CARBON CAPTURE, UTILIZATION, AND SEQUESTRATION: Technology and Policy Status and Opportunities

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Executive Summary

In the 19th and 20th centuries, coal was the energy resource that drove the electrification of the modern world, and to this day remains a key source of fuel for generating electricity in the United States and worldwide. Domestically, rising concern over environmental degradation associated with coal plants and competition from abundant natural gas and renewable generation have challenged coal's dominance. From 2000 to 2017, more than 100 GW of U.S. coal-fired generation was retired, according to M.J. Bradley & Associates. Coal presently accounts for approximately 30 percent of overall electricity generation in the U.S., down from nearly 45 percent in 2009.

Recently, the coal industry has focused on making a case for the reliability benefits coal plants offer and the national security advantages of domestic coal production, as well as the importance of maintaining fuel diversity in the electric sector. However, coal still faces a multitude of policy, technological, and financial obstacles to its remaining an indispensable source of power in the 21st century.

Carbon capture, utilization, and storage (CCUS) technologies constitute an important opportunity for coal. Decades of public and private research, development, and demonstration (RD&D) have led to crucial breakthroughs in CCUS on coal-fired power plants. Although CCUS is confined to a handful of power plants and faces barriers to widespread adoption in the power sector, CCUS has shown promising results in industrial uses, and results from power sector applications have been encouraging. CCUS is an exciting technology area with the potential to deliver environmental benefits, improved reliability, and increased economic activity. These broad benefits have attracted support for CCUS from a wide range of stakeholders. With thoughtful policies at the federal, state, and local levels and continued investment in RD&D, the deployment of CCUS technology could be increased to improve the environmental performance of coal-fired power plants and other industrial processes. Such action could enable coal to deliver the benefits the industry cites while improving environmental performance—making coal a more robust clean energy competitor.

This paper examines the present state of CCUS and the challenges to widespread deployment in the energy sector. It explores the policy and technology environment for coal-fired power generation and CCUS for energy and industrial uses. It offers an array of actions policymakers and regulators can use to encourage CCUS adoption to extend the life of existing coal-fired power plants while drastically cutting carbon dioxide emissions, illuminating how the coal plant of the future could look.

This paper can be a resource for any stakeholder concerned with the intersection of energy and environmental issues related to coal, but focuses on the role state public utility commissions play in the future of CCUS technology. As economic regulators, state commissions must balance reliability, resilience, policy goals, and customer needs while maintaining fair prices for ratepayers. However, the energy sector is subject to a complex combination of regulatory bodies at all levels of government, and state commissions have limited authority in some key areas. Therefore, the paper also looks at federal and other state and local actions that could encourage CCUS adoption.

I. Historical Context

Coal has been generating electricity in the U.S. for over a century. Peaking at close to 50 percent of annual generation in the mid-2000s, by 2017, coal had fallen to supplying approximately 30 percent of total generation.[1] Coal use expanded rapidly in the 1970s and 1980s after the 1973 oil embargo. Reliance on an abundant domestic resource became much more attractive once the American public experienced petroleum shortages. The Power Plant and Industrial Fuel Use Act of 1978 restricted the use of natural gas for electricity generation by regulated utilities until its eventual repeal in 1987.[2] On a dollars per unit of energy basis, coal was substantially cheaper and more stable than petroleum or gas during the 1980s and 1990s.[3]

A. Regulation of coal-fired electricity, 1970–2018

Coal combustion produces a number of byproducts that are harmful to human health and the environment, mainly particulate matter (some of which contains mercury), sulfur dioxide, nitrogen oxides, and carbon dioxide (CO_2). Particulate matter can cause respiratory problems, heart and lung disease, and haze. Sulfur dioxide causes acid rain. Nitrogen oxides contribute to acid rain and ground-level ozone (smog), which causes respiratory problems. CO_2 has no immediate adverse effect on human health, but contributes to climate change by trapping heat in the earth's atmosphere. Coal-fired electricity generation produces nearly 70 percent of CO^2 emissions from the electric power sector.[4]

Pollution from coal plants has been regulated in two ways: through the Clean Air Act and through the use of targeted incentives to encourage generation from other sources.[5] In 1970, the Clean Air Act regulated emissions of particulates, sulfur dioxide, and nitrogen oxides by requiring the U.S. Environmental Protection Agency (EPA) to set national ambient air quality standards (NAAQS). Stationary (or point source) polluters are required to obtain state permits before emitting regulated pollutants into the air. State air quality regulators can dictate a precise emissions limitation to reflect currently available technology, ideally resulting in gradual pollution reductions over time as pollution control technology advances.[6] Congress originally exempted existing power plants from permitting requirements.

1 U.S. Energy Information Administration, "Electricity Explained: Electricity in the United States," April 20, 2018, https://www.eia.gov/energyexplained/index.php?page=electricity_in_the_united_states.

2 David Tuttle et al., "The Full Cost of Electricity (FCe-): The History and Evolution of the U.S. Electricity Industry," University of Texas at Austin Energy Institute, 2016, http://sites.utexas.edu/energyinstitute/files/2016/09/UTAustin_FCe_History_2016.pdf.

3 David Spence, "Coal-Fired Power in a Restructured Electricity Market," *Duke Environmental Law & Policy Forum* 15 No. 187 (Spring 2005): 187–220. https://scholarship.law.duke.edu/cgi/viewcontent.cgi?article=1100&context=delpf.

4 U.S. Energy Information Administration, "Where Greenhouse Gases Come From," July 20, 2018. https://www.eia.gov/energyexplained/index.php?page=environment_where_ghg_come_from.

5 Ibid.

6 Ibid.

After the passage of the Clean Air Act, partially due to the decision to grandfather existing plants, acid rain remained a persistent issue with adverse effects on vegetation and aquatic life. The 1990 amendments to the Clean Air Act created the Acid Rain Program, a national cap-and-trade program to target acid rain by controlling sulfur dioxide and nitrogen oxide emissions. The sulfur dioxide program set a national cap on total emissions by electric generators, then granted tradeable allowances to generators in a market-based effort to reduce pollution by the most cost-effective means. By 2016, the program had reduced sulfur dioxide emissions by approximately 91 percent from 1990 levels. Nitrogen oxide was controlled through more traditional rate-based regulation. The program reduced nitrogen oxide emissions by 81 percent from 1990 levels.[7] The Acid Rain Program is widely recognized as a successful application of market-based regulation to price an externality and let private actors respond accordingly.

Unlike particulate matter, sulfur dioxide, and nitrogen oxides, CO_2 emissions are not regulated by the federal government, although the 2007 Supreme Court decision in *Massachusetts v. EPA* ordered the EPA to regulate greenhouse gases including CO_2 as air pollutants under the Clean Air Act if the agency made a finding that greenhouse gases endanger public health or welfare.[8] In 2009, the EPA found that emissions of six greenhouse gases (CO_2, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride) from motor vehicles threatened public health and welfare.[9] The EPA cited this endangerment finding in the Clean Power Plan, proposed in June 2014. The proposal required substantial cuts to CO_2 emissions from existing electricity generators, aiming to reduce emissions by 30 percent below 2005 levels by 2030.[10] The proposal was predicted to force the retirement of 92 GW of coal-fired generation by 2030.[11] The Clean Power Plan was stayed by the Supreme Court in February 2016[12] and the EPA proposed to repeal it in October 2017.[13] The EPA proposed a new rule to address emissions from coal-fired power plants in July 2018.[14] As of the time of writing, the status of this rule is unknown.

Other regulations passed during the Obama administration targeted pollutants from coal plants, mainly the Mercury and Air Toxics Standard (MATS). MATS targeted coal- and oil-fired electricity emissions of heavy metals, sulfur dioxide, and fine particulate matter. Approximately 1,100 coal-fired units at 600 power plants had to comply with the rule. The total annual cost was estimated to reach $9.6 billion, with between $37 billion and $90 billion in annual benefits.[15] Bloomberg New Energy Finance estimated that 30 GW of coal-fired power would retire by 2020 due to MATS.[16] At the time of writing, the EPA was conducting a residual risk and technology review of the rule while leaving the standard in place. The future of the rule is uncertain.[17]

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7 U.S. Environmental Protection Agency, "Clean Air Markets: Acid Rain Program," https://www.epa.gov/airmarkets/acid-rain-program.

8 U.S. Department of Justice, "Massachusetts v. EPA," May 14, 2015, https://www.justice.gov/enrd/massachusetts-v-epa.

9 U.S. Environmental Protection Agency, "Greenhouse Gas Emissions: Endangerment and Cause or Contribute Findings for the Greenhouse Gases under the Section 202(a) of the Clean Air Act," https://www.epa.gov/ghgemissions/endangerment-and-cause-or-contribute-findings-greenhouse-gases-under-section-202a-clean.

10 "Regulation Database – Clean Power Plan," Columbia Law School, Sabin Center for Climate Change Law, http://columbiaclimatelaw.com/resources/climate-deregulation-tracker/database/clean-power-plan/.

11 Robert Rapier, "Premature Power Plant Retirements: Drivers and Responses," GE Power, April 12, 2018. https://www.ge.com/power/transform/article.transform.articles.2018.apr.premature-power-plant-retirements.

12 U.S. Supreme Court, "Order in Pending Case: Chamber of Commerce, et al. v. EPA, et al.," February 9, 2016, https://www.supremecourt.gov/orders/courtorders/020916zr3_hf5m.pdf.

13 U.S. Environmental Protection Agency, "Electric Utility Generating Units: Repealing the Clean Power Plan," https://www.epa.gov/stationary-sources-air-pollution/electric-utility-generating-units-repealing-clean-power-plan.

14 U.S. Environmental Protection Agency, "Proposal: Affordable Clean Energy (ACE) Rule," https://www.epa.gov/stationary-sources-air-pollution/proposal-affordable-clean-energy-ace-rule.

15 U.S. Environmental Protection Agency, "Fact Sheet: Mercury and Air Toxics Standards for Power Plants," https://www.epa.gov/sites/production/files/2015-11/documents/20111221matssummaryfs.pdf.

16 Meredith Annex, "Medium-Term Outlook for US Power: 2015 = Deepest De-Carbonization Ever," Bloomberg New Energy Finance, April 8, 2015, https://data.bloomberglp.com/bnef/sites/4/2015/04/BNEF_2015-02_AMER_US-Power-Fleet-De-Carbonisation-WP.pdf.

17 "Mercury and Air Toxics Standards (MATS)," Harvard School of Law, Harvard Environmental Law Program, 2018, http://environment.law.harvard.edu/2017/09/mercury-air-toxics-standards-mats/.

In 2016, the EPA finalized the Cross-State Air Pollution Rule (CSAPR), requiring a select number of states to reduce sulfur dioxide and nitrogen oxide emissions that were causing neighboring states to exceed ground-level ozone NAAQS. (Previously, states had been allowed to petition the EPA to address pollution from particular electricity generating units in neighboring states under section 126 of the Clean Air Act.) The new rule largely targeted Eastern and Midwestern states with coal-, gas-, or oil-fired electricity generation units.[18] The EPA estimated that by 2017, CSAPR would cost industry $68 million per year and reduce nitrogen oxide emissions by 20 percent compared to 2005 levels, leading to between $530 million and $880 million in annual benefits.[19] In April 2018, the EPA denied a petition from Connecticut requesting EPA regulation on a coal-fired power plant in Pennsylvania, signaling that the agency may reduce enforcement.[20]

In April 2015, the EPA published a final rule on the safe disposal of coal combustion residuals (CCRs), a byproduct of more than 400 coal-fired power plants. The rule established technical requirements for CCR landfills and surface storage under the Resource Conservation and Recovery Act (RCRA)[21] and included provisions to allow for the beneficial use of CCRs, such as in concrete or gypsum panel products.[22] The EPA estimated the total annualized costs of the rule at $509 billion to $735 billion and benefits at $236 billion to $294 billion using discount rates of 3 or 7 percent, respectively.[23] In July 2017, the EPA revised the 2015 rule to provide utilities and states with more flexibility in CCR management.[24]

B. Coal and competing generation sources

In the last three decades, coal has plateaued and then declined as a share of total electricity generation. Regulation and economics have contributed to this change. The "shale revolution" (the combination of hydraulic fracturing and horizontal drilling to produce natural gas from previously uneconomic shale rock) around 2008 resulted in a flood of cheap gas produced mainly in Texas, Louisiana, Oklahoma, North Dakota, Wyoming, Pennsylvania, Ohio, and West Virginia.[25] In addition to natural gas, coal faced competition from increasingly less expensive renewable generation. Federal funding for research and development and federal and state incentives such as the Production Tax Credit for solar, Investment Tax Credit for wind, and state renewable portfolio standards eventually contributed to economically competitive renewable generation. Beyond a difficult regulatory and economic environment, coal plants built in the 1970s and 1980s are simply aging out of the generation fleet.[26]

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18 U.S. Environmental Protection Agency, "States that are Affected by the Cross-State Air Pollution Rule (CSAPR)," https://www.epa.gov/csapr/states-are-affected-cross-state-air-pollution-rule-csapr.

19 U.S. Environmental Protection Agency, "Clean Air Markets: Final Cross-State Air Pollution Rule Update – Benefits Information and Maps," https://www.epa.gov/airmarkets/final-cross-state-air-pollution-rule-update-benefits-information-and-maps.

20 "Cross-State Air Pollution Rule and Section 126 Petitions," Harvard School of Law, Harvard Environmental Law Program, 2018, http://environment.law.harvard.edu/2018/07/cross-state-air-pollution-rule-section-126-petitions-information/.

21 U.S. Environmental Protection Agency, "Disposal of Coal Combustion Residuals from Electric Utilities," https://www.epa.gov/coalash/coal-ash-rule.

22 U.S. Environmental Protection Agency, "Coal Ash Reuse," https://www.epa.gov/coalash/coal-ash-reuse.

23 U.S. Environmental Protection Agency, "Final Rule: Hazardous and Solid Waste Management Systems: Disposal of Coal Combustion Residuals from Electric Utilities," 40 CFR Parts 257 and 261, April 17, 2015, https://www.regulations.gov/document?D=EPA-HQ-RCRA-2009-0640-11970.

24 U.S. Environmental Protection Agency, "EPA Finalizes First Amendments to the Coal Ash Disposal Regulations Providing Flexibilities for States and $30M in Annual Cost Savings," July 18, 2018, https://www.epa.gov/newsreleases/epa-finalizes-first-amendments-coal-ash-disposal-regulations-providing-flexibilities.

25 "The U.S. Shale Revolution," The University of Texas at Austin, https://www.strausscenter.org/energy-and-security/the-u-s-shale-revolution.html.

26 Meredith Annex, "Medium-Term Outlook for US Power: 2015 = Deepest De-Carbonization Ever," Bloomberg New Energy Finance, April 8, 2015, https://data.bloomberglp.com/bnef/sites/4/2015/04/BNEF_2015-02_AMER_US-Power-Fleet-De-Carbonisation-WP.pdf.

Coal-fired power continues to face a difficult economic outlook at present. Demand for electricity fell to below one percent annual growth from 2000 to 2008, and essentially flat for the past ten years.[27] No new coal plants are under construction, and the majority of new generation build is divided between renewables (wind and solar PV) and natural gas.[28] As renewables produce a greater share of electricity, they make the generation fleet more intermittent, thereby creating an incentive for flexible generation that can quickly ramp up and down to match wind- and solar-driven output. Whereas natural gas generation can exhibit this quality, coal plants have a harder time doing so and face higher costs. In North Dakota, where intermittent wind now supplies a quarter of electricity demand,[29] Coal Creek Station estimated that rapid ramping was imposing an additional $3 million in annual operating costs.

Between 2008 and 2018, about half of the nation's coal-fired power plants retired, with 262 plants still operating as of March 2018.[30] The capacity-weighted average age of operating coal plants is 39 years, whereas coal-fired units have a typical lifetime of between 35 and 50 years.[31] Broader deployment of cost-effective CCUS can enhance coal's competitiveness with other forms of generation, including natural gas and renewable energy.

C. CCUS at coal facilities

The leading example of carbon capture on a coal-fired power plant resides at the Petra Nova project at NRG's W.A. Parish plant outside Houston, TX. Delivered on-time in December 2016 and on-budget at $1 billion, Petra Nova captures CO_2 from Unit 8 of the 3.7-GW plant via the amine-based Kansai Mitsubishi Carbon Dioxide Recovery (KM-CDR) process and KS-1 high-performance solvent. While Unit 8's capacity is 650 MW, Petra Nova's capture capacity is equivalent to 240 MW. A 70-MW gas-fired cogeneration system helps power the system, reducing Petra Nova's parasitic load to 22 percent.

Petra Nova is based on technology originally tested at Alabama Power's James M. Barry Electric Generating Plant. Mitsubishi Heavy Industries (MHI) demonstrated that the KM-CDR process and KS-1 solvent could capture up to 500 tons of CO_2 per day at a 25-MW coal-fired facility. Petra Nova scaled this technology up by nearly 10 times to capture approximately 1.6 million metric tons of CO_2 per year. Captured CO_2 is pressurized and transported via pipeline 80 miles to the West Ranch Oilfield to be used in enhanced oil recovery (EOR).

W.A. Parish was selected due to its proximity to carbon sequestration opportunities in oilfields. Additionally, Texas offered abatement of half of the EOR severance tax, franchise tax credits, and property and sales tax exemptions. NRG entered into a joint venture with JX Nippon Oil & Gas Exploration Corporation and received $190 million in cost sharing from the U.S. Department of Energy and a $250 million loan from the Japan Bank for International Cooperation. NRG and JX Nippon each contributed up to $300 million in equity. Hilcorp, the oilfield operator, estimates that EOR from captured CO_2 will increase the field's output from 300 to 15,000 barrels per day. The project breaks even with oil prices at $50 per barrel.[32]

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27 Robert Rapier, "Premature Power Plant Retirements: Drivers and Responses," GE Power, April 12, 2018, https://www.ge.com/power/transform/article.transform.articles.2018.apr.premature-power-plant-retirements.

28 David Tuttle et al., "The Full Cost of Electricity (FCe-): The History and Evolution of the U.S. Electricity Industry," University of Texas at Austin Energy Institute, 2016, http://sites.utexas.edu/energyinstitute/files/2016/09/UTAustin_FCe_History_2016.pdf.

29 U.S. Energy Information Administration, "North Dakota: State Profile and Energy Estimates," https://www.eia.gov/state/?sid=ND.

30 "The U.S. Shale Revolution," The University of Texas at Austin, https://www.strausscenter.org/energy-and-security/the-u-s-shale-revolution.html.

31 U.S. Department of Energy, "Staff Report to the Secretary on Electricity Markets and Reliability," August 2017, https://www.energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf.

32 Sonal Patel, "Capturing Carbon and Seizing Innovation: Petra Nova is POWER's Plant of the Year," *Power* 161 No. 8 (August 2017): 20 – 25, https://cdn2.hubspot.net/hubfs/3999852/Power%20Magazine%20Aug%202017%20Desalitech%20-%20Full%20Version.pdf?t=1510942883532.

1. Projects in development

Petra Nova is the only operating large-scale power generation carbon capture facility in the U.S., according to the Global CCS Institute (GCCSI). GCCSI counts five power generation pilot and demonstration projects nationwide: NET Power (Texas), Plant Barry and Citronelle Integrated Project (Alabama), Pleasant Prairie Power Plant Field Pilot (Wisconsin), Jupiter Oxy-Combustion and Integrated Pollutant Removal Test Facility (Indiana), and the Mountaineer Validation Facility (West Virginia).[33] In addition, Project Tundra in North Dakota involves Allete Clean Energy, Minnkota Power Cooperative, Energy & Environmental Research Center, and National Energy Technology Laboratory and DOE carbon capture research programs. Several Phase II CarbonSAFE projects are considering the feasibility of CO_2 capture from coal-fired power plants.[34]

Internationally, large-scale operational power generation projects can be found at Boundary Dam in Canada, Caledonia Clean Energy in the United Kingdom, and a handful of projects in East Asia—four in China and two in South Korea.[35] GCCSI counts 31 pilot and demonstration projects in the power generation industry outside the U.S.[36] Section III.H contains case studies of a selection of major CCUS projects with key lessons learned.

2. Utilization: Enhanced Oil Recovery (EOR)

The Petra Nova project extracts a revenue stream from captured CO_2 by selling the pressurized gas for use in EOR. EOR refers to methods to enhance oil production once extraction from an oilfield has begun to decline due to a drop in pressure that naturally occurs as more oil is drawn out of the reservoir. CO_2 acts as a solvent to cause a portion of immobile oil to expand and flow to wells for extraction. EOR may be conducted with other solvents and/or heat.[37] CO_2-EOR has been successfully applied for more than 50 years[38] and is currently in use to produce an additional 170,000 barrels of oil per day in the Permian Basin in west Texas and southeastern New Mexico. CO_2 is competitive for EOR use due to its low price compared to other solvents and its miscibility (ability to mix in all proportions) with crude oil.[39]

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33 Global CCS Institute, "Projects Database," https://www.globalccsinstitute.com/projects.

34 National Energy Technology Laboratory, "Carbon Storage and Oil and Natural Gas Technologies Review Meeting," August 2018, https://www.netl.doe.gov/events/conference-proceedings/2018/2018-mastering-the-subsurface-through-technology-innovation-partnerships-and-collaboration-carbon-storage-and-oil-and-natural-gas-technologies-review-meeting/.

35 Global CCS Institute, "Projects Database: Large-Scale CCS Facilities," https://www.globalccsinstitute.com/projects/large-scale-ccs-projects.

36 Ibid.

37 Global CCS Institute, "What is CO_2-EOR?" https://hub.globalccsinstitute.com/publications/what-happens-when-co2-stored-underground-qa-ieaghg-weyburn-midale-co2-monitoring-and-storage-project/8-what-co2-eor.

38 From EOR to CCS Philip Marston and Patricia Moore, "From EOR to CCS: The Evolving Legal and Regulatory Framework for Carbon Capture and Storage," *Energy Law Journal* 29 No. 421 (2008): 421–490. http://groundwork.iogcc.ok.gov/sites/default/files/From%20EOR%20to%20CCS.pdf.

39 National Energy Technology Laboratory, "Carbon Dioxide Enhanced Oil Recovery," https://www.netl.doe.gov/file%20library/research/oil-gas/CO2_EOR_Primer.pdf.

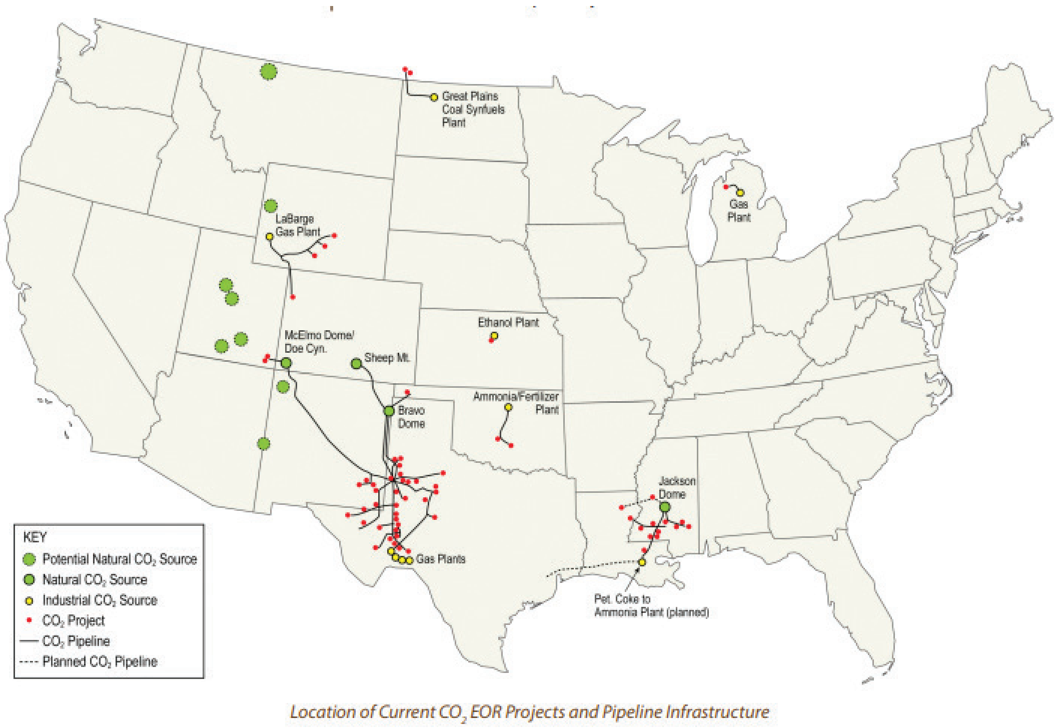

Figure I.1 Current CO_2-EOR projects and pipeline infrastructure[40]

Given current technology, EOR is the most attractive option for CCUS on coal-fired power plants. The oil industry is a highly motivated customer. Based on U.S. Energy Information Administration oil market projections, CO_2-EOR will be worth approximately $26 per metric ton in 2020 and up to $40 per metric ton by 2050.[41] EOR can recover up to 28 billion additional barrels of oil.[42] The biggest barrier to additional utilization of CO_2-EOR is affordable CO_2 supply. CO_2 pipelines are a critical component of affordability. NETL estimates that the CO_2-EOR industry has spent $1 billion on 2,200 miles of CO_2 pipelines in the Permian Basin.[43]

Additional opportunities for CO_2-EOR exist in unconventional oil extraction. Residual oil zones (ROZ) located in the Permian Basin in west Texas contain 238 billion barrels of oil, according to analysis by Advanced Resources International. With CO_2-EOR, ARI estimates the area contains 18 billion economically recoverable barrels.[44] Application of CO_2-EOR to shale oil reservoirs is more technically challenging than CO_2-EOR at traditional sites but still feasible under favorable geologic and economic conditions.[45]

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40 National Energy Technology Laboratory, "Carbon Dioxide Enhanced Oil Recovery," https://www.netl.doe.gov/file%20library/research/oil-gas/CO2_EOR_Primer.pdf.

41 Carbon Utilization Research Council and ClearPath Foundation, "Making Carbon a Commodity: The Potential of Carbon Capture RD&D," July 25, 2018, http://www.curc.net/webfiles/Making%20Carbon%20a%20Commodity/180724%20Making%20Carbon%20a%20Commodity%20FINAL%20with%20color.pdf.

42 State CO_2-EOR State Deployment Work Group, "Infrastructure for Carbon Capture: Technology, Policy, and Economics," National Association of Regulatory Utility Commissioners, May 15, 2017, https://www.naruc.org/default/assets/File/GPI%20NARUC%20webinar%20slides.pdf.

43 Carbon Utilization Research Council and ClearPath Foundation, "Making Carbon a Commodity: The Potential of Carbon Capture RD&D," July 25, 2018, http://www.curc.net/webfiles/Making%20Carbon%20a%20Commodity/180724%20Making%20Carbon%20a%20Commodity%20FINAL%20with%20color.pdf.

44 Vello Kuuskraa, Advanced Resources International, "Using CO_2-EOR, the ROZ and Carbon Management for Energy Independence," December 6, 2016, http://www.adv-res.com/pdf/Kuuskraa-ROZ-Midland-CO2-ROZ-DEC-2016.pdf.

45 Dheiaa Alfarge et al., "Feasibility of CO_2-EOR in Shale-Oil Reservoirs: Numerical Simulation Study and Pilot Tests," *Carbon Management Technology Conference* (2017), https://doi.org/10.7122/485111-MS.

II. Benefits of Encouraging Carbon Capture and Storage for Coal Power Plants

Carbon capture and storage/sequestration (CCS) refers to technology that captures CO_2 from sources of emissions, compresses it for transportation, and permanently sequesters it underground in geologic repositories.[46] CO_2 may also be captured and utilized (CCUS) in enhanced oil recovery or other uses. This paper generally uses the more expansive term, CCUS, when discussing carbon capture, utilization, and/or sequestration.

Without regulation limiting CO_2 emissions, there is no regulatory driver for coal-fired power plants to install CCUS technology. However, there are a number of other reasons why coal plants may want to consider CCUS. Federal tax incentives reward CCUS, and state subsidies make CCUS more cost-effective. State pollution standards can also create a more hospitable environment for CCUS.

This paper focuses on CCUS applied to new and existing coal-fired power plants, paying particular attention to CCUS retrofits on existing plants, as few coal plants have been built in recent years and no plants are currently under construction. Encouraging CCUS on existing coal plants has four main benefits: decreased emissions, economic development, grid reliability, and global leadership in market development.

A. Decreasing CO_2 emissions

CCUS has the potential to decrease CO_2 emissions from baseload generation. Coal-fired power is a particularly attractive area of focus for reducing these emissions, as electricity generation is responsible for 41 percent of U.S. CO_2 emissions from combustion of fossil fuels and coal is the most carbon-intensive fossil fuel. Further, electricity generation emissions come from a manageable number of stationary emitters with emissions monitoring and existing pollution controls—particularly compared to other sectors (transportation emissions come from millions of small, mobile sources; industrial, residential, and commercial sector emissions likewise come from millions of decentralized, stationary sources of varying sizes). In other words, coal-fired power is a sensible place to start for policymakers looking to reduce CO_2 emissions.[47]

Unlike renewable generation, coal-fired power is always available, particularly during emergencies. Decreasing coal-fired emissions would therefore have a magnified impact compared to replacing fossil generation with intermittent renewable generation. The State CO_2-EOR Deployment Working Group, a collection of public utility commission staff, state energy officials, state-level cabinet secretaries, and other state regulatory staff from 14 states, estimated the cost per ton of CO_2 reductions from various generation and storage technologies and found that CCUS retrofits of existing coal plants was similar in cost to replacing existing fossil fuel plants with wind and retrofitting natural gas combined cycle plants with CCUS. Coal CCUS retrofits were cheaper than several renewable options and only slightly more expensive than maintaining the existing nuclear fleet and replacing coal plants with natural gas combined cycle plants (**Figure II.1**).[48]

46 Global CCS Institute, "Understanding Carbon Capture and Storage," https://www.globalccsinstitute.com/understanding-ccs

47 Peter Folger, "Carbon Capture and Sequestration (CCS): A Primer," Congressional Research Service, July 16, 2013, https://fas.org/sgp/crs/misc/R42532.pdf.

48 State CO_2-EOR Deployment Work Group, "Electricity Market Design and Carbon Capture Technology: The Opportunities and the Challenges," June 2017, http://www.betterenergy.org/wp-content/uploads/2018/02/Electric-Markets-and-CCS-White-Paper-1.pdf.

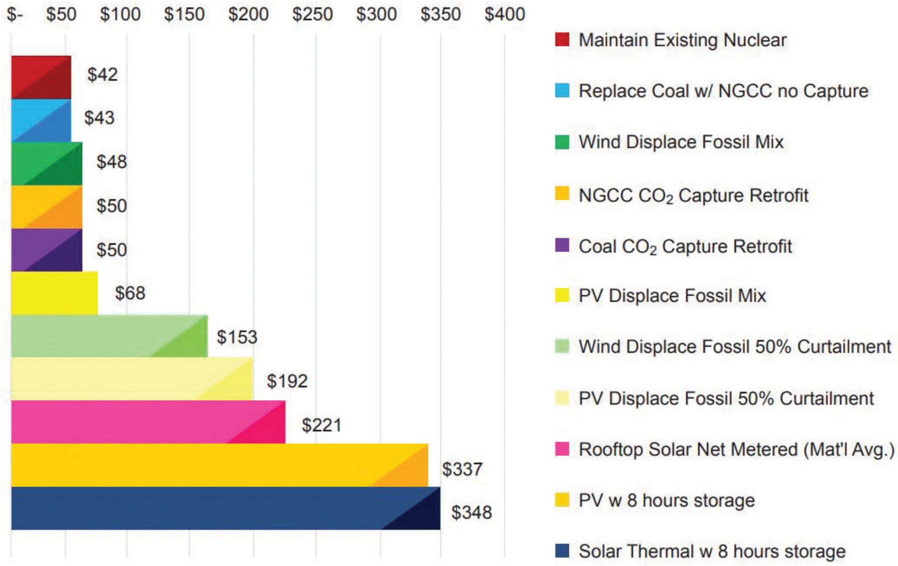

Figure II.1 Comparative costs of CO_2 reductions across technologies[49]

Further, although some environmental groups have hesitated to endorse captured CO_2 being used for additional fossil fuel production, CO_2-EOR actually results in net lifecycle emissions reductions. Including emissions from oil combustion, a barrel of oil produced through CO_2-EOR emits 37 percent less net CO_2 than a traditional barrel of oil.[50] EOR also results in permanent geologic sequestration of CO_2 once the efficient amount of oil has been extracted from the field.

