MEETING THE
DUAL CHALLENGE

A Roadmap to At-Scale Deployment of CARBON CAPTURE, USE, AND STORAGE

CHAPTER THREE – POLICY, REGULATORY, AND LEGAL ENABLERS

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POLICY, REGULATORY, AND LEGAL ENABLERS

I. CHAPTER SUMMARY

The U.S. federal and several state governments have a long history of enacting policy, legislation, and regulations intended to support the development and deployment of carbon capture, use, and storage (CCUS). As noted in Chapter 2 of this report, four of the ten existing CCUS projects in the United States received significant levels of financial policy support, in various forms, to enable their development. This world-leading policy support includes a 20-year history of Department of Energy (DOE) leadership and funding in leading CCUS research, development, and demonstration (RD&D) programs and projects, including support for industrial-scale demonstration projects like Petra Nova, Great Plains, ADM, Air Products, and hundreds of small-scale R&D projects involving various CCUS technologies.

This chapter explains the existing policy and regulatory framework in place in the United States for CCUS and describes the current challenges it presents for CCUS development and deployment. It then details, across three proposed phases of implementation, the changes that will be needed to enable CCUS deployment at scale within the next 25 years. This chapter also describes the critical need for RD&D and provides detailed recommendations for its increased support.

CCUS deployment has been supported by federal tax policy as well as state and regional incentives. For example, the Energy Improvement and Extension Act of 2008 (amended 2009) provides a tax credit to operators of carbon capture equipment for the capture and storage of up to 75 million tonnes of CO_2 (Section 45Q). To date, approximately 85% of those tax credits have been claimed.[1] The Bipartisan Budget Act of 2018 (BBA) amended Section 45Q, significantly expanding the value, duration, and eligibility of the credits.

A strong regulatory and legal framework has also been developed to ensure safe and secure transportation and storage of CO_2. Agencies such as the Environmental Protection Agency (EPA), Department of the Interior (DOI), and the Pipeline and Hazardous Materials Safety Administration (PHMSA), among others, have established regulations, guidance, and orders that underpin federal CCUS policy. For example, the EPA has developed specific regulatory frameworks under the Safe Drinking Water Act (SDWA) to protect underground sources of drinking water (USDW), and maintains the accounting protocols under the Clean Air Act Greenhouse Gas Reporting Program for the injection of CO_2 into geologic storage; while PHMSA sets and regulates the standards for design, construction, and operation of CO_2 pipelines.

Originally driven by businesses that use natural sources of CO_2 for enhanced oil recovery (EOR), the United States has successfully developed ~80% of the world's CO_2 capture capacity[2] and ~85% of the world's CO_2 pipelines, establishing itself as the world leader in CCUS

1 *Internal Revenue Bulletin, Bulletin* No. 2019-20, May 13, 2019, Section 4. Tax Credit Utilization.

2 Global CCS Institute large-scale facility database provided to NPC study.

project deployment. However, today's ~25 million tonnes per annum (Mtpa) of CCUS capacity represents less than 1% of U.S. stationary emissions. As described in the previous chapter, currently only a small volume of CO_2 can be economically captured, transported, and stored. Achieving at-scale CCUS deployment (e.g., 20% of U.S. stationary emissions) will require establishing adequate financial incentives through government policy underpinned by a durable regulatory and legal framework, the implementation of which should occur through a series of phases and prioritized based on deployment economics and ease of implementation.

The activation phase is designed to enable high-concentration CO_2 sources located close (~50 miles) to suitable storage or existing CO_2 pipeline—the most financially attractive projects—and offers recommendations that clarify existing policies and regulations and can be implemented quickly, without Congressional action. The expansion phase is focused on enhancing and expanding existing policies and developing a durable regulatory framework to enable additional CCUS capacity. This additional capacity is likely to be deployed where large high-concentration CO_2 sources can be connected to suitable economically accessible storage locations and in certain circumstances, where lower-concentration CO_2 sources can take advantage of infrastructure that has been developed because of high-purity source CCUS deployments. These CO_2 sources are generally more expensive to capture, transport, and store than those in the first phase. While this phase leverages existing policies and regulations, the recommendations include amendments that will require Congressional action. The third phase, at-scale deployment, intends to unlock a much larger volume of low-concentration CO_2 sources, including industries such as power generation, refining, chemicals, cement, and steel. Enabling capture at these sources will require substantially increased support driven by national policies that will require time to develop and enact. As a result of the significant allocation of resources needed to reach this level of deployment (i.e., ~500 Mtpa), the policies developed should be thoroughly evaluated and as economically efficient as possible.

II. EXISTING POLICY AND REGULATORY FRAMEWORK

The U.S. federal and several state governments have a long history of enacting policy, legislation and regulations intended to support the development and deployment of CCUS. Many of the financial incentives that have been implemented in the United States fall into two major categories: those that provide tax relief or support, and those that provide direct funding or funding support. Financial incentives that provide tax relief or support include mechanisms such as investment tax credits, production tax credits, tax-exempt financing, and tax advantaged corporate structures. Financial incentives that provide funding or funding support include mechanisms such as direct funding, loans, and loan guarantees. Additionally, the United States has a strong regulatory framework to ensure safe and secure transportation and storage of CO_2. From capture through transport and ultimately to storage, various U.S. federal and state agencies have developed specific regulatory and permitting requirements to ensure the safety of, and address the risks associated with, CCUS.

A. Financial Incentives

A range of federal tax credits exist today to incentivize emissions reduction technology and energy programs. To date, the tax incentives that support CCUS have taken the form of either Production Tax Credit (PTC) or Investment Tax Credit (ITC). A PTC provides a tax rebate based on the annual activity of the eligible project: this could be electric generation in the case of an electric project or annual tonnage of CO_2 stored underground for a carbon capture project. The most widely known PTC used to date is the PTC to incentivize wind generated power based on a per kilowatt hour of generation. An ITC is another tax credit incentive for businesses designed to encourage capital investment; but in the case of an ITC, the rebate is based on the cost of the equipment purchased for the project—rather than on the annual activity as in a PTC. The result is a reduction in the tax burden for the business, minimizing the amount of taxes owed.

