancelled the project, claiming it could not proceed without the rate increases.[48]

42. *E.g.*, H.B. 2419 (Kan. 2007); H.B. 1459 (Miss. 2009).

43. *See* Great Plains Institute, *supra* note 19, at 63.

44. *See* Eileen O'Grady, *Mississippi Allows Southern Co. to Keep Building $2.8 Billion Coal Plant*, Chi. Trib., Mar. 30, 2012, http://articles.chicagotribune.com/2012-03-30/news/sns-rt-us-utilities-southern-kemperbre82t1cm-20120330_1_coal-plant-power-plant-mississippi-public-service-commission.

45. Sierra Club v. Mississippi Pub. Serv. Comm'n, 82 So. 3d 618, 618 (Miss. 2012).

46. Mississippi Power Co., Inc. v. Mississippi Pub. Serv. Comm'n, 168 So. 3d 905, 916 (Miss. 2015). The court ordered Mississippi Power to refund $377 million to ratepayers; as of August 5, 2016, it has paid $373.4. Jeff Amy, *Kemper County Plant Refunds Almost Complete*, Clarion-Ledger, Aug. 5, 2016, http://www.clarionledger.com/story/news/2016/08/04/kemper-refunds-almost-complete/88279992/.

47. *See* Maria Gallucci, *Financial Shortfall at America's First CCS Plant Highlights Absence of Carbon Price*, Reuters, Apr. 14, 2011, http://www.reuters.com/article/idUS375884024020110414.

48. *See* Matthew L. Wald & John M. Broder, *Utility Shelves Ambitious Plan to Limit Carbon*, N.Y. Times, July 13, 2011, http://www.nytimes.

The Indiana Utility Regulatory Commission approved a carbon capture study at Duke Energy's Edwardsport integrated gasification combined-cycle (IGCC) unit, and authorized rate increases to recover that cost, contingent on approval of the cost by the Commission.[49] The study showed that the installation cost of carbon capture equipment would be about $380 million.[50] Duke Energy has not pursued CCS at Edwardsport.[51]

4. Congress Can Restructure the Conditions and Extend Federal Funding Deadlines

FutureGen was cancelled partly because investors backed off amid concerns that it could not use its American Recovery and Reinvestment Act (ARRA) funds by the strict spending deadline. One of the reasons contributing to the Plant Barry project's early withdrawal from Clean Coal Power Initiative (CCPI) was that the ARRA deadline would have required Southern Co. to commit to the demonstration project before the pilot plant was even built.[52] Similarly, the Kemper County IGCC plant had, before being suspended in June 2017, been plagued by extreme cost overruns due in large part to its rush to break ground before completing design plans in order to meet a federal funding deadline.[53] An inflexible deadline leaves inadequate time for projects to work out kinks, and funding reauthorization is often challenging given the ever-changing political environment.

5. Congress Can Authorize Additional Funds for Federal Loan Guarantees

Loan guarantees for "clean coal" projects were first included in the Energy Policy Act of 2005 and subsequently expanded to include CCS projects.[54] However, the loan guarantees have not been utilized[55]: "Many of these projects withdrew or chose not to proceed due to changing market economics associated with the dramatic reduction in natural gas prices over this time period [2006-2014]."[56] Apparently, no fully integrated CCS power project has been able to secure the requisite amount of commercial debt or equity financing in order to meet DOE's requirements to obtain funding. No federal loan guarantees have been issued to any integrated CCS power plant project as of August 2017.[57] However, in December 2016, DOE provided a conditional loan guarantee in the amount of $2 billion for a CCS project to a methanol production facility in Louisiana that will capture carbon dioxide and use it for EOR.[58]

To achieve either of the DDPP cases that rely on CCS, the federal loan guarantee program needs to be revised in several ways. First, at least for early movers, if a project receives a cash grant from the federal government (for example under the CCPI), it should also be eligible to receive a loan guarantee. At present, a project cannot qualify for both sources of federal support. Second, the administrative cost and complexity in the application and negotiation processes also pose significant barriers to entry and need to be streamlined.[59] Third, the current federal loan guarantees "do not ensure a revenue stream to recover the operating costs of capturing and compressing the carbon, and do not directly assist in creating a market for CCS technology."[60]

Fourth, transparency in the decisionmaking process is needed. Since DOE does not publicly release information about the applications for its loan guarantee program, it is unclear how many applications for "clean coal" projects were submitted in response to the solicitations. Consequently, it is difficult to gauge industry interest in seeking guaranteed loans. By making more information available

com/2011/07/14/business/energy-environment/utility-shelves-plan-to-capture-carbon-dioxide.html?_r=1.

49. Duke Energy of Indiana, Inc., 270 P.U.R. 4th 387, 407 (Ind. U.R.C. 2009) (approving a $17 million study to capture 15%-18% of carbon, and authorizing deferred rate increases, pending commission approval of costs associated with the study). *See also* Citizens Action Coalition of Ind., Inc. v. Duke Energy Ind., Inc., 44 N.E.3d 98, 101 (Ind. Ct. App. 2015).

50. *Edwardsport Plant's CO_2 Capture Costs Will Be High*, Coal Age, Aug. 25, 2011, http://www.coalage.com/news/latest/1262-edwardsport-plants-co2-capture-costs-will-be-high.html.

51. Sharryn Dotson, *Edwardsport Power Plant Makes History*, Power Engineering, Nov. 14, 2013 ("Due to the expense of capturing carbon emissions, Duke Energy customers did not want the technology installed until it was deemed necessary."), http://www.power-eng.com/articles/print/volume-117/issue-11/departments1/power-plant-profile/edwardsport-power-plant-makes-history.html.

52. *See* Howard Herzog, Lessons Learned From CCS Demonstration and Large Pilot Projects 11 (2016).

53. *See* Ian Urbina, *Piles of Dirty Secrets Behind a Model "Clean Coal" Project*, N.Y. Times, July 5, 2016 ("Documents show that in a rush to qualify for federal subsidies, Mississippi Power started construction with less than 15 percent of the plant designed."), http://www.nytimes.com/2016/07/05/science/kemper-coal-mississippi.html?_r=0.

54. 42 U.S.C. §16513(b)(5).

55. Taylor Kuykendall, *8 Years After DOE Solicits Coal Projects, $8B in Loan Guarantees Untouched*, SNL, Nov. 14, 2014, https://www.snl.com/interactiveX/Article.aspx?cdid=A-29851247-12329&FreeAccess=1.

56. *Id*.

57. DOE issued its first solicitation for the loan guarantee program on September 22, 2008, and it made $6 billion available for new and retrofitted facilities that incorporated CCS or other beneficial uses. *See* Folger & Sherlock, *supra* note 22, at 5. DOE issued its second solicitation on December 12, 2013, for projects that used advanced fossil energy technology, including CCS. *See id*. at 5-6. The second solicitation provided up to $8 billion in loan guarantees. *Id*. at 5. As of August 2017, however, no carbon capture-related projects have received a DOE loan guarantee. The Kemper County CCS project applied for federal loan guarantees, but withdrew its application in 2013 because the companies could borrow money elsewhere at a lower rate. *See* Megan Wright, *Southern Decides Against Federal Loan Guarantee for Kemper Coal Plant*, Miss. Bus. J., Apr. 3, 2013, http://msbusiness.com/2013/04/southern-decides-against-federal-loan-for-kemper-coal-plant/. *See generally* John P. Banks & Tim Boersma, Brookings Institution, Fostering Low Carbon Energy 15 (2015), *available at* https://www.brookings.edu/wp-content/uploads/2016/06/low_carbon_energy_ccs_banks_boersma_FINAL.pdf.

58. The conditional loan guarantee, which depends on the project obtaining financing and continuing development, was provided under the Advanced Fossil Energy Project solicitation issued by DOE. *See* Press Release, DOE, Energy Department Offers Conditional Commitment for First Advanced Fossil Energy Loan Guarantee (Dec. 21, 2016), https://energy.gov/articles/energy-department-offers-conditional-commitment-first-advanced-fossil-energy-loan-guarantee. As of August 2017, the facility has not met all the conditions of the conditional loan guarantee, so the loan guarantee has not yet been made available to the facility.

59. *See* Banks & Boersma, *supra* note 57, at 23 ("High administration and due diligence fees have also been cited as problems.").

60. *Id*. (if a project receives a cash grant from the federal government, for example under the CCPI, it is not eligible to receive a loan guarantee).

(without revealing confidential business information), financiers could begin assessing the competitive landscape for the industry and ascertain sustained interest by developers in moving forward with CCS projects. Finally, DOE should also release the criteria upon which projects are awarded or rejected for loan guarantees. Project developers and potential financiers need to be able to differentiate bids that do not meet the criteria for the program from bids that are disqualified for other reasons.

C. Federal Agencies and States Can Tighten Regulatory Requirements to Spur Carbon Dioxide Capture

The U.S. Environmental Protection Agency (EPA) and its state counterparts have the authority to tighten the performance standards for new and existing coal- and natural gas-fired power plants. These performance standards, combined with the financial incentives and opportunities to create markets discussed earlier in this part, will help drive the capture technology forward. Moreover, EPA and states arguably have a statutory obligation to do so to protect public health and the environment, as discussed below. Some states have taken action already. Under the Barack Obama Administration, EPA could have done more than it did via its 2015 new source performance standards (NSPS)[61] and Clean Power Plan (CPP).[62] Currently, both are embroiled in litigation, and President Donald Trump has directed EPA to review, withdraw, or modify them.[63]

To achieve the Mixed Scenario, DDPP assumes that carbon dioxide capture equipment is gradually deployed on new NGCCs beginning in 2035 until roughly 50% of NGCC capacity is equipped in 2050. Under the High CCS Scenario, carbon dioxide capture equipment is deployed at new coal-fired units beginning in the 2020s and then at NGCCs beginning in the 2030s, such that all coal-fired units and two-thirds of NGCC units are capturing 90% of their carbon dioxide emissions by mid-century. Unless EPA tightens in the near term the NSPS for new coal-fired and NGCC units to levels only achievable with CCS or even partial CCS,[64] this CCS deployment schedule will not be achieved.

Given the assumed lifetimes in the DDPP for coal-fired and NGCC generators[65] and a gradual phasein of CCS, the DDPP relies entirely on CCS deployment at new builds, rather than retrofits on existing plants, in order to meet its 2050 emissions reduction targets. However, if the NSPS for NGCCs is not tightened in the near term, then NGCC plants without CCS will continue to be built, potentially requiring CCS retrofits later. Thus, we propose regulatory reforms to encourage CCS retrofits in addition to CCS deployment at new builds.

1. Under a New President, EPA Could Tighten the NSPS for Coal- and Natural Gas-Fired Power Plants

The NSPS for carbon dioxide emissions from newly constructed, modified, and reconstructed coal- and gas-fired power plants[66] (referred to in the rule as electric generating units (EGUs)), promulgated in 2015, are not tight enough to achieve the CCS deployment level needed for either the DDPP Mixed or High CCS Scenario. The NSPS emissions rates are based on what can be achieved by the application of partial post-combustion capture at a conventional coal plant and do not require any carbon dioxide capture from NGCC or gas-fired combustion turbine plants.[67]

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61. The 2015 NSPS rule applies only to new coal-fired plants. Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Final Rule, 80 Fed. Reg. 64510, 64545 (Oct. 23, 2015) [hereinafter 2015 NSPS Rule] ("the [best system of emission reductions] BSER for newly constructed steam generating units is a new highly efficient supercritical pulverized coal . . . boiler implementing partial CCS technology"); *id.* at 64631:

    > [I]t is possible that partial CCS could be considered in a [best available control technology] BACT review as an available control option for a modified or reconstructed [electric generating unit] EGU facility . . . but this NSPS is not an applicable standard to such sources so it would not establish a requirement that partial CCS is a minimum level of stringency for the BACT for those sources.

    It does not apply to NGCC plants. 2015 NSPS Rule, *supra*, at 64601 ("For newly constructed and reconstructed base load natural gas-fired stationary combustion turbines, the BSER is the use of efficient NGCC technology. For newly constructed and reconstructed non-base load natural gas fired stationary combustion turbines, the BSER is the use of clean fuels[.]"). Nor are the plant-specific rates or the state goals derived from them (and established in EPA's Clean Power Plan (CPP)) based on CCS at existing coal- or gas-fired power plants. The CPP does, however, allow retrofit CCS units to generate credits or sell allowances for excess emissions reductions. *See* Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64662, 64904 (Oct. 23, 2015) (to be codified at 40 C.F.R. pt. 60) [hereinafter Clean Power Plan] ("[Emission rate credits] may be issued to affected EGUs that emit below a specified carbon dioxide emission rate[.]"). The 2015 NSPS rule and the CPP are currently the subject of litigation in the U.S. Court of Appeals for the District of Columbia (D.C.) Circuit.
62. *Id.*
63. *Id.*; Promoting Energy Independence and Economic Growth, Exec. Order No. 13783, 82 Fed. Reg. 16093, 16093-95 (Mar. 28, 2017).
64. Specifically, the NSPS would need to be tightened to carbon dioxide emissions limits of roughly 204 and 91 pounds (lb) carbon dioxide/MWh-gross for coal-fired and NGCC power plants, respectively, to reflect full CCS deployment on each. To estimate what carbon dioxide emissions rate the NSPS would need to be set at to require full CCS deployment on coal-fired or NGCC plants, we constructed "Typical New Plants" for a coal-fired plant and an NGCC using Carnegie Mellon University's Integrated Environmental Control Model (IECM), which is available for download at https://www.cmu.edu/epp/iecm/iecm_dl.html. The IECM is a free, public, power plant modeling tool that provides systematic estimates of the performance, fuel consumption, emissions, and costs of fossil fuel-fired power plants with and without CCS. We installed the default amine CCS system on each and recorded their carbon dioxide emissions rates. To calculate the emissions rates, we multiplied carbon dioxide flue gas emissions (lb/million British thermal unit (MMBtu)) by the gross heat rate (MMBtu/MWh-gross).
65. The DDPP assumes mean generator lifetimes for pulverized coal-fired and NGCC generators without CCS of 60 and 30 years, respectively. Personal Communication With Ryan Jones, co-founder of Evolved Energy Research and contributing author to the DDPP report, *supra* note 1 (Aug. 7, 2017).
66. *See supra* note 61. The rule applies to steam generation units, IGCCs, and stationary combustion turbines that commence either construction after Jan. 8, 2014, or reconstruction or modification after June 18, 2014. 40 C.F.R. §60.5509 (2016). To qualify, facilities must have a baseload rating greater than 260 gigajoules per hour of fossil fuel, and have a power output capacity greater than 25 MW. *Id.*; 40 C.F.R. §60.5580 (further defining qualifying facilities).
67. Newly constructed coal plants (referred to in the rule as steam generating units) must have a carbon dioxide emissions rate less than 1,400 lb carbon

Because the number of new NGCC plants is steadily increasing and the number of coal plants is steadily declining, near-term modifications to the NSPS applicable to NGCC (and/or state emission limits) are crucial to achieving significant reductions in carbon dioxide emissions from the power sector. Reducing the allowable carbon dioxide emissions from NGCC plants will drive investment in even cleaner technologies, including CCS. A major purpose of §111(b) of the Clean Air Act (CAA), under which these standards were adopted, is to drive technological innovation to reduce pollution.[68]

Importantly, EPA has legal authority to tighten the NSPS for NGCC plants based on current information, studies, and applications. The CAA instructs EPA to adopt:

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.[69]

As applied to new emissions sources, the NSPS are forward-looking and may be designed by EPA to spur technological innovation; indeed, the courts have historically supported EPA when it has projected that a new technology should work and determines it to be the best system of emission reductions (BSER).