B. Economic development benefits

Coal is a widely available domestic fuel source. Coal mining employs approximately 53,100 American workers as of May 2018.[51] Coal mining is a significant source of employment in rural areas including Appalachia, the northern Rockies, and the Illinois Basin.[52] In many of these places, work in coal production offers a steady, competitive income where few other opportunities exist. Coal miners produce coal as fuel for electricity generators and also metallurgical coal for steel manufacturing. However, domestic electricity production is a major driver of coal mining employment and the mining sector has stagnated as coal-fired power plants have struggled to remain competitive and coal mining has become more automated. More than 80 percent of coal mining jobs support electricity production and are vulnerable to power plant retirements.[53] To the extent that CCUS can increase the competitiveness and prolong the life of existing coal plants, coal producers and their employees have an interest in supporting its expansion.

49 State CO_2-EOR Deployment Work Group, "21st Century Energy Infrastructure: Policy Recommendations for Development of American CO_2 Pipeline Networks," February 2017, http://www.betterenergy.org/wp-content/uploads/2018/02/White_Paper_21st_Century_Infrastructure_CO2_Pipelines_0.pdf.

50 State CO_2-EOR Deployment Work Group, "Putting the Puzzle Together: State & Federal Policy Drivers for Growing America's Carbon Capture & CO_2-EOR Industry," December 2016, http://www.betterenergy.org/wp-content/uploads/2018/02/PolicyDriversCO2_EOR-V1.1_0.pdf, and Carbon Utilization Research Council and ClearPath Foundation, "Making Carbon a Commodity: The Potential of Carbon Capture RD&D," July 25, 2018, http://www.curc.net/webfiles/Making%20Carbon%20a%20Commodity/180724%20Making%20Carbon%20a%20Commodity%20FINAL%20with%20color.pdf.

51 U.S. Department of Labor, Bureau of Labor Statistics, "Employment, Hours, and Earnings from the Current Employment Statistics Survey (National): CES1021210001," 2018, https://data.bls.gov/timeseries/CES1021210001.

52 U.S. Energy Information Administration, "Table 18: Average Number of Employees by State and Mine Type, 2016 and 2015," https://www.eia.gov/coal/annual/pdf/table18.pdf.

53 U.S. Department of Energy, "Staff Report to the Secretary on Electricity Markets and Reliability," August 2017, https://www.energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf.

In addition, the market for using CCUS-produced CO_2 is growing. Enhanced oil recovery requires steady delivery of pressurized CO_2 to produce an additional 10 to 20 percent of oil once conventional extraction methods remove 30 to 50 percent of the original oil. The EOR market is in need of reliable CO_2 supply, representing an important opportunity for CCUS to support jobs in that sector.[54] The Carbon Utilization Research Council and ClearPath Foundation estimate that an aggressive RD&D program for CO_2-EOR could support between 270,000 and 780,000 new jobs in oil production and $70 to $90 billion in additional GDP by 2040.[55] Further, enhancing the use of carbon capture for enhanced oil recovery lessens U.S. dependence on foreign oil imports and stimulates domestic economic activity: "Producing more domestic oil through EOR also further displaces heavier and more carbon-intensive imported crude oil and lowers our trade deficit by reducing expenditures on oil imports. Additionally, installing carbon capture facilities, building CO_2 pipelines and reworking mature oil fields to revitalize their production through CO_2-EOR brings jobs and investment to key energy and industrial sectors of the U.S. economy." [56]

Several private firms and universities are engaged in research on other utilization methods for CO_2 including CO_2 -based cement production, fuels, plastics, and building materials.[57] CCUS could supply the primary fuel for these budding industries, contributing to innovative jobs and economic development."

C. Grid reliability and fuel diversity

The federal government, the Federal Energy Regulatory Commission (FERC), regional market operators, and states are engaged in ongoing conversations about the meaning of power sector resilience and to what extent, if any, particular fuel sources provide resilience benefits to electricity customers or the grid as a whole. This discussion is beyond the scope of this paper; however, coal-fired power plants, like other generation sources, are contributors to the diversity of the electricity system. DOE noted in a 2017 staff report on electricity markets and reliability that fuel diversity is an important component of resilience and reliability.[58]

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54 Carbon Utilization Research Council and ClearPath Foundation, "Making Carbon a Commodity: The Potential of Carbon Capture RD&D," July 25, 2018, http://www.curc.net/webfiles/Making%20Carbon%20a%20Commodity/180724%20Making%20Carbon%20a%20Commodity%20FINAL%20with%20color.pdf.

55 Carbon Utilization Research Council and ClearPath Foundation, "Making Carbon a Commodity: The Potential of Carbon Capture RD&D," July 25, 2018, http://www.curc.net/webfiles/Making%20Carbon%20a%20Commodity/180724%20Making%20Carbon%20a%20Commodity%20FINAL%20with%20color.pdf.

56 State CO_2-EOR Deployment Work Group, "Electricity Market Design and Carbon Capture Technology: The Opportunities and the Challenges," June 2017, http://www.betterenergy.org/wp-content/uploads/2018/02/Electric-Markets-and-CCS-White-Paper-1.pdf, and Carbon Utilization Research Council and ClearPath Foundation, "Making Carbon a Commodity: The Potential of Carbon Capture RD&D," July 25, 2018, http://www.curc.net/webfiles/Making%20Carbon%20a%20Commodity/180724%20Making%20Carbon%20a%20Commodity%20FINAL%20with%20color.pdf.

57 "Carbon XPRIZE," NRG Cosia, https://carbon.xprize.org/.

58 U.S. Department of Energy, "Staff Report to the Secretary on Electricity Markets and Reliability," August 2017, https://www.energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf.

Retiring coal plants may leave ratepayers more vulnerable to a number of threats to affordable, reliable energy, according to NETL analysis.[59] Coal plants make up a significant portion of generation during weather-induced emergencies. For example, during a "cold snap" from December 27, 2017, through January 8, 2018, coal produced 55 percent of generation in RTO/ISO territories. Coal's key role is underscored by high natural gas prices due to limited pipeline capacity, particularly during cold weather.[60] PJM noted that it "dispatched coal units because *their costs were lower* during certain hours of the cold snap. PJM had adequate amounts of resources to supply power" (emphasis in original).[61] PJM did agree with NETL's finding that high natural gas prices led to the increased dispatch of coal units. Similarly, demand spikes during increasingly common heat waves could result in high prices and, at worst, brownouts or blackouts. Following the retirements of three large coal-fired units in Texas (1208 MW at Big Brown, 1200 MW at Sandow 4 & 5, and 1865 MW at Monticello), the Electric Reliability Council of Texas (ERCOT) North hub experienced day-ahead prices of $551/MWh and real-time 15-minute prices of $3,125/MWh in spring 2018, far above the seasonal averages.[62]

DOE emphasized the need for fuel diversity in the August 2017 DOE grid study and in a September 2017 request that FERC exercise its authority under sections 205 and 206 of the Federal Power Act to compensate fuel-secure plants for the resilience they provide to the electric grid.[63] FERC denied the request and opened a new docket to discuss the resilience of the power fleet and explore what, if any, action the commission could take to improve resilience.

The action FERC will take in response to DOE's request under section 403 of the Department of Energy Organization Act is uncertain. However, coal inarguably plays an important role in today's generation fleet, and unchecked retirements of coal-fired capacity are a concern to state and federal policymakers.

D. International development

Although the U.S. is not seeing new coal plants being built, developing countries are relying heavily on coal-fired power to supply cheap, reliable electricity to rapidly growing populations. These populations are vulnerable to the human health and environmental impacts of pollution associated with coal-fired power. Therefore, there are numerous international opportunities for U.S. firms to develop and apply CCUS to existing and new coal plants, spreading the global development benefits of increased access to energy while reducing emissions of greenhouse gases and other pollutants—a particularly important balance to strike as developing countries commit to greenhouse gas reduction goals.

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59 Peter Balash et al., "Reliability, Resilience and the Oncoming Wave of Retiring Baseload Units Volume 1: The Critical Role of Thermal Units during Extreme Weather Events," National Energy Technology Laboratory, March 13, 2018, https://www.netl.doe.gov/energy-analyses/temp/ReliabilityandtheOncomingWaveofRetiringBaseloadUnitsVolumeITheCriticalRoleofThermalUnits_031318.pdf.

60 Ibid.

61 PJM Interconnection, "Perspective and Response of PJM Interconnection to National Energy Technology Laboratories Report Issued March 13, 2018," 2018, https://www.pjm.com/~/media/library/reports-notices/weather-related/20180413-pjm-response-to-netl-report.ashx.

62 April Lee, "Coal Plant Retirements and High Summer Electricity Demand Lower Texas Reserve Margin," U.S. Energy Information Administration, July 2, 2018, https://www.eia.gov/todayinenergy/detail.php?id=36593.

63 U.S. Department of Energy, "Grid Resiliency Pricing Rule: Notice of Proposed Rulemaking," 18 CFR Part 35, Docket No. RM17-3-000, https://www.energy.gov/sites/prod/files/2017/09/f37/Notice%20of%20Proposed%20Rulemaking%20.pdf.

III. CCUS Technology Primer

CO_2 capture, as a separations process, has been in use for many years. Separation of CO_2 from natural gas started in the 1930s.[64] The use of CO_2 as a means for tertiary recovery of petroleum (CO_2-EOR) makes use of known underground formations that trap significant volumes of CO_2. This practice began in the early 1970s.[65] CO_2 has found widespread industrial applications. CO_2 gas is used in refrigeration systems, welding systems, water treatment processes (to stabilize the pH of water), and carbonated beverages. It is also used in the metals industry to enhance the hardness of casting molds and as a soldering agent. CO_2 is found in some fire extinguishers.

Organized research, development, and demonstration (RD&D) of CO^2 capture, followed by permanent storage or consumption, began to get a serious look in the United States starting in 1997. The Sleipner project was initiated in 1996 to separate CO_2 from natural gas and inject the CO_2 into a formation under the North Sea.[66] The earliest studies that considered CCUS as a means of controlling emissions of CO_2 focused on existing technologies, such as sub- and super-critical power cycles based on coal as the primary fuel. Industrial gasifiers and power cycles based on gasification of coal (integrated gasification combined cycle systems) were also identified as an important potential application.

The United States began a formal program of RD&D in 1997 with the intent of facilitating deployment as technology options matured. The technical effort was split into two major efforts. One set of activities focused on capture of CO_2 from power sector facilities and from large industrial facilities in industries that are known emitters of large amounts of CO_2. The second set of activities focused on storage options with the intent that the captured carbon (usually as CO_2) be stored in some way that ensured permanence. The storage had to be verifiable—that is, to be secure for thousands of years. Technologies that used the captured CO_2 were also included in the research portfolio. The main thrust in the storage component was to characterize different geological formations within the United States and to assess the potential that these held to store large amounts of CO_2. This characterization and assessment process was emulated by many nations to the point where global statistics on potentially suitable storage reservoirs are now available.[67]

Countries initially active in advancing CCUS developed programs that pursued both major themes: capture and storage. Some focused on early demonstration and assurance of storage integrity, others on the basic R&D necessary to underpin technology development with sound science and to create tools to guide the research and development. Global assessments of climate change mitigation strategies continue to emphasize the important role that CCUS must play.

64 National Energy Technology Laboratory, "A Review of the CO_2 Pipeline Infrastructure in the U.S.," 2015, https://www.energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20-%20A%20Review%20of%20the%20CO2%20Pipeline%20Infrastructure%20in%20the%20U.S_0.pdf

65 Global CCS Institute, "The Global Status of CCS," 2017, http://www.globalccsinstitute.com/sites/www.globalccsinstitute.com/files/uploads/global-status/1-0_4529_CCS_Global_Status_Book_layout-WAW_spreads.pdf.

66 Global CCS Institute, "The Global Status of CCS," 2017, http://www.globalccsinstitute.com/sites/www.globalccsinstitute.com/files/uploads/global-status/1-0_4529_CCS_Global_Status_Book_layout-WAW_spreads.pdf.

67 Ibid.

This chapter provides a brief overview of the existing state-of-the-art in CO_2 capture, transport, and storage technology options. **Figure III.1** is a summary of pathways to capture. **Table III.1** is a brief summary of the capture technology options currently available or under development for any of the power technologies described in this chapter. Existing and developmental thermal power generation technologies that emit CO_2 are described and linked to the capture technologies appropriate for each option:

- Subcritical and advanced (super critical, ultra-super critical) pulverized coal systems,
- Gasifiers and combined cycle power systems based on gasification, and
- Oxy-fuel combustion.

The large-scale emitting industries are also described. In addition, many of the emerging novel and advanced capture systems offer the potential to apply to a variety of existing and emerging combustion systems that may not be good candidates for the capture technologies already deployed or in large pilot-scale testing.[68] The chapter provides an overview of characterization of a range of potential geological storage formations and of tool developments that have been pursued, a discussion of lessons learned from major projects is included. The chapter concludes with a discussion of remaining issues, including non-technical obstacles to new project development and to commercial deployment.

Within the CCUS community, important lessons have been learned at all scales—from laboratory-scale work through small- and large-pilot studies up to demonstrations. Continuing efforts within several nations have further converged, allowing for improved research and development up through large pilot-scale studies.[69]

CCUS researchers are pursuing improvements to well-established methods for capture for coal- and natural gas-fired power plants as well as industrial facilities and for the development of radically new techniques that offer lower energy penalties and lower capture costs or that explore means to reuse captured CO_2.[70] In addition, separate studies have been conducted to assess storage technologies and to develop an inventory of global storage capacity.

Organizations funding CCUS RD&D assess progress toward goals for both capture system performance and for storage site capacity and permanence. In addition, widespread international participation in CCUS projects and through international meetings (such as the Greenhouse Gas Control Technologies conferences) has led to an evolving consensus on appropriate standards. Significant progress has already been made.

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68 U.S. Department of Energy, "Accelerating Breakthrough Innovation in Carbon Capture, Utilization, and Storage: Report of the Carbon Capture, Utilization and Storage Experts' Workshop," 2017. https://www.energy.gov/sites/prod/files/2018/05/f51/Accelerating%20Breakthrough%20Innovation%20in%20Carbon%20Capture%2C%20Utilization%2C%20and%20Storage%20_0.pdf.

69 Frank Morton, "International Collaboration on CCUS R&D," Carbon Management Technology Conference, Houston, Texas, 2017.

70 Ahmed Al-Mamoori et al., "Carbon Capture and Utilization Update," January 23, 2017, https://onlinelibrary.wiley.com/doi/full/10.1002/ente.201600747.

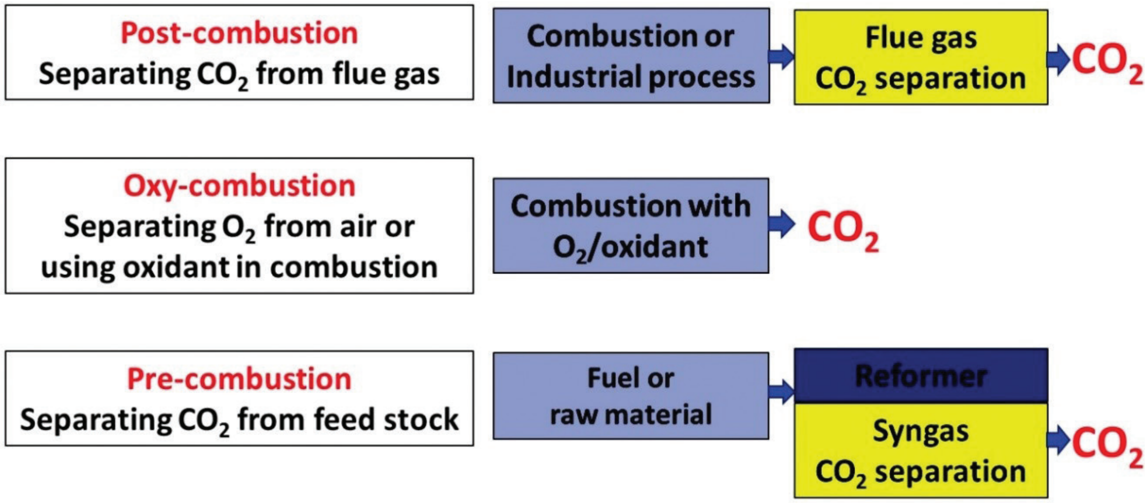

Figure III.1 Pathways for CO_2 capture[71]

A. Post-combustion

The great share of coal-burning power plants in operation today are based on the use of pulverized coal firing to produce hot gases that heat water to create steam at either subcritical or supercritical conditions.[72] The steam provides a motive force to turn a steam turbine. The numbers of sub-critical units in service globally is declining and these units are being replaced by supercritical and ultra-supercritical systems. These power cycles have greater cycle efficiencies. System design choices—combinations of steam temperatures and pressures, inclusion of reheat cycles, and technologies for feedwater reheat can strongly impact the overall cycle efficiency and operational flexibility of the unit. This is particularly apparent when dealing with variable loads and variations in coal quality. However, with respect to CO_2 capture, the fundamental characteristic is that essentially 100 percent of the incoming carbon is converted to CO_2. The principal challenge in post-combustion capture is separating the CO_2 generated during combustion from the large amounts of nitrogen found in the flue gas. An array of different techniques are available including the use of solvents, sorbents, and membranes (and novel concepts that can include hybrid technologies) all properly designed for operation at post-combustion conditions. (See **Table III.1** for a summary.)

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71 U.S. Department of Energy, "Accelerating Breakthrough Innovation in Carbon Capture, Utilization, and Storage: Report of the Carbon Capture, Utilization and Storage Experts' Workshop," 2017, https://www.energy.gov/sites/prod/files/2018/05/f51/Accelerating%20Breakthrough%20Innovation%20in%20Carbon%20Capture%2C%20Utilization%2C%20and%20Storage%20_0.pdf.

72 See glossary for definitions. Details on RDK plant mentioned in the definition can be found at: https://www.ge.com/reports/supercritical-thinking-this-coal-power-plant-applies-bullet-like-pressures-to-steam-to-achieve-worlds-best-performance/.

TECHNOLOGY	STATUS AND POTENTIAL AREAS FOR FURTHER DEVELOPMENT
Solvent-based CO_2 capture (see A.1)	**Description:** Involves chemical or physical absorption of CO_2 from CO_2-rich gas into a liquid carrier. The absorption liquid is regenerated by increasing its temperature or reducing its pressure. **Current status:** Commercially available today, but requires large amount of energy to separate CO_2 from flue gas. Second- and third-generation solvents have lower energy and capital cost requirements.
Adsorbents/sorbents (see A.2)	**Description:** CO_2 from the gas is taken up by a solid sorbent (e.g., carbon, zeolites, metal organic frameworks [MOFs]) Solid sorbent is regenerated by reducing pressure, or increasing temperature, or by using an inert gas to sweep CO_2 away from the sorbent. Potential for energy savings and operational simplicity compared to solvents **Current status:** Numerous sorbent candidates are feasible but need to be stable with continuous operation Not commercially available for power plant CO_2 capture. Both materials and processes need to be developed.
Membranes (see A.3)	**Description:** Uses permeable or semi-permeable materials that allow for the selective transport and separation of CO_2 or hydrogen from gas streams. Gas separation is accomplished by some physical or chemical interaction between the membrane and the gas being separated Allow CO_2 or other gases to travel selectively through polymeric/carbon-based/metal membrane, resulting in CO_2-rich gas on one side and CO_2-lean gas on the other side. Modular systems can result in cost savings. Both membrane materials and process configurations need to be developed Current status: Suited for bulk separations, used in offshore natural gas/N_2 separations Membranes do not need excessive amounts of cooling water, or have solvent by-product emissions and spent solvent disposal issues
Hybrid systems	**Description:** Involve a combination of bulk separation (e.g., membrane) and fine separation (e.g., solvent) processes to harness the advantages of each separation technology, or novel process intensification (e.g., supersonic flue gas de-sublimation, cryogenic CO_2 capture), which dramatically reduce the footprint and capital costs compared to state-of-the-art technologies

Table III.1 Capture technology options and areas for further development

Although high levels of CO_2 capture are possible with chemical solvent-based systems commercially available today, these systems require significant amounts of energy for regeneration, which involves a temperature swing to break the absorbent-CO_2 chemical bond. These systems also require large absorbers to capture CO_2 from dilute coal-fired flue gas streams, increasing the capital costs. R&D to develop advanced solvents that have a lower regeneration energy requirement than commercially available amine systems, and that are also resistant to flue gas impurities, are being developed.

Solid sorbents—including sodium and potassium oxides, zeolites, carbonates, amine-enriched sorbents, and metal organic frameworks—are being explored for post-combustion CO_2 capture. A temperature or pressure swing is used during sorbent regeneration following chemical and/or physical adsorption. A potential advantage of sorbents is that CO_2 separation does not occur in an aqueous solution, which reduces sensible heating and stripping energy requirements. Low-cost, durable post-combustion sorbents that have high selectivity, high CO^2 adsorption capacity, and the ability to withstand multiple regeneration cycles are being developed.

Membrane-based CO_2 capture uses permeable or semi-permeable materials that allow for the selective transport and separation of CO_2 from flue gas. Generally, gas separation is accomplished by some physical or chemical interaction between the membrane and the gas being separated, causing one component in the gas to permeate through the membrane faster than another. Selectivity for CO_2 in today's membranes is usually insufficient to achieve the desired purities and recoveries. Membranes optimal for post-combustion capture need to have low life cycle costs and to be durable. These membranes must have improved permeability and selectivity, thermal and physical stability, and be able to tolerate trace contaminants remaining in combustion flue gas.

1. Advanced solvents

Opportunities to develop transformational technologies for solvents that appear to hold promise include encapsulated ionic liquids, non-aqueous sorbents, catalyzed absorption that accelerates CO_2 uptake in solvents with lower regeneration energies, computer-aided simulations to identify designer solvents with desirable characteristics, and solvents that change phase in the presence of CO_2. These technologies and some of the approaches listed as novel technologies may be better suited to small, modular power generation units that can support incremental additions to the power generation capacity within the United States or provide power to remote locations not reliably served by the current power distribution grid.

Additional research in solvent-based CO^2 capture technologies is focused on development of low-cost, non-corrosive solvents that have a high CO^2 loading capacity; improved reaction kinetics; low regeneration energy; and resistance to degradation. In addition, considerable effort is being applied to development of process design and system integration (particularly thermal) advancements that will lead to decreased capital and operating costs. These two areas of improvement will enhance performance of solvent-based systems. Opportunities to develop transformational technologies that appear to hold promise are discussed in Chapter 6.1.5.

2. Advanced sorbents

Transformational concepts being considered for sorbents include structured solid adsorbents (e.g., metal organic frameworks, or MOFs), enhanced pressure-swing-adsorption (PSA) and temperature-swing-adsorption (TSA) processes, and amine-incorporated porous polymer networks.

Research opportunities focusing on sorbents are intended to create sorbents with the following characteristics: low-cost raw materials, low attrition rates, low heat capacity, high CO_2 adsorption capacity, and high CO_2 selectivity. These characteristics may not occur in many naturally occurring candidate materials. Engineered sorbents are an ongoing area for research. Another important focus of this research seeks to demonstrate cost-effective process equipment designs (starting at smaller-scales) that are tailored to the sorbent characteristics.

3. Membranes

The research focus for post-combustion membranes includes development of low-cost, durable membranes that have improved permeability and selectivity, thermal and physical stability, and tolerance to contaminants in combustion flue gas. Transformational membrane technologies under investigation include next generation hollow fiber membranes.

Selectivity for CO_2 in currently available membranes is often insufficient to achieve the desired purities and recoveries. Multiple stages and recycle streams may be required in an actual operation. This leads to increased complexity, additional energy consumption, and higher capital costs. Technical challenges remaining for this key technology are to address current limits to the use of membrane-based systems, such as large flue gas volume, relatively low CO_2 concentration, low flue gas pressure, flue gas contaminants, and the need for high membrane surface area. In addition, gas absorption membrane technologies are being developed where the separation is caused by the presence of an absorption liquid on one side of the membrane that selectively removes CO_2 from a gas stream on the other side of the membrane.

Novel Technologies: The potential for significant improvement and cost reduction exists with development of unique and novel CO_2 capture technologies. The novel technologies currently being pursued by U.S. DOE are at an early development stage, but the concepts offer the potential for significant improvements as compared to existing CO_2 capture technology. The DOE/FE program has emphasized the research and development of new and novel technologies in order to substantially reduce the cost of CO_2 capture. Examples include:

- **Sorption-Enhanced Mixed Matrix Membrane:** This approach would significantly improve coal gasification and integrated gasification combined cycle (IGCC) plants due to:
    - No degradation of byproduct emissions or spent solvent disposal issues;
    - Less water for cooling is needed;
    - The membrane has no moving parts and offers a less complicated system with potentially lower capital and reduced energy consumption; and
    - Reduced pre-combustion coal gasification energy and capital costs.
- **Hybrid Encapsulated Ionic Liquids:** This approach is focused on improving post combustion CO_2 capture mass transfer by increasing the mass transfer area. These ionic liquids are pure salts that are liquid at ambient temperatures and are non-volatile with a high thermal stability. These properties are important for use with amine-based solvents to reduce degradation of the amine, resulting in lower emissions of amine degradation byproducts resulting in:
    - Reduced absorber height and regenerator energy of amine-based solvents;
    - Lower cooling water requirements for cooling;
    - Reduced energy of post combustion amine-based CO_2 capture system; and
    - Potentially lower capital and reduced energy consumption of post combustion, amine-based solvents.
- **Supersonic Flue Gas De-Sublimation:** The technology involves the supersonic expansion of compressed flue gas at low temperature and pressure to achieve de-sublimation and the formation of solid phase CO_2 particles. Inertial separation of the CO_2 solid particles occurs by a change in direction of the flue gas. Once separated from the flue gas, the solid CO_2 particles are processed and melted to produce a pure CO_2 product stream. The benefits for post-combustion capture are:
    - No degradation of byproduct emissions or spent solvent disposal issues;
    - Less water for cooling is needed;
    - Reduced equipment, greater simplicity as compared to other post combustion CO_2 capture technologies;

- No moving equipment for CO_2 capture other than flue gas compression;
- No consumption of chemicals/additives; and
- Smaller footprint (and lower costs).

- **Cryogenic Carbon Capture:** The technology is a multi-pollutant capture technology that removes sulfur dioxide (SO_2), nitrogen oxides (NOx), and mercury (Hg) in addition to CO_2 from the flue gas of combustion sources. The process potentially offers high CO_2 capture efficiency (99 percent) and reduced energy and capital costs. The technology uses phase change to separate the pollutants by cooling the flue gas to low temperatures (approximately -140° C), which changes the gaseous pollutants to solids. The solid can be separated from the flue gas and processed to recover the CO_2.

  - High CO_2 capture efficiency of 99 percent;
  - No degradation of byproduct emissions or spent solvent disposal issues;
  - Lower capital costs as compared to other post combustion CO_2 capture technologies;
  - Less water for cooling is needed;
  - Uses equipment that is familiar to the power industry;
  - Allows for high-efficiency energy storage; and
  - Can be used on a retrofit or new installation.

Ongoing work within the DOE program is measured against specific performance goals. For post-combustion capture, two key indicators are: (1) reduction of the parasitic load due to CO_2 capture; and (2) reduction in the overall energy penalty due to CO_2 capture.[73] The reduction in parasitic loss and energy penalty demonstrates learning throughout the effort aimed at post- combustion capture.

Technology options demonstrating successful performance have continued forward. For example, ION Engineering is running tests at 12 MWe scale at the Test Centre in Mongstad, Norway. The intent is to develop more than one post-combustion capture option as the differences in power plant design, operational demands and site-specific limitations may mean that no single capture system is optimal for all applications.

A limited number of larger-scale test facilities are available around the globe. A network of such centers has evolved that can hasten the development of key technology components essential for rapid development of full-scale technologies. In 2013, the International Test Center Network (ITCN) was formed by the National Carbon Capture Center (NCCC) in Wilsonville, Alabama, and the Technology Centre Mongstad in Mongstad, Norway, to facilitate knowledge transfer from carbon capture test facilities around the world. The ITCN also includes facilities in Australia, Canada, Germany, and the United Kingdom.

73 National Energy Technology Laboratory, "DOE/NETL Carbon Capture Program: Carbon Dioxide Capture Handbook," 2015, https://www.netl.doe.gov/File%20Library/Research/Coal/carbon%20capture/handbook/Carbon-Dioxide-Capture-Handbook-2015.pdf.

B. Oxy-Combustion

Description: In oxy-fuel combustion, fuel is burned with an oxidant consisting of nearly pure oxygen and recycled flue gas. This method avoids the problem of energy-intensive CO_2/N_2 separation from dilute flue gas streams. For pulverized-coal power generation applications, part of the produced flue gas is recirculated to compensate for the higher flame temperature due to the nearly pure O_2. Therefore, combustion occurs in an environment that has higher CO_2 content and water (vapor) content compared to conventional air-fuel combustion. The CO_2-rich flue gas needs to be purified in a CO_2 purification unit (CPU) to remove the acid gases and other inert material. Because of the higher concentration of CO_2 (70 percent) and the lower flue gas volume, CO_2 capture is simplified compared to conventional post-combustion capture. Typically, the oxygen required for this process is supplied by an air separation unit (ASU), which by itself is energy and capital intensive, and operationally challenging.

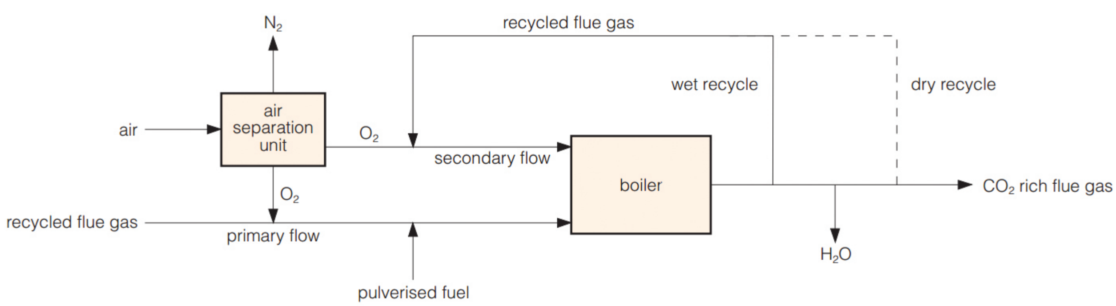

Figure III.3 Typical schematic of an oxy-fuel pulverized coal-fired power plant[74]

The three important components of oxy-fuel combustion technologies are the oxygen production, oxy-fuel combustion boiler, and the CO_2 purification and compression unit. The efficiency of oxy-fuel combustion can be improved by lowering the cost of oxygen supplied to the system, and by increasing the overall system efficiency. Commercial oxygen production systems are typically cryogenic ASUs; however, there is significant research on oxygen-transport membranes (OTMs) and chemical looping combustion (CLC) technologies. Oxy-combustion systems can be designed in either low- or high-temperature boiler configurations. Low-temperature designs have similar flame temperature as conventional combustion (~3,000° F), whereas flame temperatures in the high-temperature designs exceed 4,500° F.[75] Low-temperature designs are suited for new or retrofit applications and use flue gas recycle, and high-temperature designs, which are preferable for new power plant builds, are based on exploiting the increased radiant heat transfer to reduce the size and cost of the boiler. Furthermore, pressurized oxy-fuel combustion also reduces the equipment size, decreases air leakage, has higher heat transfer, and is projected to meet a CO_2 capture target cost of $30/ton.

74 IEAGHG, "Oxyfuel Comubstion of Pulverized Coal," IEA Clean Coal Centre, 2010.

75 National Energy Technology Laboratory, "Review – Oxy-Combustion," 2018, https://www.netl.doe.gov/research/coal/energy-systems/advanced-combustion/oxy-combustion/review-oxy-combustion.