1. Production Tax Credit (Section 45Q)

The Section 45Q tax credit is a form of PTC for an amount of CO_2 captured by the taxpayer at a qualified facility and is either "disposed of by the taxpayer in secure geologic storage"[3] or is "used by the taxpayer as a tertiary injectant in a qualified enhanced oil or natural gas recovery project and disposed of by the taxpayer in secure geological storage"[4] or "utilized by the taxpayer"[5] through fixation, chemical conversion or "for any other purpose for which a commercial market exists."[6] This program began under the Energy Improvement and Extension Act of 2008 (amended 2009). In 2018, Congress increased the value of the credit, eliminated the 75 million metric ton (tonne) cap but set a defined period in which the credit could be claimed, and extended the tax credit to include utilization beyond EOR.

As amended, in 2009, Section 45Q provided a credit for capturing CO_2 and disposing of the CO_2 in secure geological storage within the United States in accordance with the following terms:

1. A credit of $10 per tonne of CO_2 that is captured by a taxpayer at an industrial facility and used as a tertiary injectant in an enhanced oil or gas recovery project, and disposed of in secure geological storage
2. A credit of $20 per tonne of CO_2 that is captured by a taxpayer at an industrial facility and disposed of in secure geological storage
3. A cap on the amount of credit claimed of 75 million tonnes of CO_2
4. A requirement that the "The Secretary [of Treasury], in consultation with the Administrator of the Environmental Protection Agency, the Secretary of Energy, and the Secretary of the Interior, shall establish regulations for determining adequate security measures for the geological storage of carbon dioxide... such that the carbon dioxide does not escape into the atmosphere."

3 Bipartisan Budget Act of 2018 (BBA).

4 BBA.

5 BBA.

6 BBA.

In February of 2018, Congress passed the Bipartisan Budget Act of 2018, which increased the amount of the credit, provided a 12-year period to claim the credit, expanded the definition of qualifying utilization projects beyond EOR, and allowed direct air capture to be eligible for the credit. Figure 3-1 shows the level of tax credit available under the amended 45Q. Key provisions of the 2018 statute include:

- Increasing the tax credit over a 10-year period to $35/tonne for CO_2 used as a tertiary injectant for EOR or natural gas recovery and disposed of in secure geological storage
- Increasing the tax credit over a 10-year period to $50/tonne for CO_2 disposed of in secure geological storage
- Applying the credit for a 12-year period beginning on the date new carbon capture equipment is originally placed in service at a qualified facility
- Requiring construction of new carbon capture equipment to begin before January 1, 2024
- Establishing minimum capture requirements for categories of facilities (volumes detailed in Figure 3-1) to receive the tax credit
- Allowing a credit for utilization that can be shown, based upon an analysis of life-cycle greenhouse gas (GHG) emissions, to have been captured and permanently isolated from the atmosphere, or displaced from being emitted into the atmosphere
- Allowing for the recapture of the credit for any CO_2 that ceases to be captured, disposed of, or used as a tertiary injectant
- Allowing the tax credit to be transferred from the equipment owner to the party that disposes of, uses, or utilizes the CO_2
- Repeating the requirement that the Internal Revenue Service (IRS), after consultation with EPA, DOE, and DOI, promulgate regulations defining "secure geological storage."

The Section 45Q tax credit is earned by the taxpayer who owns the carbon capture equipment at a qualified facility and applies to every tonne of qualified carbon oxides[7] captured

7 Any carbon dioxide pre-BBA, any carbon dioxide, or other carbon oxide post-BBA.

	MINIMUM SIZE OF ELIGIBLE CARBON CAPTURE PLANT BY TYPE (KILOTONNES OF CO_2/YR)			RELEVANT LEVEL OF TAX CREDIT IN A GIVEN OPERATIONAL YEAR ($/$TCO_2$)									
TYPE OF CO_2 STORAGE/ USE	POWER PLANT	OTHER INDUSTRIAL FACILITY	DIRECT AIR CAPTURE	2018	2019	2020	2021	2022	2023	2024	2025	2026	BEYOND 2026
DEDICATED GEOLOGICAL STORAGE	500	100	100	28	31	34	36	39	42	45	47	50	INDEXED TO INFLATION
STORAGE VIA EOR	500	100	100	17	19	22	24	26	28	31	33	35	
OTHER UTILIZATION PROCESSES[1]	25	25	25	17[2]	19	22	24	26	28	31	33	35	

[1] Each CO_2 source cannot be greater than 500 kilotonnes of CO_2 ($KTCO_2$) per year.
[2] Any credit will only apply to the portion of the converted CO_2 that can be shown to reduce overall emissions.

Source: Energy Futures Initiative, 2018.

Figure 3-1. *Section 45Q Tax Credit Value for Different Sources and Uses of CO_2*

during the 12-year period beginning on the date the carbon capture equipment is placed in service. The taxpayer who earns the credit may transfer the credit to the entity that disposes of the qualified carbon oxide, uses it for EOR, or utilizes it in another way. Credit transferability enhances the options for a project to fully monetize the value of the tax credit and to secure financing.

Although the 2018 amendments to Section 45Q significantly expanded the value, duration and eligibility of these tax credits, clarifications regarding the access and use of the credits has not yet occurred, creating significant uncertainty for those considering investment. On June 5, 2019, the IRS issued Notice 2019-32 stating that the U.S. Department of the Treasury (Treasury) and IRS intend to issue regulations under Section 45Q and solicited public comments on many aspects of the credit, including the start of construction, transferability, recapture, and secure geologic storage, which are top priorities identified by this study. As of the date of this report, regulations had not yet been issued.