> In the seminal 1973 case *Portland Cement Ass'n v. Ruckelshaus*,[70] the court beg[a]n by rejecting the suggestion of the cement manufacturers that the [Clean Air] Act's requirement that emission limitations be "adequately demonstrated" necessarily implies that any cement plant now in existence be able to meet the proposed standards. Section 111 looks toward what may fairly be projected for the regulated future, rather than the state of the art at present, since it is addressed to standards for new plants. . . . It is the "achievability" of the proposed standard that is in issue.[71]

The court further stated:

> The Administrator [of EPA] may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on "crystal ball" inquiry. . . . Since the standards here put into effect will control new plants immediately, as opposed to one or two years in the future, the latitude of projection is correspondingly narrowed.[72]

A decade later, in *Sierra Club v. Costle*,[73] the court again confirmed that the text of CAA §111(a) defining BSER "gives EPA broad discretion to weigh different factors in setting the standard."[74] The court also said that the Act imbues EPA with authority to set NSPS that will stimulate technological innovation: "when balancing the enumerated factors to determine the basic standard it is appropriate to consider which level of required control will encourage or preclude development of a technology that promises significant advantages . . . ." (The court went on to explain that CAA §111(j) "supplements rather than restricts EPA's discretion under Section 111(a) to encourage innovative technology").[75] Subsequently, the court confirmed that §111(a) gives EPA broad discretion to balance the factors unless the cost of implementing new technology is "exorbitant."[76]

That there are no commercial-scale NGCC power plants integrating CCS technology yet[77] does not undermine

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dioxide/MWh (this emissions rate is on a gross energy output basis, so it includes energy consumed on site by a CCS unit or other control technologies or auxiliary equipment), whereas reconstructed and modified units must meet a less-stringent limit of 1,800 to 2,000 lb carbon dioxide/MWh. 40 C.F.R. pt. 60, subpt. TTTT tbl. 1 (2016). Reconstructed units with a steady state fuel input capability of 2,000 MMBtu/hour or greater must meet the 1,800 lb carbon dioxide/MWh basis, whereas units with a lower fuel input capability must meet the 2,000 lb carbon dioxide/MWh basis. *Id*. Modified units, on the other hand, must meet an emissions limit based on the unit's best annual carbon dioxide emissions rate from 2002 to the date of modification. *Id*. That limit, though, can be no larger than 1,800 lb carbon dioxide/MWh for units with a steady state fuel input capability of 2,000 MMBtu/hour or greater, or 2,000 lb carbon dioxide/MWh for units with a lower steady state fuel input capability. *Id*. Newly constructed stationary combustion turbines (i.e., gas plants), which generally emit less carbon dioxide than steam generating units, must meet a more-stringent standard. Those that generate more than 50% of their total generation potential (i.e., those on a 12-month operating and three-year rolling average basis; in other words, this part applies to units with a capacity factor greater than 50%, which primarily includes NGCC units (i.e., baseload plants)) must meet a standard of roughly 1,000 lb carbon dioxide/MWh. *Id*. tbl. 2 (units have the choice between two standards: 1,000 lb carbon dioxide/MWh gross energy output, or 1,030 lb carbon dioxide/MWh net energy output). Units that generate less of their potential (i.e., "peaker" plants) must meet a standard of 120 lb carbon dioxide/MMBtu fuel input. *Id*. And, those that combust 10% or more non-natural gas must meet standards of 120 to 160 lb carbon dioxide/MMBtu fuel input. *Id*. The exact standard depends on the input of natural gas versus other fuels. *See id*. §60.5525(a)(2) (providing an equation to determine the applicable emissions standard).

These emissions limits correspond to those achievable by the BSER as determined by EPA. For newly constructed steam generating units, the BSER is a high-efficiency coal-fired power plant with partial carbon dioxide capture of 16% or 25%, depending on the type of coal burned. *See* 2015 NSPS Rule, *supra* note 61, at 64548.

The BSER for reconstructed and modified steam units is not CCS. For baseload units, or units that generate electricity most of the year, the BSER is "the use of efficient NGCC technology." *Id*. at 64601. For non-baseload units and units that burn other types of fuels in addition to natural gas, the BSER is simply the use of clean fuels, which include natural gas, ethylene, propane, naptha, jet fuel kerosene, biodiesel, landfill gas, and other fuels. *Id*.

68. 42 U.S.C. §§7410-7671q, §7411). *See* Sierra Club v. Costle, 657 F.2d 298, 347, 11 ELR 20455 (D.C. Cir. 1981) ("[W]hen balancing the enumerated factors to determine the basic standard [required by §111(b)] it is appropriate to consider which level of required control will encourage or preclude development of a technology that promises significant advantages . . . .").
69. 42 U.S.C. §7411(a)(1).
70. 486 F.2d 375, 3 ELR 20642 (D.C. Cir. 1973).
71. *Id*. at 391.
72. *Id*. at 391-92.
73. 657 F.2d 298 (D.C. Cir. 1981).
74. *Id*. at 321.
75. *Id*. at 347.
76. Lignite Energy Council v. Environmental Prot. Agency, 198 F.3d 930, 933-34, 30 ELR 20279 (D.C. Cir. 1999).
77. *See* Carbon Capture & Sequestration Technologies @ MIT, *Power Plant Carbon Dioxide Capture and Storage Projects—Large-Scale Power Plant CCS Projects Worldwide* [hereinafter *Large-Scale Power Plant CCS Projects Worldwide*], http://sequestration.mit.edu/tools/projects/index_capture.html (last visited Sept. 23, 2017). However, an NGCC equipped with CCS operated from 1991 through 2005 in Bellingham, Massachusetts. *See* U.S. EPA, Technical Support Document, Literature Survey of Carbon Capture Technology 38 (2015), https://perma.cc/AJX4-RCVD.

EPA's authority to set standards for NGCC that reflect the application of some level of this technology. While the presumed technology may not be "speculative," it need not be in existence on facilities in the regulated industry, but only in analogous industrial applications, or overseas, for the NSPS to survive judicial scrutiny. Notably, DOE's Quadrennial Technology Review of 2015 suggests that the carbon dioxide capture technologies that have been tested and deployed to date could be transferred to NGCC.[78] For all of these reasons, a new NSPS emissions limit based on the application of some level of CCS on NGCC units could be set by EPA in the near term.

To achieve the DDPP cases for CCS, the NSPS could be modified in two ways. First, beginning in the early 2020s, the NSPS for new coal-fired units could require full carbon dioxide capture (i.e., 90%).[79] This is achievable; it has already been done at several new or retrofit facilities at a large-scale in the United States and elsewhere.[80] Second, the NSPS for new NGCCs could be strengthened to require at least partial carbon dioxide capture beginning in the mid-2020s.[81] Despite challenges related to carbon dioxide concentrations and oxygen concentrations in NGCC flue gas, carbon dioxide capture at NGCCs is also achievable.[82] Indeed, an NGCC with CCS operated from 1991 through 2005.[83]

A revised NSPS for NGCC units could be preceded and accompanied by government and private investment in NGCC-CCS projects beginning now to promote commercialization. A requirement for full carbon dioxide capture from NGCCs would need to be in place by the early 2030s to meet DDPP deployment targets for the High CCS and Mixed Scenarios,[84] but a partial carbon dioxide capture requirement could first be in place and enforceable by about 2025.

If CCS is to contribute to the economywide 80% GHG reductions by 2050, as envisioned by the DDPP's High CCS and Mixed Scenarios, then CCS should be immediately deployed on a commercial-scale NGCC unit.[85] To that end, federal and state tax credits, loan guarantees, performance-based payment schemes, and other incentives proposed earlier in this Article would enable commercial-scale CCS-equipped NGCC deployment by private entities. Offering these incentives within the next few years would leave more than five years for the construction of NGCC with CCS prior to the proposed NSPS tightening schedule. Because climate change is a global problem, it would also make sense for the U.S. government to provide some incentives to U.S. companies to invest now in integrated NGCC-CCS power plants outside the United States, where it may be faster and cheaper to build and operate them.

2. Under a New President, EPA Could Strengthen the CPP if It Survives Pending Reviews

The CPP rule,[86] issued under §111(d) of the CAA in 2015 by EPA, would regulate carbon dioxide emissions from existing coal- and gas-fired power plants in order to reduce carbon dioxide emissions from the power sector by 32% from 2005 levels by 2030.[87] More specifically, the CPP set state-level emissions reduction targets, derived from a "building block"-based BSER.[88] Under the CPP, each state would design its own plan (state implementation plan (SIP)) for achieving those reductions.[89] States would have numerous options for formulating their SIPs, including designating which technologies would be deployed and whether the state would comply with a

78. DOE, Quadrennial Technology Review 110 (2015) (observing that "[t]he technology transfer to natural gas for both new plants and retrofits would be relatively straightforward," and that "[l]arge-scale pilot test and demonstration projects are a natural next step in the application of CCS technologies to natural gas processes"). Nevertheless, EPA chose to promulgate an emissions standard for natural gas plants, which does not require CCS, which even industry lawyers acknowledged would be easily met with existing technology. *See* Jones Day, Review of EPA Authority for Upcoming Rules for Greenhouse Gas Emissions From Electric Power Plants 2 (2014).
79. Specifically, changes would be made to 40 C.F.R. pt. 60, subpt. TTTT tbl. 1. The new emissions limit should be set at 200 lb carbon dioxide/MWh gross output, which reflects a 90% capture rate at a new supercritical pulverized coal power plant. The authors derived this figure using the IECM.
80. For example, Boundary Dam is an operational retrofit with a 90% capture rate on a 110 MW net unit, *see* Global CCS Institute, *Projects Database—Large-Scale CCS Facilities*, *supra* note 3; Carbon Capture & Sequestration Technologies @ MIT, *Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project*, https://sequestration.mit.edu/tools/projects/boundary_dam.html (last visited Sept. 23, 2017), and Petra Nova is a retrofit that began operating in January 2017 with a projected 90% capture rate on a 240 MW net slipstream. *See* Carbon Capture & Sequestration Technologies @ MIT, *Petra Nova W.A. Parish Fact Sheet: Carbon Dioxide Capture and Storage Project* [hereinafter *Petra Nova W.A. Parish Fact Sheet*], http://sequestration.mit.edu/tools/projects/wa_parish.html (last visited Sept. 23, 2017).
81. These revisions would be made to 40 C.F.R. pt. 60, subpt. TTTT tbl. 2. The NSPS could begin at a 30% carbon dioxide capture rate, as done for coal-fired generators under the current NSPS, which would require a carbon dioxide emissions limit of 551 lb/MWh gross energy output. To calculate this value, we linearly interpolated between the carbon dioxide emissions rate of a "Typical New Plant" NGCC in IECM without CCS (782 lb/MWh-gross) and with CCS with a 90% capture rate (91 lb/MWh-gross).
82. *See* DOE, Quadrennial Technology Review, *supra* note 78, at 110; Tim Fout et al., NETL, Cost and Performance Baseline for Fossil Energy Plants—Volume 1A: Bituminous Coal (PC) and Natural Gas to Electricity 170 (2015) (DOE/BETL-2015/1723) [hereinafter NETL Cost Report], *available at* https://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Rev3Vol1aPC_NGCC_final.pdf (describing the technological requirements necessary to account for the reduced carbon dioxide concentrations in NGCC flue gas).
83. U.S. EPA, Technical Support Document, Literature Survey of Carbon Capture Technology 38 (2015), https://perma.cc/AJX4-RCVD.
84. Specifically, 40 C.F.R. pt. 60, subpt. TTTT tbl. 2 should be revised to enforce an 85 lb carbon dioxide/MWh gross energy output limit, which would require 90% carbon dioxide capture for a new NGCC. This figure was derived using the IECM.
85. If the CPP remains in effect, then to incentivize additional projects, EPA could clarify that NGCC plants that adopt CCS and thereby achieve reductions below their NSPS targets can generate emissions credits or sell allowances that can be used under the CPP.
86. *See* Clean Power Plan, *supra* note 61.
87. *See* U.S. EPA, Regulatory Impact Analysis for the Clean Power Plan Final Rule ES-8 (2015) (EPA-452/R-15-003) [hereinafter CPP-RIA].
88. The three building blocks were heat rate improvements to existing coal-fired units, shifting from coal-fired electricity generation to NGCC-fired electricity generation, and the deployment of new renewables. *See* Clean Power Plan, *supra* note 61, at 64667.
89. *Id*.

rate- or mass-based standard.[90] States that adopt a mass-based standard would also have the option to participate in interstate trading programs.[91] The status of the CPP is, however, uncertain.[92]

In February 2016, the U.S. Supreme Court stayed implementation of the CPP pending judicial review.[93] The U.S. Court of Appeals for the District of Columbia (D.C.) Circuit heard oral argument en banc on September 27, 2016. On March 28, 2017, President Trump issued an Executive Order directing federal agencies to "review all existing regulations, orders, guidance documents, policies, and any other similar agency actions . . . that potentially burden the development or use of domestically produced energy resources[.]"[94] On April 28, 2017, the court issued an order holding the litigation in abeyance for 60 days and requesting additional briefing by May 15, 2017.[95] At EPA's request, the court again stayed the litigation for 60 days on August 8, 2017, requiring monthly status reports from EPA regarding the progress of its regulatory review.[96] On October 16, 2017, EPA published its proposed rule to repeal the CPP based on a change in its legal interpretation of §111(d) of the CAA that would narrow its application.[97] If a later president decides to reissue the CPP and if its key provisions have not been invalidated by the courts, it needs to be strengthened to achieve implementation of either the DDPP Mixed Scenario or High CCS Scenario. Had the CPP gone into effect as originally promulgated, power-sector carbon dioxide emissions after CPP implementation would still have been five and 19 times higher than under the DDPP Mixed and High CCS Scenarios, respectively, in 2050 because of the ongoing proliferation of non-CCS NGCC plants to serve baseload electricity needs in the United States.[98] A delay of several years in implementation will make these exceedances even higher.

Additionally, EPA's original analysis of the CPP did not project that any CCS retrofits on existing coal-fired or NGCC plants will occur as a result of the CPP. Nor does its first building block (which set carbon dioxide emissions reduction potential from coal- and gas-fired power plants from which the state targets are derived) assume that any retrofit CCS on coal or gas plants will be built in the United States between now and 2030.[99] But, in order to achieve the stringent emissions reduction target for the DDPP High CCS Scenario, all existing coal plants must either retire or begin capturing 90% of their carbon dioxide emissions by 2050. (In the Mixed Scenario, coal-fired plants are presumed to be phased out completely by 2050.)