Status: The CO_2 purification unit typically consists of a direct contact cooler (condensing heat exchanger), a unit to remove SO_x and NO_x, such as Linde's cold $DeNO_x$ (LICONOX), and a catalytic deoxidation reactor to reduce the final oxygen content in the flue gas (Follett, 2015). Such technologies, along with improved in-bed heat exchanger designs, and combustor designs are considered to be enabling technologies. A short list of oxy-fuel combustion technologies currently supported by DOE is provided in **Table III.2**.

TECHNOLOGY	BENEFITS	CHALLENGES	STATUS
Pressurized fluidized bed with CO_2 purification	In-bed heat exchanger for compact combustors 1/3 the size and half the cost of a conventional boiler	Corrosion in convective or in-bed heat exchangers Need to dry coal before feeding Particle sizes may change during operation	1 MW_{th} pilot plant constructed at Canmet Energy in Canada, commissioned, initial testing demonstrated at 120 psia
Supercritical CO_2 heat exchanger, staged coal combustion, isothermal deoxidation reactor (IDR)	sCO_2 heat exchanger can reduce the pressurized oxy-combustor system size further Staged-coal combustion avoids slagging for robust operation. IDR reduces oxygen content in flue gas below 100 ppm, making CO_2 suitable for EOR.	Only the coal and oxygen streams are to be staged, not the flue gas. Power cycle needs to be balanced with the coal-combustion cycle.	sCO_2 heat exchanger installed in 1 MW_{th} combustor at Canmet Energy Second-stage fuel injectors fabricated A micro-channel heat exchanger will be used to demonstrate the quasi-IDR concept.
Simultaneous recovery of latent heat and removal of SO_x and NO_x from flue gas in pressurized oxy-fuel combustion	Simultaneous latent heat recovery and sulfur/ nitrogen oxides removal eliminates conventional FGD and de-NO_x processes, lowering cost of electricity	Reaction kinetics for the latent heat exchanger/ direct-contact cooler are being studied currently.	Prototype dynamic combustion chamber for a 100 kW_{th} boiler built
Assessing impacts to boiler operation using computational fluid dynamics simulations using oxygen and minimum recycled flue gas	Better understanding of heat transfer and ash deposition in high-temperature, high-pressure oxy-fuel combustion.	Heat transfer, char oxidation, and ash deposition are not well understood in this environment.	Tests on 1 MW_{th} coal furnace and 100 kW burners were conducted

Table III.2 Oxy-fuel combustion technologies: Benefits, challenges, status[76]

76 National Energy Technology Laboratory, "Review – Oxy-Combustion," 2018, https://www.netl.doe.gov/research/coal/energy-systems/advanced-combustion/oxy-combustion/review-oxy-combustion.

Other concepts being investigated include:

- Flameless pressurized oxy-fuel (FPO) combustion, in which a slurry of milled coal and water is burned, producing slag and particulate ash. The hot gas is quenched and expanded through a turboexpander and its heat is recovered through economizers before the CPU.

- Recovering latent heat in flue gas using a high-pressure modified transport membrane condenser (TMC) nanoporous ceramic membrane commercially used for gas-fired boilers.

1. Chemical looping

Description: Chemical looping combustion (CLC) is an indirect combustion technology that avoids gas-separation by separating the combustion process into two different reaction zones, the air reactor (AR) and the fuel reactor (FR), so that the fuel and combustion air are kept separate. It represents a second-generation oxyfuel-combustion technology. A solid oxygen carrier (OC), typically, a metal oxide, is circulated between the two reactors (AR, FR), transporting oxygen from combustion air to the fuel.[77] The carrier is oxidized by combustion air in the AR and reduced in the fuel reactor by the fuel. The process yields two different exhaust gas streams—the AR exhaust gas stream consists of N_2 and excess O_2, whereas the exhaust gas stream from the FR contains combustion products (CO_2, water), and unburnt gaseous fuel. A highly concentrated CO_2 stream can be obtained after condensing the water. A variant of this technology, based on calcium looping, can also be applied to post-combustion CO_2 capture.[78]

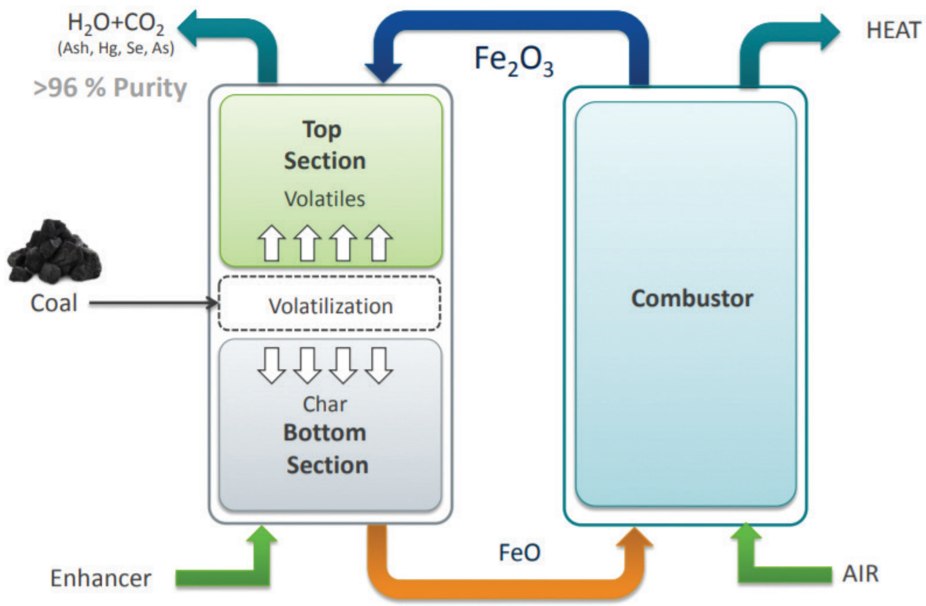

Figure III.4 Schematic of the CDCL process[79]

77 S. Penthor et al., «The EU-FP7 Project SUCCESS – Scale-up of Oxygen Carrier for Chemical Looping Combustion using Environmentally Sustainable Materials,» *Energy Procedia* (2017): 395–406.

78 Hari Mantripragada and Edward S. Rubin, "Chemical Looping for Pre-Combustion and Post-Combustion CO_2 Capture," *Energy Procedia* (2017): 6403–6410.

79 Luis Velazquez-Vargas, "Commercialization of the Iron-Based Coal Direct Chemical Looping Process for Power Production with in situ Carbon Dioxide Capture," 2017, https://www.netl.doe.gov/File%20Library/Events/2017/co2%20capture/5-Friday/L-Velazquez-Vargas-B-W-CDCL-with-CO2-Capture.pdf.

CLC eliminates the need for separate air-separation unit for producing oxygen, reducing parasitic energy demand and system costs, and uses conventional materials for construction. The projected costs of CO_2 capture using CLC are as low as $25/ton.[80] The challenges involved in scaling CLC are developing oxygen carriers that can withstand the alternating cycles in the FR and AR over long periods of time, solids circulation, and process design.

Status: Chemical looping processes are broadly classified by the type of oxygen carrier, the type of reactors, and the fuel used for combustion. Tests conducted between 2011 and 2015 identified that calcium carbonate-based oxygen carriers would not be effective for CLC. DOE has supported iron-carrier based, coal-direct chemical looping (CDCL) combustion technology, which consists of a riser for the AR and a moving bed for the FR. This technology is expected to increase the efficiency of a coal-fired power plant with CO_2 capture to 35.6 percent from 28.5 percent. This CDCL technology was tested at the 250 kW_{th} scale in 2017 using natural gas for over 200 h, achieving temperatures of 1800° F with nearly 100 percent CO_2 in condensed flue gas.[81] Other CLC technologies under development include CLC with oxygen uncoupling (CLOU), where oxygen is evolved from carrier in a gaseous form,[82] pressurized CLC with red mud (bauxite), and copper-based hybrid oxygen carriers. Further, recently, aluminum-based carriers with chemical stability over 3,000 process cycles (equivalent to eight months of lab-scale operations) having good attritional resistance and reactivity were developed.[83] Copper and aluminum-based oxygen carriers were also tested in Europe at scales up to 150 kW_{th} using natural gas feed as part of the EU-FP7 funded SUCCESS project.[84]

C. Pre-combustion

Description: Pre-combustion capture involves removing CO_2 from a gas stream before it is diluted with air or oxygen during the combustion process. The gas stream containing CO_2 will also have other components such as carbon monoxide, hydrogen, and methane, which have significant value either as fuels or chemical precursors. Unlike post-combustion capture, 100 percent of the incoming carbon is not necessarily converted to CO_2 prior to the combustion process.

It is applicable to gasification processes, including IGCC power plants, where coal or petroleum coke may be converted into synthesis gas (syngas), a mixture of hydrogen, carbon monoxide, and CO_2 and sulfur compounds such as hydrogen sulfide (H_2S). The produced syngas is burned in a gas turbine to produce electricity. The carbon is captured from the syngas before combustion in the turbine.

Status: There are only six commercially operating IGCC facilities worldwide; however, the technology concepts developed for pre-combustion capture can be applied to capture CO_2 from ammonia plants and hydrogen plants, which employ methane or naphtha reforming. Further, DOE is currently focused on developing technologies for small-scale modular coal gasifiers, which could also use pre-combustion capture technologies.

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80 J.M. Rockey, "Advanced Combustion Systems Program," 2017, https://netl.doe.gov/File%20Library/Events/2017/ucfe/5-17-1115-Technology-Portfolio--Advanced-Combustion-Rockey.pdf.

81 Luis Velazquez-Vargas, "Commercialization of the Iron-Based Coal Direct Chemical Looping Process for Power Production with in situ Carbon Dioxide Capture," 2017, https://www.netl.doe.gov/File%20Library/Events/2017/co2%20capture/5-Friday/L-Velazquez-Vargas-B-W-CDCL-with-CO2-Capture.pdf.

82 J.M. Rockey, "Advanced Combustion Systems Program," 2017, https://netl.doe.gov/File%20Library/Events/2017/ucfe/5-17-1115-Technology-Portfolio--Advanced-Combustion-Rockey.pdf.

83 C. Chung et al., "Chemically and Physically Robust, Commercially-Viable Iron-Based Composite Oxygen Carriers Sustainable over 3000 Redox Cycles at High Temperatures for Chemical Looping Applications," *Energy & Environmental Science* 10 No. 11 (2017): 2318 – 2323.

84 S. Penthor et al., «The EU-FP7 Project SUCCESS – Scale-up of Oxygen Carrier for Chemical Looping Combustion using Environmentally Sustainable Materials,» *Energy Procedia* (2017): 395 – 406.

The conversion of methane to syngas (e.g., via methane steam reforming) also produces syngas, however, the ratio of CO to H_2 from steam reformers is lower than that from coal or petroleum coke gasification. To capture a higher percentage of inlet carbon in the fuel, the syngas is shifted via water-gas shift (WGS) reaction to produce additional H2 and CO_2. The CO_2 from the shifted syngas is captured in the pre-combustion capture step, and the hydrogen fuels the gas turbine combined power generation unit.

The main challenge involved in pre-combustion capture is that any reduction in syngas temperature to enable low-temperature physical solvent-based capture (e.g., Selexol, Rectisol®) leads to a reduction in the overall power generation cycle efficiency. The DOE gasification program has already developed systems capable of removing sulfur compounds (e.g., H_2S) from syngas at high temperatures—this has been demonstrated at the 50 MW_e scale at Tampa Electric Company's Polk 1 IGCC power plant fueled by coal/petcoke-derived syngas. CO_2 capture solvents, sorbents, and membrane systems capable of operating at higher temperatures are being developed. Additionally, obtaining a relatively high/moderate pressure CO_2 product stream from the pre-combustion capture system is critical to reducing the costs of compression. Further, the loss of hydrogen to the product CO_2 stream also lowers the power generation efficiency (because the hydrogen in CO_2 stream is not used to generate power), and membranes and solvents that have lower loss of hydrogen are being explored. Finally, for integrated WGS reactions, CO_2 separation technologies are also being developed that combine the CO shift reaction with an in situ CO_2 removal step, thereby improving the reaction conversion and overall costs.

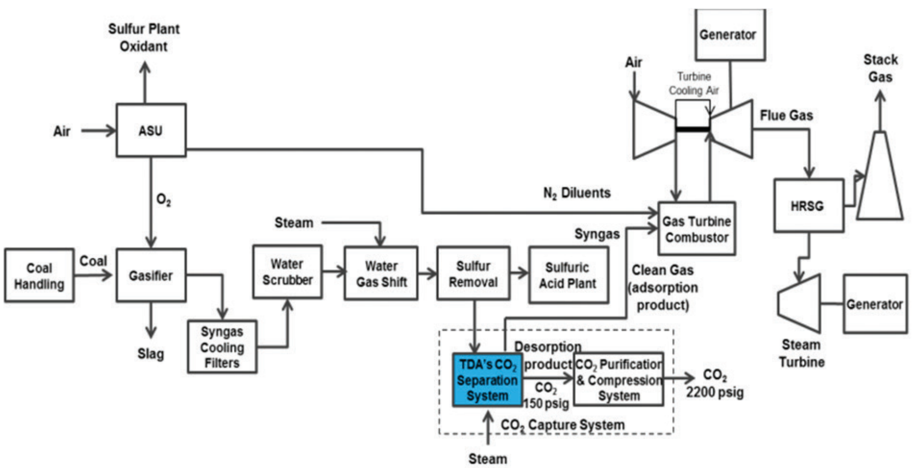

Figure III.5 Schematic of TDA Research's pre-combustion capture system in an IGCC power plant[85]

TDA Research is currently building a 0.1-MW_e scale pilot test facility at the SINOPEC Yangtzi chemicals petrochemical plant in China to test its carbon-based sorbent technology for pre-combustion CO_2 capture. The technology will be located downstream of the sulfur removal unit and uses a combination of pressure and concentration swings to separate CO_2 from the syngas (**Figure III.5**). This technology was first tested on an air-blown gasifier at the National Carbon Capture Center (NCCC) in Wilsonville, Alabama. The advantages of this system are that it produces relatively pure CO_2 at moderate pressures (150 psia), reducing the parasitic load of CO_2 capture and compression. The syngas does not need to be cooled and re-heated, eliminating the need for additional heat exchangers. Further improvements may be possible by integrating the capture step with the water-gas shift step.

85 TDA Research

D. CO_2 utilization: EOR, fuels, other

Figure III.6 illustrates most of the current and potential uses of CO_2. However, many of these uses are small scale and some emit the CO_2 to the atmosphere after use, resulting in little or no reduction in overall CO_2 emissions.[86]

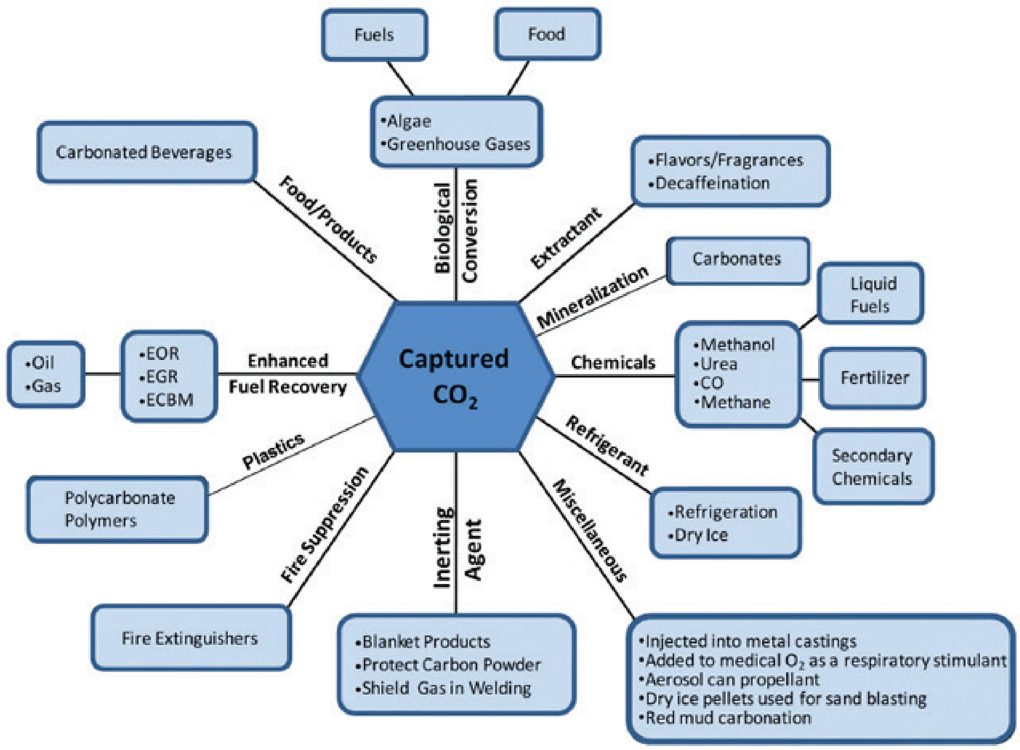

Figure III.6 Potential utilization streams for caputred CO_2[87]

Utilization is often seen as a minor part of any climate change mitigation strategy, although some of the uses being studied may have the potential to offset significant amounts of CO_2 emissions. Global CO_2 emissions in 2017 were approximately 32.5 Gt, suggesting that total annual reductions of between 10 Gt and 20 Gt per year would be needed to meet stabilization targets illustrated by International Energy Agency scenario analyses. Global storage capacity is certainly available to satisfy the requirement of such a goal. However, at current costs, CCUS is not a primary option. Successful development and commercialization of technologies that transform captured CO_2 into products may improve societal perceptions of CCUS and support development of the CCUS infrastructure. Construction of pipelines in the Gulf Coast region to provide CO_2 for EOR is an example. The presence of such a pipeline infrastructure could allow companies with other utilization technologies (e.g., chemicals, growing algae, etc.) to access enough CO_2 to operate plants that serve regional markets. An infrastructure that allows both storage and reuse could enhance the prospects for wider CCUS deployment.[88]

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86 National Energy Technology Laboratory, "CO_2 Utilization Focus Area," https://www.netl.doe.gov/research/coal/carbon-storage/research-and-development/co2-utilization.

87 NETL via CURC Carbon Utilization Research Council and ClearPath Foundation, "Making Carbon a Commodity: The Potential of Carbon Capture RD&D," July 25, 2018, http://www.curc.net/webfiles/Making%20Carbon%20a%20Commodity/180724%20Making%20Carbon%20a%20Commodity%20FINAL%20with%20color.pdf.

88 David Sandalow et al., "ICEF Carbon Dioxide Utilization Roadmap 2.0," 2017 and Global CCS Institute and Parsons Brinckerhoff, "Accelerating the Uptake of CCS: Industrial Use of Captured Carbon Dioxide," March 2011, http://hub.globalccsinstitute.com/sites/default/files/publications/14026/accelerating-uptake-ccs-industrial-use-captured-carbon-dioxide.pdf.

Common concerns with utilization are that (1) the quantity of CO_2 that would be utilized is small compared to the amount of CO_2 being emitted, (2) many uses do not necessarily consume the CO_2 and may eventually return the captured gas to the atmosphere, and (3) the energy required to transform the CO_2 into product significantly reduces the net benefit. RD&D programs within the United States and other countries have been developed to address these concerns and to create utilization pathways that ensure net environmental benefits. Current work on utilization technologies is focused on developing applications that lead to megaton-quantity reductions or greater year after year.

Many studies have examined utilization technology options typically grouped into a limited set of categories. The number of options (and target products) within a category can be quite diverse (**Figure III.6**). The main pathways are: enhanced resource recovery, concrete, fuels, polymers, chemicals, minerals, and more recently, carbon fibers, graphene sheets, and composites.

EOR and other hydrocarbon resource recovery options includes commercial applications (EOR, tight gas, some oil sand technologies) and can be readily expanded to other hydrocarbon formations. Development of these options is linked to and limited by possessing and demonstrating a sufficient knowledge of the geology of the resource-bearing formations to extract the valuable hydrocarbons while addressing all technical, environmental, and safety risks. A related option that has been proposed is to use supercritical CO_2 as the working fluid in thermal cycles to generate power from geothermal reservoirs. There has been little progress documented on this approach in recent years.

A substantial amount of ongoing work is focused on cement, concrete, and carbonate minerals. **Figure V.10** catalogs a number of projects (active in 2017) that are developing technologies to produce concrete or carbonate minerals and permanently consume anthropogenic CO_2.[89] The figure groups the methods by starting material and locates each technology within one of the four pathways by the technology readiness of the concept. Technology readiness, in this context, includes the largest scale at which the process or system has been evaluated. For example, five companies shown in the readiness column as 9 have taken their concept to the point that commercial quantities are being or can be produced.

The five main thrusts of U.S. RD&D utilization efforts are:

- Biological conversion into food or fuels;
- Using CO_2 from cement plant flue gases and local combustion sources to cure concrete while consuming substantial amounts of waste CO_2;
- Combining traditional monomers, such as ethylene and propylene, with CO_2 to produce polycarbonates, such as polyethylene carbonate and polypropylene carbonate while significantly reducing energy requirements;
- Converting CO_2 to solid inorganic carbonate minerals that are highly stable and can be used in construction or disposed of without releasing CO_2 into the atmosphere; and
- Enhanced hydrocarbon recovery by injecting CO_2 into a depleted oil- or gas-bearing field to increase production.

89 David Sandalow et al., "ICEF Carbon Dioxide Utilization Roadmap 2.0," 2017 and Global CCS Institute and Parsons Brinckerhoff, "Acceleratingthe Uptake of CCS: Industrial Use of Captured Carbon Dioxide," March 2011, http://hub.globalccsinstitute.com/sites/default/files/

Other pathways that may save energy compared to conventional approaches are also shown in **Figure III.6** and discussed in later sections. Carbonating beverages, use as an extractant or a refrigerant, use in fire extinguishers, and other miscellaneous applications do not consume the CO_2 although they may save energy. Use of supercritical CO_2 as a working fluid in power cycles, such as the Allam cycle, may lead to highly efficient power production and lower capital costs.[90] Development of technologies to convert CO_2 into stable carbon products (including carbon fiber, graphene sheets, and carbon nanotubes) is at an early stage.

E. Future applicability of CCUS to natural gas-fired generation

Work is already underway to develop systems for capturing CO_2 from natural gas-fired units. The Bellingham natural gas combined cycle (NGCC) power plant in south central Massachusetts demonstrated the commercial viability of carbon capture using Fluor's Econamine FG Plus[SM]. The 40 MW slipstream capture facility operated from 1991 to 2005 and captured 85–95 percent of CO_2 that would have otherwise been emitted. The CO_2 captured from this facility was purified and sold to the food industry.

Recently, there have been positive, new developments. Several advanced solvent technologies—including those produced by Shell-Cansolv, Aker Solutions, Carbon Capture Solutions India, and Alstom—have been validated for post combustion capture on natural gas flue gas at the large pilot scale at the Test Centre Mongstad (TCM) facility in Norway. The TCM facility hosts a 13 MW solvent system and a 15 MW chilled ammonia capture facility. These facilities are supplied flue gas from a natural gas-fired power plant and a catalytic cracker from a neighboring refinery. Generally, these first-generation capture technologies have proven that carbon capture from natural gas power plants is an available technology and can be scaled for commercial application. To date, however, the costs to do so would likely require significant financial incentives, or revenue raised through sale of the CO_2 for industrial uses, such as enhanced oil recovery or chemical production. Full commercial deployment requires a robust, well developed industry sector, R&D program, and set of policy incentives, as happened with photovoltaic solar, onshore wind, and LED lights.

Natural gas-fired power plants and pulverized coal steam plants have different integration needs, and would require modified engineering designs for post-combustion capture plant integration. For coal-fired units, the upstream pollutant capture systems impose fuel specific requirements, including the amount of parasitic power demand on the host plant. Another difference relates to load following in applications where a substantial amount of variable renewable energy is dispatched is a critical consideration. This situation is more likely to be associated with gas turbine applications than for coal-fired units, putting significant demands on the carbon capture system to follow the power demand placed on the fossil fuel-fired unit. The capital cost of the required equipment and the increased plant footprint may pose challenges to natural gas facilities, as they do to coal. Post-combustion capture at natural gas-fired power plants requires the separation of CO_2 and nitrogen after the combustion of natural gas with air. Challenges include high oxygen content, which can lead to faster solvent degradation rates and purity of permeate through a membrane system. Natural gas systems also tend to operate at higher temperatures, which can lead to the undesirable formation of nitrogen oxides and issues with durability of materials. Simple cycle gas turbines, absent the secondary heat recovery in a heat recovery steam generator, have higher exit gas temperatures and lower cycle efficiencies, which negatively affects the economics of capture. Emissions from natural gas power systems have a higher oxygen content and lower CO_2 content relative to coal-based systems. This lower CO_2 content requires a larger solvent-based absorber and demands more energy and surface area for a membrane-based capture system. Advanced CO_2 capture technologies that are being developed by DOE may be directly applicable to natural gas power plants.[91]

90 Sonal Patel, "Pioneering Zero-Emission Natural Gas Power Cycle Achieves First-Fire," *Power,* May 30, 2018, https://www.powermag.com/pioneering-zero-emission-natural-gas-power-cycle-achieves-first-fire/.

91 National Energy Technology Laboratory, "Carbon Capture Opportunities for Natural Gas Fired Power Systems," https://www.energy.gov/sites/prod/files/2017/01/f34/Carbon%20Capture%20Opportunities%20for%20Natural%20Gas%20Fired%20Power%20Systems_0.pdf.

NET Power has recently begun tests on a system that uses high-pressure sCO_2 (supercritical carbon dioxide) as a working fluid in a semi-closed loop to drive a combustion turbine. Natural gas is combusted (or synthetic gas from coal gasification) with pure oxygen and used as a working fluid. Its byproducts are liquid water, pipeline-ready CO_2, and argon and nitrogen, which could also be sold as commodities.[92] This approach should be readily adaptable to coal-fired and biomass-fired units as well.

F. CCUS outside the electricity sector: industrial facilities

In addition to capturing CO_2 from coal-fired power plants, industrial CO_2 capture, use, and storage is also required for significant emissions reductions from energy-intensive industries such as cement, steel, and chemicals. Advanced CO_2 capture technologies being developed for power generation can also be applied to industrial processes such as iron and steel, cement, ammonia, petrochemicals and hydrogen production, and natural gas processing, and reduce the total cost of production over conventional capture technologies (e.g., amines). Compared with power plant flue gas (~13 percent CO_2), it may be cheaper to capture CO_2 from industries with more concentrated CO_2 gas streams. For example, coal-fired power plant flue gas has a CO_2 partial pressure of 2 psia, whereas ethanol fermentation gas has a partial pressure of ~14 psia, and ammonia reformer process syngas has a CO_2 partial pressure of 70 psia. Capturing CO_2 from new coal-fired power plants is estimated to cost ~$50 – 60 per ton of CO_2. Industries with high-purity CO_2 gas streams such as ethanol, ammonia production, and natural gas processing have the potential to capture CO_2 at lower costs, which could serve as a springboard for wider CCUS adoption (**Figure III.7**).

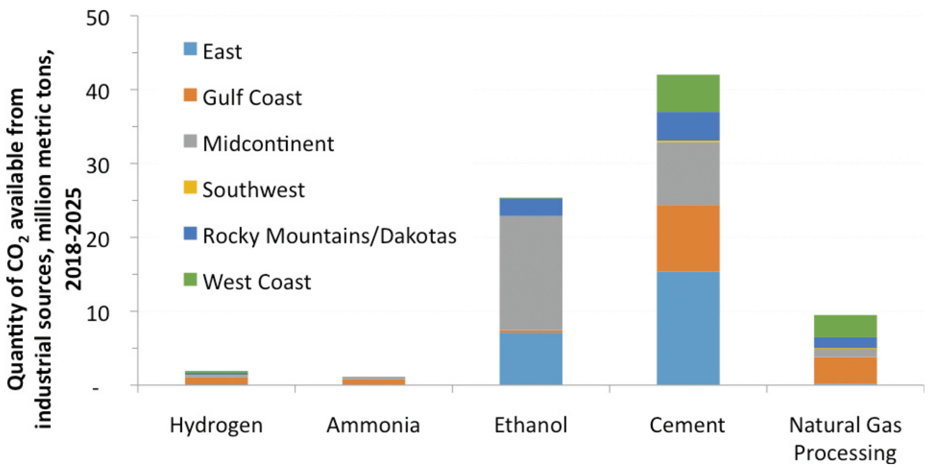

Figure III.7 Quantity of CO_2 available from U.S. industrial sources by region[93]

The U.S. Energy Information Administration (EIA) projects that up to 80 million tons of CO_2 could be available from U.S. industrial sources from 2018 to 2025 (**Figure III.7**). Power plant CO_2 capture is still relevant, because the overall quantity of CO_2 from industrial sources could be dwarfed by potential CO_2 supply from coal-fired power plants; however, industrial CO_2 capture may offer specific advantages compared to power plant CO_2 capture, including a more concentrated CO_2 stream and the potential to re-use captured CO_2 at the same facility.

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92 Sonal Patel, "Pioneering Zero-Emission Natural Gas Power Cycle Achieves First-Fire," *Power,* May 30, 2018, https://www.powermag.com/pioneering-zero-emission-natural-gas-power-cycle-achieves-first-fire/.

93 U.S. Energy Information Administration, "Oil and Gas Supply Module," 2018, https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf.

The addition of CO_2 removal may lead to the production of high-calorific value fuel gas, which could be used for process heating or for generating auxiliary power. Industries such as cement, iron and steel, and hydrogen production are already proactively involved in international efforts to reduce their greenhouse gas emissions. Advanced CO_2 capture technologies may also lead to the partial removal of air toxics, which may benefit industries subject to air permit requirements limiting the emissions of hazardous air pollutants. Further, low-grade heat from industrial processes may be used to offset steam requirements for CO_2 capture. Finally, the captured CO_2 could be used to enhance production, or could be sold for CO_2-EOR.

For industrial applications, the situation in the EU is instructive. On November 8, 2017, European negotiators struck a final deal on the revision of the Emissions Trading System (ETS) for the period 2021–2030, that had been proposed by the European Commission in July 2015. The agreement marks a major step forward in Europe's efforts against climate change, as it is the main legislative act implementing the European Union's target of reducing greenhouse gas emissions by 40 percent by 2030 on the 1990 levels.

The legislation affects about 11,000 installations (power plants and industry) in Europe, which account for 45 percent of EU greenhouse gas emissions and which will have to reduce them by 43 percent relative to 2005 levels. European industry subject to the ETS (chemicals, steel, aluminum, paper, glass, cement, etc.), has been under particular pressure due to tightening of the rules for the allocation of free allowances to industrial installations exposed at risk of carbon leakage as a consequence of asymmetric climate policies at the global level. Ensuring a sufficient number of free allowances to the best performing installations (those using the most efficient technologies commercially available today) has been finally recognized by member states as a key issue and therefore they have agreed to put three percent of their emission allowances at disposal of industry in case of need.

Sectors that are not deemed to be exposed at the risk of carbon leakage, however, will see a phasing out of the number of free allowances received (30 percent today) starting from 2026 to zero in 2030. Also, a more dynamic system of allocation of free allowances has been introduced, thus allowing for an allocation closer to actual production rather than historic production, meaning that the allowances will be adapted to production increases.

These actions have initiated a wide-spread interest across the EU for technology solutions – including CCUS for cement manufacturing, steel, and glass. The Norcem (a cement manufacturing operation in Norway) test facility is one of the world's first pilot plants for capturing CO_2 from a cement plant. The project started in 2013, and four different technologies will be tested: amine-based capture, membranes, solid sorbents, and carbonate looping. An important part of the project is to test if CO_2 capture can be performed by spill heat from the cement plant.[94]

A challenge to advancing industrial CO_2 is the wide variation in the characteristics of CO_2-containing gas streams from industrial sources, requiring special design considerations on a case-by-case basis. Technologies that have been evaluated to capture CO_2 from industrial gas streams include:

- Solvent absorption
- Adsorption
- Membranes
- Chemical looping

94 http://www.zeroco2.no/projects/norcem-cement-plant-in-brevik-norway.