2. Enhanced Oil Recovery Production Tax Credit (Section 43C)

The EOR production tax credit under Section 43 of the Internal Revenue Code was put into place to incentivize EOR projects when oil prices fall below a reference price. The EOR tax credit offers a 15% federal tax credit on qualified costs of projects implemented or expanded after 1990. The credit is applicable to specific project costs, both capital expenditure and operating expense, and reduces the overall tax burden for the owner of the working interest. Because the credit was put in place during a period of relatively low oil prices, its value is based on reference price for oil price of $28 per barrel (adjusted for inflation). Once the reference price exceeds the original $28 per barrel of oil (adjusted for inflation), the credit is reduced. The credit is fully phased out once the reference price exceeds the inflation adjusted price by $6. Based on 2019 oil prices, the credit is not available. In 2019, the reference price of $61.41 exceeds the inflation adjusted oil price of $48.54 by more than $6, resulting in a complete phase out of the credit for 2019.

3. Investment Tax Credit (Section 48)

Policy support in the form of investment tax credits for CCUS to date has emphasized demonstrations of CCUS at coal plants. These policies included Section 48A investment tax credits for coal plants with CCUS (26 U.S. Code § 48A) and Section 48B investment tax credits for industrial gasification (26 U.S. Code § 48B).

In 2005, Congress established the "Credit for Investment in Clean Coal Facilities" in the Energy Tax Incentives Act (ETIA). ETIA authorized $1.3 billion in tax credits to support advanced coal-based generation technology designed to incentivize the construction of new, highly efficient coal units, and to incentivize projects at existing units to improve their efficiency. In 2008, Congress provided an additional $1.25 billion in tax credits through the Energy Improvement and Extension Act, which increased the value of the tax credit to 30% of the eligible investment and imposed a new requirement to capture and store at least 65% of the CO_2 in order to be eligible for the tax credits. As part of the BBA, Sections 48A and 48B of the American Recovery and Reinvestment Tax Act of 2009 were amended and authorized by Congress for $3.15 billion.

The tax credit is available to the investor the year qualifying equipment is placed into service whether it is a newly constructed unit, retrofit, or equipment that was acquired if the original use of the property commences with the taxpayer. The tax credit is available to integrated gasification combined cycle (IGCC) projects and advanced coal-based generation technologies. The amount of the tax credit is 20% for IGCC, up to $800 million, and 15% and 30% for advanced coal projects, based on when the equipment is placed into service, with limits of $500 million and $1.2 billion respectively.

4. Other Tax Incentives

In addition to tax credits, other tax-related instruments and structures can provide incentives for CCUS deployment. For example, master limited partnerships (MLPs) and private activity bonds (PABs) could provide incremental incentives to CCUS projects. Historically, MLPs have been crucial to building infrastructure and pipeline networks by allowing a lower effective tax rate for investors. PABs can lower the cost of debt and provide incremental incentives for potential CCUS projects. Currently, CCUS projects do not have the ability to use MLP structures or issue PABs.

An MLP is a partnership that is publicly traded and listed on a national securities exchange. Its two defining features are the ability to pass through gains and losses to partners without corporate double taxation, while at the same time being able to access public stock markets in a way not normally available to partnerships. For a corporation or C-corp., income is subject to corporate-level income taxes, and any shareholder would additionally be subject to income tax on dividends received. In contrast, MLPs and other types of partnerships, and limited liability corporations, pay no income tax at the partnership level for income derived from qualified sources, as defined in 26 U.S. Code § 7704(d), and instead pass through to their limited partner unitholders their pro rata share of taxable income. Typically, the benefits of avoiding double taxation in a partnership are partly counteracted by U.S. laws that generally prohibit partnerships from accessing the public stock markets—but MLPs are the exception to that restriction on public fundraising. These structures have the effect of reducing the overall costs of financing projects. MLPs have historically been used for oil and natural gas exploration and for coal mining, transportation, and processing. The challenge with the existing MLP structure is that it is only applicable to qualifying income from depleting resources such as natural gas, oil, and naturally occurring CO_2. The Master Limited Partnership Parity Act, introduced in Congress in 2019, would allow a broad range of clean energy and renewable projects, including carbon capture projects, to be eligible for MLP structuring and tax treatment—combining the benefits of avoiding double taxation and ready access to the public stock markets.

5. Tax-Exempt Bond Financing

Private Activity Bonds are a form of tax-exempt debt issued by a U.S. state or local government entity "on behalf of" certain Congressionally authorized categories of privately owned or privately used industrial development, transportation, or pollution control projects. That is, Congress sometimes allows tax-exempt bonds—normally only allowed to be issued for traditional government projects—to be used for certain special types of private projects. They are essentially corporate bonds that have the benefit of lower interest rates paid on tax free municipal bonds. The rules by which, and purposes for which, such PABs can be issued were substantially overhauled by the Tax Reform Act of 1986. "The federal government currently allocates to the states permission to issue approximately $33 billion of PABs annually."[8] The transactions involve the sale of bonds to investors by the government agencies, which then loan the bond proceeds to the privately owned project. The loan to the private company mirrors exactly the terms of the bond issued to the public, and repayment of that public bond is based solely on cash flows from the loan. Because investors pay no tax on the interest income, they require a lower interest rate from the company than would be the case for taxable debt.

PABs could be used to attract investment in CCUS projects if Congress amends the portion of the tax code that lists the types of projects permitted to use PABs to include CCUS projects.[9] The benefit to the company is the lower cost of borrowing due to the tax-exempt status of the bonds. PABs provide projects that might not otherwise qualify for debt financing with access to long-term bond financing.

6. Cost-Share Grants and Cooperative Agreements

Grants are financial awards given by the government to partially fund a project. The U.S. government has a long history of providing competitively awarded, cost-share grants as a mechanism to fund ideas and projects that provide public services. Cost-share grants and cooperative agreements are often used to stimulate the economy during recessions, fund infrastructure development, or support innovative research into new technologies.[10] Because they are funded by tax dollars, they are subject to a number of compliance and reporting processes to ensure the use of the funds is consistent with the purpose of the grant.