Moreover, the price signals attributable to the emissions reduction targets in the CPP (combined with NSPS that require no carbon dioxide controls before 2022) are not strong enough to provide an adequate price incentive to spur CCS deployment. In 2015, Royal Dutch Shell estimated that the carbon price would need to be \$60-\$80 per ton of carbon dioxide to justify CCS projects.[100] Similarly, researchers from Carnegie Mellon University, the International Energy Agency, and the Massachusetts Institute of Technology estimated a carbon price of \$50-\$100 per ton of carbon dioxide would be necessary.[101] Initial estimates of the carbon dioxide price that would be necessary to comply with the CPP were much lower, only ranging up to \$26 per ton of carbon dioxide.[102] These low carbon dioxide prices

90. *Id*. at 64667-68, 64832-43 (describing in further detail the different SIP approaches).
91. *Id*. at 64839-40. For further details, see *id*. at 64892-94 (addressing mass-based interstate trading programs), and *id*. at 64910-11 (addressing rate-based interstate trading programs).
92. The CPP is being challenged by 27 states and affected industrial groups, which argue that the CPP is an overreach of EPA's constitutional authority, and that the rule will damage the coal mining industry, raise power rates for consumers, and compromise the reliability of the electric grid, thereby causing harm to the plaintiff states. *See* Oliver Milman, *Obama's Climate Change Legacy at Stake as Clean Power Plan Has Its Day in Court*, Guardian, Sept. 28, 2016, https://www.theguardian.com/environment/2016/sep/28/clean-power-plan-court-obama-climate-change; Alan Neuhauser, *Supreme Court Blocks Signature Obama Climate Rule*, U.S. News & World Rep., Feb. 10, 2016, http://www.usnews.com/news/articles/2016-02-10/supreme-court-puts-epas-clean-power-plan-on-hold; Tomas Carbonell, *En Banc Review of the Clean Power Plan—What the Court Order Means, and Doesn't Mean*, Climate 411, May 26, 2016, http://blogs.edf.org/climate411/2016/05/26/en-banc-review-of-the-clean-power-plan-what-the-court-order-means-and-doesnt-mean/.
93. West Virginia v. Environmental Prot. Agency, 136 S. Ct. 1000 (2016) (mem.).
94. Promoting Energy Independence and Economic Growth, Exec. Order No. 13783, 82 Fed. Reg. 16093, 16093 (Mar. 28, 2017). *See also* Review of the Clean Power Plan, 82 Fed. Reg. 16329 (Apr. 4, 2017).
95. West Virginia v. Environmental Prot. Agency, No. 15-1363 (D.C. Cir. filed Apr. 28, 2017).
96. West Virginia v. Environmental Prot. Agency, No. 15-1363 (D.C. Cir. filed Aug. 8, 2017).
97. U.S. EPA, Proposed Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 82 Fed. Reg. 48035, 48049 (Oct. 16, 2017).
98. Under the CPP, EPA estimates that total annual carbon dioxide emissions will be roughly 1.6 million metric tons assuming rate- or mass-based compliance. *See* CPP-RIA, *supra* note 87, at ES-6 to ES-7 tbls. ES-2 & ES-3. Assuming no further carbon emissions regulations are adopted and that the emissions level remains constant after 2030, the annual carbon emissions from the power sector under CPP would be nearly five times higher than that under the DDPP High CCS Scenario, and nearly 19 times higher than the DDPP Mixed Scenario in 2050. *See* Williams et al., *supra* note 1, at 43 fig. 38 (showing carbon dioxide emissions by energy type for each of the DDPP cases in 2050). Even if the reduction rate of carbon dioxide emissions was extrapolated beyond 2030, reaching an annual carbon dioxide emission of 1,100 million metric tons in 2050, that is still three times higher than that under the DDPP High CCS Scenario, which is the case with the highest carbon emission from the power sector among all four DDPP cases.
99. *See* CPP-RIA, *supra* note 87, at 3-23 to 3-33 (discussing compliance actions for emissions reductions expected by EPA under the CPP).
100. Jeremy Van Loon, *Shell Sees Carbon Price of \$60 to \$80 Needed to Justify CCS*, Bloomberg, Nov. 6, 2015, http://www.bloomberg.com/news/articles/2015-11-06/shell-sees-carbon-price-of-60-to-80-needed-to-justify-ccs. Another method to estimate the carbon price necessary to incentivize CCS is cost per ton of carbon dioxide avoided, which is approximately \$63/ton of carbon dioxide for supercritical pulverized coal power plants using bituminous coals in 2013 dollars. *See* Rubin et al., *supra* note 18, at 382 tbl. 2.
101. *See* Rubin et al., *supra* note 18, at 389.
102. Josiah Neeley, *Using the Clean Power Plan's Carbon Fee Option to Offset State Taxes*, 13 R Street Shorts 1, 2 (2015), *available at* http://www.rstreet.org/wp-content/uploads/2015/08/RSTREETSHORT13.pdf. In addition, David Oates and Paulina Jaramillo have assessed the state-by-state carbon dioxide price necessary to comply with the proposed CPP, which differs in some ways from the final CPP, but aimed for a similar nationwide carbon dioxide emissions reduction of 30% from 2005 levels by 2030. They found that state-by-state carbon dioxide prices varied from \$0-\$100/ton under the rate-based scenario, and \$0-\$40/ton under the mass-based scenario. *See* David Luke Oates & Paulina Jaramillo, *State Cooperation Under the EPA's Proposed Clean Power Plan*, 28 Elec. J. 26, 35 fig. 4 (2015). Assuming national cooperation in complying with the rule (i.e., all states participate in the same market under a combined emissions limit), carbon dioxide prices

reflect the amount of emissions reductions required by the CPP. In short, the CPP did not set strong enough emissions reduction targets to create incentives for CCS deployment. Instead, in combination with a weak NGCC NSPS, it provided incentives to developers to build unabated NGCC to serve baseload electricity needs in the United States during the eight-year period between 2014 and 2022.[103]

To achieve the CCS deployment rates in the DDPP Mixed and High CCS Scenarios, several reforms to the CPP would be necessary.[104] First, the CPP would need to be extended through 2050, and the emissions reduction targets would need to be recalculated using CCS as part of the BSER for reducing individual generators' carbon dioxide emissions rates.[105] More specifically, the BSER should be based on CCS retrofits such that carbon dioxide emissions from coal-fired generators are reduced by 90%. CCS retrofits on coal-fired generators are technically and economically feasible.

CCS retrofits on coal-fired generators were found to be technically feasible as early as 2011,[106] and more recent experience at Boundary Dam[107] and Petra Nova,[108] as well as additional studies, confirm that CCS retrofits are feasible on many types of fossil fuel-fired power plants and other major emitters of carbon dioxide.[109] Neither available space, proximity to potential sequestration sites, nor pipeline infrastructure are technical obstacles to widespread CCS retrofits, although these issues vary plant-by-plant and may preclude CCS retrofits at particular power plants.[110] More than 95% of major point sources, including coal-fired generators, in the United States are located above or within 100 kilometers of potential geologic reservoirs for sequestration or pipeline transport to such reservoirs,[111] and a competitive carbon dioxide pipeline industry already exists in the United States.[112]

Importantly, CCS retrofits achieve significant emissions reductions. Using available historic data as an illustrative example, retrofitting CCS on all existing coal-fired generators would have reduced power-sector carbon dioxide emissions by roughly 1,200 million metric tons in 2015,[113] more than three times the CPP's total predicted emissions reductions by 2030 of roughly 370 million metric tons.[114] EPA has found that the costs of post-combustion CCS coupled with EOR sequestration (based on the Boundary Dam retrofit experience) are reasonable now for new coal plants,[115] although CCS costs tend to be greater for retrofits than new builds.[116]

These costs are expected to decline significantly over the next several decades.[117] Several studies estimate reductions in the levelized cost of energy[118] of CCS technologies on the order of 20%-30% over the next two decades.[119] Based on these cost reductions and costs of currently commercially available CCS technologies, carbon dioxide mitigation costs of CCS are expected to reach roughly $40-$100 per ton of carbon dioxide avoided for coal-fired plants,[120]

of $30 and $25 would be necessary to comply with the rate- and mass-based standards, respectively. *Id*.

103. EPA is required under §111 of the CAA to revisit and, if appropriate, revise its NSPS at least every eight years for each source category. 42 U.S.C. §7411(b)(1)(B).

104. We note that rather than reforming the CPP, alternative policies could be put in place to reduce carbon dioxide emissions from existing generators, such as a national carbon tax or cap-and-trade system (such as that set up under the Acid Rain Program (*see* 42 U.S.C. §7651b). Both measures would directly support CCS investment by valuing its contribution to carbon dioxide emissions reductions. Moreover, economic theory suggests that both would be more efficient than the CPP at reducing carbon dioxide emissions. *See* Nathaniel O. Keohane & Shelia M. Olmstead, Markets and the Environment 180-81 (2d ed. 2007) (arguing that "market-based instruments have two substantial advantages over technology and performance standards": they are cost efficient, and they drive technological innovation). While states can comply with the CPP via a carbon tax or a national, regional, or state cap-and-trade system, the CPP provides many other compliance options to states, so compliance with the CPP via either approach is not guaranteed.

105. The CPP sets its emissions reduction targets using three building blocks, which look at the carbon dioxide emissions reductions that can be achieved through heat rate improvements at coal-fired generators, deployment of new renewable energy, and replacing electricity generation from coal-fired generators with NGCC units. Clean Power Plan, *supra* note 61, at 64667. *See* U.S. EPA, CO_2 Emission Performance Rate and Goal Computation Technical Support Document for CPP Final Rule (2015).

106. *See generally* Nsakala ya Nsakala et al., Engineering Feasibility of CO_2 Capture on an Existing U.S. Coal-Fired Power Plant, Presented at the First National Conference on Carbon Sequestration (May 15-17, 2011) (showing that it was feasible to retrofit one of AEP's coal burning units with carbon capture equipment), https://www.netl.doe.gov/publications/proceedings/01/carbon_seq/7c1.pdf.

107. *See Boundary Dam Fact Sheet*, *supra* note 80.

108. *See Petra Nova W.A. Parish Fact Sheet*, *supra* note 80.

109. Desmond Dillon et al., *A Summary of EPRI's Engineering and Economic Studies of Post Combustion Capture Retrofit Applied at Various North American Host Sites*, 37 Energy Procedia 2349, 2357 (2013) (finding five sites to be suitable for carbon capture retrofits); International Energy Agency Greenhouse Gas R&D Programme (IEAGHG), Retrofitting CO_2 Capture to Existing Power Plants 97-98 (2011).

110. *See* IEAGHG, *supra* note 109, at 98 ("significant numbers of sites exist with space to add capture equipment and access to storage").

111. *See* Dooley, *supra* note 4, at 29, and other references *supra* note 4.

112. *See* Matthew Wallace et al., NETL, A Review of the CO_2 Pipeline Infrastructure in the U.S. 3-12 (2015) (cataloguing existing carbon dioxide pipeline infrastructure in the United States).

113. This point assumes 90% capture. Total carbon dioxide emissions from coal-fired generators in 2015 was 1,364 million metric tons. EIA, *Frequently Asked Questions—How Much of U.S. Carbon Dioxide Emissions Are Associated With Electricity Generation?*, http://www.eia.gov/tools/faqs/faq.cfm?id=77&t=11 (last updated May 10, 2017).

114. *See* CPP-RIA, *supra* note 87, at ES-6 tbl. ES-2 (estimating an emissions reduction of 415 million short tons by 2030).

115. These costs are deemed reasonable on an LCOE basis relative to comparable electricity generation dispatchable technologies, namely a new nuclear and biomass-fired plant. *See* 2015 NSPS Rule, *supra* note 61, at 64558, 64564.

116. *See* Rubin et al., *supra* note 18, at 391.

117. Machteld van den Broek et al., *Effects of Technological Learning on Future Cost and Performance of Power Plants With CO_2 Capture*, 35 Progress Energy & Combustion Sci. 457, 474 tbl. 9, 475 fig. 11 (2009).

118. The LCOE equals total lifetime electricity generation by a facility divided by its total lifetime costs, including capital and operational costs.

119. Specifically, based on three studies, the LCOEs of pulverized coal plants with post-combustion CCS and IGCC with CCS are expected to decrease by roughly 20% and 30%, respectively. *Compare* Kristin Gerdes et al., *Current and Future Power Generation Technologies*, 63 Energy Procedia 7541, 7546, 7547 fig. 4, 7552 fig. 9, 7553 (2014) (showing reductions in cost of energy (COE) of 21%-23% for pulverized coal plants with post-combustion capture and 28% for IGCC plants), *with* van den Broek et al., *supra* note 117, at 474 tbls. 8 & 9 (showing reductions in COE of 17% for pulverized coal plants with post-combustion capture and 31% for IGCC plants), *and* Rubin et al., *supra* note 18, at 390 (estimating "cost reductions of approximately 20% . . . and 27% in the LCOE of advanced coal-based power plants with post-combustion . . . and IGCC/pre-combustion capture, respectively").

120. Without EOR, initial costs per ton of carbon dioxide avoided $46-$99 with supercritical pulverized coal with CCS, and $38-$84 with IGCC with CCS. Rubin et al., *supra* note 18, at 389 tbl. 16. Assuming reduc-

and even lower when using carbon dioxide for EOR.[121] These mitigation costs can be lower than or comparable to carbon dioxide mitigation costs of other technologies currently included in the CPP BSER. For instance, the cost per ton of carbon dioxide emissions avoided with wind can range up to $104 per ton.[122]

To achieve the DDPP targets for the High CCS and Mixed Scenarios, the CPP BSER for NGCC plants would need to be based on the application of at least partial (50%) CCS retrofits on NGCCs by 2050, meaning each NGCC generator would need to capture 50% of its carbon dioxide emissions. Carbon capture at an NGCC is technically feasible.[123] Indeed, as already noted, an NGCC capturing carbon dioxide for sale as a commodity operated from 1991 through 2005.[124] Furthermore, several demonstration and commercial-scale NGCC with CCS projects have been proposed in recent years, some of which are still under development.[125]

Significant cost reductions are expected for CCS on NGCCs in the coming years.[126] Accounting for these cost reductions, NGCC with CCS would be as cost effective at reducing carbon dioxide emissions as many other carbon dioxide mitigation strategies.[127] Even so, CCS retrofits on NGCCs are more expensive than CCS retrofits on coal-fired plants on a cost per ton of carbon dioxide avoided basis,[128] so a longer-term and lower BSER deployment standard is appropriate.

As issued, the CPP would award additional allowances or emission rate credits to early movers of renewable energy and demand-side energy-efficiency projects that are implemented in low-income communities.[129] This so-called Clean Energy Incentive Program could be expanded so that it is technology-neutral, allowing credit or allowance generation for any zero-carbon emitting source that can be operational between now and the start of the first CPP compliance period. Under such an approach, early investment in CCS projects could receive credits or allowances with a multiplier. Rewarding early movers can bring national momentum to the plan and help achieve experience implementing CCS sooner.

To further promote CCS deployment, the CPP, if revived, could be revised to allow and "credit" certain emissions reductions achieved by U.S. investment in CCS projects outside the United States. Though this would represent a considerable departure from prior practice under the CAA, which only credits reductions in domestic emissions, there are two good reasons for this. First, it may be faster and cheaper to demonstrate carbon dioxide capture on NGCC plants abroad given the lengthy permitting process, strong private land ownership rights, and resistance to CCS from certain groups in the United States. These may be less problematic in other countries because of different legal systems and political environments. In addition, a large share of the CCS cost is labor and materials,[130] which could be cheaper elsewhere in the world. Thus, it might be faster and less costly to implement CCS abroad, which simultaneously moves the technology development forward and reduces global emissions.[131]

3. State Legislators and Regulators Can Impose Restrictions on Carbon Dioxide Emissions to Drive CCS

States have ample authority under the federal CAA and many parallel state clean air statutes to restrict emissions

tions in LCOEs produce roughly proportional reductions in carbon dioxide mitigation costs.

121. For instance, carbon dioxide mitigation costs decrease from $46-$99/ton for supercritical pulverized coal plants with CCS without EOR to $-5-$58/ton with EOR, where negative mitigation costs indicate cost and CO_2 emission reductions occur with CCS and EOR. *Compare* Rubin et al., *supra* note 18, at 389 tbl. 16 (showing mitigation costs for plants without EOR), *with id.* at 390 tbl. 17 (showing mitigation costs for plants with EOR).

122. Carbon dioxide mitigation costs for wind can be approximated by dividing carbon dioxide emissions reduced by wind by the LCOE for wind. Assuming an onshore wind LCOE of $32-$62/MWh (Lazard, Lazard's Levelized Cost of Energy Analysis—Version 10.0, at 19 (2016)), then the carbon dioxide mitigation cost of wind varies from $32-$62/ton assuming wind displaces coal-fired generation and $53-$104/ton assuming wind displaces gas-fired generation.

123. *See* DOE, Quadrennial Technology Review, *supra* note 78, at 110 (noting that "[t]he technology transfer to natural gas for both new plants and retrofits would be relatively straightforward").