CO_2 capture and utilization outside the electricity sector has been demonstrated at both commercial and demonstration/pilot scales, with captured quantities varying from kilograms per day to thousands of metric tons per year. The captured CO_2-rich gas has been used for several applications such as:

- Enhanced oil recovery (CO_2-EOR)
- Industrial-grade liquid CO_2
- Food-grade CO_2
- Enhanced urea/methanol production
- Process heating

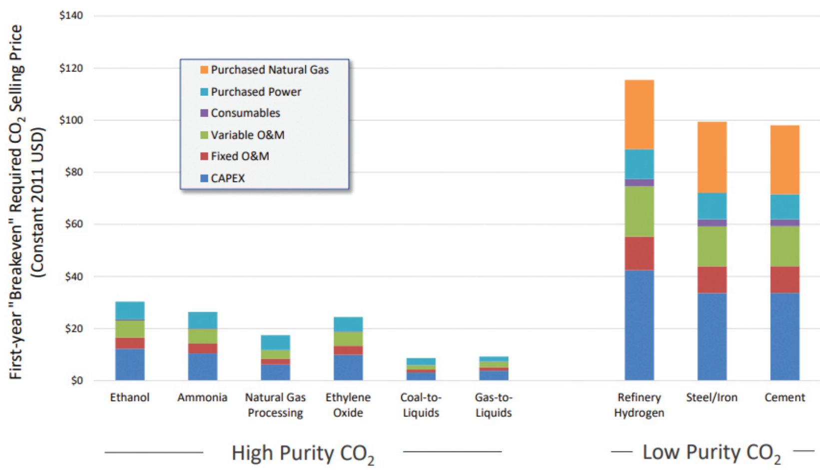

Figure III.8 Comparison of economics of CO_2 capture from industrial sources[95]

Solvent CO_2 capture technologies under development can be used to capture CO_2 from several iron and steel, cement, lime, and ammonia process gas streams. Sorbent and membrane capture technologies in general can be used for bulk CO_2 capture, but may not be used as standalone capture technologies in cases where high CO_2 removal or high-treated gas purity are needed.

In contrast, CO_2 capture from industrial processes does present certain challenges. Capital and operating cost penalties must be overcome and additional sources of steam and electric power may be required to supply the requirements for CO_2 capture. Competition from imported products manufactured using high-CO_2 intensity production methods may limit the adoption of CO_2 capture in industry. For plants that currently sell their CO_2 for industrial/food-grade gas, or for CO_2-EOR, additional CO_2 capture may require negotiating new or modified off-take agreements with their clients.

In addition to these benefits and challenges, U.S. market opportunities such as favorable industry growth rates and location near major CO_2 pipelines could act as drivers for adoption of industrial CO_2 capture technologies. Further, CO_2 capture demonstration plants on industrial processes could contribute to lowering technology costs and advancing CCUS to a higher technology-readiness level while promoting industrial interest in advanced capture technologies.

95 Chris Nichols, "Modeling of CCS: ETSAP Workshop Session," CCS in *Energy Scenarios,* 2017.

G. Sequestration

Permanent storage of captured CO_2, the likely fate of almost all of the CO_2 and some other trace gases, is an essential element of CCUS. Long-term storage must be achieved with minimal losses during transport and almost zero leakage during millennia of storage. Secure storage must be quantified and verified through accepted standards. Globally, appropriate geological formations for storage may occur within national boundaries. They may also be found in offshore subsea beds.

Within the United States, suitable geologic formations may include (a) active and depleted oil and gas reservoirs, (b) deep saline reservoirs, (c) unmineable coal seams, and (d) basalts. The National Energy Technology Laboratory's Carbon Storage Atlas V estimates that between 2,618 and 21,978 billion metric tons of CO_2 storage exists in North America.[96] Some of these structures have stored crude oil, natural gas, brine and CO_2 over millions of years. It is essential that the behavior of CO_2 when stored in any geologic formation be understood thoroughly. Issues include movement of the injected CO_2 throughout the formation, whether and how quickly physical and chemical changes occur within the formation, and whether a given formation has previously undocumented structural faults or has been penetrated by wells used for other resource extraction or waste injection. Some candidate formations have impermeable cap rock but are not fully closed–that is, the potential for leakage may exist at the edges of the confining rock layer. However, simulation capabilities, analytical tools and measuring instrumentation are available to ensure negligible risk that the plume of injected CO_2 would reach the edge of the confining cap rock.

Detailed knowledge of the geology of storage complexes in a variety of geologic settings is key to ensuring that carbon storage will not affect the structural integrity of the storage reservoir and seal(s), and that CO_2 storage is secure and environmentally acceptable. To that end, the U.S. DOE inaugurated the Regional Carbon Sequestration Partnership activity in 2003 with seven partnerships (which is described in more detail in section V.B below). These partnerships included many experts from all regions of the United States in subsurface characterization, modeling, monitoring, remote diagnostics, and risk assessment. Work involved selection of potential storage sites based on their geologic characteristics and regional distribution. The approach recognized that the subsurface of the earth is complex and it is unlikely that any two formations are exactly alike. Similar geologies have many similarities. When comparing between different types of geologic structures, it is not so simple.

In the United States, significant effort has been expended on pilot-scale and large-demonstration scale storage projects. Site assessments performed by the Regional Carbon Sequestration Partnership teams have been a key aspect of this. The knowledge base that has been created under DOE funding is captured in best practice manuals and risk assessment tools. The DOE Carbon Storage Program supports Monitoring, Verification, Accounting (MVA), and Assessment research into MVA tools applicable to four key needs: atmospheric measurements (leakage), near surface (early signs of leakage into ground water or well casing failures), subsurface (plume tracking, potential migration pathways) and intelligent monitoring (integrated, customizable approach to acquisition, analysis, and interpretation of monitoring tools and data for decision making). Research in these areas, in conjunction with small- and large-scale injection field tests, is producing advanced MVA tools. These tools can be applied in a systematic approach to address monitoring requirements across the range of storage formations, depths, porosities, permeabilities, temperatures, pressures, and associated confining formation properties likely to be encountered in CCUS. The increased capabilities of MVA tools will yield the ability to differentiate between natural and anthropogenic CO_2, monitor the migration of the CO_2 plume and pressure front, and verify storage efficiency (and utilization efficiency in the case of CO_2-EOR) and containment effectiveness. This will ensure protection of human health and the environment, as well as

96 National Energy Technology Laboratory, "Carbon Storage Atlas," Fifth Edition, August 2015, https://www.netl.doe.gov/File%20Library/Research/Coal/carbon-storage/atlasv/ATLAS-V-2015.pdf.

compliance with applicable regulations. An additional benefit of these research efforts will be the reduction in storage cost through optimal application of these tools.

MVA tools have advanced in application, sensitivity, and resolution over the last 10 years as field laboratory testing and both large- and small-scale demonstrations of geologic CO_2 storage have occurred. Large commercial operations—such as Sleipner in Norway, Weyburn in Canada, In Salah in Algeria, and efforts of the Regional Carbon Sequestration Partnerships in the United States—have resulted in the application and validation of monitoring tools from DOE's Carbon Storage R&D Program that identify CO_2 in the target formation, overburden, or at the surface, and in potential migration pathways from the formation to the surface. For example, the Carbon Storage Program supported the first successful application of gravity measurements to augment seismic monitoring at the Sleipner project. In the In Salah project, the Carbon Storage Program supported modeling and analysis of InSAR data, which was important to understanding CO_2 injection related pressure changes in and above the reservoir. The Midwest Regional Carbon Sequestration Partnership is evaluating the application of InSAR to detect ground surface movement as a result of CO_2 injection in closed carbonate reef reservoirs.[97]

1. Oil and gas reservoirs

The United States has practiced CO_2 injection for enhanced oil recovery and has been using approximately 32 million ton of CO_2 at recent market prices for the oil. During enhanced oil recovery, the integrity of the CO_2 that remains in the reservoir is well-understood and very high, as long as the original pressure of the reservoir is not exceeded. The scope of this EOR application is currently economically limited to tapping point sources of CO_2 emissions that are near an oil or natural gas reservoir. Similar uses for CO_2 have been made for select gas reservoirs.

2. Deep saline reservoirs

Saline formations may represent the largest potential for storage of CO_2. It has been estimated that deep saline formations in the United States could potentially store more than 12,000 billion tons of CO_2 making them a viable, long-term solution. Injection of CO_2 into deep saline formations does not produce value-added by-products, but it has other advantages. Likely suitable saline formations have been cataloged to exist near most existing large CO_2 point sources. Assuring the environmental acceptability and safety of CO_2 storage in saline formations is key. The determination that CO_2 will not induce impactful seismicity or escape from formations and either migrate up to the earth's surface or contaminate drinking water supplies are key aspects of on-going research. Currently, a significant baseline of information and experience exists.

3. Unmineable coal seams

Coal beds typically contain large amounts of methane-rich gas that is adsorbed onto the surface of the coal. The current practice for recovering coal bed methane is to depressurize the bed, usually by pumping water out of the reservoir. An alternative approach is to inject CO_2 into the bed. Tests have shown that the adsorption rate for CO_2 to be approximately twice that of methane, giving it the potential to efficiently displace methane and remain stored in the bed. CO_2 recovery of coal bed methane has been demonstrated in limited field tests, and more work is necessary to understand and optimize the process to determine feasibility and containment assurance.

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97 National Energy Technology Laboratory, "Best Practices: Monitoring, Verification, and Accounting (MVA) for Geologic Storage Projects, 2017 Revised Edition," August 2017, https://www.netl.doe.gov/File%20Library/Research/Carbon-Storage/Project-Portfolio/BPM-MVA-2012.pdf.

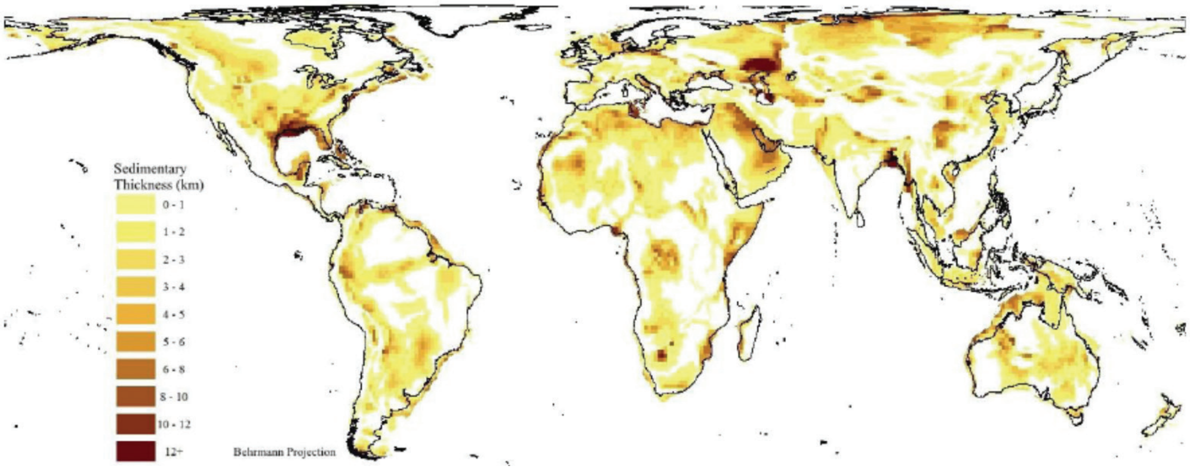

Figure III.9 Global CO_2 storage potential

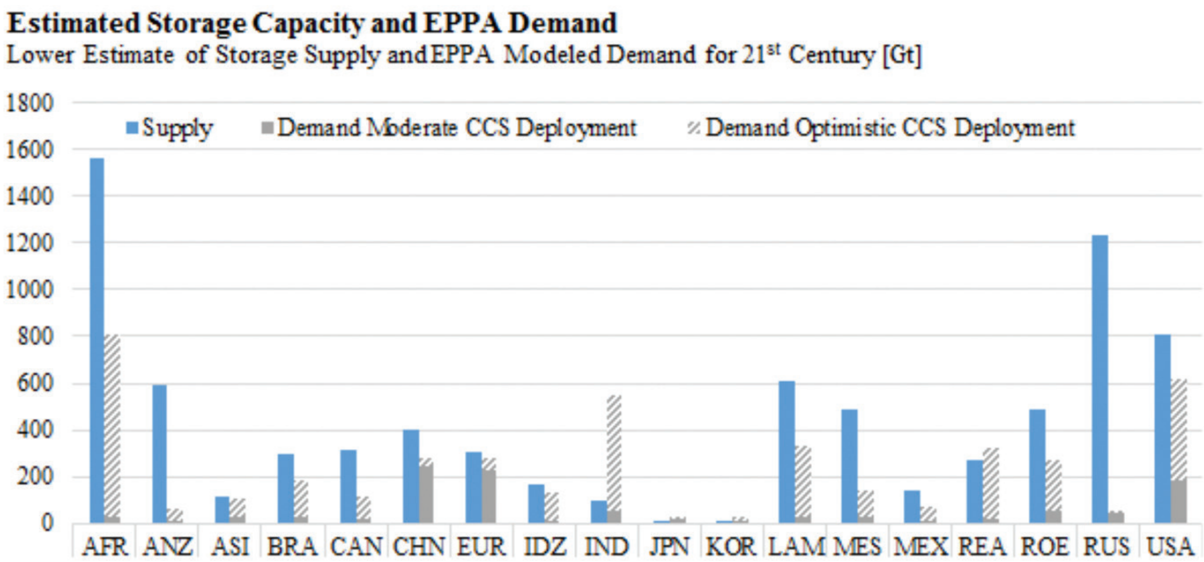

Figure III.10 Comparison of lower storage capacity estimates and the demand for carbon storage under various scenarios[98]

A key need before widespread development of storage facilities, onshore or offshore, can begin is to prove that adequate measurement tools and protocols will be available. These must accurately predict future capacity in geologic storage systems, assess and minimize the impacts of CO_2 and co-contaminants on geophysical processes, and improve our understanding of multiphase fluid migration. Simulation models and tools have been developed and are being improved to accurately predict the flow of the CO_2 in the target formations, assess chemical changes that may occur in the reservoir, and evaluate geomechanical effects that increased pressures might have on the target formation and seal(s). Early versions have been used during the RCSP projects and for other demonstration projects, and efforts to further advance and integrate these tools and technologies are ongoing through the Carbon Storage Program.

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98 J. Kearns et al., "Developing a Consistent Database for Regional Geologic CO_2 Storage," *Energy Procedia* 114: 4697–4709

Globally, many countries have completed assessments of on-shore storage capacity. A large proportion of the world's key CO_2 storage locations have now been assessed by national organizations (i.e., often a geological survey equivalent to the USGS). Many high-emitting nations have demonstrated substantial underground storage resources. Aside from the totals for the United States, China, Canada, Norway, Australia, and the UK all boast significant storage availability. Countries such as Japan, India, Brazil, and South Africa have also evaluated their storage capability.[99] **Figure III.9** presents an estimate based on available data and modeling analysis. Detailed data for the United States, developed by field assessments, is discussed in V.C. The low range for the U.S. is estimated to be ~2600 gigatons (Gt).

4. Future potential

Kearns et al., 2017, applied a standardized methodology for estimating storage capacity in sedimentary basins as a function of extent and thickness (**Figure III.9** and **Figure III.10**). The modeling method selected was used to address a concern that separate country regional estimates could not be compared as most were developed with different assumptions and methodologies. The research team applied a consistent methodology to develop several bar charts; the one in **Figure III.10** is the low estimate (the blue bars). The two grey bars represent different scenarios for captured CO_2 that might require access to safe storage. Note that this analysis includes both onshore and offshore storage. The lower total global storage capacity is estimated to be 7,910 Gt, whereas the upper estimate is 55,581 Gt.

5. Global status

Over 200 million tons of anthropogenic CO_2 has been successfully injected underground. Accumulated experience of CO_2 injection worldwide over several decades has proven there are no technical barriers preventing the implementation of storage. More than 40 sites have or are presently safely and securely injecting man-made CO_2 underground, mainly for EOR or explicitly for dedicated geological storage.[100]

6. Offshore

The UK and Australia have both looked at the potential for storage off-shore. The UK Crown Estate has been extensively assessed for potential storage. In Norway, the Sleipner and Snohvit projects have demonstrated offshore injection for CO_2 separated from natural gas. The Gorgon project in Australia is slated to begin injection in 2018 or 2019.[101] The United States is currently making a preliminary assessment of storage capacity in the Gulf of Mexico and the East Coast. Additionally, two offshore regional projects were recently initiated to identify and address knowledge gaps, regulatory issues, infrastructure requirements, and technical challenges associated with offshore storage in the Gulf of Mexico.[102]

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99 GCCSI, 2017a) Global CCS Institute, "The Global Status of CCS," 2017, http://www.globalccsinstitute.com/sites/www.globalccsinstitute.com/files/uploads/global-status/1-0_4529_CCS_Global_Status_Book_layout-WAW_spreads.pdf.

100 Ibid.

101 Ibid.

102 "Two Projects to Receive $8 Million for Offshore Carbon Storage Resources and Technology Development in the Gulf of Mexico," U.S. Department of Energy, Office of Fossil Energy, November 7, 2017, https://www.energy.gov/fe/articles/two-projects-receive-8-million-offshore-carbon-storage-resources-and-technology.

H. Technology lessons learned from major demonstration projects

This section provides an overview of major demonstration projects in North America. The key lessons and timeline for each project highlight the lead times and the specific issues involved in deploying carbon capture technologies across coal-fired power generation, gasification, hydrogen, ethanol, and petrochemical production.

1. Petra Nova

The Petra Nova CCS project is the world's largest post-combustion CO_2 capture system delivering and storing around 1.4 million metric tons of CO_2 per year for EOR. It is a 50/50 joint venture between NRG and JX Nippon Oil & Gas, with both companies sharing financial risks and benefits from this project. NRG is an independent power producer (not a regulated utility), so the project did not impact electricity rates for consumers. U.S. DOE provided up to $190 million in grants as part of the Clean Coal Power Initiative Program (CCPI), a cost-shared collaboration between the federal government and private industry. In addition, the project also received a loan of $250 million from the Japanese government and equity shares of $300 million each from NRG and JX Nippon.

Key Dates – Petra Nova

- Project awarded: May 2010
- Air permit: December 2012
- NEPA record of decision: May 2013
- Financial close: July 2014
- End of startup: December 2016
- Started operations: January 10, 2017
- Project construction completed on-budget and on-schedule.

The project captures 90 percent of CO_2 at 99 percent purity at an approximate generation scale of 240 MWe from the WA Parish Unit 8 boiler fueled by Powder River Basin sub-bituminous coal. CO_2 is separated from flue gas using the advanced MHI KM-CDR Process®, based on a proprietary MHI KS-1 high-performance amine solvent. The project was scaled-up from the original 64 MW to 240 MW level to significantly improve project economics and to produce enough CO_2 for use in enhanced oil recovery at the West Ranch oil field. Construction on the Petra Nova project began in 2014 and was completed on time and within the $1 billion ($4167/kW) budget.

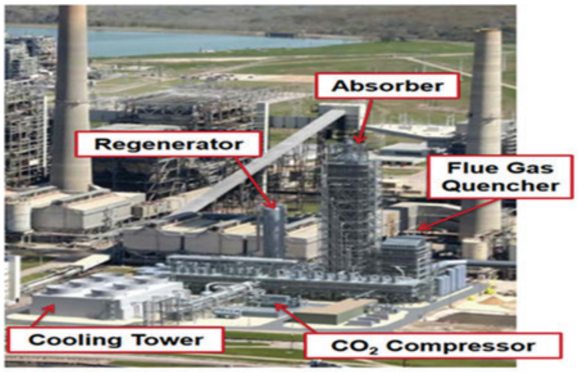

Figure III.11 View of the WA Parish Petra Nova[103]

103 Takashi Kamijo, "Current Status of MHI CO_2 Capture Plant Technology and Commercial Experiences," 2014 CO_2 Conference Week: The 12th Annual (2014) EOR Carbon Management Workshop, 2014.

Hilcorp Energy Company (Hilcorp), the operator of West Ranch oilfield, will use the captured CO_2 to boost production at West Ranch oilfield. The oilfield is jointly owned by NRG, JX Nippon, and Hilcorp. Both Hilcorp and the University of Texas Bureau of Economic Geology will monitor the movement of CO_2 deep in the oil reservoir. Over the next few years, oil production at the field is estimated to increase from ~300 barrels per day before beginning EOR operations to up to 15,000 barrels per day using captured CO_2. Currently, the production is ~4,100 bbl/d.

Key technology lessons – Petra Nova

- Prior to building the 4,776 t-CO^2/d capture plant at Petra Nova, MHI, the CO^2 capture technology licensor, demonstrated that it could capture up to 500 tons of CO_2 per day at a 25-MW fully integrated facility at Alabama Power's coal-fired James M. Barry Electric Generating Plant in 2011.
- The project was scaled from 64 MW to 240 MW to produce a higher CO_2 flow rate to obtain a meaningful response from the West Ranch oilfield (**Figure III.13**). A standalone co-generation unit supplies the parasitic load for the CCS process, simplifying the power plant retrofit and providing allowing for safe operation without disrupting the existing power plant operations.
- The co-gen unit was installed as a simple cycle peaking configuration in 2013, and thus was already in place and was generating revenue prior to the integration with the CCS unit.

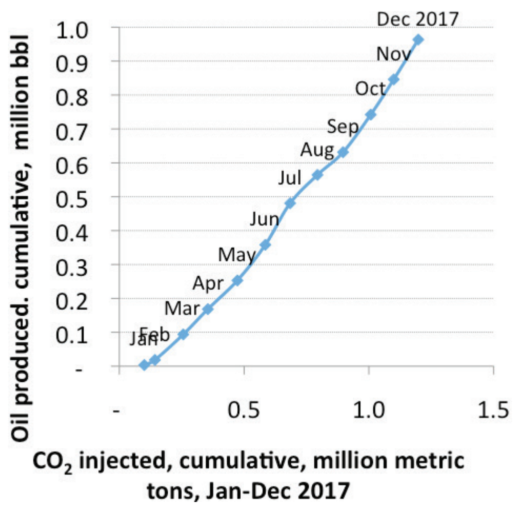

Figure III.12 Cumulative oil production from the West Ranch oilfield following CO_2 injection. Oil production increased from ~100 bbl/d to ~4100 bbl/d. Source: EIA-923, Texas RRC

- The post-combustion CO_2 capture technology demonstrated in this project can be used to retrofit existing coal-fired power plants and reduce CO_2 emissions potentially leading to a significant domestic and international market for this technology.

2. Kemper

The Kemper County IGCC project led by Southern Company, consisted of 2 gasifiers based on the transport integrated gasification (TRIG™) technology generating syngas from mine-mouth lignite coal. The syngas was combusted in two gas turbines. The project planned to capture 65 percent of the CO_2 and had a peak generation capacity of 582 MW. The project was designed to produce 3.8 million tons of CO_2 for EOR, 0.15 million tons of sulfuric acid, and 19,000 tons of ammonia as byproducts annually. CO_2 and H_2S would be captured after the syngas cooling and ammonia removal step using a Selexol® solvent. CO_2 was to be transported 60 miles for EOR.

Key Dates – Kemper IGCC project

- Project groundbreaking: June 2010
- Construction started: Q2, 2011
- Combined-cycle in service: Q3, 2014
- First coal feed to gasifier: July 2016
- Operations suspended: June 2017

Key technology lessons – Kemper

- Achieved fully integrated operation of entire IGCC: both CTs produced power with syngas, steam turbine produced power with superheated steam from syngas cooling
- Availability of the first-of-a-kind commercial TRIG™ technology was good or better than other gasification technologies during the time of operation (90 percent availability of gasifier).[104]
- Syngas clean up systems met all environmental permit requirements
- Achieved the design 65 percent CO_2 capture rate
- CO_2, ammonia, and sulfuric acid were produced within the quality specifications

3. Boundary Dam

The SaskPower Boundary Dam integrated carbon capture and storage demonstration project is the world's first large-scale post-combustion coal-fired carbon capture and sequestration project. It is located in Estevan, Saskatchewan, Canada. It is expected to capture around 1 million metric tons/year of CO_2, which is up to 90 percent of CO_2 emissions from one train (Unit 3) of the power plant. The facility uses Shell Cansolv technology to capture both CO_2 and SO^2 from the plant's flue gas. Most of the captured CO_2 will be used for EOR, some CO_2 will also be injected into a deep saline aquifer as part of the Aquistore Project. The captured SO_2 will be used to produce sulfuric acid.

Impending regulations limiting CO_2 emissions from power plants in Saskatchewan forced SaskPower (a Crown-owned power provider, i.e., public power utility) to evaluate the economics of replacing an old 150-MWe turbine (Boundary Dam unit 3 [BD3]) with an equivalent combined-cycle gas turbine, or to retrofit it using CCS.

SaskPower concluded that retrofitting BD3 with CCS using the Cansolv process and selling the captured CO_2 for EOR was more financially attractive. Two factors – namely, the ability to continue to re-use the existing plant infrastructure after CCS retrofits instead of building a new power plant and the income due from sales of CO^2, sulfuric acid, and fly ash over the next thirty years – helped to offset the costs. The cost of the

Key Dates – Boundary Dam CCS

- Project development started: 2007
- Decision to proceed: 2010
- Construction started: Spring 2011
- Construction completed: Summer 2014
- Project launched: October 2014
- First planned maintenance outage: September 2015
- Second planned maintenance outage: June 2017

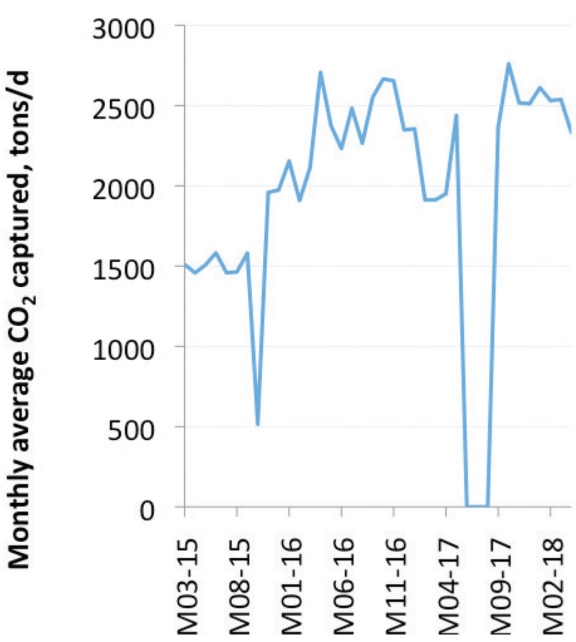

Figure III.13 Average monthly quantity of CO_2 captured from BD3[105]

104 Landon Lunsford, "Kemper County IGCC - Overview and Operational Summary," IEAGHG 4th Post Combustion Capture Conference Birmingham, AL, 2017.

105 SaskPower

120 MW (net) Unit 3 retrofit and CCS plant was C$1.5 billion.[106] The Canadian government provided C$200 million in subsidies, and SaskPower and its customers are responsible for the remaining balance. Cenovus has the option to take 50 percent to 99 percent of the CO_2 captured at the Boundary Dam project. SaskPower could not meet the minimum contract quantities in 2014 and 2015 and thus paid fines to Cenovus. The total CO_2 captured from 2014 to 2017 was 1.8 million tons. In 2016 and 2017, BD3 captured 0.79 million tons and 0.51 million tons, respectively. The average capture rate for BD3, from November 2015 to April 2018 (excluding plant shutdown) was 2338 tons per day (**Figure III.13**).

Key technology lessons: Boundary Dam

- Units 1 and 2 at Boundary Dam were approaching the end of their useful life (62 MW each, installed in 1959). Unit 3 was installed in 1970 and could be upgraded to be more efficient and was of a sufficient size to be economical for the addition of a CCS plant (pre-retrofit capacity of 139 MW). A thirty-year life of the retrofitted BD3 power plant was a requirement to attain an acceptable cost of electricity

- Parasitic load of capture and compression was reduced by one-third compared to what was expected at the beginning of the retrofit in 2009 – mainly by improving the efficiency of power generation and capture plant performance.

    - The boiler was upgraded from 1,000° F to 1,050° F and had significantly more surface area to increase the boiler efficiency and the plant efficiency.

    - The 1969 turbine was replaced with a modern dual-mode turbine incorporating better steam and thermal integration to support the large steam extraction required for solvent regeneration. The plant is required to run at baseload irrespective of the CO^2 capture plant operation. Power unit's output in non-capture mode was increased by 11.1 MW (7.4 percent) over the original retrofit design as a result of the boiler and turbine improvements.107

- Excessive amine foaming resulted in high differential pressure, increasing the parasitic load. Activated carbon filtration decreased foaming issues.

- Ash plugging resulted in high fan drafts and was controlled by online demister wash systems and using sprays for particulate control before the SO^2 absorber.

- CO_2 amine degradation was higher (4x) than expected. On-site thermal reclamation option was developed to reduce buildup of degradation products in amine

- Production bottlenecks are being identified—minor maintenance issues can be addressed without shutting down the CCS plant.

- For future retrofitting construction projects, design needs to be modularized to enable simpler construction at a lower cost.[108]

- It is expected that the next plant using similar technology would be up to 30 percent less expensive compared to this project.[109]

106 IEAGHG, 2015 International Energy Agency Greenhouse Gas R&D Program, "Integrated Carbon Capture and Storage Project at SaskPower's Boundary Dam Power Station," June 2015, https://ieaghg.org/docs/General_Docs/Reports/2015-06.pdf.

107 International Energy Agency Greenhouse Gas R&D Program, "Integrated Carbon Capture and Storage Project at SaskPower's Boundary Dam Power Station," June 2015, https://ieaghg.org/docs/General_Docs/Reports/2015-06.pdf.

108 Ibid.

109 Ibid.

4. Industrial projects: Air Products, Archer Daniels Midland

Air Products' Port Arthur CCS project: The Port Arthur CCS project is built and operated by Air Products and Chemicals Inc. and is located at the Valero Oil Refinery in Port Arthur, Tex. CO_2 capture was retrofitted to two existing steam methane reformers (SMRs) used for hydrogen production. Approximately 925,000 tons CO_2 annually is captured from the SMR process gas stream (10 – 20 percent CO_2) using a vacuum swing adsorption (VSA) process. The project has a 30 MW_e cogeneration unit to provide steam for SMRs and power to VSA and compressors. The captured CO_2 is compressed and transported via Denbury's Green pipeline for EOR at the West Hastings oilfield in Texas. The total cost of the project was $431 million, with a DOE share of $284 million. DOE funding was provided under the industrial capture and storage (ICCS) program through the American Recovery and Reinvestment Act (ARRA) of 2009. The project was executed on time and under budget and has delivered over 4.0 MM tons of CO_2 as of October 2017.