In 2009, the American Recovery and Reinvestment Act (Recovery Act; P.L. 111-5) provided DOE $3.4 billion for CCUS projects and activities.[11] The large and rapid influx of funding for industrial-scale CCUS projects was intended to accelerate development and demonstration of CCUS in the United States. Table 3-1 shows the allocation of Recovery Act funding to CCS projects. Approximately $1.4 billion of the $3.4 billion allocated for CCUS activities was unspent by the 2015 spending deadline because six of the nine major development projects were cancelled or withdrawn. Various issues, including lengthy Underground Injection Control (UIC) Class VI permitting periods, court challenges, poor development planning, ownership structures lacking large project implementation experience, and lawsuits, prevented projects like those listed in Table 3-1 from moving forward prior to the spending deadline.

DOE provided the unspent $1.4 billion in funding for 785 RD&D projects. Recovery Act funding was intended, in part, to help DOE achieve its RD&D goals as outlined in the department's 2010 Carbon Dioxide Capture and Storage RD&D Roadmap.[12] About 90% of the 785 RD&D projects involved coal technologies, such as coal gasification, which is the conversion of carbon-containing material into synthetic natural gas.

7. Loans and Loan Guarantee Programs

a. *Transportation Infrastructure Finance and Innovation Act*

One federal loan program is the Transportation Infrastructure Finance and Innovation Act

8 *Putting the Puzzle Together: State & Federal Policy Drivers for Growing America's Carbon Capture & CO_2-EOR Industry*, 2016, https://www.betterenergy.org/wp-content/uploads/2018/02/PolicyDriversCO2_EOR-V1.1_0.pdf.

9 Section 142(a) of the Tax Code.

10 Grants.gov, "Federal Grants Lifecycle: Grants 101," https://www.grants.gov/web/grants/learn-grants/grants-101.html.

11 2018, H.R. 1 (111th): American Recovery and Reinvestment Act of 2009. ARRA 2009 Summary. Last updated October 11, 2018. Accessed September 2019.

12 Folger, P. (February 18, 2016). *Recovery Act Funding for DOE Carbon Capture and Sequestration (CCS) Projects,* Congressional Research Service.

Project	Type	Amount of Recovery Act Award ($)	Amount Unspent at Sept. 30, 2015 Deadline ($)	Net Recovery Act Spent ($)	% Spent	% Returned
FutureGen—Capture	Stand-Alone	589,744,000	(473,077,241)	116,666,759	20%	80%
FutureGen—Transport & Storage	Stand-Alone	404,985,000	(321,716,380)	83,268,620	21%	79%
FutureGen Total		**994,729,000**	**(794,793,621)**	**199,935,379**	**20%**	**80%**
Hydrogen Energy California	CCPI Round III	275,000,000	(122,171,564)	152,828,436	56%	44%
Summit Texas Clean Energy	CCPI Round III	211,097,445	(104,223,677)	106,873,768	51%	49%
NRG Energy/Petra Nova	CCPI Round III	167,007,179		163,007,179	100%	0%
AEP Mountaineer	CCPI Round III	146,493,376	(129,613,108)	16,880,268	12%	88%
CCPI Totals		**795,598,000**	**(356,008,349)**	**439,589,651**	**55%**	**45%**
Leucadia Energy, LLC	ICCS Large Demo	261,382,000	(248,623,661)	12,758,339	5%	95%
Archer Daniel Midlands	ICCS Large Demo	141,405,945		141,405,945		
Air Product & Chemicals, Inc.	ICCS Large Demo	284,012,496		284,012,496		
Research Triangle Institute	ICCS Advanced Gasification	168,824,716		168,824,716		
ICCS Large Project Totals		**855,625,157**	**(248,623,661)**	**607,001,496**	**71%**	**29%**
All Other ICCS Projects	ICCS	630,751,232		630,751,232		
ICCS Totals		**1,486,376,389**	**(248,623,661)**	**1,237,752,728**	**83%**	**17%**
Grand Totals		**3,276,703,389**	**(1,399,425,631)**	**1,877,277,758**	**57%**	**43%**

Source: Congressional Research Service, *Recovery Act Funding for DOE Carbon Capture and Sequestration (CCS) Projects*, February 18, 2016.

Table 3-1. *DOE CCS Projects with Recovery Act Funding (nominal dollars)*

(TIFIA) program, which was enacted in 1998 as part of the Transportation Equity Act for the 21st Century (TEA-21). TEA-21, as extended and expanded in subsequent law, provides credit assistance to major transportation investments in the form of direct loans, loan guarantees, and lines of credit. TIFIA provides credit assistance for qualified projects of regional and national significance. Many large-scale, surface transportation projects including highway, transit, railroad, intermodal freight, and port access are eligible for assistance. Eligible applicants include state and local governments, transit agencies, railroad companies, special authorities, special districts, and private entities. The government assumes the default risk associated with extending credit to project sponsors, which can include private firms. Loans typically are made at rates based on the U.S. Treasury's cost of long-term borrowing, which in most cases will be substantially less than alternative borrowing rates. The TIFIA credit program offers three distinct types of financial assistance designed to address the varying requirements of projects throughout their life cycles:

- Secured (direct) loan — Offers flexible repayment terms and provides combined construction and permanent financing of capital costs; maximum term of 35 years from substantial completion; repayments can start up to 5 years after substantial completion to allow time for facility construction and ramp-up
- Loan guarantee — Provides full-faith-and-credit guarantees by the federal government and guarantees a borrower's repayments to nonfederal lender; loan repayments to lender must commence no later than 5 years after substantial completion of project
- Standby line of credit — Represents a secondary source of funding in the form of a contingent federal loan to supplement project revenues, if needed, during the first 10 years of project operations; available up to 10 years after substantial completion of project.