124. U.S. EPA, Technical Support Document, *supra* note 83, at 38 (Fluor Corp. in Bellingham, Massachusetts).

125. These include the Peterhead project in the United Kingdom, Carbon Capture & Sequestration Technologies @ MIT, *Peterhead Project Fact Sheet: Carbon Dioxide Capture and Storage Project*, https://sequestration.mit.edu/tools/projects/peterhead.html (last visited Sept. 23, 2017), and the Gaojing plant in China. Global CCS Institute, International Activities on NGCC-CCS 15-17 (2015), http://www.energy.ca.gov/research/notices/2015-04-16_workshop/presentations/International_Natural_Gas_Projects-EBurton.pdf.

126. Specifically, the LCOE of NGCC with CCS is expected to decline by roughly 15%. *Compare* van den Broek et al., *supra* note 117, at 473 tbl. 7 (showing a decrease in COE of 12% for NGCC plants), *with* Rubin et al., *supra* note 18, at 390 ("reductions in LCOE would be roughly . . . 13% for gas-fired plants").

127. Specifically, carbon dioxide mitigation costs for wind vary from roughly $32-$104/ton, depending on the LCOE of wind and whether it displaces coal- or gas-fired generation. *See* PJM, *supra* note 18. Using a 15% LCOE reduction provided above, and an initial carbon dioxide mitigation cost for NGCC with CCS of $59-$143/ton without EOR and $10-$112/ton with EOR, *compare* Rubin et al., *supra* note 18, at 389 tbl. 16 (showing mitigation costs for plants without EOR), *with id.* at 390 tbl. 17 (showing mitigation costs for plants with EOR), projected NGCC with CCS carbon dioxide mitigation costs would equal roughly $50-$122/ton without EOR and $9-$100/ton with EOR. These costs are within the range of costs for wind.

128. Without EOR, costs per ton of carbon dioxide avoided equal $59-$143 for NGCC with post-combustion CCS and $46-$99 with supercritical pulverized coal with CCS. Rubin et al. *supra* note 18, at 389 tbl. 16. With EOR, those values are $10-$112/ton and $-5-$58/ton, respectively, where negative costs indicate cost and CO_2 emission reductions occur with CCS and EOR. *Id.* at 390 tbl. 17.

129. *See* Clean Power Plan, *supra* note 61, at 64829-32.

130. Cost of labor and materials is on par with that of all the equipment at an NGCC-CCS power plant. *See* NETL Cost Report, *supra* note 82, at 205-06 ex. 4-28 (showing the cost of labor and materials at an NGCC plant with CCS to be $248,200, while the total equipment costs are $376,068).

131. If the United States were to adhere to the 2015 Paris Agreement, U.S. CCS projects could potentially produce "internationally transferred mitigation outcomes" within the meaning of Article 6 of the 2015 Paris Agreement. CCS technologies could then become supported by a new international market mechanism, which will be developed further by the Conference of the Parties to the Paris Agreement.

of carbon dioxide from new and existing sources, thereby directly or effectively requiring use of CCS. State action is of key importance in the near term in light of resource constraints imposed by the Trump Administration on EPA and reconsideration of federal regulations ordered by the Administration.

Some states have already set standards on new and existing sources. For example, with respect to new sources, California has adopted a law effectively requiring the use of CCS at new coal plants by means of an emissions standard that exempts captured and sequestered carbon dioxide.[132] Montana requires new coal plants to capture and store at least 50% of their carbon dioxide emissions.[133] Oregon and New York also limit carbon dioxide emissions from new power plants.[134] Other states can also pass carbon emissions regulations on new sources. These standards should follow our proposed time line for EPA to tighten its NSPS, as detailed above. Specifically, these standards should require full CCS on new coal-fired units by the early 2020s, and partial and full CCS on new NGCC units by the mid-2020s and early 2030s, respectively.

Other states have already adopted standards on carbon emissions from existing sources. These standards have mostly taken the form of cap-and-trade systems, as in the cases of California and the Regional Greenhouse Gas Initiative, which covers Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.[135] Cap-and-trade systems do not set strict limits on carbon emissions from power plants. Rather, they set a declining cap on total carbon emissions from the power sector, which is divided among power plants via emission permits, and allow market forces to determine which power plants reduce their carbon emissions. Due to the technology-agnostic nature of such systems, predicting what carbon emissions cap would be necessary to drive CCS deployment exceeds the scope of this Article. However, due to the low cost of renewables[136] and surplus NGCC capacity,[137] carbon emissions caps would have to be fairly stringent to incentivize CCS.[138]

132. Cal. Pub. Util. Code §8341(d)(1) (West 2016).
133. Mont. Code Ann. §69-8-421(8) (West 2016).
134. *See* Or. Rev. Stat. §469.501(1)(o) (West 2016); N.Y. Comp. Codes R. & Regs. tit. 6, §251.3 (West 2016).
135. Regional Greenhouse Gas Initiative, *Program Design*, https://www.rggi.org/design (last visited Sept. 23, 2017).
136. For levelized cost estimates of renewables, see Lazard, *supra* note 122, at 18-19.
137. EIA, *Average Utilization for Natural Gas Combined-Cycle Plants Exceeded Coal Plants in 2015*, Today in Energy, Apr. 4, 2016 (showing that the average annual capacity factor of NGCCs in the United States was 56.3% in 2015), https://www.eia.gov/todayinenergy/detail.php?id=25652.
138. Researchers at Carnegie Mellon University have confirmed this, finding that under a regional cap-and-trade program in line with the CPP's carbon emissions reduction targets in 2030 of 32% from 2005 levels, adding wind capacity or shifting electricity generation from existing coal-fired to NGCC units would be more cost effective than CCS retrofits. Michael T. Craig et al., *The Economic Merits of Flexible Carbon Capture and Sequestration as a Compliance Strategy With the Clean Power Plan*, 51 Envtl. Sci. & Tech. 1102, 1102-09 (2017).

4. EPA Can Revise the New Source Review and Prevention of Significant Deterioration Permitting Requirements

New coal-fired and NGCC power plants (or major modifications to existing plants) are subject to various permitting requirements triggered by a variety of air pollutant emissions other than carbon dioxide.[139] Plants built in places that meet (are in "attainment" with) the national ambient air quality standards may trigger permitting requirements under the prevention of significant deterioration (PSD) provisions of the CAA, whereas permitting under the new source review (NSR) provisions would be triggered in nonattainment areas.[140] Once NSR or PSD are triggered, then carbon dioxide emissions can also be limited in the resulting permit.[141]

Coal-fired generators typically trigger PSD or NSR permitting due to their significant emissions of conventional air pollutants.[142] By contrast, many NGCC units may not trigger PSD or NSR permitting.[143] Therefore, while the

139. The CAA, 42 U.S.C. §§7401 et seq., establishes the regulatory regime for air pollution in the United States. For NSPS, see *id*. §7411, for permit requirements in nonattainment areas, see *id*. §7503, and for the operating permit program, see *id*. §7661a.
140. New facilities in PSD areas must obtain a permit under *id*. §7475. New facilities in nonattainment areas are subject to NSR permitting under *id*. §7502(c)(5).
141. Utility Air Regulatory Group v. Environmental Prot. Agency, 134 S. Ct. 2427, 2448-49, 44 ELR 20132 (2014) (holding that EPA may require BACTs for GHGs emitted by "anyway" sources, or sources otherwise subject to PSD review). *See* Memorandum From Janet G. McCabe, Acting Assistant Administrator, Office of Air and Radiation, U.S. EPA, to Regional Administrators, Regions 1-10 (July 24, 2014) (Next Steps and Preliminary Views on the Application of Clean Air Act Permitting Programs to Greenhouse Gases Following the Supreme Court's Decision in *Utility Air Regulatory Group v. Environmental Protection Agency*), https://www.epa.gov/sites/production/files/2015-07/documents/2014scotus.pdf. According to analysis by EPA, even if sources only trigger PSD permitting based on non-carbon dioxide emissions, most (~65%) GHG emissions from stationary sources would still be regulated under the PSD program. Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule, 75 Fed. Reg. 31514, 31540 tbl. V-1 (June 3, 2010) (to be codified at 40 C.F.R. pts. 51, 52, 70, and 71).
142. For instance, assuming a nitrogen oxide (NO_x) emissions rate of 0.700 lb/MWh of electricity generated, *see* NETL Cost Report, *supra* note 82, at 121 ex. 3-42, a relatively small 40-MW coal plant would have annual NO_x emissions in excess of 100 tons per year, thereby triggering PSD permitting. 40 C.F.R. §52.21(b)(1)(i) (2016). Emissions of particulate matter, sulfur dioxide, and other regulated pollutants would also require PSD permitting for coal plants.
143. NGCC units have much lower emissions of conventional air pollutants than coal plants. NGCCs tend to have higher NO_x emissions than other conventional pollutants. *See* NETL, Life Cycle Analysis: Natural Gas Combined Cycle (NGCC) Power Plant, Appendix: Process Modeling Data Assumptions and GaBi Modeling Inputs 47 tbl. A-22 (2010) (showing emissions of various pollutants during NGCC plant operations); to confirm this, we also built a "Typical New Plant" NGCC facility in IECM, *see supra* note 64, and compared emissions rates of conventional air pollutants. However, carbon monoxide emissions can be higher than NO_x emissions, *see*, *e.g.*, U.S. EPA, Permit No. PSD-TX-1012-GHG, Statement of Basis: Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the City of Austin dba Austin Energy, Sand Hill Energy Center 4 (2014), https://archive.epa.gov/region6/6pd/air/pd-r/ghg/web/pdf/austin-energy-sandhill-sob.pdf, depending on combustion control factors. *See* ENVIRON International Corp., Best Available Control Technology Analysis for a Combined-Cycle Combustion Turbine Project: Kalama, Wa 10 (2011). Nonetheless, assuming a new NGCC unit has an NO_x emissions

parameters for NSR and PSD permits could be tightened to drive CCS for coal plants and other industrial sources of carbon dioxide emissions, NSR and PSD permitting will not likely be an effective driver of CCS for NGCC plants unless Congress revises the CAA in a way that makes this permitting applicable.[144]

To obtain a PSD or NSR permit, the applicant must demonstrate how it will comply with NSPS,[145] lowest achievable emissions rates (LAER),[146] and/or best available control technology (BACT).[147] BACT and LAER are determined by state agencies, the former on a case-by-case basis,[148] and the latter by source categories.[149] The NSPS for a given source category serves as the floor for both BACT and LAER.[150] EPA provides the states with guidance for applying BACT and LAER.[151]

One way to bolster BACT and LAER as drivers for CCS would be for EPA to revise its guidance to separate consideration of the transport and sequestration facets from the capture facet, so that the cost and availability of transport and sequestration do not influence the BACT/LAER outcome.[152] This could occur as a companion to the recommendation provided later in this part that the federal government take responsibility for developing sequestration sites and transportation to move carbon dioxide. At least for several of the earliest NGCC plants, the federal government could take responsibility for the transport and sequestration aspects in order to push the capture process forward.

In any event, even before a federal sequestration facility is developed, EPA climate pollution BACT guidance should be revised in order to reflect NSPS requirements for partial CCS on coal-fired generators, and that opportunity could be used to strengthen it in the ways discussed above. EPA should also continue to revise the guidance in the future as NSPS requirements for coal-fired and NGCC units are tightened.[153] States could be reminded by EPA in the guidance or in a separate memorandum from the Administrator that they have authority to go beyond the floor set by EPA's guidance for BACT and LAER. Finally, with respect to transportation and sequestration, the guidance should emphasize that numerous sequestration projects have been successfully undertaken in the United States and elsewhere that demonstrate the safety and efficacy of sequestration.[154]

D. *Federal and State Agencies Could Streamline Permitting and Improve Interagency Coordination*

One factor in the failure of the FutureGen project was the extended delay in securing a Class VI underground injection control (UIC) well permit from EPA to inject carbon dioxide into the subsurface for permanent sequestration.[155] The application process took two years. The permit was issued on September 2, 2014, barely one year before the September 2015 ARRA spending deadline. While it was a first-of-its-kind permit, EPA, DOE, the Bureau of Land Management (BLM), and other agencies could facilitate integrated CCS projects through improved interagency coordination and finding appropriate ways to streamline permitting and funding decisions, such as tax credits and loan guarantees previously proposed here, in particular for early movers.

III. Legal Reforms Needed to Encourage Construction of Carbon Dioxide Pipelines

The existing carbon dioxide pipeline network in the United States is woefully inadequate to transport the amount of captured carbon dioxide necessary to meet the DDPP projections for either the Mixed or High CCS Scenario.

rate of roughly 0.02 lb/MWh (with selective catalytic reduction for post-combustion NO_x control), *see* NETL Cost Report, *supra* note 82, at 180 ex. 4-8, relatively large NGCC units of up to roughly 400 MW may not trigger PSD permitting.

144. For example, revisions of §179(1) of the CAA, 42 U.S.C. §7479(1), would be necessary.
145. *See generally* 40 C.F.R. pt. 60, subpt. TTTT (2016) (NSPS for GHG emissions for EGUs).
146. 42 U.S.C. §7501(3).
147. *Id.* §7475(a)(4).
148. *Id.* §7479(3).
149. *Id.* §7501(3).
150. *See* U.S. EPA, New Source Review Workshop Manual B.1 (1990) ("In no event shall application of [BACT] result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61."); 42 U.S.C. §7501(3)(B) ("In no event shall the [LAER] permit a proposed new or modified source to emit any pollutant in excess of the amount allowable under [NSPS]."). Setting CCS as the NSPS for electricity generators does not necessarily set the BACT floor at CCS for other sources (e.g., ethanol production facilities). *See* 2015 NSPS Rule, *supra* note 61, at 64631-32 (noting that "BACT is a case-specific" determination, and drawing distinctions between "fossil fuel-fired power plants and . . . industrial facilities with high-purity CO_2 streams."). However, we also recommend revising the NSPS for such facilities to require CCS, which should be followed by a revision to BACT guidance for such facilities as well.
151. For BACT guidance, see generally U.S. EPA, PSD and Title V Permitting Guidance for Greenhouse Gases (2011) [hereinafter PSD and Title V Permitting]. For LAER guidance, see generally Memorandum From John Calcagni, Director, Air Quality Management Division, U.S. EPA, to David Kee, Director, Air and Radiation Division, Region V, U.S. EPA (Feb. 28, 1989) (Guidance on Determining Lowest Achievable Emission Rate (LAER)), https://www.epa.gov/sites/production/files/2015-07/documents/gdnclaer.pdf.
152. *See, e.g.*, U.S. EPA, Permit No. PSD-TX-612-GHG, Statement of Basis: Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for Air Liquide Large Industries U.S., LP 13-14 (2013) (where pipeline costs were included, and CCS was ultimately rejected on cost-effective grounds), https://archive.epa.gov/region6/6pd/air/pd-r/ghg/web/pdf/air-liquide-sob.pdf. *See also* PSD and Title V Permitting, *supra* note 151.
153. BACT determinations in 2012 and 2013 for NGCC and chemical units considered CCS as technically feasible, but ultimately did not include CCS as BACT due to high costs. *See, e.g.*, U.S. EPA, Permit No. PSD-TX-955-GHG, Statement of Basis: Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for Channel Energy Center (CEC), LLC 18-19 (2012), https://archive.epa.gov/region6/6pd/air/pd-r/ghg/web/pdf/calpline_energy_sob.pdf; U.S. EPA, Permit No. PSD-TX-612-GHG, *supra* note 152, at 13-14; U.S. EPA, Permit No. PSD-TX-1012-GHG, *supra* note 143, at 11.
154. *See* Dooley et al., *supra* note 4 (discussing the availability of suitable sites for geologic storage of carbon dioxide in North America).
155. Peter Folger, Congressional Research Service, Recovery Act Funding for DOE Carbon Capture and Sequestration 10-11 (2016) (R44387).