Key technology lessons- Port Arthur CCS project

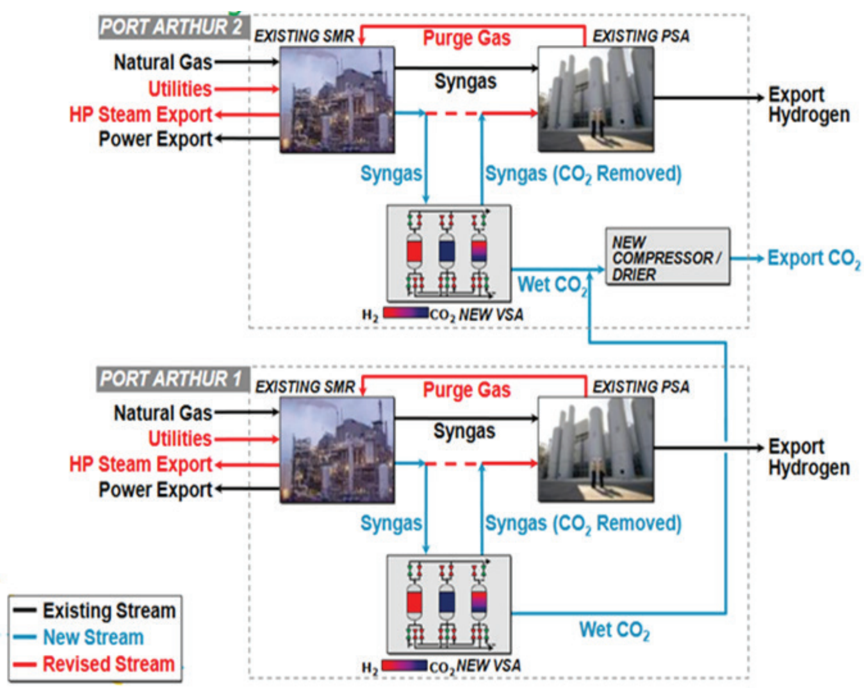

Figure III.14 Schemeatic of Port Arthur CCS project[110]

110 W. Baade et al., "CO_2 Capture from SMRs: A Demonstration Project," *Hydrocarbon Processing,* September 2012: 63–68.

- Capturing CO_2 from existing hydrogen plants with PSAs is challenging because the thermal efficiency is already highly optimized. Project demonstrated that VSAs are preferable for CO_2 capture retrofits because they can be installed with minimal disruptions to hydrogen supply for the existing refinery.[111]

- Project has been in full continuous operation since December 2012 and has captured over 4.04 million metric tons of CO_2 as of October 2017.

- DOE funding and revenues through 45Q tax credits and CO_2 sales for EOR helped to cover the costs of CO_2 storage and compression; SMR operations are not affected.

Key Dates – Port Arthur CCS project

- Phase 2 Awarded: June 15, 2010
- Permits issued: May 2011
- NEPA FONSI: July 2011
- Construction started: Aug. 2011
- Operation started: Dec. 2012
- Full capacity achieved: April 2013

Archer Daniels Midland (ADM) Illinois CO_2 capture project: This industrial CCS project is built and operated by ADM at their existing biofuel plant in Decatur, Ill. CO_2, which is a byproduct from production of fuel-grade ethanol by fermentation is dried and compressed (energy-intensive capture not needed) for storage in deep saline formations. The project captures and stores approximately 0.9 million tons/y in the Mt. Simon sandstone. This is the first project to use the EPA Class VI well permit for CO_2 injection, and cost $208 million, of which $141 million were provided under the DOE's CCSI funding. CO_2 is transported via an eight-inch, one-mile pipeline and is stored at a depth of more than 7,000 ft.

Key Dates – ADM CCS project

- FEED Completed: April 2011
- Construction started: May 2011
- Two monitoring wells drilled: Nov. 2012
- UIC Class VI Injection Well Permit: Sept. 2014
- Injection well drilled and completed: Sept. 2015
- Construction April 2016
- Commercial Operation: April 2017

Key technical lessons: ADM Illinois CO_2 capture project

- The ADM CCS project demonstrates commercial-scale applicability of CCS technology in saline storage formations.

- Was the first to use the new EPA Class VI underground injection permit for CO_2 storage.

- Project is currently permitted to operate for five years, with a potential to store 5.5 million tons of CO_2 in total.

111 IW. Baade et al., "CO2 Capture from SMRs: A Demonstration Project," Hydrocarbon Processing, September 2012: 63–68.

5. International lessons: Where has CCUS worked in other countries?

There are a number of carbon capture and storage projects that are operational around the world. In 2017, the Global Carbon Capture and Storage Institute identified 21 capture and storage facilities, some commercial, some still focused on R&D around the world.[112] Seventeen of these were operational. Nine were in the United States, three in Canada, one in Brazil, two in Norway, and one each in Abu Dhabi and Saudi Arabia. In addition, the Gorgon facility was identified as slated for operation in 2018. A brief discussion of those units with a significant operational history and lessons learned from them, is given in this section. The various field projects have proven to be an invaluable source of information on means to assess a geologic formation for the purposes of CO_2 storage. Many of these are oil and gas fields which are routinely characterized to assess both potential yield of a product and to develop plans to extract the resource efficiently and cost effectively. Additional measures need to be taken when planning CO_2 injection including the injection phase and any additional monitoring wells. This work, coupled with the information developed from the Regional Partnership (RCSP) activities in the United States, has greatly improved our understanding and lead to the development of best practices and to both a Canadian national standard for CO_2 storage and an ISO standard for storage as discussed elsewhere in this document.

a) Sleipner

A number of gas separation projects have included storage as the completion step. Sleipner was an important early step, as it included off-shore processing and storage with substantial oversight as to the fate of the CO_2 once it was pumped into the subsea formation. The Sleipner CO_2 Storage facility was the first in the world to inject CO_2 into a dedicated geological storage setting. Sleipner, located off the coast of Norway, has captured CO_2 as part of a natural gas production project since 1996. The captured CO_2 is directly injected into an offshore sandstone reservoir. Approximately 0.85 million tons of CO_2 is injected per annum and, as of June 20, 2017, over 17 million tons has been injected since inception. The capture technology employed is an amine scrubber. The captured CO_2 is compressed and also routed to the injection station (at Sleipner A), where it is injected into the Utsira Formation, a sandstone reservoir 820 foot thick. The reservoir unit is at a depth of 2,625 – 3,610 feet below sea level. The seal to the reservoir is provided by a 2,430-foot-thick gas-tight caprock above the Utsira Formation.

The purity of the injected CO_2 is ~98 percent. The remaining 2 percent is mostly methane. Initial development plans indicated that the amount of CO_2 to be injected over the field's expected life (25 years) was around 25 million tons. However, lower CO_2 content and a decreasing production profile for Sleipner Vest has seen this figure revised to around 17.5 million tons by 2020. Since 2014 the CO_2 capture facilities at Sleipner T process an additional 100,000 – 200,000 tons per annum of CO_2 associated with gas production from the Gudrun field.

An extensive program to monitor and model the distribution of injected CO_2 in the Utsira Formation has been undertaken by a number of organizations (and has been partly funded by the European Union). This program includes a baseline 3D seismic survey and eight time-lapse (4D) seismic surveys, four seabed micro gravimetric surveys, one electromagnetics survey, and two seabed imaging surveys.[113]

112 Global CCS Institute, "The Global Status of CCS," 2017, http://www.globalccsinstitute.com/sites/www.globalccsinstitute.com/files/uploads/global-status/1-0_4529_CCS_Global_Status_Book_layout-WAW_spreads.pdf.

113 CCS Network, "Sleipner CO[2] Injection - EU CCS Demonstration Project Network." https://ccsnetwork.eu/projects/sleipner-CO2-injection.

b) In Salah

Located in central Algeria, injection at In Salah started in 2004. Injection was suspended in 2011 due to concerns about the integrity of the seal. During the project's lifetime, 3.8MT/CO_2 was successfully stored in the Krechba Formation. A depleted gas reservoir located near the gas processing plant is located 1.9km deep in a carboniferous sandstone unit. Three long-reach horizontal injection wells were used to inject the CO_2 into the down-dip aquifer leg of the gas reservoir. No leakage of CO_2 was reported during the lifetime of the project. The formation has an estimated 17 million tons total storage capacity. CO_2 injection cost approximately $6/ton CO_2.

The successful storage of CO_2 in the Krechba Formation gives valuable insight into how CO_2 can be stored. Carboniferous sandstone wells are common in the United States, Northwest Europe, and China. The site has been closely monitored with a variety of monitoring techniques. Monitoring data has been used to update and refine the geological, geomechanical, and flow dynamical models of the storage complex.

Analysis of the reservoir and 2010 seismic and geomechanical data led to the decision to suspend CO_2 injection in June 2011.[114]

Storage at In Salah has been monitored using a diverse portfolio of geophysical and geochemical methods, including time-lapse seismic, micro-seismic, wellhead sampling using CO_2 gas tracers, down-hole logging and core analysis, surface gas monitoring, groundwater aquifer monitoring, and satellite InSAR data. These choices were based on a wealth of experience highly relevant to CCUS projects worldwide. Routines and procedures for collecting and interpreting these data have been developed, and valuable insights into appropriate Monitoring, Modelling and Verification (MMV) approaches for CO_2 storage have been gained. Key lessons learned from this demonstration project that can be applied to other major CCUS projects, are: need for detailed geological and geomechanical characterization of the reservoir and overburden; importance of regular risk assessments based on the integration of multiple different datasets; importance of flexibility in the design and operation of the capture, compression, and injection system.

c) Weyburn

The Weyburn-Midale project injects CO_2 captured at the Great Plains Gasification facility. The CO_2 captured in Beulah, North Dakota is pipelined ~200 miles to the injection sites in the Weyburn and Midale oil fields. It is then injected, along with water, ~15,000 feet underground into a depleted oil and gas reservoir. Additional oil and gas are produced, along with water and injected CO_2. A significant amount of the CO_2 stays safely underground while the water and some CO_2 that are produced with the oil are separated from it and reinjected. Successful demonstration of this approach added another 20 years to the operating life of the fields.

Overall, it is anticipated that some 40 million tons of CO_2 will be permanently sequestered over the lifespan of the project. At the plant, CO_2 is captured by a commercially available scrubbing technology (Rectisol) in the gas cleanup train. Approximately 8,000 metric tons of compressed CO_2 (in liquid form) is provided to the Weyburn and Midale fields each day via the pipeline.

During its life, the Weyburn and Midale fields combined are expected to produce at least 220 million additional barrels of incremental oil, through miscible or near-miscible displacement with CO_2, from fields that have already produced over 500 million barrels (79,000,000 m^3) since discovery in 1954. It has been estimated that, on a full life-cycle basis, the oil produced at Weyburn by CO_2-EOR will release only two-thirds as much CO_2 to the atmosphere compared to oil produced using conventional technology.

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114 Massachusetts Institute of Technology, In "Salah Fact Sheet: Carbon Dioxide Capture and Storage Project," *Carbon Capture & Sequestration Technologies* @ MIT, https://sequestration.mit.edu/tools/projects/in_salah.html.

A multi-year, two-phase research effort was initiated to evaluate the consequences of CO_2 injection. The IEAGHG Weyburn CO_2 Monitoring and Storage Project Phase 1 ran from 2000 through 2004. A critical part of the First Phase was the accumulation of baseline surveys for both CO_2 soil content, and water wells in the area. These baselines were identified in 2001 and have helped to confirm through comparison with more recent readings that CO_2 is not leaking from the reservoir into the biosphere in the study area. Based on preliminary results, the natural geological setting of the oil field was deemed to be highly suitable for long-term CO_2 geological storage. At the end of phase 1, additional research was deemed appropriate to further develop and refine CO_2 monitoring and verification technologies (the Midale oil field did not join the research project until the second research phase). The overall purpose of the first phase was to verify the ability of an oil reservoir to securely store CO_2 for significant lengths of time. This was done through a comprehensive analysis of the various process factors as well as monitoring/modeling methods designed to measure, monitor, and track the CO_2. Prediction, monitoring, and verification techniques were used to examine the movements of the CO_2. Finally, both the economic and geologic limits of the CO_2 storage capacity were predicted, and a long-term risk assessment developed for storage of CO_2 permanently in the formation. Permanent storage is often described as for geologic periods of time or millennia. Practical considerations in permitting suggest a post-closure period monitoring lasting 50 years for sites that have been characterized (measured) and modeled, with reasonable scientific confidence, so as to ensure that the area of review can hold all the injected CO_2 without risk of leakage.

The second phase ran from 2005 to 2012 and brought scientific experts from most of the world's leading carbon capture and storage research organizations and universities to further develop and build upon the most scrutinized CO_2 geological storage data set in the world. The project's major technical research "themes" can be broadly broken out into four areas:

Technical Components:

- Site Characterization
- Wellbore Integrity
- Monitoring and Verification
- Performance Assessment

A final report on the assessment project was issued by IEA and is available online.

d) Uthmaniyah, Saudi Arabia

The Uthmaniyah CO_2-EOR Demonstration project compresses and dehydrates CO_2 from the Hawiyah NGL (natural gas liquids) Recovery Plant in the Eastern Province of the Kingdom of Saudi Arabia. Operations commenced in 2015 with a CO_2 capture capacity of around 0.8 Mtpa. The captured CO_2 is transported via pipeline to the injection site in Ghawar oil field (a small flooded area in the Uthmaniyah production unit) for enhanced oil recovery.[115]

115 Global CCS Institute, "Uthmaniyah CO_2-EOR Demonstration." https://www.globalccsinstitute.com/projects/uthmaniyah-CO2-eor-demonstration-project.

The objectives of the project are determination of incremental oil recovery (beyond water flooding), estimation of sequestered CO_2, addressing the risks and uncertainties involved (including migration of CO_2 within the reservoir), and identifying operational concerns. The project has an elaborate monitoring and surveillance program to provide a clear assessment of CO_2 storage underground. As a result, the project has become a site for testing new monitoring technologies. Extensive monitoring and surveillance is underway. Technologies deployed and being evaluated include:

- Plume tracking and CO_2 saturation monitoring using seismic, EM, and gravity.
- Inter-well connectivity using chemical tracers.

e) Emirates Steel, Abu Dhabi

The Abu Dhabi National Oil Company (ADNOC) has stored approximately 240,000 metric tons of CO_2, collected from Emirates Steel Industries (ESI), by injecting it into its reservoirs at Rumaitha and Bab oilfields to bolster oil recovery. Abdulmunim Saif Al Kindy, director of ADNOC's Upstream Directorate and chairman of Al Reyadah said: "As we push forward plans to create value by maximizing oil recovery over the life time of our fields, we will increasingly utilize a range of Enhanced Oil Recovery technologies, of which carbon capture, use and storage is not only good for the environment but also makes sound business sense."[116]

Starting in 2021, ADNOC will gradually increase the utilization of CO_2, expecting to reach ~14,000 metric tons per day (250 million standard cubic feet per day [MMscfd]) by 2027. ADNOC plans to capture additional CO_2 from its gas processing plants and inject it into different onshore oil fields. ADNOC was the first National Oil Company to pilot CO_2 injection for EOR in 2009. In 2016 ADNOC joined forces with Masdar to launch Al Reyadah, the first commercial-scale CCUS facility in the Middle East & North Africa (MENA). Al Reyadah is now fully owned by ADNOC and integrated into ADNOC Onshore. To meet the increased demand for CO_2, which will be injected into Abu Dhabi's maturing oil reservoirs, ADNOC has drawn up ambitious plans to capture the greenhouse gas from its own operations. ADNOC aspires to achieve up to 70 percent ultimate oil recovery rate from its reservoirs, which is twice as much as the global average, applying conventional recovery methods.

f) Gorgon

The Gorgon Project is located approximately 60 kilometers off the northwest coast of Western Australia. Although the wells are off-shore, the natural gas is gathered through a sub-sea infrastructure and delivered to the processing plant with equipment to separate natural gas and CO_2. This plant is located on Barrow Island. Start-up problems have delayed the CO_2 injection phase although the Gorgon field has begun to produce raw gas and to separate the CO_2 from the natural gas. The CO_2 is currently being vented until the piping system needed for injection has been upgraded to avoid corrosion risks.

116 HP, "ADNOC to Expand Carbon Capture, Use & Storage Technology for Enhanced Oil Recovery," 2018. http://www.hydrocarbonprocessing.com/news/2018/02/adnoc-to-expand-carbon-capture-use-storage-technology-for-enhanced-oil-recovery.

In summary, approximately 200 million tons of CO_2 have been injected as part of demonstration projects and commercial EOR around the world. As a result of knowledge gained from these activities, international standards are being developed under the auspices of the International Organization for Standardization (ISO). Four ISO standards have been developed dealing with: performance evaluation of post-combustion, solvent-based capture systems; pipeline transportation; geological storage; and CO_2 storage derived from enhanced oil recovery. In addition, standards are under development related to quantification and verification; and procedures to assure and maintain stable performance of post-combustion CO_2 capture plant. ISO documents are developed using a consensus process by expert groups and rely on the lessons learned from test programs, demonstrations, and operating facilities. Twenty-one countries are full participants in this technical committee.[117]

I. Challenges remaining/barriers to widespread adoption

To date, substantial progress has been made along the complete system for CO_2 capture and storage for both power plant and industrial applications. Performance of solvent-based systems has been increased by improvements to both the fundamental capture system and through understanding of the impact of thermal integration. Cost of capture per ton of CO_2 is now estimated to be between \$50 and \$60 (USD) for coal-fired power.[118] A substantial body of large pilot-scale studies of CO_2 injection and storage in a variety of geologic formations has allowed development of measurement tools and assessment techniques to support site selection. Data acquired at commercial plants and storage sites are available to raise confidence in the technologies and the long-term security of injected CO_2. A number of alternative methods, particularly focused on sorbents and solvents, are encouraging and suggest further significant reductions in capture cost and the cost of electricity. But important work remains.

1. Technical status

Both pre- and post-combustion technology capture technologies require further research to reach the cost and performance goals adequate to begin commercial deployment on a variety of power systems. Novel concepts for CO_2 capture that are being evaluated include hybrid systems that combine attributes from multiple technologies, electrochemical membranes, and advanced manufacturing to enable enhanced processes. These novel concepts need to be tested at relevant scales to demonstrate proofs-of-concept and significant reduction in the cost of CO_2 capture.

CO_2 utilization can involve many uses. The DOE/FE program continues to pursue applications tied to cement curing. Research is currently focused on:

- Improving curing rates and CO_2 yield to increase efficiency of use.
- Developing curing processes based on carbonation chemistry rather than hydration chemistry. This shift in process focus should reduce energy requirements and CO_2 emissions.

117 International Standards Organization, "ISO/TC 265: Carbon Dioxide Capture, Transportation, and Geological Storage," 2016, https://www.iso.org/committee/648607/x/catalogue/p/1/u/0/w/0/d/0.

118 Global CCS Institute, "Global Costs of Carbon Capture and Storage: 2017 Update," https://hub.globalccsinstitute.com/sites/default/files/publications/201688/global-ccs-cost-updatev4.pdf.

In the area of chemical conversion, a major challenge is the complexity caused by the need to consume the CO_2 in a two-step process: first convert the CO_2 to carbon monoxide (CO) or some other reactive species; then follow that by using the reactive species to interact with a monomer to make polycarbonates. Causing this two-step process to occur in a single step (for example using a catalyst that does both in the same reaction vessel) may result in a more efficient pathway and reduces energy requirements while producing polycarbonate plastics from CO_2. The advantage of this process is that it copolymerizes CO_2 directly with other monomers. Research is currently focused on:_

- Utilizing waste energy or alternative energy sources to convert CO_2.
- Developing catalysts to reduce energy requirements.
- Developing stabilizers to inhibit degradation of plastics.

Mineralization may consume CO_2 to produce commodity minerals or to that can be disposed of without concern that the CO_2 they contain will release into the atmosphere. The research focus for this pathway includes:

- Reducing energy requirements for grinding process feedstock;
- Utilizing waste streams to obtain oxides from existing mining operations;
- Developing chemicals or catalysts to speed reaction rates and reduce thermal and pressure requirements; and
- Meeting industrial standards for building materials.

Finally, the use of CO_2 for enhanced hydrocarbon recovery is already being practiced for enhanced oil recovery and tight gas. Improvements may be possible for this application as the range of geologic formations to which this technique has been applied is limited. In addition, other unconventional oil and gas reservoirs may be candidates where enhanced recovery techniques can be applied. The current research focus is to:

- Maximize the amount of CO_2 that could be stored as well as maximize hydrocarbon production as part of these enhanced hydrocarbon recovery operations; and
- Develop sequestration sites and adjacent CO_2 infrastructure

2. Cost status

Capture technologies developed primarily for gas separation (typically natural gas and acid gases) have not been shown to be cost-effective when applied to flue gas streams. **Figure III.15** shows the range of costs and availability for CO_2 capture from various sources.

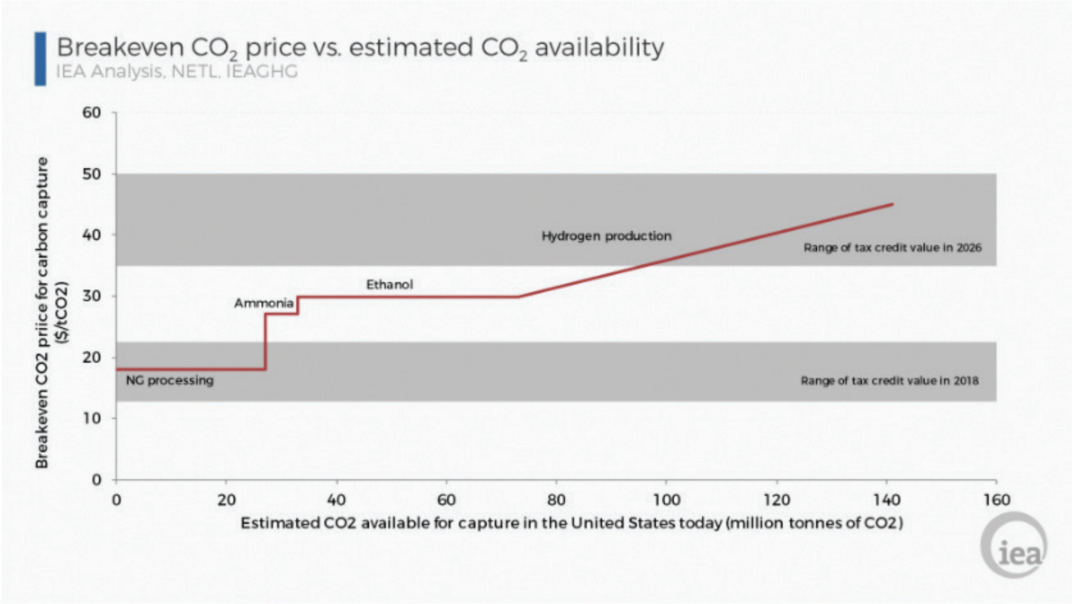

Figure III.15 Breakeven costs for CO_2 capture and availability[119]

3. Immediately achievable cost reductions for power plants

According to the GCCSI, on a like-for-like total system cost basis, CCUS is cheaper than intermittent renewables and costs continue to decrease as more commercial facilities are built. The analysis included credit for other grid services such as reliability, back-up power, and ancillary services. The study dealt with power supply issues across a number of countries. CCUS was seen as a means to provide backup to complement intermittent renewables. Since the Boundary Dam CCS facility in Canada began operations in 2014 and Petra Nova successfully started up in December 2016, the IEA has estimated that the next generation of CCUS projects will achieve 25 to 30 percent cost reductions in capital and operating costs.[120] These assessments support the idea that costs will come down with more facilities.[121]

More large-scale data from operating power generating units equipped with CCUS is needed to further advance first generation designs (now commercial) and to upgrade performance of these systems with improved solvents or by improved heat management and integration. To the extent that projects are funded by governmental entities or part of international collaborations, data are being shared (ITCN, the Mission Innovation activity, and the CSLF are examples).

The cost of CCUS on several industrial applications is far below what many would expect. Recent forecasts show that for "first-of-a-kind" commercial-scale facilities, addition of CCUS to unabated power and industrial facilities can result in additional costs of as low as two percent and up to 70 percent to the lifecycle or levelized unit cost of production, see **Figure III.16**. Higher-cost applications also exhibit wide variations across different countries owing to differences in labor and fuel costs. Industries where the addition of CCUS adds relatively higher incremental costs are also industries in which advanced capture techniques and technologies are being developed.

119 Simon Bennett and Tristan Stanley, "US Budget Bill May Help Carbon Capture Get Back on Track," International Energy Agency, March 2018, https://www.iea.org/newsroom/news/2018/march/commentary-us-budget-bill-may-help-carbon-capture-get-back-on-track.html.

120 "CCUS in Power: Tracking Clean Energy Progress," International Energy Agency, May 23, 2018, https://www.iea.org/tcep/power/ccs/.

121 Global CCS Institute, "The Global Status of CCS," 2017, http://www.globalccsinstitute.com/sites/www.globalccsinstitute.com/files/uploads/global-status/1-0_4529_CCS_Global_Status_Book_layout-WAW_spreads.pdf.

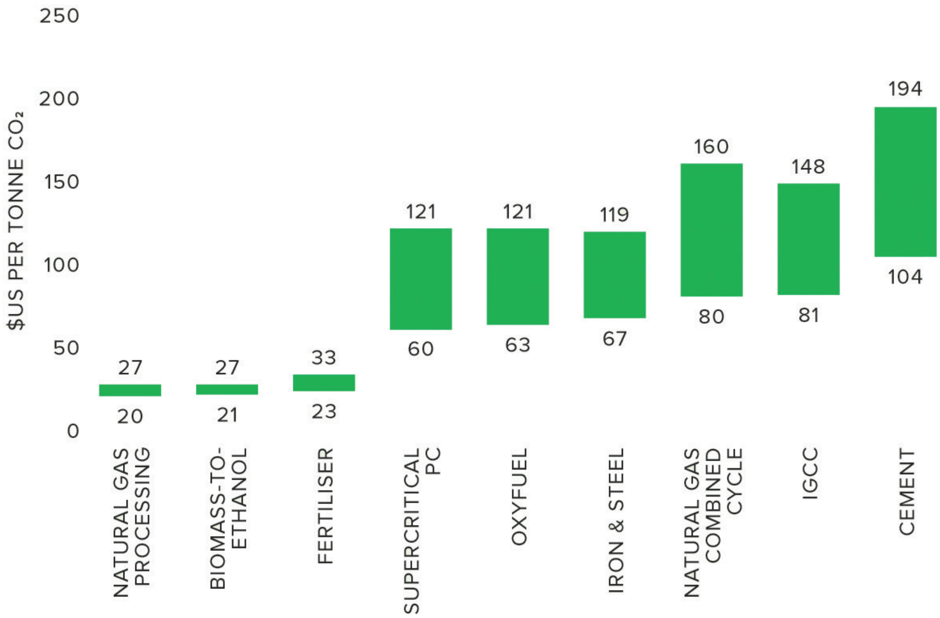

Figure III.16 Comparative costs for capture from candidate CO_2 emitters[122]

Cost studies show costs for construction and operation of current commercial CCUS for retrofit or new capacity applications substantially adds to the cost of electricity. Absent an opportunity to sell the captured CO_2 (for example, enhanced hydrocarbon resource recovery such as EOR), there is little incentive at this time to capture CO_2.

Ongoing major RD&D programs are focused on further reducing these costs. Continued RD&D can often have as big or a bigger impact on cost (replacement technology or subsystem advances) than does operating experience. **Figure III.17** shows progress has been made to date by U.S. DOE (based on dollars per ton captured) and identifies additional R&D goals to further reduce the overall cost of electricity.

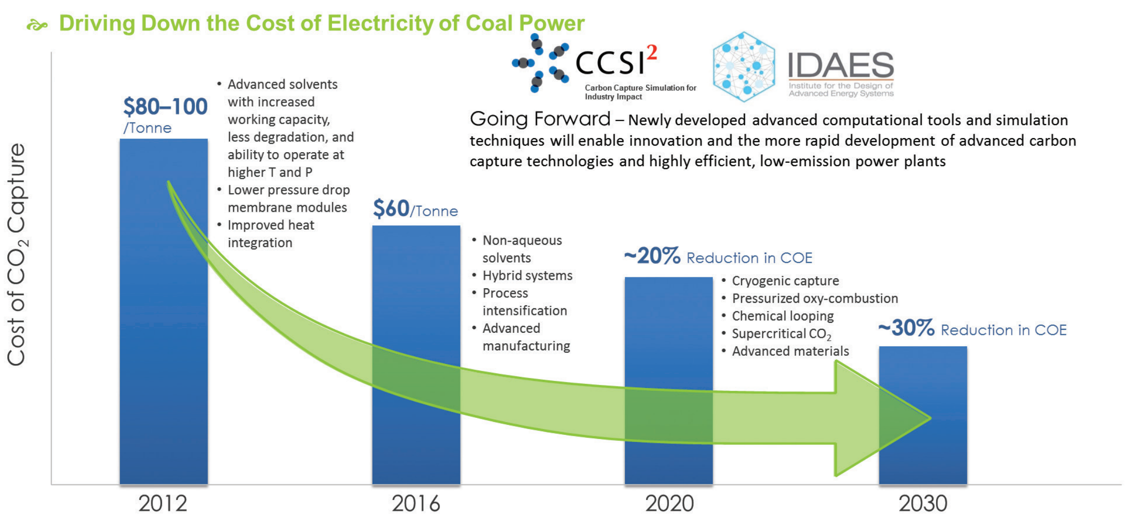

Figure III.17 Actual and nticipated progress in reducing CCUS costs[123]

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122 Global CCS Institute, "The Global Status of CCS," 2017, http://www.globalccsinstitute.com/sites/www.globalccsinstitute.com/files/uploads/global-status/1-0_4529_CCS_Global_Status_Book_layout-WAW_spreads.pdf.

123 John Litynski, "US DOE CCUS Program Overview," IEA 4th Post-Combustion Capture Conference, Birmingham, AL, 2017.

Volatile oil prices make EOR an uncertain revenue stream. A minimum "floor" price is needed to justify the cost of purchasing CO2 to inject for EOR. Other unconventional hydrocarbon resources are amenable to enhanced recovery techniques but a similar "floor" price for the recovered hydrocarbon would be required. IEA's world energy outlook (WEO2017) scenario analyses suggested that oil and natural gas would remain important energy sources through 2040.124 The report also projected that unconventional sources for both liquids and gaseous fuels would provide a rapidly growing share of the total.

4. Regulatory status

Public utility commissions have regulated electric utilities for over a century. Today, commissions generally exercise power through six primary activities:

1. Setting retail electricity rates
2. Siting
3. Overseeing distribution of retail electricity
4. Creating reliability standards
5. Preventing discrimination among customer classes
6. Providing a public venue for electric utility decision-making[125]

Historically, coal-fired power has supplied reliable, low-cost electricity. However, with growing public concern over air pollution in the 1970s and greater attention toward anthropogenic climate change in recent decades, policymakers have begun to consider alternatives to coal-fired electricity.

Issues and concerns focused on CO_2 transportation and storage remain an important aspect within ongoing RD&D efforts to develop and ensure the performance of the complete technological system (capture, transport, injection, long-term safe storage). Risk assessment leading to effective risk management is a key aspect of this overall process. In addition, the novelty of both capture for storage and, particularly, capture for use may be a barrier.

The following quote highlights the concern of some technology developers:

"CO_2 utilization can be pursued to create products using new methods, materials, or feedstocks. In many instances, the products will need to adhere to existing codes and standards to be accepted in the marketplace. Often, there can be barriers within the codes and standards framework that discourage products made using new technologies. Codes and standards are typically overseen by members of government and industry, and developed by consensus-based and voluntary committees. Often, there are few incentives to update or expand existing standards. Further, even if the willingness exists, the changes to the regulatory framework can occur slowly… The route to acceptance under codes and standards can be long enough to discourage the entrance of new technology into the market."[126]

124 IEA, "World Energy Outlook 2017," 2017, https://www.iea.org/Textbase/npsum/weo2017SUM.pdf.

125 M.J. Bradley & Associates LLC, "Public Utility Commission Study," March 31, 2011, https://www3.epa.gov/airtoxics/utility/puc_study_march2011.pdf.

126 Quote attributed to Sean Monkman, Carbon Cure, in David Sandalow et al., "ICEF Carbon Dioxide Utilization Roadmap 2.0," 2017.

Permitting: Successful development of geologic CO_2 storage tools and protocols that provide assurance of permanence will decrease the cost and uncertainty of tracking the fate of subsurface CO_2 and quantify any emissions to the atmosphere. Application of proven tools and techniques should enable a project developer to assess risk and answer questions during the permitting process. The RCSPs discussed in **V.B** characterized eight depleted oil and gas fields, five unmineable coal seams, five saline formations, and one basalt formation to better understand the differences amongst geologic formations. This effort produced eight best practices manuals.[127] The knowledge gained in this effort also contributed to development of both the Canadian standard for CO_2 storage and the ISO standard for storage. The work on monitoring, verification, and accounting draws on lessons learned and has improved subsurface modeling tools and risk assessment tools including results from the National Risk Assessment Program (NRAP). The U.S. effort, along with international efforts, has enabled communication of risk and subsurface assessments essential for permitting to be standardized across jurisdictions.