The amount of federal credit assistance may not exceed 33% of total reasonably anticipated, eligible project costs. The exact terms for each loan are negotiated between the U.S. Department of Transportation (DOT) and the borrower, based on the project economics, the cost and revenue profile of the project, and any other relevant factors. For example, DOT policy does not generally permit equity investors to receive project returns unless the borrower is current on TIFIA interest payments. TIFIA interest rates are equivalent to Treasury rates. Depending on market conditions, these rates are often much lower than what most borrowers can obtain in the private markets. Unlike private commercial loans with variable rate debt, TIFIA interest rates are fixed. Overall, borrowers benefit from improved access to capital markets and potentially achieve earlier completion of large-scale, capital intensive projects that otherwise might be delayed or not built at all because of their size and complexity and the market's uncertainty over the timing of revenues.[13] For CO_2 pipeline projects to be TIFIA eligible, Congress would need to enact new legislation providing budget authority for an expanded program and modify current statutory provisions.

b. DOE and USDA Loans and Loan Guarantee Programs

A loan guarantee is a contractual obligation between the government, private creditors, such as banks and other commercial loan institutions, and a borrower that obligates the federal government to cover the borrower's debt obligation in the event that the borrower defaults. The U.S. government has been providing financial assistance through loan guarantees since the 1930s. In some instances, instead of private parties providing loans that are then federally guaranteed, the U.S. government lends to the project directly from the U.S. Treasury's Federal Financing Bank. Because loan guarantees and direct loans generally accomplish the same purpose, the two terms are often used interchangeably.

Government loan guarantees help protect lenders against defaults, making it viable for commercial lenders to offer loans to borrowers who may not qualify for a loan on the open market. In 2005, Section 1703 of Title XVII of the Energy Policy Act created DOE's Loan Guarantee Program. DOE's loan guarantees are designed to facilitate the commercial introduction of new technologies through projects that are not yet financeable with private loans or debt investment, and, in doing so, promote the development of private debt sources.[14] By statute, DOE loan guarantees can be used to finance up to 80% of eligible project costs. One of the various solicitations currently available under the Innovative Energy Loan Guarantee Program is for Advanced Fossil Energy Projects, which has $8.5 billion of loan guarantee authority available. To qualify for the program, a project must avoid, reduce, or sequester air pollutants or greenhouse gases, employ a new or significantly improved technology, and provide a reasonable prospect of repayment.

To date, DOE has issued one conditional commitment for an Advanced Fossil Energy project and up to $2 billion has been approved for

13 U.S. Department of Transportation, "Build America Bureau," June 27, 2018, https://www.transportation.gov/buildamerica/programs-services/tifia/overview.

14 U.S. Department of Energy, "Title 17 Innovative Energy Loan Guarantee Program," https://www.energy.gov/lpo/title-xvii.

the Lake Charles Methanol Project that utilizes carbon capture technology for enhanced oil recovery. The Loan Program Office (LPO) administers a two-part application process under the Innovative Energy Loan Guarantee Program. Under Part I, an applicant provides basic project information for the LPO to determine if the project meets key eligibility criteria under the program. Under Part II, an applicant provides more detailed information for the LPO to conduct its due diligence and determine the overall terms of the financing. For the Part I application, a fee of $50,000 is required. For the Part II application, fees are tiered based on the amount of debt a project is seeking from DOE. Projects seeking less than $150 million in debt are responsible for paying $150,000, and projects seeking more than $150 million in debt are responsible for paying $350,000. In addition, the borrower pays a facility fee equal to 0.5% of the principal amount of the loan, and a $500,000 maintenance fee annually once the loan is approved.[15] The LPO continues to focus on CCUS projects under the Section 1703 program and is available for no-cost pre-application consultations with potential applicants.

Loan guarantees are available today from the U.S. Department of Agriculture (USDA) to projects under the Consolidated Farm and Rural Development Act. These loan guarantees are for economic development in rural areas. They can be used to purchase and develop land, easements, rights-of-way, buildings or facilities, and for business and industrial acquisitions when the loan will create or save jobs. To date, this program has not been utilized for a CCUS project.

B. Regulatory Framework for CCUS

The United States has a strong regulatory framework to assure safe and secure transportation and storage of CO_2. From capture through transport, and ultimately to storage, various U.S. federal and state agencies have developed specific regulatory and permitting requirements to ensure the safety of, and address the risks associated with, CCUS. The EPA has developed specific regulatory and permitting frameworks under the SDWA to protect USDW during injection and geologic storage operations. The EPA has developed accounting protocols under the Clean Air Act Greenhouse Gas Reporting Program for the injection of CO_2 into geologic storage. The CO_2 pipelines are regulated by the PHMSA within the DOT, which sets the standards for construction and operation.

1. EPA Underground Injection Control Program

The EPA established requirements for the injection of fluids into the subsurface under the SDWA through the UIC program. The statutory mandate for the UIC program is protection of USDW and that goal is fundamentally achieved by ensuring safe, long-term containment of the injected CO_2 streams and displaced formation fluid. With respect to CO_2 injection, these requirements include regulations for Class II wells used for EOR and Class VI wells used for geologic storage of CO_2 in saline formations. The UIC program in both cases is designed to prevent impacts to USDWs from the operation of injection wells and to confine injected fluids to the permitted formation(s). The Class II regulations were established as part of the original federal UIC program in 1980. Approximately 180,000 Class II wells are in operation in the United States of which approximately 80% inject fluids including water or CO_2 for the purpose of EOR.[16]

a. Class II Well Program

The Class II program is specific to oil and gas related injection wells used to inject fluids associated with oil and natural gas production including disposal wells (e.g., oil and natural gas wastewater disposal), EOR wells, and hydrocarbon storage wells other than natural gas. Many aspects of well design and operation are identified and documented as part of the Class II permitting process, including well design and construction, injection pressure, fracture pressure, injection fluid volumes, identification of confining strata,

15 Section 1703 Innovative Energy Loan Guarantee Program, Advanced Fossil Energy Projects Solicitation, https://www.energy.gov/lpo/services/solicitations/advanced-fossil-energy-projects-solicitation.