This section explores the types of regulatory and financial reforms needed to facilitate expansion of the carbon dioxide pipeline network.[156]

After carbon dioxide is captured, it must be compressed and transported either to a sequestration site or to a downstream user. A carbon dioxide pipeline network already exists in the United States that primarily transports mined carbon dioxide to aging oil fields for EOR.[157] As of January 2017, this network transports roughly 69 million metric tons per year and spans 4,600 miles.[158] Much of the existing pipeline infrastructure was built when oil prices were high and it was profitable for oil companies to invest in the pipelines to facilitate EOR. To achieve the DDPP Mixed and High CCS Scenarios, the amount of carbon dioxide captured from coal and NGCC plants would be on the order of 0.5 to two billion metric tons per year.[159] Thus, to achieve widespread CCS deployment as envisioned in the DDPP CCS cases, the extent and carrying capacity of the carbon dioxide pipeline network would need to be increased considerably.[160]

While oil and natural gas prices remain low, the private sector lacks the financial incentive to extend this pipeline infrastructure. Moreover, according to DOE, the "vast majority of the [carbon dioxide] pipeline network is west of the Mississippi River, while most of the sources that may require capture of their [carbon dioxide] are east of the Mississippi River."[161]

A. States and/or Regions Can Establish Pipeline Agencies

Agencies akin to public utilities could be formed and funded by individual states and/or regions to conduct siting analyses, acquire property access rights, and otherwise coordinate and facilitate expansion of the pipeline network. Given the significant threat of local opposition to siting carbon dioxide pipelines,[162] these agencies should also engage early and vigorously with citizens and other stakeholders to address public concerns regarding siting of carbon dioxide pipelines. Financing of the pipeline expansion could devolve to DOE as part of the Trump Administration's commitment to invest in infrastructure and pipelines and/or Congress could create an ITC for pipelines.[163]

B. DOE Can Study Repurposing and Requalifying Existing Oil or Gas Pipelines to Carry Carbon Dioxide

Congress could also direct DOE to analyze whether existing oil and natural gas pipelines could be repurposed to transport captured carbon dioxide. Whether such repurposing is feasible is unclear.[164] The properties of carbon dioxide, such as its density and phase behavior, differ from oil and natural gas.[165] Consequently, operating conditions for which existing oil and natural gas pipelines are designed may differ from those necessary for carbon dioxide transportation.[166] Many existing oil and natural gas pipelines have been in service for decades and could be suffering from corrosion and fatigue.[167] Even if these pipelines could be repurposed for the transport of captured carbon dioxide, these pipelines would need to be requalified for carbon dioxide transportation on a case-by-case basis.[168]

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156. For related discussions, see DOE Workshop Report, *supra* note 7; Interstate Oil and Gas Compact Commission, A Policy, Legal, and Regulatory Evaluation of the Feasibility of a National Pipeline Infrastructure for the Transport and Storage of Carbon Dioxide 39-47 (2010) (discussing possible future regulatory scenarios).
157. Roughly 80% of carbon dioxide currently used for EOR is from natural sources as opposed to carbon dioxide captured from an industrial or power generation source. Wallace et al., *supra* note 112, at 3.
158. DOE Workshop Report, *supra* note 7, at 7.
159. To estimate this value, we first estimate total generation by CCS-equipped coal and NGCC plants under the DDPP cases. Under the Mixed Scenario, CCS is only installed on NGCC plants, so they account for all CCS generation, or four exajoules (EJ). James H. Williams et al., Energy and Environmental Economics, Inc. et al., Pathways to Deep Decarbonization in the United States, US 2050 Report, Volume 1: Technical Report 36 fig. 29 (2015). Under the High CCS Scenario, we assume CCS-equipped NGCC and coal plants account for 66.7% and 33.3% of total CCS generation based on their installed capacities, *id*. at 36 fig. 30, so CCS-equipped NGCC and coal plants generate 4.3 and 8.7 EJ, respectively. Using the NREL's Annual Technology Baseline, we then estimate captured carbon dioxide per unit of electricity generated for CCS-equipped coal and NGCC units as 1,856 and 805 lb/MWh, respectively, *see* NREL, *Annual Technology Baseline and Standard Scenarios*, https://www.nrel.gov/_noctp/analysis/atb.html (last visited Sept. 23, 2017). To obtain this value, we use the heat rate and carbon dioxide emissions rate for the reference CCS plant to calculate emissions per unit of electricity generation at the reference plant. We calculate the same value for a hypothetical plant with the same heat rate that does not capture carbon dioxide emissions, so divide the emissions rate of the reference CCS plant by 0.1 (thereby assuming a 90% capture rate at the CCS plant). Subtracting the two emissions rates yields captured carbon dioxide per unit of electricity generated. Multiplying annual electricity generation by the captured carbon dioxide per unit of electricity generated yields annual captured carbon dioxide.
160. DOE estimates new pipeline construction to transport 170 million metric tons of carbon dioxide per year would be on the order of 21,000 miles. *See* DOE Workshop Report, *supra* note 7, at 20. Assuming the length of this network linearly scales with transported carbon dioxide, achieving the DDPP CCS targets would require roughly 60,000 to 252,000 miles of pipeline. *See also* Paul W. Parfomak & Peter Folger, Congressional Research Service Carbon Dioxide (CO_2) Pipelines for Carbon Sequestration: Emerging Policy Issues 1 (2008) (RL33971) ("[M]oving the enormous quantities of CO_2 implied by a widespread implementation of CCS technologies would likely require a dedicated interstate pipeline network.").
161. DOE Workshop Report, *supra* note 7, at 20.
162. In a study by Rachel Krause et al., 166 of 779 respondents switched their view of CCS from supporting it at the national level to opposition to it at the local level, indicating a "not-in-my-backyard" approach to CCS (*see* Rachel M. Krause et al., *"Not in (or Under) My Backyard": Geographic Proximity and Public Acceptance of Carbon Capture and Storage Facilities*, 34 Risk Analysis 529-40 (2013)). Indeed, several protests have already occurred against the siting of CCS facilities, including sequestration sites (*see* Richard Van Noorden, *Carbon Sequestration: Buried Trouble*, 463 Nature 871-73 (2010)).
163. DOE Workshop Report, *supra* note 7, at 9.
164. *See* Joana Serpa et al., European Commission, Technical and Economic Characteristics of a CO_2 Transmission Pipeline Infrastructure 14-15 (2011); Intergovernmental Panel on Climate Change (IPCC), Carbon Dioxide Capture and Storage 187 (Bert Metz et al. eds., Cambridge Univ. Press 2005).
165. *See generally* Thesis: Sean T. McCoy, The Economics of CO_2 Transport by Pipeline and Storage in Saline Aquifers and Oil Reservoirs 24 (Apr. 2009) (Ph.D. thesis, Carnegie Mellon University), https://www.andrew.cmu.edu/user/stmccoy/pdf/Thesis_Final_2.pdf.
166. *Id*.
167. Serpa et al., *supra* note 164, at 15.
168. *See id*.

C. *DOE Can Resolve Uncertainties About Locations of Key Capture and Sequestration or Utilization Facilities and Jurisdictional Authority*

Several uncertainties crucial to developing an effective regulatory framework for large-scale carbon dioxide pipeline deployment remain unresolved. Where will new power plants and industrial facilities equipped with carbon dioxide capture be built? Are there sequestration sites or EOR operations nearby? Could clusters of industrial and/or power generation facilities mutually benefit from a single pipeline and sequestration site?

Answers to these questions will help determine whether the pipeline network should be local, regional, or national in scale.

1. Evolving Regulatory Framework for Carbon Dioxide Pipelines

Currently, regulation of carbon dioxide pipelines is almost entirely left to the states, which have permitting and siting authority for new, intrastate pipelines and regulate their operation, including rates and access.[169] Some states, such as Wyoming, are developing pipeline right-of-way corridors to connect sources of carbon dioxide to active oil fields for EOR.[170] Other states are creating agencies to coordinate and pave the way for private investment in pipeline construction and operation.[171] Some are advocating for ITCs and/or CfDs to subsidize the carbon dioxide pipeline build-out.[172] Some combination of these approaches will likely be needed to advance CCS.

To date, federal involvement with carbon dioxide pipelines has been minimal. Carbon dioxide pipelines that cross federal lands must be approved by the federal agency that manages that land.[173] BLM has permitting authority over lands managed by the U.S. Department of the Interior (DOI).[174] Safety regulation of interstate pipelines is overseen by the Pipeline and Hazardous Materials Safety Administration in the same manner as pipelines that carry hazardous liquids.[175] No federal agency has asserted siting authority over carbon dioxide pipelines that cross state borders without crossing federal lands.

The Federal Energy Regulatory Commission (FERC) and the Surface Transportation Board (STB) have both declined to regulate pipelines carrying carbon dioxide. In 1980, the Interstate Commerce Commission (ICC), STB's predecessor, claimed that it did not have jurisdiction over carbon dioxide pipelines because the Interstate Commerce Act did not apply to pipelines transporting "gas," interpreted by the ICC to include carbon dioxide.[176] The STB has not reversed this ruling of the ICC, which will remain in effect "until modified, terminated, superseded, set aside, or revoked in accordance with law."[177]

FERC approves siting and regulates transportation rates of interstate natural gas pipelines.[178] FERC ruled in 1979 that because carbon dioxide only contains traces of methane, it cannot be defined as "natural gas" within the meaning of the Natural Gas Act (NGA).[179] Since a carbon dioxide pipeline operator is not a "natural-gas company" under the NGA, FERC concluded that it lacks jurisdiction over carbon dioxide pipelines.[180] As a result, interstate carbon dioxide pipelines are not economically regulated at the federal level.[181] Thus, unlike natural gas pipeline developers, carbon dioxide pipeline developers lack access to federal eminent domain to secure rights-of-way.

Interstate carbon dioxide pipelines for sequestration that do not cross federal land are therefore subject to state-by-state siting approval, a complex and lengthy process.[182] Significant variation exists at the state level in the regulation of carbon dioxide pipelines.[183] The regulation has largely been focused on carbon dioxide pipelines to support EOR, although some states' regulations also pertain to carbon dioxide pipelines for geologic sequestration.[184] Some states, including oil-producing states such as Colorado, Louisiana, and Texas, define carbon dioxide pipelines by statute as "common carriers."[185] While the meaning of that term varies among states, it generally refers to a business that is required to serve all customers at a reasonable rate, to the extent that it is able to.[186]

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169. *See* Philip M. Marston & Patricia A. Moore, *From EOR to CCS: The Evolving Legal and Regulatory Framework for Carbon Capture and Storage*, 29 Energy L.J. 421, 456-61 (2008) (discussing state regulatory frameworks for carbon dioxide pipelines).
170. *See* DOE Workshop Report, *supra* note 7, at 8. *See also* Wyoming Pipeline Authority, *Wyoming Pipeline Corridor Initiative (WPCI)*, https://www.wyopipeline.com/projects/wpci/ (last visited Sept. 23, 2017).
171. *See* DOE Workshop Report, *supra* note 7, at 8 n.104; Great Plains Institute, *supra* note 19, at 19.
172. *See* DOE Workshop Report, *supra* note 7, at 9, 38.
173. *See generally* Anthony P. Raven et al., *Securing Rights-of-Way to CO_2 Pipeline Corridors in the United States*, 17 Pratt's Energy L. Rep. 42-43 (2017); Robert R. Nordhaus & Emily Pitlick, *Carbon Dioxide Pipeline Regulation*, 30 Energy L.J. 85, 93-94 (2009).
174. BLM has chosen to exercise this authority under the rights-of-way provision of the Mineral Leasing Act (MLA), 30 U.S.C. §185, rather than a similar provision in the Federal Land Policy and Management Act, 43 U.S.C. §1761(a)(2). *See* Exxon Corp. v. Lujan, 970 F.2d 757, 758, 23 ELR 20206 (10th Cir. 1992); Marston & Moore, *supra* note 169, at 454-56.
175. 49 U.S.C. §§60102(i) (regulation of carbon dioxide pipelines), 60102(a) (regulation of pipeline safety standards).
176. Cortez Pipeline Co., 46 Fed. Reg. 18805 (Mar. 26, 1981) (affirming ICC's tentative decision that carbon dioxide pipelines were not within its jursidiction).
177. ICC Termination Act of 1995, Pub. L. No. 104-88, §204, 109 Stat. 803.
178. Natural Gas Act, 15 U.S.C. §§717(b) (regulation of interstate natural gas pipelines), 717(c) (regulation of rates), 717f(e) (siting).
179. Cortez Pipeline Co., 7 F.E.R.C. ¶ 61024 (1979).
180. *Id.* at 61041-42. *See* also Southern Natural Gas, 115 F.E.R.C. ¶ 62266 (2006) (finding the transmission of carbon dioxide is an activity not subject to NGA or the jurisdiction of FERC).
181. *See* Parfomak & Folger, *supra* note 160, at 10.
182. *Id.*
183. *See* Interstate Oil and Gas Compact Commission, *supra* note 156, app. II, at 82-84.
184. Interstate Oil and Gas Compact Commission, *supra* note 156.
185. For instance, Texas defines all carbon dioxide pipelines as common carriers (Tex. Nat. Res. Code Ann. §111.002(6) (West 2015)), whereas Louisiana provides eminent domain authority to carbon dioxide pipelines transporting carbon dioxide for sequestration (La. Rev. Stat. Ann. §19:2(12) (West 2016)).
186. *See* Marston & Moore, *supra* note 169, at 456 ("In modern times, the term [common carrier] has been generally used to mean a business that

How carriers become common carriers, as opposed to private contract carriers, differs among states.[187] For example, in Texas, owners, operators, and managers of carbon dioxide pipelines are offered the option of becoming a common carrier.[188] If they choose common carrier status, they receive the power of eminent domain, which is not available to private contract carriers.[189] While a number of states provide eminent domain authority to facilitate the development of carbon dioxide pipelines, that authority is sometimes limited to the transportation of carbon dioxide to be used for EOR and thus not available for the development of pipelines intended to carry carbon dioxide to CCS sequestration sites.[190] For example, the power of eminent domain granted to pipeline developers under Mississippi law is limited to "use in connection with secondary or tertiary recovery projects located within the state of Mississippi for the enhanced recovery of liquid or gaseous hydrocarbons."[191]

Since most existing carbon dioxide pipelines operate on a contractual basis for a specific function, such as transporting to EOR sites, the attention to rate regulation has been limited.[192] There are, however, some states that regulate rates. For example, in Texas, once a carbon dioxide pipeline owner-operator has chosen common carrier status, the Texas Railroad Commission regulates the rates.[193] In other states, including New Mexico, carbon dioxide pipelines are not subject to rate regulation.[194]

2. Layers of Uncertainty Pose Challenges to the Development of a New Regulatory Framework for Carbon Dioxide Pipelines

Given uncertainties in the locations of future facilities equipped with carbon dioxide capture, the proximity of sequestration sites or EOR operations to those facilities, and the degree to which those facilities may be clustered together, it is unclear whether the carbon dioxide pipeline network should be local, regional, or national in scale. A local network could be established to connect point sources to nearby sequestration sites, whereas regional or national networks would transport carbon dioxide from point sources longer distances and across state boundaries to a smaller number of sequestration sites. A variety of approaches are viable. Studies have found that most major sources of carbon dioxide emissions sit above or close to potential sequestration sites[195] that might, at least in the early stages of the network development, favor a local network of carbon dioxide pipelines with shorter and less-expensive pipelines.

When deployment of CCS becomes more widespread, however, pipelines' significant economies of scale[196] would favor a centralized CCS pipeline scheme. Depending on the outcome of additional studies, another factor that may ultimately favor a centralized carbon dioxide pipeline system would be preferential sequestration in basalt formations. As explained more fully in Part IV, two recent studies documented nearly complete mineralization of injected carbon dioxide within several years, versus more common estimates on the order of hundreds to thousands of years.[197]

One challenge to a centralized scheme is the sheer volume of carbon dioxide that would need to be sequestered from a single, large, coal-fired power plant. Specifically, wide-diameter pipelines commonly used in the U.S. natural gas network[198] would only have sufficient capacity to transport the carbon dioxide captured from five to 10 large coal-fired power plants.[199] Consequently, even a "centralized" carbon dioxide pipeline network could still require the construction of hundreds of wide-diameter pipelines.