Pipelines: Another area of concern is the pipeline infrastructure that would be needed if large-scale CO_2 capture and storage is to occur. The design, permitting, construction, and operation of CO_2 pipelines are comparable to natural gas pipelines because they both transport a pressurized gas and utilize carbon steel pipe. Due to these similarities, statistics such as material costs, labor costs, and difficulties in obtaining rights-of-way (ROWs) can be used to anticipate future costs and challenges. However, there are differences between CO_2 and natural gas pipelines, including: CO_2 is transported at higher pressures, thus requiring thicker and more expensive pipe and welds; CO_2 is piped as a liquid-like supercritical fluid that uses pumps instead of compressors; and natural gas requires different materials for joints and seals. Items of particular concern for CO_2 transportation in support of storage has been addressed by one of the ISO standards mentioned earlier.

New pipelines, monitoring systems, pumping equipment, and wells will be needed for the establishment of a robust CCUS industry. A study prepared in 2011 for the Interstate Natural Gas Association of America Foundation found that, depending upon the quantity of CO_2 that must be stored and the degree to which EOR will be involved, the length of pipeline needed to transport CO_2 will be in the range of 15,000 to 66,000 miles by 2030.[128] The Interstate Oil & Gas Compact Commission (IOGCC) and the Southern States Electricity Board (SSEB) identified models for CO_2 pipeline deployment across the U.S. in a report titled, *A Policy, Legal, and Regulatory Evaluation of the Feasibility of a National Pipeline Infrastructure for the Transport and Storage of Carbon Dioxide."*[129] These statistics highlight the scale-up required for widespread deployment of CCUS. An expanded pipeline infrastructure will affect numerous stakeholders (e.g., landowners, nearby residents, pipeline companies, storage site owners, power plants, environmental groups).

127 Available at https://www.netl.doe.gov/research/coal/carbon-storage/publications.

128 ICF International, «Developing a Pipeline Infrastructure for CO_2 Capture and Storage: Issues and Challenges,» 2009, http://www.ingaa.org/File.aspx?id=8288.

129 K. Bliss et al., «A Policy, Legal, and Regulatory Evaluation of the Feasibility of a National Pipeline Infrastructure for the Transport and Storage of Carbon Dioxide,» Southern States Energy Board, 2010, http://www.sseb.org/downloads/pipeline.pdf.

Examination of the full scope of legislative, regulatory, policy, and funding issues that might affect the deployment of pipeline technologies and other components of the CO_2 capture, transportation, and storage value chain is needed. A recent report from the Great Plains Institute State CO_2-EOR Deployment Working Group[130] looked at issues related to U.S. deployment of CCUS more broadly than the focus on pipelines in the IOGCC report. The report is the result of state officials' endorsing the need for federal action to provide incentives to accelerate commercial deployment of carbon capture, utilization, and storage, with a particular focus on CO_2-EOR.

The authors of the Great Plains Institute study[131] noted that further deployment of carbon capture faces challenges, including high capital costs, low revenues from CO_2 sales due to low oil prices, limited availability of debt and equity for projects due to policy uncertainty and market risk. A number of measures were recommended for consideration by the federal government. They also noted a role for individual states: "States can also assist by optimizing existing tax and other policies to complement federal incentives in helping carbon capture projects achieve commercial feasibility." The report recommended a more integrated set of policies and incentives that would support expansion of the current infrastructure for CO_2 capture by allowing smaller, industrial facilities to capture and transport CO_2; expanding the mix of organizations that can team up in projects that capture, transport, and utilize CO_2; and uncapping the tax credits available to reduce uncertainty and raise investor confidence.

The GPI report identifies three areas in which state action can encourage the development of projects and deployment of the integrated set of technologies (capture, transport, and injection for enhanced resource recovery):

- Changes in state taxes that provide incentives for the capture of CO_2 from power plants and industrial sources, and/or for the use of captured CO_2 to produce oil through EOR;
- State portfolio requirements and mandatory power purchases or offtake agreements for facilities that capture carbon; and
- State regulatory and other policies and strategies to facilitate CO_2 storage, project development, and pipeline transport.

These efforts coupled with federal efforts can significantly improve the competitiveness of CCUS projects. State and federal policy options are expanded upon in Section IV.

J. Summary of RD&D opportunities

A number of issues discussed above remain to be resolved through additional RD&D. This chapter has outlined both the ongoing pilot-scale work on advanced approaches and has identified many technologies being developed at smaller-scale that promise to further reduce costs of capture. Success with the work described promises to move CCUS technologies toward being a cost-competitive approach for CO_2 capture and storage or utilization. Technologies such as chemical looping represent examples of novel combustion systems that need not be large scale to be cost effective while emitting very low levels of CO_2. Utilization techniques, some tested at full-scale, others early in the developmental process, offer the opportunity to make saleable products while eliminating costs to ensure secure long-term storage.

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130 State CO_2-EOR Deployment Work Group, "Putting the Puzzle Together: State & Federal Policy Drivers for Growing America's Carbon Capture & CO_2-EOR Industry," December 2016, http://www.betterenergy.org/wp-content/uploads/2018/02/PolicyDriversCO2_EOR-V1.1_0.pdf.

131 Ibid.

IV. Policy Approaches to Expand CCUS

CCUS offers numerous environmental, economic, and reliability benefits, but has not been widely deployed by coal-fired power plants. State and federal policymakers and regulators have a range of options at hand to encourage broader adoption. Carbon capture faces the same problem as do other low- or zero-carbon technologies: there is no national policy that attempts to internalize the externality of greenhouse gas emissions and power sector regulation is uniquely fragmented, as shown in **Figure IV.1** and **Figure IV.2**. As a result, carbon capture requires action from a patchwork of regulatory and policy authorities. However, CCUS advocates argue that CCUS technologies do not benefit from the robust suite of federal and state incentives available to other low- or zero-carbon technologies like solar and wind.

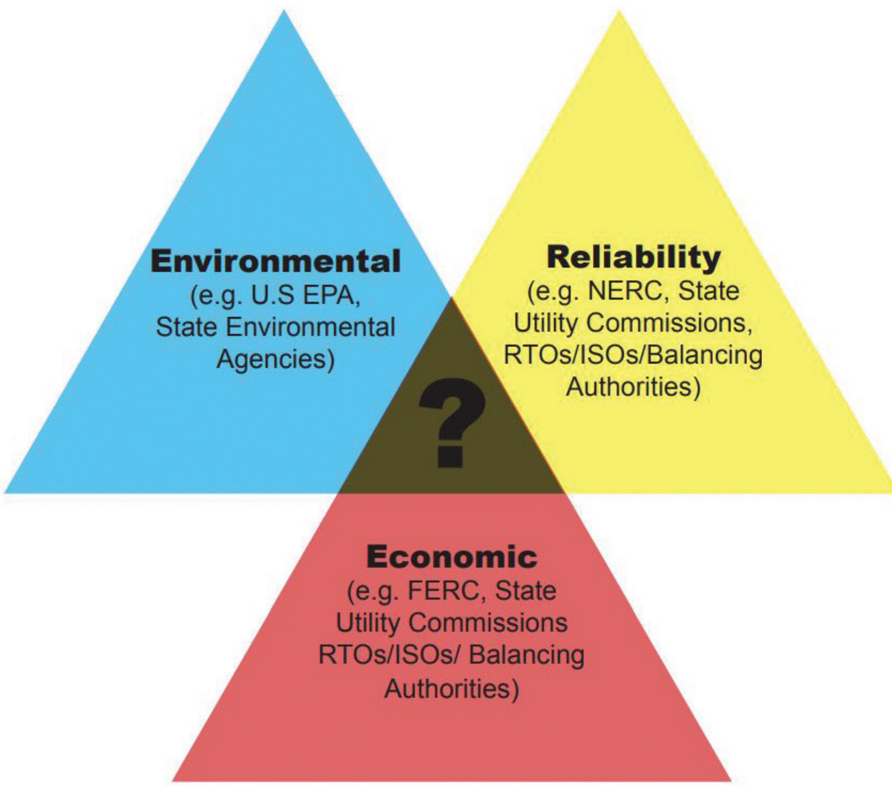

Figure IV.1 Power sector regulation[132]

132 State CO_2-EOR Deployment Work Group, "Electricity Market Design and Carbon Capture Technology: The Opportunities and the Challenges," June 2017, http://www.betterenergy.org/wp-content/uploads/2018/02/Electric-Markets-and-CCS-White-Paper-1.pdf.

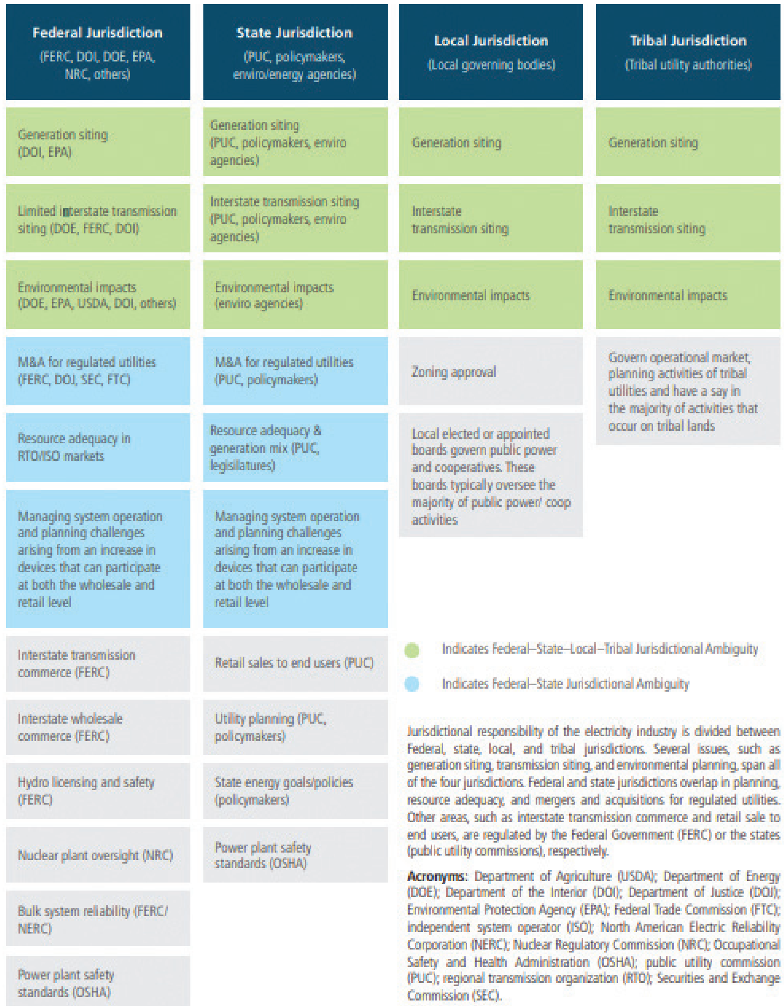

Figure IV.2 Federal, State, local, and tribal jurisdiction over electricity[133]

133 U.S. Department of Energy, "Quadrenntal Energy Review: Transforming the Nation's Electricity System: The Second Installment of the QER," January 2017: Figure A-5, p. A-15, https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

A. Public utility commission options

Public utility commissions are responsible for the economic regulation of electricity delivery. As economic regulators, commissions are primarily concerned with cost and are discouraged from considering environmental or employment impacts of decisions. In both vertically integrated and restructured/deregulated states, commissions approve retail electric prices, approve siting, and carry out the will of the state legislature as directed. Traditionally, commission authority over pollution control is expressed through rate recovery and siting review.[134] Both of these activities are relevant to carbon capture. However, commissions have other options to increase CCUS deployment as well. When CO_2 does not fit into a clear governmental mandate to reduce pollution, states must take additional action to stimulate the growth of CCUS technologies to achieve its benefits (see B below). With alternative tools, Commissions can create regulatory certainty and shorten payback periods for utility investments in CCUS. These options include:

- RPS compliance
- Low-carbon credits
- Enabling cost recovery for CCUS
- Siting
- Planning

1. RPS compliance

Twenty-nine states, plus Washington, D.C., and three U.S. territories have adopted renewable portfolio standards (RPS) requiring utilities to procure either a percentage of load or a set amount of generation from renewable resources.[135] RPSs have been highly successful in encouraging added renewable generation. The Lawrence Berkeley National Lab estimates that RPSs supported 44 percent of new renewable capacity additions in 2016 and up to 90 percent of new renewable build in the West, Mid-Atlantic, and Northeast regions.[136]

RPSs are generally set by state legislatures and implemented by commissions. Motivations have typically included greenhouse gas reduction, air quality, and economic development goals. RPSs only apply to utilities that are regulated by state commissions (investor-owned utilities or cooperatives in certain circumstances).[137] Commissions are responsible for ensuring utility compliance with RPSs, reviewing implementation plans to achieve the state's public policy goal at the least cost to ratepayers. The National Renewable Energy Lab and LBNL estimate that RPS implementation has cost ratepayers less than a one percent increase to retail rates compared to a business-as-usual scenario.[138]

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134 M.J. Bradley & Associates LLC, "Public Utility Commission Study," March 31, 2011, https://www3.epa.gov/airtoxics/utility/puc_study_march2011.pdf.

135 National Conference of State Legislatures, "State Renewable Portfolio Standards and Goals," July 20, 2018, http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx.

136 Galen Barbose, "U.S. Renewables Portfolio Standards: 2017 Annual Status Report," Lawrence Berkeley National Laboratory, July 2017, https://emp.lbl.gov/sites/default/files/2017-annual-rps-summary-report.pdf.

137 State public utility commissions regulate electric cooperatives who sell retail electricity to non-members. Although this represents a small minority of cooperatives, this scenario occurs in several states.

138 J. Heeter et al., "A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards," National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory, May 2014, https://www.nrel.gov/docs/fy14osti/61042.pdf.

RPSs typically define renewable resources as wind, solar, biomass, geothermal, or other alternatives to traditional centralized generation.[139] Some programs include specific goals for distributed or customer-owned renewables. Eight states include energy efficiency and 16 states consider at least one of four thermal resources (solar water heat, solar space heat, solar thermal process heat, and CHP/cogeneration/waste heat) to be eligible resources. Coal-fired plants with CCUS are usually left out of the definition of RPS compliance options. Just four states have broader "clean energy standards" that bring coal with CCUS to the table (see **Figure IV.3**).

	Coal	Other Non-Renewables	Nuclear	Natural Gas	Hydro (not included as RE)
Pennsylvania	New and existing waste coal; Integrated Gasification Combined Cycle (IGCC) technology	Wood pulping and manufacturing byproducts			Large scale hydro
Ohio	Clean coal	Fuel cells that generate electricity; advanced solid waste conversion technologies	Generation III advanced nuclear power		
Michigan	Coal-fired facilities that capture and sequester 85% of CO_2 emissions	Gasification			
West Virginia	New and existing waste coal; IGCC technology; advanced coal technology; fuel produced by coal gasification or liquification facility	Coal bed methane; tire-derived fuel; synthetic gas		Natural gas	Pumped storage hydro

Note: For detailed definitions of eligible resources, see state statutes: Pennsylvania 73 P.S. § 1648.1 et seq., Ohio ORC 4928.01(34), Michigan MCL § 460.1001 et seq., West Virginia W. Va. Code and §24-2F-1 et seq.

Figure IV.3 Non-renewable resources eligible for RPS compliance[140]

In cases where greenhouse gas reductions or economic development are driving forces in establishing an RPS, broadening RPS (or clean energy standard) eligibility to coal with CCUS could be an option. This approach would require legislative approval, with commissions responsible for overseeing utility implementation. Commissions would have a role in setting and reviewing cost-benefit analyses and/or approving investment decisions by utilities across RPS-eligible technologies.

California's SB 100, still under consideration as of the time of writing, requires 100 percent "zero-carbon" electricity generation by 2045. By using the term "zero-carbon" instead of "renewable," the law opens opportunities for carbon capture to contribute as an eligible technology.[141] Other states could likewise broaden legislation aimed at cutting electricity sector emissions to include zero- or low-carbon fuels, enabling CCUS to compete alongside renewable generation.

139 David Hurlbut, "State Clean Energy Practices: Renewable Portfolio Standards," National Renewable Energy Laboratory, July 2008, https://www.nrel.gov/docs/fy08osti/43512.pdf.

140 Jenny Heeter and Lori Bird, "Including Alternative Resources in State Renewable Portfolio Standards: Current Design and Implementation Experience," National Renewable Energy Laboratory, November 2012, https://www.nrel.gov/docs/fy13osti/55979.pdf.

141 California Legislative Information, "SB-100 California Renewables Portfolio Standard Program: Emissions of Greenhouse Gases," September 10, 2018, https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100.

2. Low-carbon credits

Similar to state policies in Illinois and New York that incentivize purchases of certain amounts of nuclear power to retain existing nuclear plants while achieving greenhouse gas emissions reduction goals, commissions could implement low-carbon credit programs to include carbon capture and storage. Utilities would be required to purchase capacity and/or energy from fossil units incorporating carbon capture.[142] Such a policy could apply to both vertically integrated and restructured states. Utilities would need to either identify suitable plants for CCUS retrofits and install the equipment (in a vertically integrated state) or accept bids for electricity generated by plants with CCUS equipment (in a restructured state).

3. Enabling cost recovery for CCUS

In vertically integrated states, commissions decide what costs are passed on to ratepayers as "prudent" investments in electricity generation, transmission, and distribution. By considering CCUS retrofit costs as a prudent investment, commissions can create a hospitable environment for regulated utilities to identify favorable generators for CCUS retrofits, the costs of which will be recovered through rate bases. Alternatives to a traditional rate case may be particularly attractive due to granting commissions increased flexibility and offering utilities shorter decision-making timeframes. Rate cases are traditionally decided after a project is completed, creating a lengthy regulatory lag between initial shareholder investment and utility revenue to recover that investment.

In the absence of federal regulation of CO_2, state-level regulatory certainty is particularly important to increase carbon capture deployment. As stated by the Alabama PSC regarding pollution control technology, "[Environmental compliance costs] by definition are the product of governmental mandates establishing environmental requirements with which Alabama Power, by law, must comply. These are not costs that Alabama Power can simply choose not to incur, which in turn strongly supports a presumption that they are prudent expenditures."[143]

Colorado offers another example of such a hospitable environment. State law orders the commission to "give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities…Where utilities eliminate or reduce CO_2 emissions through the use of capture and sequestration, the commission may consider the benefits of using CO_2 for enhanced oil recovery or other uses." The statute includes language specifically directed at cost recovery for IGCC generation and financial support from the state's clean energy development fund for study, engineering, and development of IGCC facilities.[144]

Commissions can also take steps to speed or ease cost recovery of carbon capture development on new or existing power plants. Commissions can approve rate recovery on construction work in progress (CWIP), enabling shareholders to begin recovering their investments before the project is operational.[145] However, CWIP runs the risk of imposing high costs on ratepayers if a project is not completed on-time and on-budget.

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142 State CO_2-EOR Deployment Work Group, "Electricity Market Design and Carbon Capture Technology: The Opportunities and the Challenges," June 2017, http://www.betterenergy.org/wp-content/uploads/2018/02/Electric-Markets-and-CCS-White-Paper-1.pdf.

143 Alabama PSC Docket Nos. 18117 and 18416, October 29, 2004.

144 CO Rev Stat § 40-2-123 (2016), https://law.justia.com/codes/colorado/2016/title-40/public-utilities/article-2/section-40-2-123/.

145 M.J. Bradley & Associates LLC, "Public Utility Commission Study," March 31, 2011, https://www3.epa.gov/airtoxics/utility/puc_study_march2011.pdf.

In some cases, legislative approval may be required to enable utilities to request commission permission to use specific financial mechanisms to recover costs of a carbon capture investment. In West Virginia, a regulated utility sought to use securitization to create and sell bonds to finance costs related to environmental compliance. The commission expended a significant "level of effort…to develop the knowledge to utilize securitization, which was newly authorized by the legislature."[146] Other financial tools are discussed in Bonding Authority and Financial Options.

Selected states have also allowed periodic adjustment mechanisms to recover environmental compliance costs, rather than requiring utilities to go through a general rate case. A 2006 Brattle Group survey found that 11 of 27 traditionally regulated states allow rate adjustments for environmental capital costs and emissions allowance costs. These mechanisms allow a simplified cost recovery process by adding a separate surcharge to the rate base that includes after-the-fact auditing and a periodic process for matching revenues to expenses.[147] Periodic adjustment mechanisms for CCUS projects would offer gradual payback to developers or shareholders while reducing ratepayer risks of overpaying for a project.

4. Siting

CCUS requires three foundational pieces of infrastructure: a source facility, pipeline, and sequestration site. The source facility and pipeline pieces bring unique siting challenges to commissions; they have no authority over geologic sequestration sites, which are mainly regulated by the EPA under the Safe Drinking Water Act (see Section IV.X). In general, Commissions can increase their literacy of CCUS infrastructure to better position themselves to consider the costs and benefits of CCUS to ratepayers. There are also specific actions commissions can take to improve the siting process.

a) Source facility

Commissions can encourage carbon capture development by pre-approving project siting and environmental criteria.[148] Commissions may grant a certificate of public convenience and necessity authorizing a utility to operate a public facility in a given area. Commissions may also include environmental considerations in the certification process, as 30 states currently do. Kentucky, for example, requires the state's Environmental Cabinet to review all new generation facilities.[149]

Other states have allowed pre-approvals for pollution controls at specific plants. Minnesota's legislature passed a law allowing utilities to apply for an "advance determination of prudence" by submitting a description of the project, implementation schedule, cost estimate, and description of the utility's efforts to ensure the lowest reasonable costs to the commission.[150] Similar to certification, advance determination creates certainty that an investment will be recovered through rate base once a project is completed. Commissions can use these tools to attract CCUS projects by reducing the risk that a project could be slowed or stopped during the permitting process.

146 M.J. Bradley & Associates LLC, "Public Utility Commission Study," March 31, 2011, https://www3.epa.gov/airtoxics/utility/puc_study_march2011.pdf.

147 Ibid.

148 Ibid.

149 Ibid.

150 Ibid.

b) Pipeline

The federal government, through the FERC and Surface Transportation Board, has disclaimed jurisdiction over CO_2 pipeline siting, leaving it up to states.[151] Little research of public attitudes toward CO_2 pipelines has been conducted, but landowner and environmental groups have led strong opposition to oil and gas pipeline development by participating in stakeholder processes at FERC and state siting authorities.

Federal policymakers have proposed a partial fix to pipeline siting by proposing to make large CO_2 pipeline projects eligible for a streamlined permitting process.[152] Although this solution could help projects move forward, it is not a complete solution. State regulators are uniquely positioned to facilitate stakeholder processes inclusive of project developers, utilities, landowners, interest groups, and others. Commissions can improve their capacity to facilitate this stakeholder process with CO_2 pipelines by hiring specialized staff with expertise in CCUS pipelines, which pose the same difficulties in project siting as oil and natural gas pipelines but carry far lower risk to human health.

5. Planning

Many commissions require regulated utilities to submit integrated resource plans (IRPs) describing how the utility will procure reliable, least-cost electric service for a given timeline, often five years. IRPs are valuable from multiple perspectives. For the commission, the process provides information about the utility's future decisions. For the utility, it offers an avenue to inform regulators and the public about the utility's options. For the public, IRPs are a way to comment on electricity procurement. Commissions could issue guidance requiring the consideration of carbon capture in IRPs. Such a statement would not require utilities to install CCUS equipment or procure electricity only from plants with CCUS, but would ensure that utilities consider CCUS alongside other forms of generation.

B. State government beyond PUC

In addition to Commissions, state legislatures and regulatory bodies also have options to encourage more CCUS. In general, states can strive to reduce regulatory uncertainty by addressing the details of carbon capture in statute and/or regulation, as an MIT paper pointed out: "The lack of a regulatory framework can result in an environment of uncertainty and as a result projects may become delayed and even cancelled."[153] Just as the Resource Conservation and Recovery Act created a "cradle to grave" regulatory framework covering the generation, transportation, treatment, storage, and disposal of hazardous waste,[154] States can pursue a similarly comprehensive regulatory framework for CO_2 capture and utilization or sequestration.

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151 Adam Vann and Paul Parfomak, "Regulation of Carbon Dioxide (CO_2) Sequestration Pipelines: Jurisdictional Issues," Congressional Research Service, https://digital.library.unt.edu/ark:/67531/metadc94130/m1/1/high_res_d/RL34307_2008Apr15.pdf.

152 Carbon Utilization Research Council and ClearPath Foundation, "Making Carbon a Commodity: The Potential of Carbon Capture RD&D," July 25, 2018, http://www.curc.net/webfiles/Making%20Carbon%20a%20Commodity/180724%20Making%20Carbon%20a%20Commodity%20FINAL%20with%20color.pdf.

153 Holly Javedan, "Regulation for Underground Storage of CO_2 Passed by U.S. States," Massachusetts Institute of Technology, https://sequestration.mit.edu/pdf/US_State_Regulations_Underground_CO2_Storage.pdf.

154 U.S. Environmental Protection Agency, "Laws & Regulations: Summary of the Resource Conservation and Recovery Act," https://www.epa.gov/laws-regulations/summary-resource-conservation-and-recovery-act.

1. Requiring CCUS

State legislatures could simply mandate the installation of carbon capture on coal-fired power plants. However, based on current retrofit and new build costs for CCUS equipment on coal plants, such a decision would be likely to significantly raise costs for ratepayers, in addition to failing to account for plant-specific characteristics that may make CCUS retrofits a more attractive investment at certain plants over others. A mandate could also lead to premature coal retirements, as some generators may choose to cease operations rather than install expensive CCUS equipment.

2. Bonding authority

The state CO_2-EOR Deployment Work Group recommends the use of private activity bonds to reduce risk for CCUS projects. With permission from the federal government, states can allocate up to $33 billion of tax-exempt private activity bonds annually. Enabling carbon capture to participate in the PAB market would offer less expensive, long-term, fixed-rate debt for CCUS projects.[155]

The Wyoming Infrastructure Authority is a state agency created by the legislature in 2004 to oversee infrastructure development through PABs. WIA's mission is to "diversify and expand the state's economy by adding value to Wyoming's energy resources and infrastructure for the benefit of Wyoming and the region."[156] WIA's statutory authority includes the ability to issue up to $1 billion in bonds to finance energy infrastructure including CO_2 pipelines.[157] Bonding authority is one way for states to finance CCUS infrastructure at no cost or risk to the state itself. Other states could pass similar legislation to extend bonding authority to cover CCUS projects. For more discussion of the federal government's role in PABs, see Financial Options.

3. Underground injection control program primacy

In December 2010, under the Safe Drinking Water Act, the EPA created a new class of underground injection wells covering CO_2 storage.[158] EPA can grant a state the authority to permit Class VI Underground Injection Control (UIC) wells to replace federal enforcement. Class VI wells are used for long-term storage of capture CO_2.[159] The EPA issued Class VI guidance documents to assist program directors and well owners and operators.[160] Well operators must carefully manage the pressure of a CO_2 storage reservoir by extracting, processing, and selling or disposing of in situ fluids and gases.[161]

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155 State CO_2-EOR Deployment Work Group, "Putting the Puzzle Together: State & Federal Policy Drivers for Growing America's Carbon Capture & CO_2-EOR Industry," December 2016, http://www.betterenergy.org/wp-content/uploads/2018/02/PolicyDriversCO2_EOR-V1.1_0.pdf.

156 Wyoming Infrastructure Authority, "About Us," http://www.wyia.org/about-us/.

157 Wyoming Infrastructure Authority, "Bonding Authority," http://www.wyia.org/projects/bonding-authority/.

158 National Energy Technology Laboratory, "Permanence and Safety of CCS: What Regulations Are in Place to Govern CO_2 Injection(s)?" https://www.netl.doe.gov/research/coal/carbon-storage-1/faqs/what-regulations-are-in-place-to-govern-co2-injection

159 Class VI wells are one of six classes of Underground Injection Control wells regulated by the EPA under the Safe Drinking Water Act. The other classes are Class I: Industrial and Municipal Waste Disposal Wells; Class II: Oil and Gas Related Injection Wells; Class III: Injection Wells for Solution Mining; Class IV: Shallow Hazardous and Radioactive Injection Wells; Class V: Wells for Injection of Non-Hazardous Fluids into or Above Underground Sources of Drinking Water. EPA has granted state primacy to at least one state for all five classes; North Dakota is the only state with Class VI primacy as of the time of writing. EPA maintains authority over tribal land.

160 U.S. Environmental Protection Agency, "Underground Injection Control (UIC): Final Class VI Guidance Documents," https://www.epa.gov/uic/final-class-vi-guidance-documents

161 Steven Anderson, "Risk, Liability, and Economic Issues with Long-Term CO_2 Storage – A Review," *Natural Resources Research* 26 No. 1 (January 2017): 89–112, https://link.springer.com/article/10.1007/s11053-016-9303-6.

The Class VI rule required that storage site owners demonstrate financial responsibility to cover corrective action to plug abandoned wells and underground mines, injection well plugging, post-injection site case and closure, and emergency and remedial response.[162] EPA suggests a 50-year timeframe for these stewardship liabilities.[163] Under the Safe Drinking Water Act, long-term stewardship liability for CO_2 storage cannot be transferred to the U.S. government but can be transferred to a state government or other entity.[164]

In April 2018, the EPA granted a state's request for the first time by approving North Dakota's request to enforce its own Class VI program.[165] The decision shifts authority to the North Dakota Industrial Commission, which can implement and enforce a Class VI program that advances North Dakota's energy goals and is responsive to specific state needs. Other states can also consider attaining Class VI primacy to reduce regulatory barriers to carbon sequestration.

4. Long-term sequestration liability

Long-term liability for carbon sequestration sites is still an area of regulatory uncertainty. States can take action to clarify sequestration liability. As the National Energy Technology Laboratory states, "EPA regulations on storage of CO_2 in the subsurface and increased reporting requirements provide an initial regulatory framework for CO_2 storage; however, responsibility for the long-term management of a storage site after it has received formal closure from the EPA still needs to be resolved in some states."[166]

Five states—Illinois, Louisiana, Montana, North Dakota, and Texas—have passed legislation transferring liability for CO_2 sequestration sites to the state after a certain amount of time. Illinois and Texas assume responsibility for carbon sequestration immediately upon well closure, although Illinois law specifically targets the now-inactive FutureGen project and Texas only assumes liability for offshore wells. North Dakota and Louisiana assume liability after 10 years, and Montana after 30 years.[167]

Long-term liability also requires the dedication of sufficient funding to ensure that the liable party carry out its duties under the law. Kansas, Louisiana, Montana, North Dakota, Wyoming, and Texas (both offshore and onshore) have established storage funds for long-term management and monitoring of carbon sequestration sites.[168] The storage funds are provided by user fees assessed on well operators per metric ton of CO_2 injected. Operators can also be required to pay permitting fees, application fees, penalties for the release of CO_2, annual fees, or major injury fees.[169]

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162 Steven Anderson, "Risk, Liability, and Economic Issues with Long-Term CO2 Storage – A Review," *Natural Resources Research* 26 No. 1 (January 2017): 89–112, https://link.springer.com/article/10.1007/s11053-016-9303-6.

163 Holly Javedan, "Regulation for Underground Storage of CO_2 Passed by U.S. States," Massachusetts Institute of Technology, https://sequestration.mit.edu/pdf/US_State_Regulations_Underground_CO2_Storage.pdf.

164 Steven Anderson, "Risk, Liability, and Economic Issues with Long-Term CO_2 Storage – A Review," *Natural Resources Research* 26 No. 1 (January 2017): 89–112, https://link.springer.com/article/10.1007/s11053-016-9303-6.

165 U.S. Environmental Protection Agency, "EPA Approves First Underground Injection Control Program Primacy for Carbon Sequestration Wells to North Dakota," April 10, 2018, https://www.epa.gov/newsreleases/epa-approves-first-underground-injection-control-program-primacy-carbon-sequestration.

166 Charles Zelek et al. "Analysis of Benefits of the NETL Clean Coal and Carbon Management Program," National Energy Technology Laboratory, April 15, 2016, https://www.netl.doe.gov/energy-analyses/temp/BenefitsoftheNETLCleanCoalandCarbonManagementProgram_041516.pdf.