16 U.S. Environmental Protection Agency, Underground Injection Control (UIC) "Class II Oil and Gas Related Injection Wells." Last updated August 26, 2019, https://www.epa.gov/uic/class-ii-oil-and-gas-related-injection-wells.

area of review, monthly fluid injection reports, and a plan for plugging and abandonment.

Most states with oil and natural gas activity have obtained Class II primacy and administer the UIC Class II program for permitting. It generally takes states an average of 90 days or less[17] to process a permit application for a Class II well.

This report does not recommend any changes to the Class II program. The EPA has recognized "CO_2 storage associated with Class II wells is a common occurrence and CO_2 can be safely stored where injected through Class II-permitted wells for the purpose of enhanced oil or gas-related recovery."[18]

b. *Class VI UIC Well Program*

In 2010, EPA developed a Class VI UIC program, with well design and permitting processes, for the injection of CO_2 for storage in saline formations. The program was developed to provide near-term regulatory certainty for CO_2 geologic storage, promote consistent permitting approaches, and ensure that permitting agencies are able to meet their demands. The elements of the rulemaking were based on the existing UIC regulatory frameworks, with modifications to address the unique nature of CO_2 injection for geologic storage. Class VI sets minimum technical criteria for the permitting, geologic site characterization, area of review (AoR) and corrective action, financial responsibility, well construction, operation, mechanical integrity testing, monitoring, well plugging, post-injection site care (PISC), and site closure. As demonstrated by ongoing commercial-scale projects, the injection of large volumes of CO_2 into deep saline formations can result in safe, secure, and permanent geologic storage.

Class VI permitting is a procedural process that initially involves submitting a permit application to the EPA. The rule also establishes specific procedural requirements to provide the opportunity for public participation in the permitting process. EPA then reviews and comments or issues a permit with authorization to drill an injection well. After the injection well has been drilled and construction completed, EPA reviews consistency with the permit application and any new information that is developed and ultimately authorizes injection. The permit process is made up of the steps shown in Figure 3-2.

The period between issuance of the Authorization to Drill and Authorization to Inject is highly variable and dependent upon several factors including:

- The length of time it takes to drill the well
- The geology and its resemblance to that described in the permit application
- The modeling of area of review, which may need to be revised if geology is significantly different than anticipated
- The possibility of EPA requesting additional information or modeling, resulting in changes to permit, triggering a major modification.

In the permitting process, the operator provides their plan to meet these performance

17 Ground Water Protection Council poll of 7 states.

18 Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units, 80 Fed.Reg.64510, at 64585.

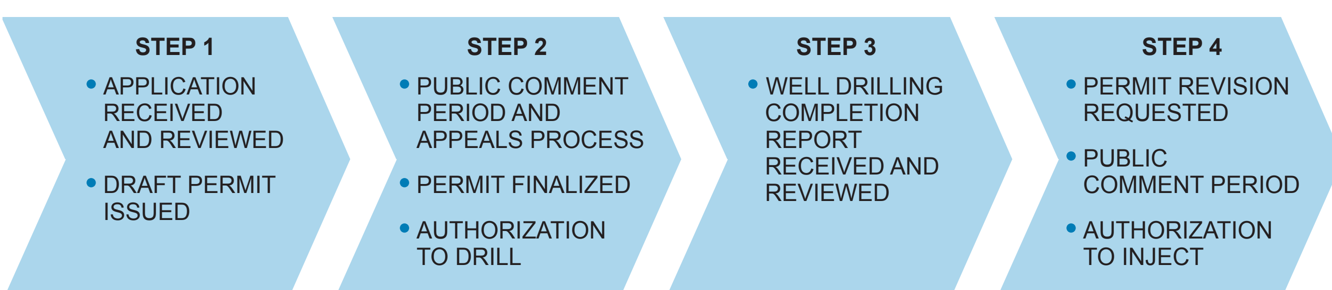


Figure 3-2. *Class VI Well Permitting Process Flow*

standards, based on site- and project-specific conditions. Examples of these plans include injection well construction procedures, a pre-operational formation testing program to follow construction, any well stimulation program, injection operation procedures, an AoR delineation and corrective action plan, financial assurance, a testing and monitoring strategy, an emergency and remedial response plan, an injection well plugging plan, and a post-injection site care and site closure plan. The Class VI rule requires geologic storage project developers to apply for and obtain a permit for each individual CO_2 injection well even for projects involving multiple injection wells.

As noted above, the Class VI permit application requires estimation of an AoR, defined as the region surrounding the project where USDWs may be endangered by the injection activity. In practice, the area (footprint) of the free-phase CO_2 plume around an injection well is much smaller than the area of the elevated pressure, which could allow upward movement of formation fluids (e.g., brine). However, the density differences between buoyant free-phase CO_2 and heavier brine create different risks of upward leakage. This suggests that the total AoR can be defensibly subdivided into different areas with different regulatory requirements depending on whether the concern is buoyant free-phase CO_2 or pressure-driven dense brine migration. Currently, the Class VI regulations do not reflect this.

Permits are issued for the life of the project and can cover any period of time, but the default PISC period established in regulation is 50 years with the potential to be shortened through a computational modeling demonstration to support an alternative PISC timeframe or by demonstrating during the PISC period that the project "no longer poses a risk of endangerment to USDWs." This timeframe is at the higher end of other related monitoring requirements for similar programs. For example, the default post-closure care period for Resource Conservation and Recovery Act Subtitle C hazardous waste management facilities is 30 years, with provisions for adjusting the default period (40 CFR 264/265.117). In addition, in implementing the European Union's Directive 2009/31/EC, the European Commission recommends a 20-year post-closure monitoring period as a default because the actual length of the post-closure period cannot be predicted in advance. (Implementation of Directive 2009/31/EC on the Geological Storage of Carbon Dioxide, Guidance Document 4, Article 19 Financial Security and Article 20 Financial Mechanism.)