In the case of a national or regional carbon dioxide pipeline network, many of the pipelines cross state borders, which raises questions about the role of the federal government and whether pipeline developers should have

is required to serve all customers to the extent of its capacity at reasonable rates.").

187. *Id.* ("CO_2 pipelines *are* subject to considerable oversight at the state level and may be common carriers in some jurisdictions but private contract carriers in others.").

188. Tex. Nat. Res. Code Ann. §111.002(6) (West 2015).

189. *Id.* §111.019(a).

190. *See supra* note 183 and accompanying text.

191. Miss. Code §11-27-47 (2013).

192. Nordhaus & Pitlick, *supra* note 173, at 99.

193. Tex. Nat. Res. Code Ann. §111.181 (West 2015) ("The commission shall establish and promulgate rates of charges for gathering, transporting, loading, and delivering crude petroleum by common carriers in this state and for use of storage facilities necessarily incident to this transportation.").

194. N.M. Stat. Ann. §70-3-1.

195. For instance, James Dooley et al. estimated that 77% of major point sources sit above potential reservoirs for sequestered carbon dioxide and another 20% are within 100 miles of a potential sequestration site. Dooley et al., *supra* note 4, at 597-98. Another study estimated that of the 500 largest carbon dioxide sources in the United States, 95% are within 50 miles of a possible storage site. Interagency Task Force on Carbon Capture and Storage, Report of the Interagency Task Force on Carbon Capture and Storage 7 (2010), *available at* https://energy.gov/sites/prod/files/2013/04/f0/CCSTaskForceReport2010_0.pdf. *See* Katzer, *supra* note 4, at 43-62.

196. *See* Katzer, *supra* note 4, at 58 ("Transport costs can be lowered through the development of pipeline networks as opposed to dedicated pipes between a given source and sink."). *See also* Sean T. McCoy & Edward S. Rubin, *An Engineering-Economic Model of Pipeline Transport of CO_2 With Application to Carbon Capture and Storage*, 2 Int'l J. Greenhouse Gas Control 219, 226 (2008) (The authors conclude that "levelized transport cost increases with distance and decreases with increasing design capacity for a fixed distance." A network of pipelines collecting carbon dioxide from several different plants will increase the design capacity and thus lower levelized transport cost for a fixed distance.) *See generally* Nordhaus & Pitlick, *supra* note 173, at 99 (noting that "[p]olicies aimed at avoiding duplication of facilities and capturing economics of scale may impel Congress or the states to impose nondiscriminatory access requirements").

197. Juerg M. Matter et al., *Rapid Carbon Mineralization for Permanent Disposal of Anthropogenic Carbon Dioxide Emissions*, 352 Science 1312, 1312 (2016); B. Peter McGrail et al., *Field Validation of Supercritical CO_2 Reactivity With Basalts*, 4 Envtl. Sci. & Tech. Letters 6-10 (2016). Basalt formations are unevenly distributed across the United States, occurring in pockets mainly in the Southeast, eastern Midwest, and Northwest. Thus, sequestering carbon dioxide only in basalt formations would require new pipeline capacity.

198. Such pipelines have diameters of 16-48 inches. *See* Argonne National Laboratory, Natural Gas Pipeline Technology Overview 3 (2007).

199. Based on Sean McCoy & Rubin, *supra* note 196, at 223 fig. 3, who found a 16-inch diameter pipeline could carry the carbon dioxide from an 800-MW power plant. Thus, a 42-inch diameter pipeline could carry the carbon dioxide from roughly five to 10 plants of 600 to 800 MW in size.

access to federal eminent domain to facilitate construction of new pipelines, as is provided to carbon dioxide pipelines that cross federal lands under the Mineral Leasing Act.[200] Because STB and FERC have disclaimed jurisdiction over interstate carbon dioxide pipelines, operators of interstate carbon dioxide pipelines that do not cross federal lands are at present not subject to nondiscriminatory access requirements, and rates charged by carbon dioxide pipelines are not regulated by the federal government.[201]

Although states may be in the best position to make decisions about pipeline siting, the urgent need to accelerate deployment of CCS in order to protect public health and the environment would justify a greater federal—or at least regional—role, including access to federal eminent domain to support development of pipelines that would carry carbon dioxide from multiple power plants and other industrial sources of carbon dioxide to sequestration sites that could serve multiple sources of carbon dioxide.[202] The regulatory framework for natural gas pipelines offers one useful model because it confers upon FERC authority for pipeline siting, provides pipeline developers with access to federal eminent domain,[203] and addresses common carrier issues such as transportation rates and nondiscriminatory access.[204] The model is useful, too, because there are a number of technical and other similarities between natural gas and carbon dioxide pipelines,[205] and the two types of pipelines raise similar concerns in terms of siting issues and environmental impacts.[206]

However, economic issues and financing options are different for carbon dioxide pipelines than for natural gas pipelines, which may require different regulatory approaches.[207] Carbon dioxide pipelines will serve far fewer customers (large sources of captured carbon dioxide) and deliver the gas to far fewer end points than does the natural gas pipeline system.[208] The carbon dioxide pipelines are thus likely to be a "wholesale-oriented" business, compared to the "many-to-many" network of natural gas pipelines.[209]

D. *Regulatory Flexibility Should Be Maintained in the Near Term*

In light of the above discussion, a flexible regulatory scheme for carbon dioxide pipelines is best in the near term.[210] While a federal siting and permitting scheme for interstate carbon dioxide pipelines could be developed under the jurisdiction of FERC, similar to that for natural gas pipelines, the framework could provide interstate pipeline developers an opt-out option by which they would instead undergo a multistate process.[211] The scheme could furthermore allow FERC to address challenges regarding planning and siting of interstate carbon dioxide pipelines, and facilitate the integration of new carbon dioxide pipelines into the existing carbon dioxide pipeline network, similar to FERC's recent efforts to integrate renewable energy generation resources into the U.S. electric system.[212] As the carbon dioxide pipeline network expands in the United States, regulations governing the network will need to be revisited.

IV. Legal Reforms Needed to Facilitate Sequestration of Captured Carbon Dioxide

Millions of tons of carbon dioxide have been successfully stored in a variety of geological formations for many decades.[213] DOE estimates that national carbon dioxide sequestration capacity could range from 2,600 to 22,000 billion metric tons.[214] By comparison, and as previously explained, to achieve the DDPP Mixed and High CCS

200. 30 U.S.C. §181; *see* Nordhaus & Pitlick, *supra* note 173, at 101.
201. By contrast, after receiving a permit from BLM to cross federal land under the MLA, a pipeline must operate as a common carrier and provide nondiscriminatory access to anyone requesting its service. *See* Nordhaus & Pitlick, *supra* note 173, at 99.
202. *See* Jonas J. Monast et al., *A Cooperative Federalism Framework for CCS Regulation*, 7 Envtl. & Energy L. & Pol'y J. 1, 26 (2012); CCSReg Project, Carnegie Mellon University, Policy Brief: Regulating Carbon Dioxide Pipelines for the Purpose of Transporting Carbon Dioxide to Geologic Sequestration Sites 5 (2009); Jonas Monast, From Carbon Capture to Storage: Designing an Effective Regulatory Structure for CO_2 Pipelines 15 (2008); Interagency Task Force on Carbon Capture and Storage, *supra* note 195, apps. M1-M3.
203. *See* Monast, *supra* note 202, at 15.
204. *See* Nordhaus & Pitlick, *supra* note 173, at 98-99.
205. *See* Parfomak & Folger, *supra* note 160, at 4.
206. *See* ICF International, Developing a Pipeline Infrastructure for CO_2 Capture and Storage: Issues and Challenges 94 (2009).
207. *See* Interstate Oil and Gas Compact Commission, *supra* note 156, at 54-57.
208. *Id*. at 35 (noting many pipelines serve only the owner's end use and do not transport for third parties at this time).
209. *Id*.
210. *See* CCSReg Project, *supra* note 202, at 5-6; Joel Mack & Buck Endemann, *Making Carbon Dioxide Sequestration Feasible: Toward Federal Regulation of CO_2 Sequestration Pipelines*, 38 Energy Pol'y 735-43 (2010).
211. *See* CCSReg Project, *supra* note 202, at 5-6.
212. *See, e.g.*, FERC Order No. 764, which removes barriers to the integration of variable energy resources by requiring public utility transmission providers to offer increased flexibility in transmission scheduling (Integration of Variable Energy Resources, F.E.R.C. Stats. & Regs. ¶ 31331, 77 Fed. Reg. 41482 (July 13, 2012)), and FERC Order No. 1000, which is intended to improve coordination across regional transmission planning processes and methods for allocating the cost of new transmission facilities (Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, F.E.R.C. Stats. & Regs. ¶ 31323, 76 Fed. Reg. 49842 (Aug. 11, 2011)).
213. Facilities at the Sleipner gas field in Norway are presently capturing and storing one million tons of carbon dioxide per year in a deep saline aquifer formation overlain by caprock beneath the sea floor. Zero Emission Resource Organisation, *Sleipner West*, http://www.zeroco2.no/projects/sleipner-west (last visited Sept. 23, 2017). Operational since October 2007, the Snøhvit field in the Barents Sea had stored nearly two million tons of carbon dioxide by 2013 in Tubåen formation—a geological layer of porous sandstone. Statoil, *Snøhvit*, https://www.statoil.com/en/what-we-do/norwegian-continental-shelf-platforms/snohvit.html (last visited Sept. 23, 2017). Additionally, ADM is presently capturing and storing one million tons of carbon dioxide in Mount Simon sandstone. Global CCS Institute, *Projects Database—Illinois Industrial Carbon Capture and Storage*, https://www.globalccsinstitute.com/projects/illinois-industrial-carbon-capture-and-storage-project (last updated June 20, 2017). The Boundary Dam coal-fired power plant equipped with CCS in Canada has sequestered more than 750,000 tons of carbon dioxide via EOR. *Boundary Dam Fact Sheet*, *supra* note 80.
214. This range equals the sum of carbon dioxide storage resource estimates for oil and natural gas reservoirs, unmineable coal, and saline formations. NETL, Carbon Storage Atlas 25-28 (5th ed. 2015).

Scenarios, the amount of carbon dioxide captured from coal and NGCC plants would be on the order of 0.5 to two billion metric tons per year.[215] Hence, the United States has ample geological storage capacity to accommodate centuries of CCS operations.

Significant long-term experience exists, and numerous studies of sequestration have been conducted. Nonetheless, theoretically, there remain several types of risks to human health and the environment from the injection and storage of carbon dioxide. It is this theoretical possibility that damages will become the responsibility of private entities that gives rise to long-term liability concerns that must be addressed and managed. Options include improved and expanded insurance, creation of federal and/or state trust funds, clear liability rules, federal and state assumption of long-term liability for early projects, transitioning abandoned oil and gas production reservoirs for geologic sequestration, and managing land use priorities. These and other options will be explored in this part.

A. Nature of Concerns About Long-Term Liability

Injected carbon dioxide remains mobile and able to escape from geologic formations until it becomes physically trapped or immobilized via dissolution or mineralization, which can take hundreds to thousands of years. Until that time, injected carbon dioxide can escape and harm humans and the environment, raising concerns about responsibility for long-term liability. Notably, two recent studies have demonstrated that carbon dioxide injected into basalt formations can mineralize in a matter of years, potentially mitigating long-term liability issues. Furthermore, the National Energy Technology Laboratory (NETL) has worked with industry to inject millions of tons of carbon dioxide for more than 10 years, demonstrating carbon dioxide can be injected safely and establishing best practices for injection.

Upon injection into a reservoir, carbon dioxide remains mobile and able to escape through fractures, wells, and other paths.[216] Eventually, the carbon dioxide will become physically trapped or immobilized through dissolution into water[217] or mineralization,[218] depending on the reservoir's hydrologic and geologic properties. In most reservoirs, the dominant long-term sink for sequestered carbon dioxide will be dissolution into water. Typical estimates for the time to dissolve or mineralize carbon dioxide are on the order of hundreds to thousands of years.[219]

Two recent studies have documented the first findings of rapid mineralization of sequestered carbon dioxide in basalt formations. One study documented nearly complete (>95%) mineralization of 230 tons of injected carbon dioxide in Iceland.[220] The second study, part of the NETL Regional Carbon Sequestration Partnerships (RCSPs),[221] similarly observed mineralization of injected carbon dioxide within two years in Washington State.[222] Notably, the basalt formation used in the second study is an older formation than that used in the first study, and older formations are more prevalent across the globe, including in the United States.[223]

Subsequent analyses will be necessary to confirm these findings, explore the potential for rapid mineralization in other basalt formations, and determine how the studies' findings translate to larger volumes of injected carbon dioxide. These and additional studies, depending on their results, may ultimately help support CCS in the United States because large basalt formations exist in key strategic locations.[224] For example, several of these basalt formations underlie federal lands,[225] which presents an important opportunity for the federal government to play a role in managing or assuming cost and risk associated with early CCS projects, as will be explained further below.

Until sequestered carbon dioxide dissolves or mineralizes, it poses several possible threats to human and environmental health. These are the potential for elevated ambient surface carbon dioxide concentrations, increased contaminant concentration in groundwater due to dissolved carbon dioxide, displacement of fluids (e.g., brine in saline aquifers) from carbon dioxide injection,[226] and management of the brine. Elevated surface fluxes and groundwater contamination can occur when carbon dioxide escapes from a sequestration reservoir through fractures or cracks in the surrounding geology, through the injection well itself, or through another well puncturing the reservoir.[227]

215. *See supra* note 159.
216. IPCC, *supra* note 164, at 242-43.
217. Mark G. Little & Robert B. Jackson, *Potential Impacts of Leakage From Deep CO_2 Geosequestration Overlying Freshwater Aquifers*, 44 Envtl. Sci. & Tech. 9225, 9225 (2010) (noting that the bulk of carbon dioxide sequestered in a properly chosen saline aquifer is unlikely to escape because of solubility trapping); Stuart M.V. Gilfillan et al., *Solubility Trapping in Formation Water as Dominant CO_2 Sink in Natural Gas Fields*, 458 Nature 614, 614 (2009) ("Within a geological storage site, carbon dioxide injected as a free carbon dioxide phase . . . may over time be dissolved in solution (solubility trapping), or locked within carbonate minerals by precipitation (mineral trapping).").
218. IPCC, *supra* note 164, at 222 ("There are multiple mechanisms for storage, including physical trapping beneath low permeability caprock, dissolution and mineralization.").
219. *Id.* at 209 (noting that mineral trapping dominates over thousands to millions of years).
220. Matter et al., *supra* note 197, at 1312. The carbon dioxide was injected in two phases—175 tons in the first phase and 55 tons in the second. Pure and mixed carbon dioxide streams were dissolved in water prior to injection. The mixed gas stream was roughly two parts carbon dioxide to one part hydrogen sulfide by weight. *Id.*
221. Big Sky Carbon Sequestration Partnership, *Basalt Pilot Project*, http://www.bigskyco2.org/research/geologic/basaltproject (last visited Sept. 23, 2017).
222. McGrail et al., *supra* note 197, at 6.
223. Bobby Magill, *Scientists Take Big Step Toward Safely Burying CO_2*, Climate Cent., Nov. 18, 2016, http://www.climatecentral.org/news/scientists-take-big-step-toward-safely-burying-co2-20896.
224. NETL, Carbon Storage Atlas, *supra* note 214, at 29 (containing a high-level assessment of the geological storage capacity in the United States).
225. For instance, basalt formations underlie U.S. Forest Service lands in central Washington, northern California, central Idaho, and southern Georgia. U.S. Geological Survey, *Federal Lands and Indian Reservations*, http://nationalmap.gov/small_scale/printable/fedlands.html (last updated Feb. 6, 2017); NETL, Carbon Storage Atlas, *supra* note 214, at 29.
226. IPCC, *supra* note 164, at 242.
227. More specifically, carbon dioxide can escape through a wellbore after injection is complete due to a degraded or improperly set cement plug, or through the annulus (i.e., space between the well and surrounding geology), during or after injection.