167 Holly Javedan, "Regulation for Underground Storage of CO_2 Passed by U.S. States," Massachusetts Institute of Technology, https://sequestration.mit.edu/pdf/US_State_Regulations_Underground_CO2_Storage.pdf.

168 Megan Cleveland, "Carbon Capture and Sequestration," National Conference of State Legislatures, April 14, 2017, http://www.wyoleg.gov/InterimCommittee/2017/09-0629APPENDIXG-1.pdf.

169 Holly Javedan, "Regulation for Underground Storage of CO_2 Passed by U.S. States," Massachusetts Institute of Technology, https://sequestration.mit.edu/pdf/US_State_Regulations_Underground_CO2_Storage.pdf.

5. Subsurface ownership

Montana, North Dakota, and Wyoming have passed statutes defining ownership of CO_2 and the pore space into which it is injected. Under all of these statutes, subsurface pore space belongs to the surface owner. North Dakota allows pore space to be leased by the surface landowner, while Montana and Wyoming allow pore space to be transferred separately from surface ownership. All three states have unitization laws setting requirements for landowner consent to a sequestration project before it can proceed—at least 60 percent of pore space owners in Montana and North Dakota and at least 80 percent in Wyoming must approve.[170] Additional clarification of pore space ownership would reduce regulatory uncertainty of long-term sequestration.

C. Federal government

The federal government has a broad range of options available to encourage CCUS, including financial methods, tax incentives, R&D funding, and policy and regulatory tools. In considering options to advance the deployment of CCUS, policymakers should draw lessons from past efforts to support innovation in renewable generation and advanced oil and gas extraction. Several of these options come directly from those fields and can be applied to CCUS to achieve similar price reduction and commercial deployment goals.

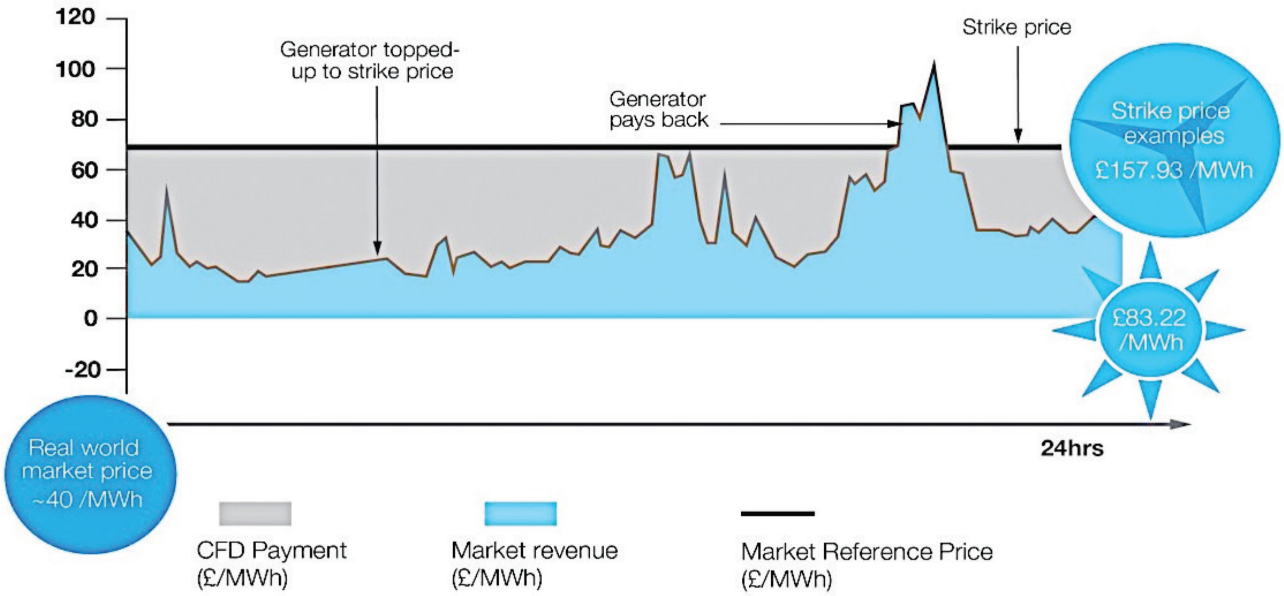
1. Financial options to reduce risk and lower cost of capital

The price of CO_2 used in EOR operations is dependent on the volatile price of oil, subjecting CCUS operators to substantial risk. Further, once EOR operations begin, the oilfield requires a steady supply of CO_2 to maintain the pressure needed to extract oil. Both CCUS and EOR stakeholders have an interest in reducing their risk of oil price shocks.

Through its electricity market reforms, the United Kingdom instituted a contracts-for-differences (CFD) framework enabling a 15-year bilateral contract between a low-carbon electricity generator and the Department of Energy and Climate Change (DECC). The contract provides stable revenues to generators, removing the risk of volatility in wholesale electricity prices, by providing a flat reference price. The difference between the strike price (market price) and reference price is paid by DECC to the generator if the reference price exceeds the strike price, or vice versa if the strike price exceeds the reference price. See **Figure IV.4** for a visualization.[171]

170 Megan Cleveland, "Carbon Capture and Sequestration," National Conference of State Legislatures, April 14, 2017, http://www.wyoleg.gov/InterimCommittee/2017/09-0629APPENDIXG-1.pdf.

171 Ian Wood and Robert Broom, "EMR: A Review of the Contract for Difference and Capacity Market Schemes," Lexology, August 10, 2016, https://www.kwm.com/en/uk/knowledge/insights/emr-a-review-of-the-contract-for-difference-and-capacity-market-schemes-20160810.



Source of graph: UK Government White Paper, July 2011, licensed under the Open Government Licence v1.0
Source of strike price examples: https://lowcarboncontracts.uk/cfds
Source of real world market price: Cornwall Energy publication, 19 October 2015

Figure IV.4 Illustration of UK CFD scheme[172]

The federal government could replicate the price stabilization effect of the CFD program through contracts for CO_2 from CCUS facilities to EOR operators, reducing the risk oil price volatility poses to CO_2-EOR projects. The State CO_2-EOR Deployment Work Group advocated for the federal government to establish price stabilization contracts for CO_2 sold from capture facilities to EOR operators. Such an arrangement would provide a single uniform oil price over the term of a contact, potentially based on forecasts from the Energy Information Administration. When the price of oil exceeds the uniform price, the CCUS project would return any excess revenue to the Treasury; when the price of oil falls under the uniform price, the federal government would make up the difference to the project operators.[173]

The Work Group also recommends the use of master limited partnerships (MLPs) for CCUS projects to encourage equity investment. MLPs have long been used in the oil and gas sector to fund infrastructure projects like pipelines and storage facilities. MLPs pay no tax, instead passing income through to partners who then receive tax statements showing their share of the partnership's profits or losses. MLPs can be traded to raise equity funding.

Federal action would be needed to enable CCUS projects to obtain eligibility for PABs (see Bonding Authority section above) and MLPs.[174] Congress could also make PABs more attractive by permanently codifying the ARRA's exemption of PABs from the Alternative Minimum Tax.[175]

172 Ian Wood and Robert Broom, "EMR: A Review of the Contract for Difference and Capacity Market Schemes," Lexology, August 10, 2016, https://www.kwm.com/en/uk/knowledge/insights/emr-a-review-of-the-contract-for-difference-and-capacity-market-schemes-20160810.

173 State CO_2-EOR Deployment Work Group, "Putting the Puzzle Together: State & Federal Policy Drivers for Growing America's Carbon Capture & CO_2-EOR Industry," December 2016, http://www.betterenergy.org/wp-content/uploads/2018/02/PolicyDriversCO2_EOR-V1.1_0.pdf.

174 Ibid.

175 Robert Puentes, "Promoting Infrastructure Investment through Private Activity Bonds," Brookings Institution, October 25, 2012, https://www.brookings.edu/blog/the-avenue/2012/10/25/promoting-infrastructure-investment-through-private-activity-bonds/.

2. Section 45Q tax credits

In 2008, Congress passed tax credits for CO_2 capture, utilization, and storage in the Energy Improvement and Extension Act. The statute authorized tax credits of $10 per metric ton of CO_2 captured for enhanced oil recovery and $20 per metric ton for CO_2 that was geologically sequestered. Projects had to capture and store at least 500,000 metric tons of CO_2 per year to receive the credits. After 75 million metric tons of credits had been awarded, the program was set to expire. The program was criticized on three prongs: credits were thought to be too low to incentivize CCUS; small projects were unable to participate; and the total limit created uncertainty that the program would support projects into the future.

The Bipartisan Budget Act, passed in February 2018, expanded the existing tax credits by increasing the credit value, lengthening the time horizon in which the credit could be claimed, and broadening the definition of qualifying projects. The new statute added "other utilization processes" as an eligible category for receiving the credits and enabled small projects to participate by implementing an eligibility cap of 500,000 tons of CO_2 per year. Power generators, industrial processes, and direct air capture projects were able to receive credits. A gradual 10-year ramp increases the credits from the 2008 amounts to $50 per ton for dedicated geological storage and $35 per ton for enhanced oil recovery or other utilization processes. After 2026, the credits rise with inflation.[176] Projects must begin construction by January 1, 2024, to claim credits. Credits are transferable but not refundable, and can be claimed for 12 years. The U.S. Treasury must issue regulations to clarify the definition of "begin construction" and "other utilization processes."[177] As of the time of writing, the Internal Revenue Service (IRS) had not yet released regulations on these terms. The IRS's interpretation "will have a significant influence on short- and medium-term development and important project finance decisions."[178]

Like many CCUS experts, the Energy Futures Initiative is cautiously optimistic about the updated credits, but notes that tax incentives are just one of many tools needed to bring projects into development: "The new 45Q provisions have the potential to significantly enhance the development and market diffusion of CCUS technologies and processes in both industrial and power applications, creating commercial opportunities both in the U.S. and abroad. . . . [However] the size and duration of the credits may be insufficient to incentivize retrofits for the variety of facilities that are eligible, including many coal and natural gas plants."[179]

176 Simon Bennett, "US Budget Bill May Help Carbon Capture Get Back on Track," International Energy Agency, March 2018, https://www.iea.org/newsroom/news/2018/march/commentary-us-budget-bill-may-help-carbon-capture-get-back-on-track.html.

177 Frederick Eames and David Lowman, Jr., "Section 45Q Tax Credit Enhancements Could Boost CCS," Hunton Andrews Kurth, February 22, 2018, https://www.huntonnickelreportblog.com/2018/02/section-45q-tax-credit-enhancements-could-boost-ccs/.

178 Making Carbon a Commodity Carbon Utilization Research Council and ClearPath Foundation, "Making Carbon a Commodity: The Potential of Carbon Capture RD&D," July 25, 2018, http://www.curc.net/webfiles/Making%20Carbon%20a%20Commodity/180724%20Making%20Carbon%20a%20Commodity%20FINAL%20with%20color.pdf.

179 Energy Futures Initiative, "Advancing Large Scale Carbon Management: Expansion of the 45Q Tax Credit," May 2018: 1, https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5b0604f30e2e7287abb8f3c1/1527121150675/45Q_EFI_5.23.18.pdf.

3. New source review

Congress and the EPA could consider how current laws and regulations hold back increased investment in CCUS. The clearest example of this hindrance is EPA's New Source Review (NSR), particularly uncertainty over whether CCUS retrofits would trigger NSR. DOE's August 2017 grid study cited how permitting requirements create uncertainty and difficulty for utilities that may want to retrofit plants with CCUS systems: "the uncertainty surrounding NSR requirements has led to a significant lack of investment in plant and efficiency upgrades, which would otherwise lead to more efficient power generation, benefits to grid management, and reduced environmental impacts."[180] Companies including Ameren Corp, BP America, and Koch Industries have also called for increased clarity of what constitutes a modification triggering NSR: "In the past, improving the efficiency of power plants has been placed in regulatory doubt by misapplication of the so-called New Source Review (NSR) program."[181]

In testimony before the House Energy and Commerce Committee, Arkansas Department of Environmental Quality Associate Director Stuart Spencer expressed support for a proposal from Rep. Morgan Griffith (R-Va.) to narrow the definition of "modification" in NSR to mean a substantial modification excluding energy efficiency, pollution reduction, and reliability projects.[182] One possible alternative could be considering changes in emissions rates rather than increases in overall tons of emissions, a change that could be promulgated through EPA's existing regulatory authority.[183] Indeed, EPA's proposed Affordable Clean Energy rule in August 2018 included a modification of NSR to apply only to projects that increase a plant's hourly rate of pollutant emissions.[184] As of the time of writing, the EPA was accepting public comments on the proposal, and the final rule has yet to be written and could differ substantially from the proposal.

4. Direct funding

Since fiscal year 2008, Congress has appropriated more than $7 billion to the DOE in support of carbon capture utilization and storage activities.[185] The American Recovery and Reinvestment Act of 2009 provided $781 million in cost-share funding to support four commercial scale demonstrations of CCUS technologies for industrial and power applications.[186] Not all projects were successful, and DOE did not spend all of the money it was appropriated. However, such results are typical for risky RD&D portfolios. Federal funding did play a significant role in the success of Petra Nova and has played "a key role in enabling market-wide deployment of environmentally responsible fossil fueled energy conversion technologies," according to NETL.[187]

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180 U.S. Department of Energy, "Staff Report to the Secretary on Electricity Markets and Reliability," August 2017, https://www.energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf.

181 Sonal Patel, "Capturing Carbon and Seizing Innovation: Petra Nova is POWER's Plant of the Year," *Power* 161 No. 8 (August 2017): 20–25, https://cdn2.hubspot.net/hubfs/3999852/Power%20Magazine%20Aug%202017%20Desalitech%20-%20Full%20Version.pdf?t=1510942883532.

182 Stuart Spencer, "Testimony of Stuart Spencer before the House Committee on Energy and Commerce, Subcommittee on Environment," U.S. House of Representatives, February 14, 2018, https://docs.house.gov/meetings/IF/IF18/20180214/106852/HHRG-115-IF18-Wstate-SpencerS-20180214.pdf.

183 Abby Smith and Dean Scott, "Grid Study Resurrects Debate over Utility Air Pollution Permits," Bloomberg News, August 28, 2017. https://www.bna.com/grid-study-resurrects-n73014463779/,

184 Gavin Bade, "EPA Moves to Replace Clean Power Plan with Modest Carbon Regulations,"" Utility Dive, August 21, 2018, https://www.utilitydive.com/news/breaking-epa-moves-to-replace-clean-power-plan-with-modest-carbon-regulati/530586/.

185 Peter Folger, "Recovery Act Funding for DOE Carbon Capture and Sequestration (CCS) Projects," Congressional Research Service, February 18, 2016, https://fas.org/sgp/crs/misc/R44387.pdf.

186 Energy Futures Initiative, "Advancing Large Scale Carbon Management: Expansion of the 45Q Tax Credit," May 2018: 7, https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5b0604f30e2e7287abb8f3c1/1527121150675/45Q_EFI_5.23.18.pdf.

187 Charles Zelek et al., "Analysis of Benefits of the NETL Clean Coal and Carbon Management Program," National Energy Technology Laboratory, April 15, 2016. https://www.netl.doe.gov/energy-analyses/temp/BenefitsoftheNETLCleanCoalandCarbonManagementProgram_041516.pdf.

The Carbon Utilization Research Council has called for an aggressive RD&D portfolio totaling $6.8 billion in federal funding and $3.8 billion in industry funding through 2025.[188] This scale of support—comparable to prior levels of funding through ARRA, but a substantial increase from current levels—is projected to significantly advance the deployment of carbon capture on fossil-fueled power generation by two to three times compared to a baseline lacking aggressive RD&D.[189] Robust RD&D programs have resulted in cost decreases of 40 to 90 percent for wind, distributed and utility-scale solar PV, batteries, and LEDs between 2008 and 2014 (see **Figure IV.5**). Focused investment in CCUS could have similar results. In a study of NETL's CCUS program, analysts found that RD&D funding contributed to DOE's sustainability and national security goals and led to "robust" economic growth.[190]

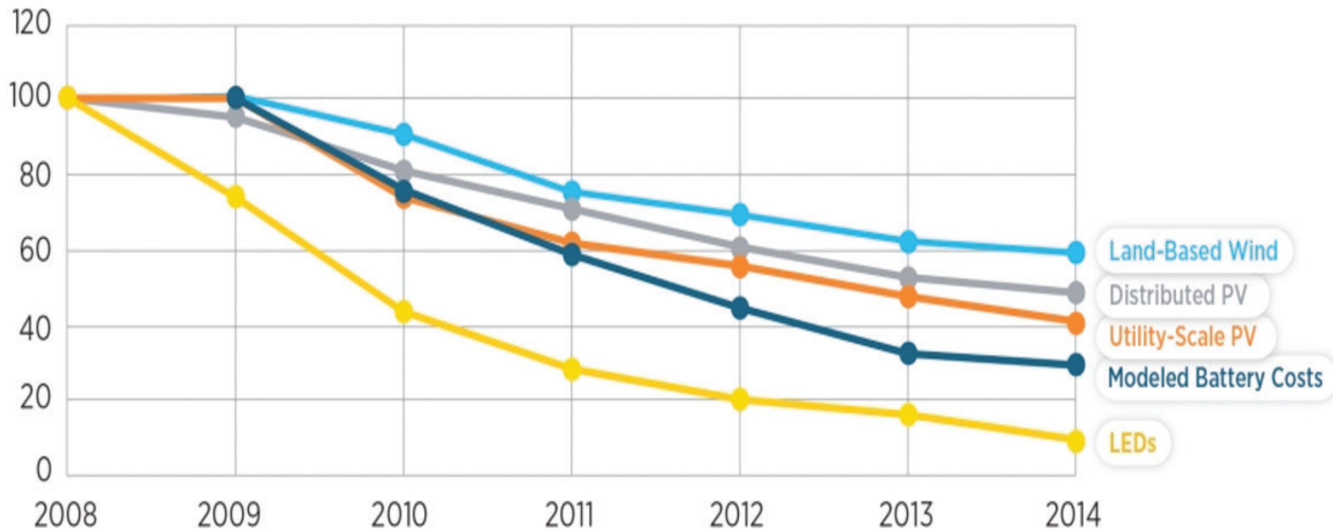

Figure IV.5 Cost declines for renewable technologies, 2008 - 2014[191]

188 Carbon Utilization Research Council, "CURC-EPRI Advanced Fossil Energy Technology Roadmap," 2018, http://curc.net/curc-epri-advanced-technology-roadmap-1.

189 Carbon Utilization Research Council and ClearPath Foundation, "Making Carbon a Commodity: The Potential of Carbon Capture RD&D," July 25, 2018, http://www.curc.net/webfiles/Making%20Carbon%20a%20Commodity/180724%20Making%20Carbon%20a%20Commodity%20FINAL%20with%20color.pdf.

190 Charles Zelek et al., "Analysis of Benefits of the NETL Clean Coal and Carbon Management Program," National Energy Technology Laboratory, April 15, 2016, https://www.netl.doe.gov/energy-analyses/temp/BenefitsoftheNETLCleanCoalandCarbonManagementProgram_041516.pdf.

191 U.S. Department of Energy, "Revolution Now: The Future Arrives for Five Clean Energy Technologies – 2015 Update," November 2015, https://www.energy.gov/eere/downloads/revolution-now-future-arrives-five-clean-energy-technologies-2015-update.

5. National infrastructure planning

Texas created competitive renewable energy zones (CREZ) to facilitate the construction of high-voltage transmission lines bringing wind power produced in the sparsely populated western region of the state to population centers in central and southeastern Texas. A state law passed in 2005 directed the Public Utility Commission of Texas to select transmission providers and oversee the siting process. The CREZ program resulted in 3600 miles of open-access 345 kW transmission lines carrying 18.5 GW of wind capacity, at a total cost of $6.9 billion.[192]

The CREZ process offers valuable lessons for CO_2 pipeline planning. The federal government could apply this attitude to national CO_2 pipeline infrastructure by including CO_2 pipelines as a component of a national infrastructure plan. A sample plan is shown in **Figure IV.6**. Such a plan could include the development of a select number of priority CO_2 trunk pipelines in critical areas to scale up the CO_2-EOR market.[193] By designating pipelines as a key piece of a national infrastructure strategy, the federal government could highlight their importance to project developers and state and local regulators with direct control over siting and permitting.

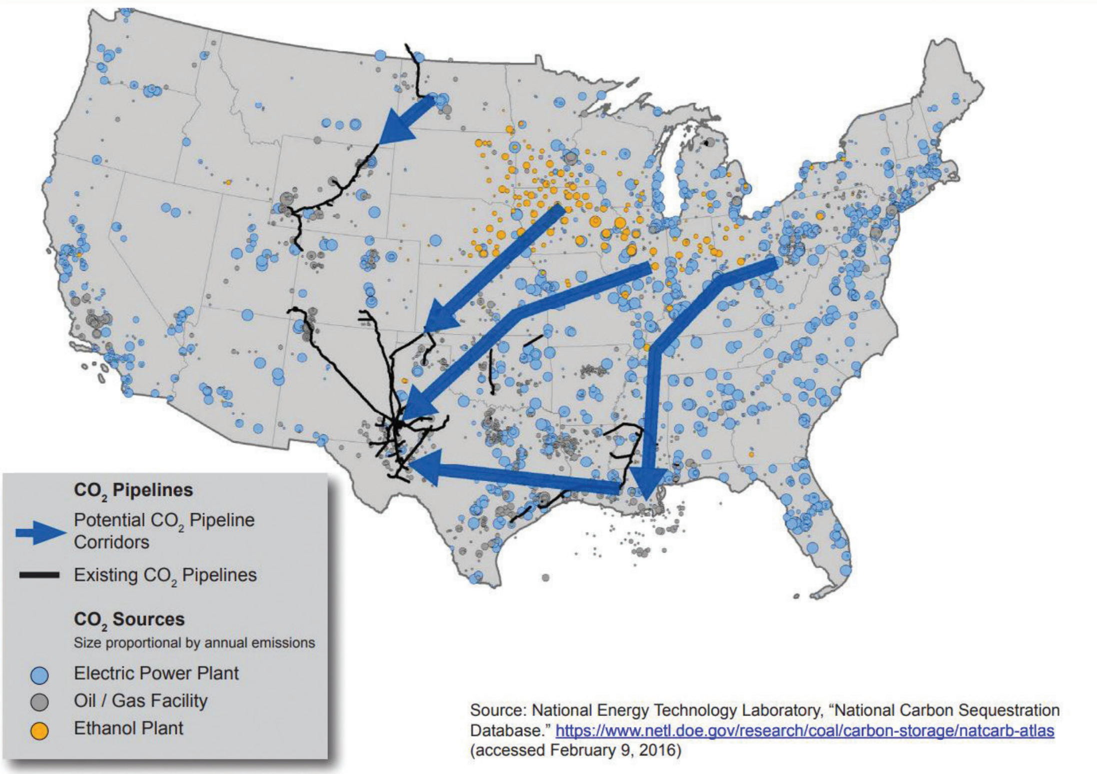

Figure IV.6 Recommendations for regional CO_2 pipeline infrastructure[194]

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192 Warren Lasher, "The Competitive Renewable Energy Zones Process," ERCOT, August 11, 2014, https://www.energy.gov/sites/prod/files/2014/08/f18/c_lasher_qer_santafe_presentation.pdf.

193 State CO_2-EOR Deployment Work Group, "21st Century Energy Infrastructure: Policy Recommendations for Development of American CO_2 Pipeline Networks," February 2017, http://www.betterenergy.org/wp-content/uploads/2018/02/White_Paper_21st_Century_Infrastructure_CO2_Pipelines_0.pdf.

194 Ibid.

V. Collaboration and Partnerships

This chapter examines critical public-private partnerships that have and will continue to drive progress in CCUS RD&D. Section C discusses opportunities for CCUS in the Eastern Interconnection region and CO_2 utilization in the U.S.

A. International Collaboration

Status

The U.S., Norway, and Saudi Arabia launched a CCUS initiative in 2018 to advance global collaboration in this area. Other international partners include Canada, China, Japan, Mexico, Netherlands, United Arab Emirates, the UK, and the European Commission. The CCUS initiative will focus on strengthening the framework for collaborative partnerships between the public and private sectors, and will complement the existing CCUS efforts led by the Carbon Sequestration Leadership Forum (CSLF), the IEA's Greenhouse Gas R&D Programme, Mission Innovation, and the Global CCS Institute. Higher levels of investments are required to fully develop and deploy CCUS to lower emissions and the joint CCUS initiative aims to foster greater international collaboration in this area.

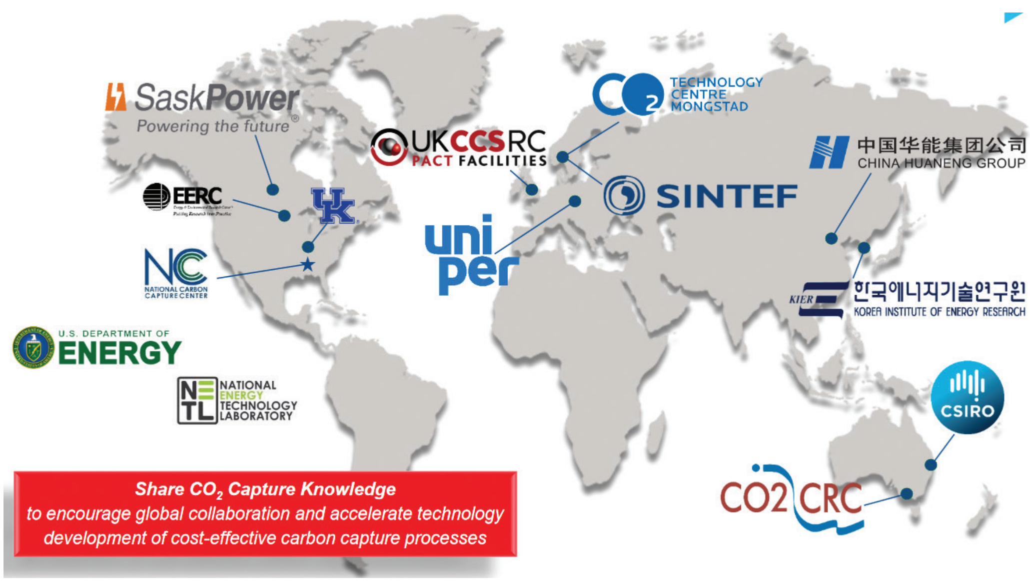

Figure V.1 ITCN sites around the world[195]

U.S. DOE and the National Carbon Capture Center (NCCC) in Wilsonville, Alabama are actively involved in the Carbon Capture International Test Center Network (ITCN). ITCN was formed in 2013 as a collaboration with DOE and Norway. It facilitates knowledge-sharing among carbon capture test facilities around the world to accelerate the commercial deployment of carbon capture technologies. ITCN members collaborate on one technical item per year (e.g., amine emissions from stack, measurement techniques, support advanced simulations and model development to reduce capital and operating costs). They also share public knowledge with other carbon capture test facilities on items such as facility operations, funding, safety, and analytical techniques.

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195 Frank Morton, "International Collaboration on CCUS R&D," Carbon Management Technology Conference, Houston, TX, 2017.

One example of an existing partnership between the U.S. and other countries is that between U.S. and Norway. The existing partnership between U.S. and Norway on CO_2 capture, utilization, and storage continue to leverage research efforts that are of significance to both countries (e.g., CO_2-EOR, improved resource recovery). In 2004, the U.S. DOE and the Kingdom of Norway's Royal Ministry of Petroleum and Energy (MPE) signed a bilateral Memorandum of Understanding (MoU) covering fossil energy-related research to leverage each country's investments in carbon capture, utilization and storage, hydrogen, and novel energy technologies. In particular, Norway is Europe's largest petroleum liquids producer and the world's third-largest natural gas exporter, and represents a potential market for cutting-edge U.S. technologies such as CO_2-enhanced hydrocarbon recovery. There are several Norwegian projects where the captured CO_2 is being stored in geologic formations, such as Sleipner (one million tons CO_2/y, started in 1996), and Snøhvit (700 kT/y, operational in 2008). U.S. technology developers have benefited immensely from access to the test centers and from the exchange of knowledge with Norwegian academia and industries. The main goal is to reduce the cost, and the risks related to large-scale CO_2 capture and storage. U.S. DOE has supported test campaigns for U.S. companies such as Research Triangle International (RTI), ION Engineering, and General Electric (GE).

Ongoing Research

ION Engineering has tested its advanced solvent drop-in technology at Technology Center Mongstad (TCM) in Norway. TCM is a leading carbon capture test facility in the world and ION's two-year (2016-2017) project was being funded from a $7.6 million award from the DOE and a $6.7 million cost share provided by TCM. ION Engineering's second-generation post-combustion CO_2 capture solvent system was first successfully tested at small pilot scale (0.5 MW_e) at the DOE-funded NCCC in Alabama. Subsequently, amine degradation testing was done at Norwegian Foundation for Scientific and Industrial Research (SINTEF), in Trondheim. As the next step in technology scale up, ION's semi-aqueous solvent was tested at a larger scale (12 MW_e) at TCM. Currently, the Fluor/PNNL water-lean solvent is also being tested at TCM.

Previously, DOE funded General Electric to demonstrate its aminosilicone-based CO_2 solvent capture technology at demonstration (~10 MW) scale at TCM. Research Triangle Institute (RTI) tested a non-aqueous CO_2 capture solvent using real coal-derived flue gas at the 40 kW_e scale at the Tiller pilot plant at SINTEF.

Examples of international companies which tested their technologies at NCCC include Aker Solutions (Norway), Shell Cansolv (Canada), Carbon Clean Solutions (India), BASF (Germany), Chiyoda, MHI and Hitachi (Japan), and University of Edinburgh sensors (UK). Future tests may include a South Korean solvent, a Chinese solvent, a Japanese membrane, Norwegian membrane, and an Australian sensor.

B. U.S. Regional Partnerships

DOE/NETL established the regional carbon sequestration partnership (RCSP) initiative in 2003 to support and advance technologies to enable geologic storage of CO_2, with a goal to achieve readiness for commercial deployment in the 2025 – 2035 time period. The RCSP initiative consists of seven partnerships located throughout the U.S. (see **Figure V.2**), and each partnership focuses on creating technologies for safe storage of CO_2 in a particular geologic and geographic setting.[196] The RCSPs are at the forefront in creating, advancing, and field-testing geologic storage approaches and technologies. Each RCSP executed geologic storage projects in three phases, according to increasing levels of project maturity: characterization phase, validation phase, and development phase field projects.

196 Traci Rodosta et al., "U.S. DOE Regional Carbon Sequestration Partnership Initiative: New Insights and Lessons Learned," *Energy Procedia* 114 (2017): 5580 – 5592.

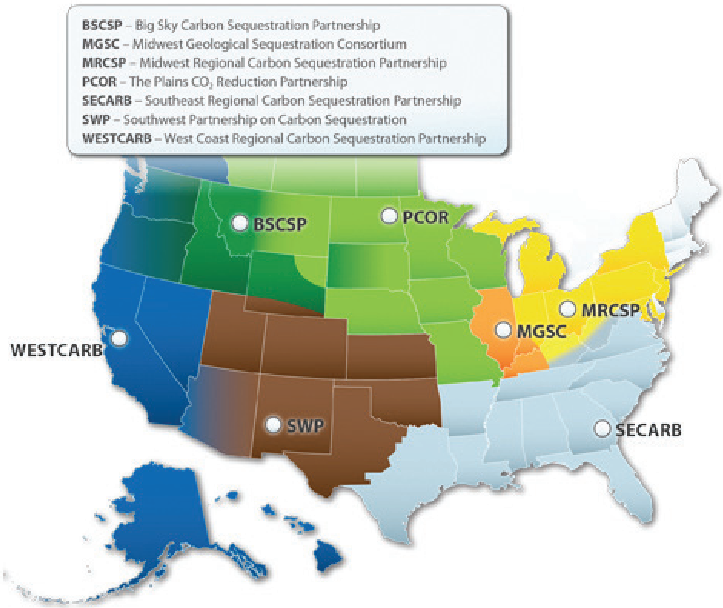

Figure V.2 Regional Carbon Sequestration Partnerships[197]

In the characterization phase, which began in 2003, the RCSPs focused on collecting and analyzing data on potential CO_2 reservoirs, and developing resources for field testing of CO_2 storage. By the end of this phase, each RCSP established a regional network of organizations and individuals working to develop the foundations for CO_2 storage deployment. A standard, consistent methodology to estimate the CO_2 storage resource was developed and used in a series of carbon storage atlases for the U.S., and portions of Canada.[198]

In the validation phase, which began in 2005, the focus shifted to small-scale field projects to identify the most promising storage opportunities. Nineteen small-scale field projects were completed, injecting and monitoring more than one million metric tons of CO_2 safely. Of these, eight projects were in depleted oil and gas fields, five in unmineable coal seams, five in saline formations, and one in basalt formation. These small-scale tests provided information for the larger-scale, development-phase field projects.