The Class VI UIC program restricts the geologic formations into which CO_2 can be injected. Injection must be into an injection zone that is below the lower-most USDW unless the applicant can demonstrate, via an injection depth waiver process, that any lower USDWs will be protected against endangerment. For other UIC classes, EPA has a process for exempting aquifers from the definition of USWD if they have "no real potential to be used as drinking water sources." (40 CFR §144.1(g)) However, the use of exempted aquifers was not extended to Class VI. This prohibition has already prevented the permitting of at least one important scientific research project designed to further the development of CCUS technologies.

As of mid-2019, only two Class VI well permits with permission to inject have been issued by EPA. These two permits each took 6 years. This timeframe presents an obstacle for the development of future CCUS projects especially those trying to take advantage of the 45Q tax credit.

By default, EPA is the regulatory authority under the UIC program, but states can apply for primacy to obtain state permitting authority. States must submit to EPA an application for primacy to implement the UIC program. For the Class VI program, the state must demonstrate under Section 1422 of the SDWA that its program is "at least as stringent as" the federal requirements. For Class II, which is under Section 1425 of the SDWA, a state must demonstrate that its program is equally effective as the federal program.

Whereas many states have obtained primacy for other well classes, only North Dakota has successfully sought and obtained primacy for Class VI permitting. Wyoming submitted its first application for primacy in January 2018. EPA action is anticipated in fall 2020.

2. EPA Greenhouse Gas Reporting Program[19]

On November 22, 2010, the EPA issued final rules that require facilities that conduct geologic sequestration of carbon dioxide and all other facilities that inject CO_2 underground to report GHG data to EPA annually.

Subpart RR requires reporting of quantities of CO_2 securely stored from facilities that inject CO_2 underground for geologic sequestration. Subpart RR requires facilities conducting geologic sequestration of CO_2 to develop and implement an approved EPA site-specific monitoring, reporting, and verification plan, and to report the amount of sequestered CO_2 using a mass balance approach. This rule is complementary to the Class VI program for geologic storage wells and permits participation by Class II wells.

Under Subpart UU, all facilities that inject CO_2 underground for any reason, including EOR, are required to report basic information on CO_2 received for injection, and it allows EPA to evaluate data obtained on CO_2 received for injection in conjunction with data obtained from Subpart PP on CO_2 supplied to the economy. EOR operators are also subject to reporting requirements under subparts W and C (if applicable) for above ground equipment leaks.

3. Pore Space Access

Additionally, when developing CO_2 storage projects, project developers need to ensure they have rights to the applicable contiguous pore space. In many countries, subsurface pore space is owned by the federal government or a sovereign. In the United States, mineral rights and water rights belong to landowners or to those who purchase them from landowners. Under common law, oil and natural gas operators have the right to use a surface owner's pore space as reasonably necessary to produce the minerals on the property. Therefore, the pore space owner's rights are not violated when the CO_2 remains in the pore space. Among the three states (Montana, North Dakota, and Wyoming) that have clarified pore space ownership, all have recognized that pore space rights generally belong to the surface owners. Operators may need to pursue acquisition of both surface and mineral rights, which requires a time and monetary commitment.

In some cases, pore space access might require agreements with many parties. Some states allow forced unitization of mineral resources, in which case if some percentage of owners agree, the remaining owners can be forced to participate. Yet, it is unclear if and how these laws extend to pore space. The challenges that accompany obtaining the rights to pore space will also likely require legislative or legal clarification for each state. For example, North Dakota has adopted a statute that allows for amalgamation of pore space rights, which has much in common with the unitization model.

a. Pore Space — Federal Lands

The Federal Land Policy and Management Act authorizes the Secretary of the Interior to issue leases, permits, and easements for the use, occupancy, and development of public lands. The regulations implementing this authority are at 43 CFR 2920. The statute and regulations are sufficiently broad to allow for a variety of authorizations related to geologic storage and related activities while sufficiently flexible in form and terms to accommodate many different actions and activities, including surface and subsurface rights-of-way and leases for subsurface storage.

The Mineral Leasing Act (MLA) allows the Secretary of the Interior to approve the subsurface storage of gas, regardless of whether the gas is produced on federally owned lands or the lands are leased, in order to promote conservation of resources. Such gas storage agreements are used today for the temporary storage of produced natural gas in order to balance production rates and address delivery issues. However, the broad language of the MLA could be modified to allow for the use of gas storage agreements to authorize long-term geologic storage of CO_2.

The MLA also allows for lessees to join together and collectively operate under a cooperative or unit plan of development where it is determined by the Secretary of the Interior to be necessary or advisable in the public interest. CO_2 EOR

19 EPA. (November 2010). "Fact Sheet for Geologic Sequestration and Injection of Carbon Dioxide: Subparts RR and UU," Greenhouse Gas Reporting Program.

operations are conducted today under unit plans of development and could serve as a model for long-term geologic storage of CO_2.

b. Pore Space — Private Lands

Prior to injection, the operators seeking to undertake storage operations must either own the pore space, have permission from the owner, or have statutory or common law right to use the pore space that avoids potential liability or exposure to trespass and nuisance claims. In the United States, the law concerning private property rights is a basic responsibility of the state rather than the federal government. In most states, the surface estate owns the pore space except to the extent pore space rights have been conveyed away.

This ownership is subject to a right of the mineral estate to make reasonable use of the surface estate as necessary to produce minerals from the tract. The right of use would include the right to inject substances, such as CO_2, for EOR. The fact that CO_2 injection might also result in the long-term sequestration of CO_2 should not alter the right of the mineral estate owner to engage in CO_2 injection for enhanced recovery.