Even in geologic formations initially without escape paths for injected carbon dioxide, injected carbon dioxide may induce low-magnitude seismic events that could allow carbon dioxide to escape.[228] Debate surrounds whether such induced seismicity could affect long-term sequestration of carbon dioxide.[229] Careful site selection should mitigate risk of induced seismicity.[230] Carbon dioxide can also have environmental impacts without escaping, such as by displacing preexisting fluids or gases within the reservoir (e.g., brine in saline aquifers).[231]

Historically, contamination of groundwater by displaced brines in analogous scenarios has been rare.[232] Nonetheless, in order for project developers, operators, and financing entities to be willing to move forward with CCS projects, it is important to address this perceived potential liability for permanent sequestration of captured carbon dioxide through law or contract.[233] At present, neither the existing legal framework nor the insurance industry adequately addresses—or allocates—these long-term liability issues.

Surface carbon dioxide fluxes and groundwater contamination or displacement could result in personal injury, property damage, and/or natural resource damage for which a company could be held liable under theories such as trespass, negligence, nuisance, or breach of contract. These potential liabilities could persist for the decades to centuries that it would take for the carbon dioxide to mineralize or dissolve. As such, industry has expressed concerns regarding the magnitude and longevity of the liability it could potentially incur.[234]

Notably, however, NETL has worked with industry to inject more than 10 million tons of carbon dioxide into a variety of geologic formations in the United States since 2006. To date, no carbon dioxide releases have been detected.[235] But several challenges to sequestration were identified, including significant storage potential heterogeneity among storage sites despite similar geology,[236] lower than expected storage potential at several sites,[237] and, importantly, the lack of a legal framework for dealing with long-term liability issues.[238] Based on these experiences, NETL has developed CCS-related best practices manuals to guide future CCS activity in the United States.[239] These efforts help demonstrate that carbon dioxide can be safely injected and effectively sequestered in the years immediately following injection. They do not, however, eliminate risk completely, and hence they do not eliminate concerns about long-term liability.

B. *Ownership of Pore Space*

Ownership of property is typically a matter of state law. Ownership rights to the subsurface vary from state to state. This can complicate negotiations for access to property to create sequestration facilities; it can also create potential trespass liability because the migration of the injected carbon dioxide does not respect property boundaries and may not always be accurately predicted by modeling.[240]

One option, albeit a controversial one, for addressing these concerns is for Congress to federalize ownership of the deep pore space.[241] Another option is for states to provide certainty via legislation. Some states have done this.[242]

A third option is for Congress to study and consider creating a comprehensive regulatory framework for offshore sequestration of captured carbon dioxide. This option is briefly discussed below at Part IV.C.6.

C. *Options for Managing Long-Term Liability and Costs of Geological Sequestration*

Here, we propose six potential strategies for dealing with the long-term liability challenges posed by sequestered carbon dioxide that could be used separately or together. In the first option, to jumpstart the sequestration industry, the federal government (Congress, DOI's BLM, and DOE) would establish several sequestration sites and assume some

228. Mark D. Zoback & Steven M. Gorelick, *Earthquake Triggering and Large-Scale Geologic Storage of Carbon Dioxide*, 109 Proc. Nat'l Acad. Sci. 10165 (2012) (notably, such low-magnitude earthquakes are likely too small to cause property damage or human harm).

229. Ruben Juanes et al., *No Geologic Evidence That Seismicity Causes Fault Leakage That Would Render Large-Scale Carbon Capture and Storage Unsuccessful*, 109 Proc. Nat'l Acad. Sci. E3623 (2012).

230. *See* Zoback & Gorelick, *supra* note 228, at 10165-67.

231. IPCC, *supra* note 164, at 242.

232. *Id*. at 248.

233. Liability concerns were the dominant topic at the June 2010 CCS workshop convened in Washington, D.C., by Wendy Jacobs, director of Harvard Law School's Emmett Environmental Law and Policy Clinic. Three of the five proposals discussed at the workshop dealt with (1) limits on liability for CCS projects; (2) mechanisms to limit liability; and (3) the role of states in managing liability. Discussions "highlighted the lack of consensus among experts on this issue" and a summary of the various viewpoints on the liability proposals was compiled. *See* Wendy B. Jacobs, Harvard Law School, Expert Workshop Addressing CCS Liability, Oversight, and Trust Fund Issues: Summary Report 3-7, 11, app. B (2010) [hereinafter Jacobs Summary Report]; Wendy B. Jacobs & Debra Stump, Emmett Environmental Law and Policy Clinic, Proposed Liability Framework for Geological Sequestration of Carbon Dioxide 1-2 (2010) (generally discussing uncertainty regarding liability as a barrier to CCS).

234. Craig A. Hart, Advancing Carbon Sequestration Research in an Uncertain Legal and Regulatory Environment 11-13 (Harvard Kennedy School, Discussion Paper No. 2009-01, 2009).

235. Personal Communication With Traci Rodosta, Carbon Storage Program Technology Manager, NETL (July 27, 2016).

236. Traci Rodosta et al., *U.S. Department of Energy's Regional Carbon Sequestration Partnership Initiative: Update on Validation and Development Phases*, 4 Energy Procedia 3457, 3460 (2011).

237. Several projects did not meet their carbon dioxide injection targets for various reasons. For instance, at an enhanced coal bed methane injection test in the San Juan Basin, New Mexico, sequestered carbon dioxide equaled roughly one-fourth of that originally proposed due to greater than expected coal swelling. *See* Southwest Carbon Partnership, *Phase II—Validation*, https://www.southwestcarbonpartnership.org/phase-ii/ (last visited Sept. 23, 2017); Rodosta et al., *supra* note 236, at 3462.

238. Hart, *supra* note 234, at 12-13.

239. NETL, *Best Practices Manuals*, http://www.netl.doe.gov/research/coal/carbon-storage/strategic-program-support/best-practices (last visited Sept. 23, 2017).

240. *See* Tara K. Righetti, *Correlative Rights and Limited Common Property in the Pore Space: A Response to the Challenge of Subsurface Trespass in Carbon Capture and Sequestration*, 47 ELR 10420 (May 2017).

241. Wendy B. Jacobs, *Carbon Capture and Sequestration*, *in* Global Climate Change and U.S. Law 598-600 (Michael B. Gerrard & Jody Freeman eds., ABA 2014).

242. DOE Workshop Report, *supra* note 7, at n.114.

of the long-term liability, allaying risks and costs of sequestration. Option two entails the establishment of a liability trust fund run by the government and funded via fees on sequestered carbon dioxide. In option three, EPA would allow sequestration of carbon dioxide in depleted oil and gas reservoirs, which provide a lower-cost option than sequestering in new sites. Fourth, EPA and state governments could shorten the time frame for which companies are liable for sequestered carbon dioxide. Fifth, BLM could encourage sequestration on lands it manages through prioritizing sequestration over other land uses. Finally, Congress could create a comprehensive regulatory framework for off-shore carbon dioxide sequestration to help reduce liability costs and local opposition.

1. Congress Can Authorize DOI and DOE to Own and Control Several Sequestration Sites

One option is for DOE and BLM, using information and experience developed through DOE's regional partnerships, to designate several locations on federal land for sequestration, and retain some of the long-term responsibility. In so doing, the federal government could incentivize initial CCS deployment by mitigating cost and risk associated with the sequestration part of CCS while also jumpstarting the sequestration industry through initial investment and experience.

The locations would be chosen to be proximate to new and existing NGCC plants, coal-fired plants, and other major emitters of carbon dioxide. Efficiencies of scale and better management of cost may be achieved by creating centralized sequestration sites that could be used by multiple industrial enterprises. Given the small well pad size (less than one acre) and minimal equipment at sequestration sites, other noninvasive surface activities near these sites would not be impeded.

Such centralized locations exist and can be identified by comparing the locales of large carbon dioxide point sources, NETL's atlas of suitable geologic formations,[243] and federal lands.[244] This comparison indicates that such locations exist in eastern West Virginia, northwest Pennsylvania, southern Illinois,[245] east Texas, and southern California.[246] If federal land is not available and suitable private land is not for sale, then, given the importance of establishing CCS in the United States and its benefits to all U.S. citizens and residents, this could be an appropriate use of strategic federal condemnation authority.

To incentivize early movers, BLM and DOE could take several important actions for which they already have legislative authority. BLM could make federal property available at a low lease price for sequestration; DOE could purchase or condemn additional property for sequestration; and BLM could prioritize sequestration over other invasive, surficial activities and other subsurface uses of federal property, namely mining, oil and gas drilling, and geothermal operations. With legislative reform, DOE or BLM (or another federal agency) could be empowered to retain some or all of the long-term liability. And, these agencies could also enter into public-private partnerships for development of the necessary pipeline infrastructure to connect the plants to the sequestration sites. A package of this type of subsidy could help drive integrated CCS projects forward.

2. Congress Can Create a Liability Trust Fund

Another option is for Congress to require emitters and storers of carbon dioxide to pay a fee to fund a liability program in exchange for certain limits on their potential liability for damages resulting from sequestration.[247] For example, each carbon dioxide sequestration well operator would pay into the trust fund, and money in the fund would be used to mitigate future potential liability in two ways. First, the trust fund would be implemented in conjunction with a liability cap, and liability payments above the cap would be paid for by the fund. This would mitigate uncertainty about the magnitude of potential liability from carbon dioxide sequestration (e.g., from catastrophic events).

Second, the trust fund could be used to pay for long-term stewardship of sequestration wells and post-closure liability claims that arise *after* the well owner-operator has completed post-injection activities and a period of post-injection monitoring (together with associated maintenance and repairs of the wells and any corrective action).[248] This would shorten the duration of a corporation's liability, while ensuring any unforeseen damages or well maintenance operations could be paid for.

One of the primary challenges associated with such a trust fund is ensuring that payments by injection well operators cover disbursements for damages and post-closure well care. The many uncertainties regarding sequestration including the location of sequestration sites, the timing of mineralization (faster if in basalt formations) or dissolution of the sequestered carbon dioxide, and the potential of leaks in the distant future, all make estimating

243. NETL, Carbon Storage Atlas, *supra* note 214, app. A, at 106-07.
244. *See supra* note 225. Including coal-fired and NGCC electricity generators, refineries, and ethanol producers.
245. In November 2016, DOE provided nearly $9 million to the University of Illinois to "establish the feasibility of a commercial-scale CO_2 geologic storage complex" in Macon County, Illinois. *See* Press Release, DOE Office of the Under Secretary for Science and Energy, Energy Department Announces More Than $44 Million for CO_2 Storage Projects (Nov. 30, 2016), http://energy.gov/under-secretary-science-and-energy/articles/energy-department-announces-more-44-million-co2-storage.
246. Unlike the other potential sites, southern California sequestration would occur offshore on the federal Outer Continental Shelf.
247. Jacobs Summary Report, *supra* note 233, at 5-7 (noting that various industry participants have expressed support for such a fund).
248. This time frame balances the need to encourage investment in carbon dioxide sequestration with discouraging poor sequestration practices that result in early carbon dioxide releases (e.g., within several years of injection operations due to inadequate well cementing). This time frame should be revised if early experience indicates 10 years is not sufficient to determine whether carbon dioxide has been effectively sequestered. Similar trust fund systems are in place for hazardous waste disposal facilities under the hazardous waste regulations of RCRA, *see* 40 C.F.R. §264.143 (2016), and for the restoration of mine lands under the Surface Mining Control and Reclamation Act of 1977, *see* 30 U.S.C. §1231.

the costs for long-term stewardship and liability unpredictable at present. Experience will, however, facilitate better and more reliable cost estimates. Thus, periodic reviews of the fund should be conducted, and industry fees should be reassessed as more experience with carbon dioxide sequestration is obtained.

3. EPA Can Authorize Expanded Use of Existing Oil and Gas Reservoirs for Sequestration

A third option would involve EPA allowing the repurposing of existing but depleted oil and gas reservoirs to reduce costs associated with development of sequestration facilities. Oil and gas reservoirs could store roughly 180 to 230 billion metric tons of carbon dioxide in the United States,[249] enough to store captured carbon dioxide from CCS-equipped coal and NGCC plants in the DDPP Mixed and High CCS Scenarios for 100 years or more.[250] Specifically, the existing federal regulatory framework for geologic sequestration wells could be expanded to authorize the transitioning of certain abandoned oil and gas production operations from production to sequestration.[251] Depleted oil and gas reservoirs are considered attractive repositories for geologic sequestration of carbon dioxide, as they previously trapped oil or gas for millennia and therefore are expected to retain sequestered carbon dioxide for long periods of time when and if abandoned production wells have been properly plugged.[252]

EPA has taken a step in this direction by regulating and clarifying the use of EOR wells for sequestration.[253] Wells used for the injection and sequestration of carbon dioxide are presently regulated by EPA under the UIC program. Specifically, two classes of wells under the UIC program pertain to sequestration of carbon dioxide. Class II wells are designed for oil and gas injection operations including injection of carbon dioxide for EOR.[254] Class VI wells are designed for geologic sequestration of carbon dioxide.[255]

The UIC program was established by the Safe Drinking Water Act (SDWA)[256] to protect public drinking water supplies. In general, the UIC program lays out requirements for injection operations, post-injection site care, liability, and monitoring during and after injection. Key provisions of the UIC program require pre-injection geologic surveys to identify potential fractures or preexisting wells that penetrate the reservoir[257]; a demonstration that the reservoir and preexisting wells can withstand the proposed injection operations[258]; furnishing of certain financial instruments to cover corrective actions, plugging the carbon dioxide injection well once operations cease, and post-injection care until government officials determine the site can be closed[259]; compliance with specified injection well construction protocols[260]; and monitoring of injection operations, the surrounding geology and water resources, and the carbon dioxide plume during and after injection.[261]

Wells that sequester carbon dioxide must also comply with GHG reporting requirements.[262] Class VI wells must report all carbon dioxide masses from the point of reception to sequestration,[263] and must develop monitoring, reporting, and verification (MRV) plans to demonstrate that injected carbon dioxide remains underground.[264] Class II wells do not need to prepare MRV plans and must only report the mass of carbon dioxide received for injection unless the owner-operator wishes to receive credit for the sequestration activity under the NSPS and CPP. If so, they must meet the same monitoring and reporting requirements as Class VI wells.[265]

Wells installed to transition the operation from oil or gas production to geologic sequestration must demonstrate, under current UIC regulations, that there will be no jeopardy to drinking water wells and that there is adequate provision for well integrity monitoring.[266] All other Class VI requirements would apply to transitioning wells.[267] It is crucial to ensure that the review process for transitioning oil and gas operations from production to sequestration is rigorous. Oil and gas production and carbon dioxide injection wells for EOR are designed for different conditions and life-spans than are geologic sequestration wells. For instance, geologic sequestration wells must maintain