The RCSP development-phase projects began in 2008 with a goal to confirm that CO_2 capture, transportation, injection, and storage can be achieved safely, permanently, and economically. The formations being tested in this phase are regionally significant, and are expected to have the potential to store hundreds of years of CO_2 emissions from stationary sources. As of December 2017, more than 14 million metric tons of CO_2 were stored in geologic formations in this development phase.[199] Projects in this phase include saline storage and enhanced oil recovery using CO_2 from natural sources (Kevin Dome, Jackson Dome), industrial sources (ethanol fermentation, natural gas processing, fertilizer production), and coal-fired power plant flue gas (Plant Barry).

197 National Energy Technology Laboratory, "Regional Carbon Sequestration Partnerships (RCSP) Initiative," https://www.netl.doe.gov/research/coal/carbon-storage/carbon-storage-infrastructure/rcsp.

198 See https://www.netl.doe.gov/research/coal/carbon-storage/natcarb-atlas for the most up-to-date version of the carbon storage atlas.

199 National Energy Technology Laboratory, "RCSP Development Phase," https://www.netl.doe.gov/research/coal/carbon-storage/carbon-storage-infrastructure/regional-partnership-development-phase-iii.

The Carbon Storage Assurance Facility Enterprise (CarbonSAFE) Initiative projects aim to develop geologic storage sites for the storage of at least 50 MMT of CO_2 from industrial sources. The program improves understanding of project screening, site selection, characterization, and baseline monitoring, verification, accounting (MVA), and assessment procedures, as well as permitting, injection, and monitoring strategies for commercial-scale capture and storage projects. CarbonSAFE projects will develop storage ready for injection by 2026. Currently, CarbonSAFE projects are located mostly onshore in the continental U.S., with 13 initial pre-feasibility studies in progress and three more detailed feasibility studies underway at sites that have completed initial studies.[200]

Project Name	Project Type	CO_2 Source	Geologic Basin	Metric Tons of CO_2 Stored
Big Sky Carbon Sequestration Partnership–Kevin Dome Project	Saline Storage	Kevin Dome (natural)	Kevin Dome	N/A (no injection date)
Midwest Geological Sequestration Consortium–Illinois Basin Decatur Project	Saline Storage	ADM Ethanol Production Facility	Illinois Basin	999,215 (final stored and project in post-injection monitoring phase)
Midwest Regional Carbon Sequestration Partnership–Michigan Basin Project	Enhanced Oil Recovery	Core CO_2 Services, LLC Natural Gas Processing Facility	Michigan Basin	596,282 (as of Sept. 30, 2016)
The Plains CO_2 Reduction Partnership–Bell Creek Field Project	Enhanced Oil Recovery	Conoco Philips Lost Cabin/Madden Natural Gas Processing Plant	Powder River Basin	2,982,000 (final stored and project in post-injection monitoring phase)
Southeast Regional Carbon Sequestration Partnership–Citronelle Project	Saline Storage	Southern Company's Plant Barry Coal-Fired Power Plant	Interior Salt Basin, Gulf Coast Region	114,104 (final stored and project in post-injection monitoring phase)
Southeast Regional Carbon Sequestration Partnership–Cranfield Project	Enhanced Oil Recovery/ Saline Storage	Jackson Dome (natural)	Interior Salt Basin, Gulf Coast Region	4,743,898 (final stored and project in post-injection monitoring phase)
Southwest Carbon Sequestration Partnership–Farnsworth Unit Project	Enhanced Oil Recovery	Arkalon Ethanol Plant (Liberal, KS) Agrium Fertilizer Plant (Borger, TX)	Anadarko Basin	490,720 (as of Sept. 30, 2016)

Figure V.3 RSCP large-scale development-phase projects[201]

200 National Energy Technology Laboratory, "CarbonSAFE," https://www.netl.doe.gov/research/coal/carbon-storage-1/storage-infrastructure/carbonsafe

201 Traci Rodosta et al., "U.S. DOE Regional Carbon Sequestration Partnership Initiative: New Insights and Lessons Learned," *Energy Procedia* 114 (2017): 5580 – 5592.

In addition to these projects, the RCSPs also completed a series of best practice manuals (BPMs) between 2009 and 2013 and incorporated findings from RCSP characterization phase and validation phase projects. Recently, they revised the BPMs to include results and lessons from the development-phase projects. The revised BPMs discuss:

- Site screening, site selection, and site characterization for geologic storage projects
- Public outreach and education for geologic storage projects
- Risk management and simulation for geologic storage projects
- Monitoring, verification, and accounting (MVA) for geologic storage projects
- Operations for geologic storage projects

An overview of each revised BPM can be found in Rodosta et al., 2017.

C. CCUS Possibilities in the Eastern Interconnection

The geologic resources within the region demarcated by the Eastern Interconnection are quite significant. Power production facilities include a significant number of CO_2 sources (both coal- and natural-gas fired), and pipeline rights-of-way are also common. However, a driver to encourage development of CO_2 transport capacity is absent. Extraction of unconventional natural gas and gas liquids may provide one driving force, when natural gas prices increase, and as natural gas liquids become more difficult to extract.

POWER MARKET	GENERATING CAPACITY (MW)
ISO-NE	31,000
NYISO	38,777
PJM	165,569
SERC	238,000
MISO	174,724
SPP	84,943

Table V.1 Generating capacity within the Eastern Interconnection[202]

Traditional wholesale electricity markets exist primarily in the Southeast, Southwest and Northwest where utilities are responsible for system operations and management, and, typically, provide power to retail consumers. Utilities in these markets are frequently vertically integrated—they own the generation, transmission, and distribution systems used to serve electricity consumers. Wholesale physical power trade typically occurs through bilateral transactions.

202 Federal Energy Regulatory Commission, “Electricity Market Overview.” https://www.ferc.gov/market-oversight/mkt-electric/overview.asp.

Through a series of orders, FERC promoted the concept of independent system operators (ISOs). Several groups of transmission owners formed ISOs, some from existing power pools. The commission further encouraged utilities to join regional transmission organizations (RTOs) which, like an ISO, would operate the transmission systems and develop innovative procedures to manage transmission equitably. The ISOs and RTOs use bid-based markets to determine economic dispatch. Whereas major sections of the country operate under more traditional market structures, two-thirds of the nation's electricity load is served by RTOs.

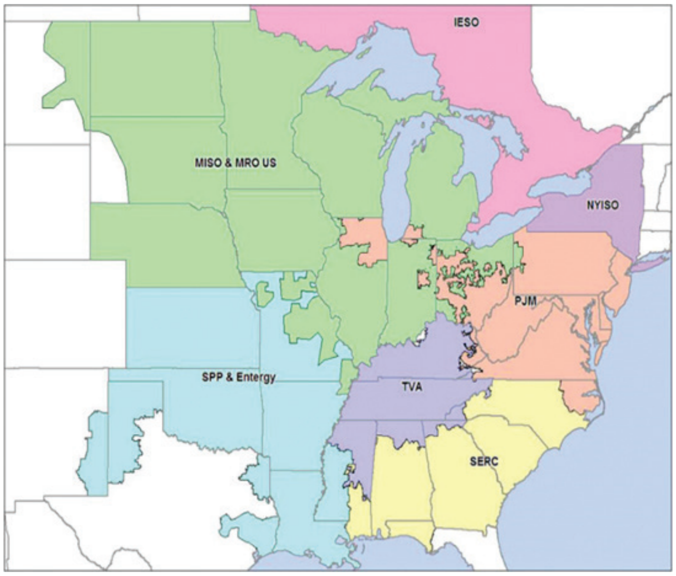

Figure V.4 RTOs/ISOs and non-RTOs comprising the Eastern Interconnection

The area demarcated as the Eastern Interconnection covers a large part of the U.S. and Canada, extending from the East Coast into the Plains States and from the Canadian border down to the Gulf Coast, excluding the area covered by ERCOT. The overlap between the Eastern Interconnection and the RTOs within that region is shown in **Figure V.4**, which identifies each region by the NERC region and the associated RTO/ISO. **Table 6.1** lists total generation capacity by market. Within that region, there are several NERC regions and a number of RTOs and other generating/transmitting entities. The market regions identified as MISO, PJM, NYISO, SPP, ISO-NE, and a portion of non-RTO/ISO represent most of the generation assets within the eastern interconnection.

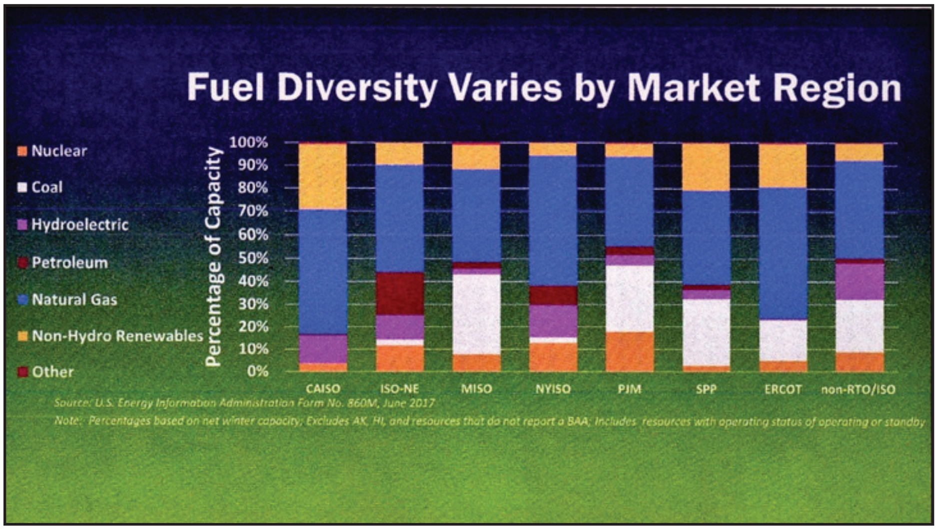

Figure V.5 Fuel mix by power markets

Each of the transmission organizations operates in a unique operating environment marked by different state requirements. Each has generating companies with individual profiles of power generation units, unique geology that might be suitable for sequestration, and pipeline access. **Figure V.5** is from a FERC market report on supply adequacy during the winter of 2017–2018. This plot shows fuel diversity by market region. The non-RTO/ISO bar on the far right covers that portion of the U.S. where power is generated, transmitted, and sold primarily through bilateral arrangements.

Figure V.6 shows a summary of storage potential by geological characteristics and maps of the United States showing areas evaluated for their storage potential and cataloged in the 2015 version of the Carbon Storage Atlas (V). Total storage capacity, based on the medium estimates, likely approaches 8,700 billion tons of CO_2. Simply dividing this total by the typical annual emissions (based on 2014) results suggests that the storage capacity could serve as a repository for over 1000 years.

Estimates of CO_2 Stationary Source Emissions and Estimates of CO_2 Storage Resources for Geologic Storage Sites

RCSP or Geographic Region	CO_2 Stationary Sources		CO_2 Storage Resource Estimates (billion metric tons of CO_2)								
	CO_2 Emissions (million metric tons per year)	Number of Sources	Saline Formations			Oil and Gas Reservoirs			Unmineable Coal Areas		
			Low	Med***	High	Low	Med***	High	Low	Med***	High
BSCSP	115	301	211	805	2,152	<1	<1	1	<1	<1	<1
MGSC	267	380	41	163	421	<1	<1	<1	2	3	3
MRCSP	604	1,308	108	122	143	9	14	26	<1	<1	<1
PCOR*	522	946	305	583	1,012	2	4	9	7	7	7
SECARB	1,022	1,857	1,376	5,257	14,089	27	34	41	33	51	75
SWP	326	779	256	1,000	2,693	144	147	148	<1	1	2
WESTCARB*	162	555	82	398	1,124	4	5	7	11	17	25
Non-RCSP**	53	232	--	--	--	--	--	--	--	--	--
Total	3,071	6,358	2,379	8,328	21,633	186	205	232	54	80	113

Source: U.S. Carbon Storage Atlas – Fifth Edition (Atlas V); data current as of November 2014

* Totals include Canadian sources identified by the RCSP

** As of November 2014, "U.S. Non-RCSP" includes Connecticut, Delaware, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont, and Puerto Rico

*** Medium = p50

Figure V.6 Summary of storage potential[203]

If one focuses only on areas within the eastern interconnection, power generation produced ~2.42 billion tons, whereas the estimated potential storage capacity within PCOR, MRCSP, MGSC, and the SECARB regional carbon sequestration partnerships was estimated to be ~1,900 gigatons (total potential sufficient for more than 100 years) based on the low range estimates. These numbers represent over 70 percent of both the emissions and the storage potential, with SECARB having the largest share of both emissions and storage.

The final piece of the puzzle is pipeline routing and potential capacity. **Figure V.8** shows the natural gas pipeline infrastructure within the U.S. in 2015. There is an extensive network of natural gas pipelines that run from production areas to large urban centers and to concentrations of major industrial sites.

The CO_2 pipeline network is not as extensive and comprises mainly of pipelines from natural sources of CO_2 to oilfields. Other sources include CO_2 separated from natural gas plants, ammonia plants, ethanol plants, a hydrogen production plant, and a power plant. In addition, there is a pipeline from the Dakota Gasification facility to EOR sites in Canada and additional plans to build out infrastructure in Wyoming and add to that existing along the Gulf Coast.

203 National Energy Technology Laboratory, "Carbon Storage Atlas – Fifth Edition (ATLAS V)," 2015, https://www.netl.doe.gov/research/coal/carbon-storage/atlasv.

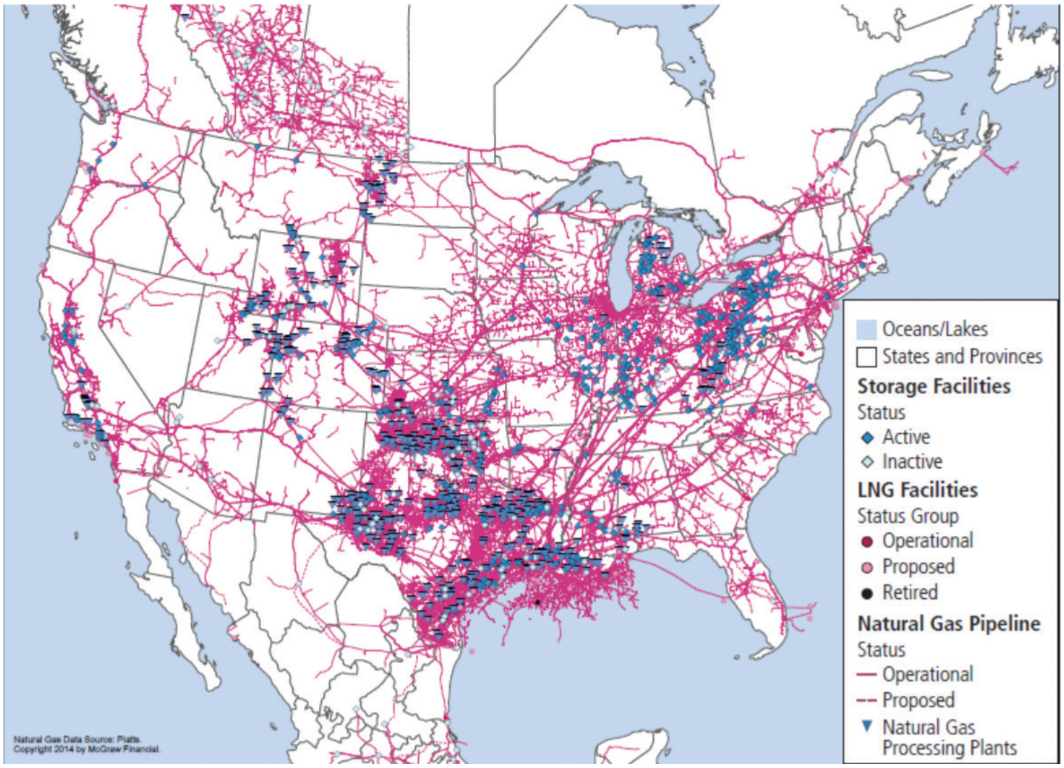

Figure V.8 U.S. natural gas pipeline network[204]

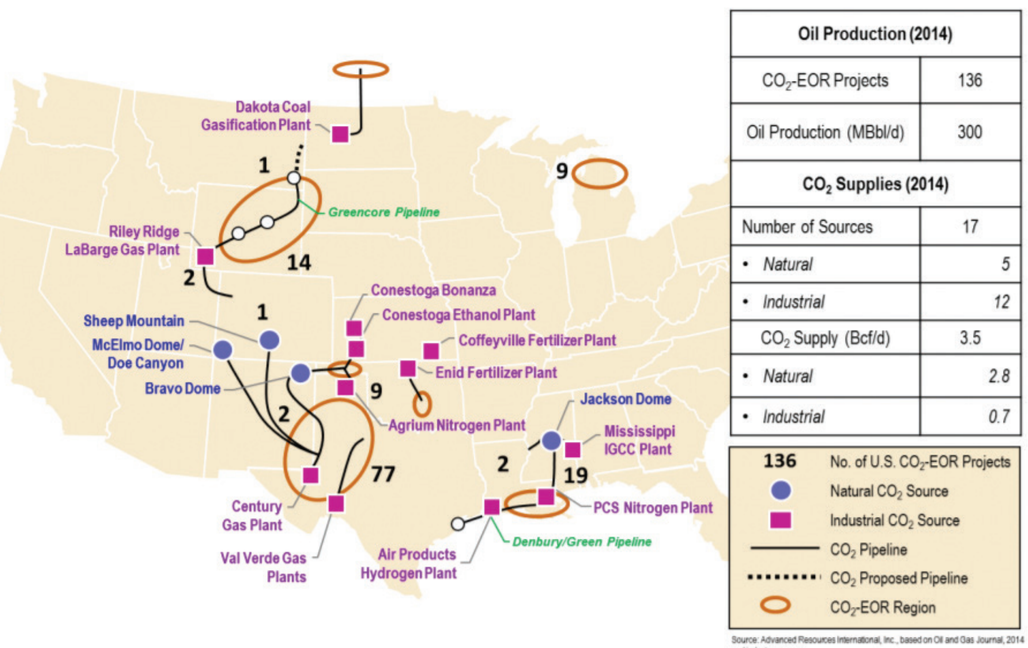

Figure V.9 U.S. CO_2 pipeline network[205]

204 U.S. Energy Information Administration, "U.S. Natural Gas Pipeline Network," https://www.eia.gov/naturalgas/archive/analysis_publications/ngpipeline/ngpipelines_map.html.

205 National Energy Technology Laboratory, "A Review of the CO_2 Pipeline Infrastructure in the U.S.," 2015, https://www.energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20-%20A%20Review%20of%20the%20CO2%20Pipeline%20Infrastructure%20in%20the%20U.S_0.pdf.

U.S. regions with large-scale CO_2 pipeline systems		Miles of Pipeline
Permain Basin	(W. TX, NM, and S. CO)	2,600
Gulf Coast	(MS, LA, and E. TX)	740
Rocky Mountains	(N. CO, WY, and MT)	730
Mid-Continent	(OK and KS)	480
Other	(ND, MI, Canada)	215

Table V.2 Geographic areas with large-scale CO_2 pipeline systems operating currently in the U.S.[206]

A 2015 analysis by the National Energy Technology Laboratory explored both the current CO_2 pipeline infrastructure (as shown in **Figure V.9**) and explored future expansion. At that time, just over four percent of total U.S. crude oil production was produced through EOR. This production figure is projected to increase to seven percent by 2030 absent new policies.

A national policy to encourage CO_2-EOR[207] could significantly change the outlook, creating incentives for electric power plants and other industrial facilities to reduce CO_2 emissions through carbon capture technologies and improving the economics for oil production through EOR. In a low-carbon case, the NETL study projected that construction through 2030 would more than triple the size of current U.S. CO_2 pipeline infrastructure, through an average annual build-rate of nearly 1,000 miles per year. Assuming the CO_2-EOR driven policy would similarly incentivize substantial new pipeline construction, a modeling run using the EP-NEMS model suggests that there could be as many as 107 new pipeline segments in use to transport captured CO_2 from its source to a terminal sink (EOR or saline storage) by 2040. Although the bulk of these segments would be west of the Mississippi River, a significant number of pipeline segments are projected to be built within the region covered by the eastern interconnection. The projected pipeline segments are shown in **Figure V.9**. The analysis suggests that an incentive to develop CO_2-EOR could catalyze significant pipeline construction.

These companies include: Skyonic, CarbonFree, Carbon8, CarbonCure, and Solida Technologies. Improvements to these technologies might broaden their applicability and reduce costs. The larger subset of projects along the spectrum from 1 to 7 may broaden the application base further or may need to overcome limitations on the size of by-product markets. The Calera project cited under Brine/Seawater produces chlorine as a byproduct. The current market for chlorine is small compared to the amount of CO_2 that is produced from even a few large power plants and the amount of chlorine that would be produced as a byproduct of the Calera process.

206 National Energy Technology Laboratory, "A Review of the CO2 Pipeline Infrastructure in the U.S.," 2015, https://www.energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20-%20A%20Review%20of%20the%20CO2%20Pipeline%20Infrastructure%20in%20the%20

207 State CO_2-EOR Deployment Work Group, "Putting the Puzzle Together: State & Federal Policy Drivers for Growing America's Carbon Capture & CO_2-EOR Industry," December 2016, http://www.betterenergy.org/wp-content/uploads/2018/02/PolicyDriversCO2_EOR-V1.1_0.pdf.

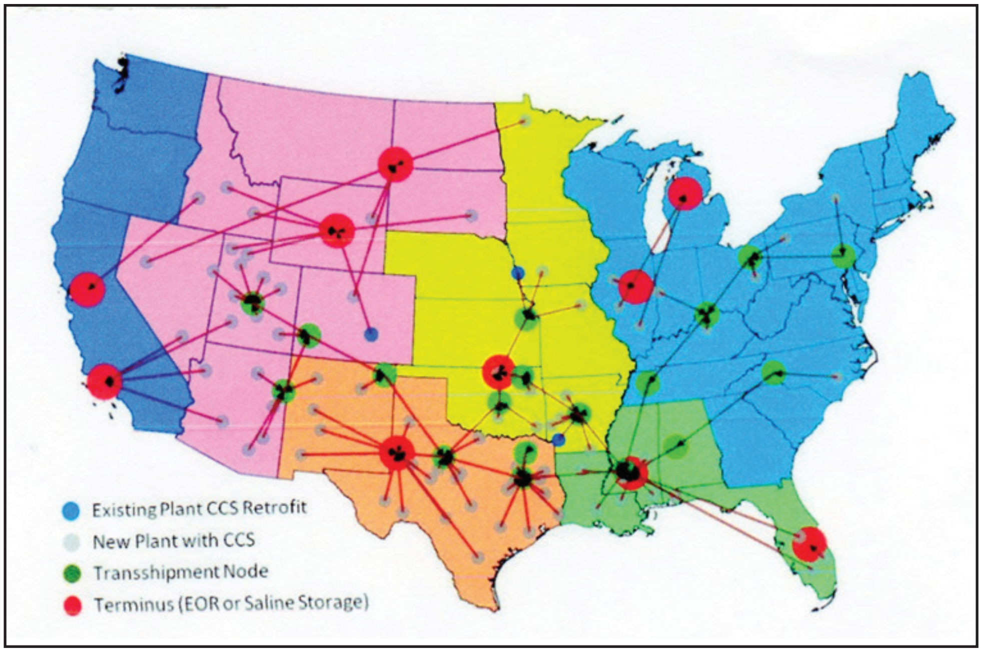

Figure V.10 Illustration of pipeline segment build-out under low-carbon scenario

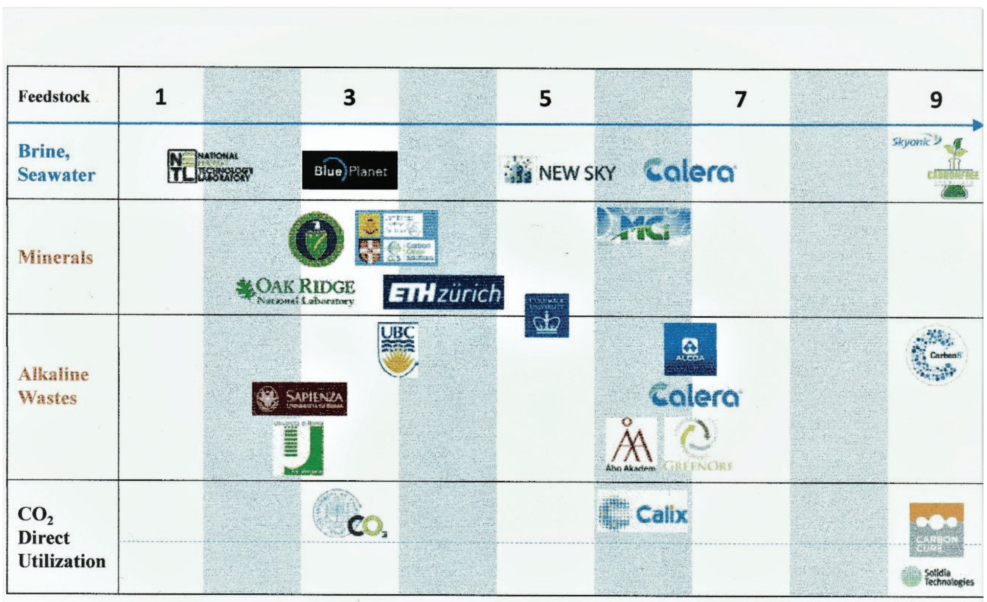

Figure 2.2. Stages of technology development for concrete and carbonate materials. (credit: Sean Zhou, Columbia University)

Figure V.11 Mineralization options and technology readiness levels

In recent years, well over 350 million tons of organic chemicals—in the form of solvents, synthetic rubber, fiber, plastics, and other products—are manufactured each year from fossil fuels. Production of these organic chemicals results in approximately 2 $GtCO_2$ of CO_2 emissions from the direct and indirect use of fossil fuels. Substitution of even a small fraction of this very large flow of materials and fuels represents an important opportunity for CO_2 utilization.[208] This sector is composed of many products that originate from a handful of precursors to the finished products—i.e., commodity chemicals. These chemicals are fewer in number and each is produced in larger volumes. Examples of these commodity chemicals include ethylene, propylene, methanol, butadiene, and polyvinyl chloride. Both direct and indirect routes exist that can convert CO_2 into a commodity chemical, often generating synthesis gas as an intermediate. Commodity chemicals are routinely considered as a consumptive end use for CO_2 because of the wide range of market opportunities and the possibility to scale up relatively mature technologies for commercial production in the medium-term.

Another possible end use with the potential to consume large amounts of CO_2 is production of high-value solid carbon materials, such as carbon nanotubes, carbon fiber, graphene and diamonds. The markets for these materials, particularly carbon fiber, is growing rapidly. This is despite the fact that the current manufacturing technology is expensive, limiting commercial use to a small number of performance sensitive applications (e.g. light-weighting aircraft for fuel savings). Lower-cost production methods would likely lead to even larger market growth. It is too early to tell whether CO_2-based methods would result in lower production costs.

This pathway is very different from the situation for cement and chemical intermediates, in which CO_2-based products will generally have to compete with conventional products in slower growing markets. First, entering a growing market is likely to be easier than competing with conventional commercial products in an existing market. Second, this early-stage technology could represent a case study of how policymakers can include emerging technologies that are still at the basic research stage in a comprehensive CO_2 strategy. Policy needs include funding support for basic R&D, some initial support for applied research and technology development, progressively detailed analysis of costs, technology gaps and impacts (life-cycle analyses of emissions, for example), and early coordination with standards and certification bodies.

208 Bojana Bajželj, et al., "Designing Climate Change Mitigation Plans That Add Up," *Environmental Science & Technology* 47 No. 14, 2013: 8062–8069.

Appendix A. Glossary

Air Separation Unit (ASU): An air separation unit separates air into its components, nitrogen, oxygen and any trace inert gases. Large-scale ASUs typically employ low temperature gas-liquid separation processes to extract pure gases from the liquefied air.

Energy penalty and parasitic load: The energy penalty reflects all loses in the output including the direct parasitic loss plus other impacts that result from the amount and quality of the steam that must be used for as part of the capture, regeneration, and compression steps. Use of lower temperature and pressure steam or use of an auxiliary unit to supply the necessary steam would lessen the overall energy penalty for the host power plant. The parasitic load is estimated as the equivalent work lost due to steam used for CCS + capture auxiliaries (e.g., pumps, blowers) + energy required for CO_2 compression from the conditions at the stripper overhead to the pressure at the interface with the transport system.

Project duration/lifespan: The lifespan of a CO_2 injection project may be determined by an assessment of the capability of the site to hold a defined amount of injected carbon dioxide if the project is only intended as a storage site. The life cycle of a CO_2 geological storage project covers all aspects, periods, and stages of the project, from those that lead to the start of the project (including site screening, selection, characterization, assessment, engineering, permitting, and construction), through the start of injection and proceeding through subsequent operations until cessation of injection and culminating in the post-injection period, which includes a closure period. The lifespan of a project injecting CO_2 for enhanced hydrocarbon recovery will be determined by the resource recovery portion. Once it is decided that no more hydrocarbon can be recovered economically, the project could be terminated following well-defined procedures as defined by the relevant jurisdiction.

Reforming: Reforming is a thermal and/or catalytic process where hydrocarbon molecules are converted to molecules which are either more valuable as premium, high-performance products, or as petrochemical feedstocks. For the purposes of this report, reforming refers to the conversion of hydrocarbons such as natural gas or naphtha to synthesis gas (hydrogen, carbon monoxide), which can be used as precursors for the production of ammonia, urea, methanol, and several other chemicals.

Regeneration: Rich solvent (containing the captured carbon dioxide) solution is removed from the absorber and pumped to a process vessel, where steam is used to separate the captured CO_2 from the solvent. Current commercial technologies to separate the CO_2 from the solvent use steam for this step. The quality of the steam, measured by its temperature and pressure, is a key consideration in the parasitic loss caused by CO_2 capture systems of this type. The steam may be drawn from low-pressure steam within the plant or provided by an auxiliary unit. Different solvents can have different requirements for the temperatures needed to cause this separation. Water vapor in the CO_2 product is then condensed, resulting in a highly concentrated (>99 percent) CO_2 product stream. The regenerated solvent (now called a lean solvent) is cooled to absorption temperature (at 40–65° C) and is recycled back into the absorption column [11].

Seal: A relatively impermeable rock, commonly shale, anhydrite or salt, which forms a barrier or cap above and around reservoir rock so that fluids cannot migrate beyond the reservoir. It is often found atop a salt dome. The permeability of a cap rock capable of retaining fluids through geologic time is ~ 10^{-6}–10^{-8} darcies. (See: https://www.glossary.oilfield.slb.com/Terms/c/cap_rock.aspx.)

Subcritical, supercritical, and ultra-supercritical power systems: Subcritical power units operate at steam temperatures and pressures below the critical point of water. A supercritical boiler operates at conditions above the critical point (3200 psi and 705^0F). The first supercritical boilers operated at conditions near to the critical point largely due to limitations in available materials. As improved materials have become available, the steam conditions have been raised. A recently commissioned unit at the Rheinhafen-Dampfkrafwerk plant in Karlsruhe, Germany, operates at steam conditions of 4000 psi and 1122° F. When tied to a district heating plant, the overall thermal efficiency of this unit approaches 60 percent. Plants with operating temperatures and pressures well above the critical point are often called ultra-supercritical units.

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