249. NETL, Carbon Storage Atlas, *supra* note 214, at 25.
250. This point assumes that annual captured carbon dioxide under the DDPP Mixed and High CCS Scenarios equal roughly 0.5 and two billion metric tons per year, respectively. *See supra* note 159.
251. Compare EPA efforts to regulate the transition of Class II operations to Class VI geologic sequestration wells, 40 C.F.R. §144.19 (2016). *See* Memorandum From Peter C. Grevatt, Director, Office of Ground Water and Drinking Water, U.S. EPA, to Regional Water Division Directors (Apr. 23, 2015) (Key Principles in EPA's Underground Injection Control Program Class VI Rule Related to Transition of Class II Enhanced Oil or Gas Recovery Wells to Class VI) (providing EPA's key principles in transitioning Class II to Class VI wells), https://www.epa.gov/sites/production/files/2015-07/documents/class2eorclass6memo_1.pdf.
252. NETL, Carbon Storage Atlas, *supra* note 214, at 13 (noting that in a depleted gas shale, the volume formerly containing natural gas may be available for carbon dioxide storage. Therefore, this is an area of active research and development by NETL on carbon storage methodologies.).
253. Memorandum From Peter C. Grevatt, *supra* note 251.
254. 40 C.F.R. §§146.21-.24 (2016) (specifying criteria and standards applicable to Class II wells) and *id.* §146.81(c) (2016) (regulating conversion of existing Class II wells to Class VI geologic sequestration wells); Memorandum From Peter C. Grevatt, *supra* note 251 (providing EPA's key principles in transitioning Class II to Class VI wells).
255. 40 C.F.R. §§146.81-.95 (2016) (specifying criteria and standards applicable to Class VI wells). *See id.* §146.81(c) (2016) (regulating conversion of existing Class I, Class II, or Class V experimental wells to Class VI geologic sequestration wells). Specific construction requirements for Class VI wells are provided at *id.* §146.86(b) (2016) and testing and logging requirements during construction at §146.87(a). Transitioning Class II wells do not have to meet requirements in either section.
256. 400 U.S.C. §§300f to 300j-26.
257. *Id.* §146.83 (2016) (specifying minimum criteria for siting Class VI wells).
258. *Id.*
259. *Id.* §146.85 (2016).
260. *Id.* §146.86 (2016).
261. *Id.* §146.87-90 (2016) and *id.* §146.93 (2016).
262. *Id.* §98.440-449 (2016) for Class VI wells and *id.* §98.470-478 (2016) for Class II wells.
263. For example, the mass of carbon dioxide received, injected underground, and lost due to leaks or venting must all be reported (*id.* §98.442 (2016)).
264. *Id.* §98.448 (2016). MRV plans must include plans for determining and monitoring surface carbon dioxide leaks, identifying potential leakage pathways, and other measures.
265. *Id.* §98.442-448 (2016). CPP provision: *id.* §60.5860(f)(1)-(2); NSPS provision: *id.* §60.5555(f)(1)-(2).
266. As listed at *id.* §146.86(a) (2016).
267. *Id.* §146.81(c) (2016).

their integrity for hundreds to thousands of years and must withstand possible corrosion from carbon dioxide once it mixes with water or other substances in the reservoir.[268]

4. EPA and State Governments Can Shorten the Period of Liability

EPA could shorten the time frame for which owners and operators of sequestration wells would be liable under the UIC program, provided that the scientific support for such relief is demonstrated on a site-specific basis. While the introduction of Class VI UIC regulation of sequestration wells provided much needed regulatory clarity regarding carbon dioxide sequestration wells, long-term liability still poses a significant challenge under the program. Currently, injection well owners and operators remain fully liable for any damages at the well until the UIC program director determines the site can be closed.[269] Under the UIC rules, this determination will be done on a well-by-well basis, but the expected time is roughly 50 years.[270]

The 50-year liability window under the UIC program is a long time to carry a potential liability on a company's books. Further shortening the time span for which a company is potentially liable for damages at a carbon dioxide sequestration site—based on site-specific scientific support—would further mitigate the dampening effect liability concerns have on CCS deployment, as would shifting some of the longer-term responsibility to the federal government. While this approach could potentially impose large future liabilities on the federal government, experience with carbon dioxide sequestration to date indicates that this liability is not likely.[271] Moreover, the time period after which liability transfers to the federal government can be periodically reviewed and adjusted based on data collected from ongoing sequestration projects in the United States.

Since 2007, several states have enacted legislation to limit private liability for sequestration of captured carbon dioxide.[272] In Louisiana, for instance, ownership of sequestered carbon dioxide is transferred to the state after 10 or more years,[273] at which point an industry-funded trust fund is used to pay for any maintenance or subsequent damages.[274] Louisiana also caps civil liability actions for noneconomic losses.[275] Similarly, North Dakota assumes ownership over stored carbon dioxide and the associated storage facility after issuing a certificate of project completion no less than 10 years after carbon dioxide injection ends.[276] North Dakota established a trust fund, funded by a fee on each ton of sequestered carbon dioxide, that pays for long-term monitoring and maintenance of transferred carbon dioxide.[277] Wyoming has also established an industry-financed trust fund for measurement, monitoring, and verification after site closure, but the state does not assume liability for sequestration sites.[278]

While such state efforts could spur CCS deployment, a uniform national approach to addressing long-term liability issues with sequestered carbon dioxide is necessary for widespread CCS deployment. In a state-by-state approach, state trust funds, such as in Wyoming, may only be paid into by a few CCS projects, which may not suffice to cover subsequent liabilities. A national approach would allow risk pooling over a broader pool of applicants. A national approach would also provide certainty and consistency for private actors. Unless and until there is a national push for CCS, state accommodations and efforts to spur CCS are needed.

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268. *See* U.S. EPA, Draft Underground Injection Control (UIC) Program Guidance on Transitioning Class II Wells to Class VI Wells 31-45 (2013) (EPA 816-P-13-004).
269. 40 C.F.R. §146.93 (2016).
270. *Id*.
271. RCSPs cover 43 U.S. states and four Canadian provinces, and comprise seven regional partnerships that aim to research and develop storage sites for captured carbon in their respective regions. The seven partnerships are the following: Big Sky Regional Carbon Sequestration Partnership (Big Sky), http://www.bigskyco2.org (covers Idaho, Montana, Oregon, South Dakota, eastern Washington, and Wyoming); Plains CO_2 Reduction (PCOR) Partnership, http://www.undeerc.org/pcor (covers nine U.S. states and four Canadian provinces); Midwest Geological Sequestration Consortium (MGSC), http://www.sequestration.org (covers Illinois, Indiana, and Kentucky); Midwest Regional Carbon Sequestration Partnership (MRCSP), http://www.mrcsp.org/ (covers Indiana, Kentucky, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, and West Virginia); Southeast Regional Carbon Sequestration Partnership (SECARB), http://www.secarbon.org (covers 13 states); Southwest Regional Partnership on Carbon Sequestration (SWP), http://www.southwestcarbonpartnership.org (covers Arizona, Colorado, Kansas, Nevada, New Mexico, Oklahoma, Texas, Utah, and Wyoming); and West Coast Regional Carbon Sequestration Partnership (WESTCARB), http://www.westcarb.org/ (covers Alaska, Arizona, California, Hawaii, Nevada, Oregon, Washington, and the province of British Columbia). For more information about RCSPs, see DOE, *Regional Partnerships*, http://energy.gov/fe/science-innovation/carbon-capture-and-storage-research/regional-partnerships (last visited Sept. 23, 2017). Phase I extended from 2003 to 2005; Phase II extended from 2005 to 2013. For more information, visit NETL, *Regional Carbon Sequestration Partnerships (RCSP) Initiative* [hereinafter *RCSP Initiative*], https://www.netl.doe.gov/research/coal/carbon-storage/carbon-storage-infrastructure/rcsp (last visited Sept. 23, 2017). In Phase II, more than one million metric tons were sequestered in basalt, unmineable coal seams, saline aquifers, and oil and gas reservoirs for EOR for up to five years, depending on the project. *Id*. Injection time frames ranged from less than one year (Gulf Coast Stacked Storage Project in SECARB) to more than five years (Zama field validation test in PCOR). *See* NETL, Southwest Regional Partnership for Carbon Sequestration—Validation Phase (2012) (NT42591-P2), *available at* https://www.southwestcarbonpartnership.org/download/the-swp/phase-ii/PhaseII_FS_SWP.pdf, and NETL, Plains CO_2 Reduction Partnership—Validation Phase (2012) (NT42592-P2), *available at* http://www.undeerc.org/pcor/newsandpubs/pdf/FS-NETL-PCOR-Partnership-Validation-Phase.pdf. Most projects injected carbon dioxide sometime between 2008 and 2010, although other projects, for example the Zama test in PCOR, injected carbon dioxide from 2006 through 2012. *See also supra* note 213 (discussing other ongoing carbon dioxide sequestration projects).
272. Holly Javedan, Regulation for Underground Storage of CO_2 Passed by U.S. States 4-5 (2011), https://sequestration.mit.edu/pdf/US_State_Regulations_Underground_CO2_Storage.pdf.
273. *See* La. Rev. Stat. Ann. §30:1109(A) (West 2016). Transfer of ownership occurs only once the storage operator demonstrates that "the reservoir is reasonably expected to retain mechanical integrity" and the carbon dioxide will remain sequestered. *Id*. Ownership also transfers only if sufficient monies are in the trust fund to pay for possible future liabilities and costs. *See id*.
274. *See id*. §30:1110(E) (West 2016).
275. *See id*. §30:1109(B) (West 2016).
276. *See* N.D. Cent. Code Ann. §38-22-17 (West 2016). To receive the certificate, the owner must demonstrate the carbon dioxide has become stable and will remain stored in the reservoir. *Id*. §38-22-17(5) (West 2016).
277. *See id*. §38-22-15 (West 2016).
278. *See* Wyo. Stat. Ann. §35-11-318 (West 2016).

5. BLM Can Prioritize Sequestration on Some Federal Lands

This option entails a reordering of land use priorities by BLM. While related to option one, this option does not entail the federal government establishing sequestration sites itself or assuming liability for sequestered carbon dioxide. Rather, this option enables carbon dioxide sequestration in the long term on federal lands. Existing statutes authorize BLM to allow geologic sequestration of carbon dioxide on public lands.[279] In authorizing land uses, BLM first prepares regional land use plans (resource management plans (RMPs)), then approves land use applications on a case-by-case basis to ensure conformance with that plan.[280]

There are several key points at which carbon sequestration on public lands can be facilitated: in the development of the RMP, in approval of individual land use applications, and in BLM guidance for approving geologic sequestration permits. This guidance could be revised. Currently, it requires proposed geologic sequestration activities to avoid interference with mineral (e.g., oil and gas) production or mineral resources.[281] To facilitate carbon dioxide transport and sequestration on these lands, this prohibition should be reversed to prioritize geologic sequestration over other, conflicting subsurface land uses. Notably, sequestration activities occupy a small (about one acre) surface area; therefore, they are unlikely to conflict with noninvasive surface land uses, such as grazing.

6. Congress Could Create a Regulatory Framework for Offshore Carbon Dioxide Sequestration

Although the bulk of this Article has focused on onshore sequestration, it should be noted that carbon dioxide could be sequestered offshore. Significant carbon dioxide storage potential may exist beneath the ocean floor: federal estimates suggest that offshore saline formations could account for up to 31% of the total U.S. storage resource.[282] Offshore sequestration offers the prospect of lower ultimate liability costs and perhaps less local opposition; however, the capital and operating costs are likely to be higher than for onshore sequestration.[283]

A fundamental obstacle to offshore sequestration is that no comprehensive federal regulatory framework for it exists. Developing such a framework would require attention to and coordination with an established body of international law, state and local laws, and a variety of federal laws and regulations pertaining to activities in the ocean that do not presently contemplate carbon dioxide sequestration.

D. Existing Insurers Can Expand Their Products and More Insurers Can Enter the Market

As yet, because CCS has not been widely deployed, few commercial insurance options exist for CCS during and after operations.[284] Zurich Financial Services Group, one of the early movers in the market, has developed two products specifically aimed at CCS project operators: CCS liability insurance and geological sequestration financial assurance.[285] Both products date back to 2009; the CCS insurance industry has not seen significant growth since that time. Significant issues with respect to insurance remain, such as large risk premiums, an insufficient pool to spread risk, and reluctance to underwrite projects given unknown future liabilities.[286]

VI. Conclusion

To achieve deep decarbonization of the United States for the DDPP's High CCS and Mixed Scenarios, widespread deployment of CCS on coal- and gas-fired power plants is necessary. This is particularly important as the mobile sector becomes electrified and other demands for electricity increase. CCS is a reliable and proven technology. Because it does increase the cost of producing electricity, a combi-

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279. *See* §302(b) of the Federal Land Policy and Management Act, 43 U.S.C. §1732(b). *See generally* U.S. Department of the Interior et al., Framework for Geological Carbon Sequestration on Public Land (2009) (report submitted to the Committee on Natural Resources of the U.S. House of Representatives and the Committee on Energy and Natural Resources of the Senate).

280. 43 C.F.R. §1610.5-3 (conformity and implementation); *see also* Instruction Memorandum From Assistant Director, Minerals and Realty Management, BLM, to All WO and Field Officials, BLM (Dec. 1, 2011) (Interim Guidance on Exploration and Site Characterization for Potential Carbon Dioxide Geologic Sequestration, No. 2012-035, expired Sept. 30, 2013).

281. Interim Guidance, supra note 280.

282. NETL, Carbon Storage Atlas, *supra* note 214, at 111. Based on "Total Storage Resource" in U.S. federal waters and in the entire United States under the "High Resource Estimate."

283. With regard to sequestration off the coast of the northeastern United States, some conclude that liability costs could decrease due to the assumed lower risk of harm to humans and property; they also recognize that sequestration costs will likely increase due to greater infrastructure needs, such as drilling and injection platforms. Romany M. Webb & Michael B. Gerrard, Sabin Center for Climate Change Law, Policy Readiness for Offshore Carbon Dioxide Storage in the Northeast 2 (2017).

284. Existing insurance policies such as "property, general liability, pollution liability, and surety" cover certain risks associated with CCS; however, insurers have developed few specific products designed to capture the risks associated with CCS operations. *See* Eliot Jamison & David Schlosberg, CalCEF Innovations, Insuring Innovation: Reducing the Cost of Performance Risk for Projects Employing Emerging Technology 14 (2011), http://docplayer.net/4590954-Insuring-innovation-reducing-the-cost-of-performance-risk-for-projects-employing-emerging-technology.html; *see also* Patrick Maguire, *Conquering Insurance Obstacles for Carbon Sequestration Technologies*, Power, Jan. 30, 2009 (discussing the emerging market in CCS insurance), http://www.powermag.com/conquering-insurance-obstacles-for-carbon-sequestration-technologies/; *see also* Cyril Tuohy, *Capturing the Carbon Market*, Risk & Ins., Oct. 15, 2009 (discussing the limitations of existing policies regarding the long-term risks of carbon capture), http://www.thefreelibrary.com/_/print/PrintArticle.aspx?id=211061545.

285. *See* Carbon Capture & Storage Association, *Zurich*, http://www.ccsassociation.org/about-us/our-members/zurich/ (last visited Sept. 23, 2017).

286. *See* Shell U.K. Ltd., Peterhead CCS Project 1 (2014); *see also* Alex Morales, *Shell Says Carbon Capture Projects Face Large Risk Premiums*, Bloomberg, June 11, 2015, http://www.bloomberg.com/news/articles/2015-06-11/shell-says-carbon-capture-projects-face-large-risk-premiums.

nation of carrots and sticks are needed to drive it forward. As explicated in this Article, these incentives can be offered by the federal and state governments.

While a national program would be most effective in providing uniformity and consistency, there are many ways in which states can band together to create markets for the purchase of electricity from plants equipped with CCS, offer financial incentives such as tax credits and other forms of tax relief, absorb some of the potential long-term liability for sequestration sites, and impose stricter standards on carbon dioxide emissions from fossil fuel-fired power plants. Finally, given the ever-increasing dominance of NGCC plants in the U.S. power sector, it is critical that legal reforms (carrots and sticks) incentivize near-term application of CCS to NGCC plants and, in addition, help develop and advance opportunities and technologies for using captured carbon dioxide, thereby reducing the need for pipeline build-out and sequestration facilities.