However, with respect to CO_2 sequestration in formations that do not include the minerals, the right to inject CO_2 solely for storage would most likely be held by the surface owner.

The Interstate Oil and Gas Compact Commission has recommended that operators hold "the necessary and sufficient property rights" for construction and operation of a CO_2 storage project, which is defined to encompass the project in its entirety including "all surface and subsurface infrastructure" and "the reservoir used" for injection and storage operations.[20]

Three states (Montana, Wyoming, and North Dakota) have enacted legislation clarifying ownership of pore space for CO_2 sequestration. These three states clarified that the subsurface pore space belongs, at least presumptively, to the surface owner. Montana and Wyoming allow pore space to be transferred as a separate property from the surface and North Dakota established that pore space belongs to the owner and cannot be separated from the owners of the overlying property, although it can be leased.[21]

Although state law generally supports surface owner title, the question of whether the surface estate or mineral estate owns the private property interest in the pore space for geologic storage of CO_2 is not clearly settled. Statutory and regulatory clarity may be needed with respect to geologic storage of CO_2.

4. Federal and State Waters

Regulation of offshore CO_2 storage differs depending on where it occurs. The federal government administers the submerged lands, subsoil, and seabed in a specified zone of exclusive U.S. federal jurisdiction beyond state-owned waters (typically 3 nautical miles from the shoreline) and up to 200 nautical miles or more from the U.S. coastline, which is known as the Outer Continental Shelf (OCS). In Texas and Florida, state waters include those waters from the coast to three leagues (approximately 10.36 miles). For an example, see text box "Texas Creates Framework for Offshore Storage." Neither federal nor state agencies have authority over the high seas (areas greater than 200 nautical miles offshore).

The principle legislation governing activity within the OCS, including CO_2 storage, is the Outer Continental Shelf Lands Act (OCSLA).[22] Under the OCSLA, the Secretary of the Interior is responsible for the administration of mineral exploration and development of the OCS and has authority to grant leases for mineral development. The statutory authority for regulating CO_2 injection on the OCS originates from the OCSLA. DOI has statutory authority under the OCSLA to permit the use and sequestration of CO_2 for EOR activities on existing oil and natural gas leases on

20 IOGCC, Storage of CO_2 in Geologic Structures – A Legal and Regulatory Guide for States and Provinces. Model General Rules and Regulations. Sections 2.0 and 4.1(a), September 25, 2007.

21 Cleveland, Megan. (April 14, 2017). "Carbon Capture and Sequestration," National Conference of State Legislatures Environment, Energy and Transportation Group.

22 The Secretary of Interior has delegated regulatory authority under the OSCLA to the Bureau of Ocean Energy Management, which manages OCS exploration and production; and the Bureau of Safety and Environmental Enforcement, which has specific jurisdiction over OCS safety and environmental issues.

TEXAS CREATES FRAMEWORK FOR OFFSHORE STORAGE

Texas is an example of a state that has anticipated offshore storage, creating a statutory framework for subsurface geologic repository for the storage of anthropogenic CO_2 in state waters.[1] The law required that the Bureau of Economic Geology (BEG) at the University of Texas at Austin study state-owned submerged land to identify potential locations for a CO_2 repository. The law also required the Land Commissioner and the Texas School Land Board to determine suitable locations and issue requests for proposals for the lease of the land for the construction of any necessary infrastructure for the transportation of CO_2 to be stored in the repository. The board could accept CO_2 for storage at a fee. The Texas Commission on Environmental Quality establishes standards for measuring, monitoring, and verification of the permanent storage status of the CO_2 and the BEG performs the measuring, monitoring, and verification. After verification of permanent storage, the board acquires title to the CO_2 stored in the repository. On the date the state acquires the right, title, and interest in CO_2, the producer of the CO_2 is relieved of liability for any act or omission regarding the CO_2 in the repository. However, transfer of title to the state does not relieve a producer of CO_2 of liability for any act or omission regarding the generation of the stored CO_2 occurring before the CO_2 was stored.[2]

1 2009 HB 1796.

2 Texas Legislature, 2009, Offshore geologic storage of carbon dioxide: 81st Texas Legislature, Regular Session, House Bill 1796, Chapter 1125, https://texashistory.unt.edu/ark:/67531/metapth148377/m1/1/.

the OCS. DOI has the statutory authority to permit the geologic sequestration of CO_2 for activities that "produce or support production, transportation, or transmission of energy from sources other than oil and gas." Specifically, under Section 8(p)(1)(C) of the OCSLA (43 U.S.C. 1337)(p)(1)(C)), DOI's Bureau of Ocean Energy Management (BOEM) may issue leases, easements, and rights-of-way for these types of projects.

In addition, Section 8(p)(1)(C) allows BOEM to issue leases for sub-seabed CO_2 sequestration. This includes sub-seabed storage of CO_2 generated as a byproduct of electricity production from an onshore coal-fired power plant. BOEM's interpretation of this language is that the agency would only be able to issue leases for CO_2 storage in the OCS for CO_2 generated as a byproduct of onshore coal-fired power production, but not from CO_2 generated as a byproduct from other industrial activities, such as refining, chemical manufacturing, natural gas power generation, or nonenergy related industries (e.g., steel or cement production).[23]

23 See U.S. Bureau of Ocean Energy Management, "Outer Continental Shelf Sub-Seabed CO_2 Sequestration Authorities and Research," PowerPoint file, https://netl.doe.gov/sites/default/files/2019-10/BOEM-CO2-on-the-OCS-2018.pdf. Accessed October 2019.

Although there is an argument that other language in the OCSLA could authorize DOI to grant leases for offshore storage of CO_2, supporting the "exploration, development, production, or storage of oil or natural gas," this language is something less than explicit for that purpose and would not apply to CO_2 from nonoil and natural gas-related industries.[24] This ambiguity will continue to hinder investment, development, and deployment of offshore CCUS opportunities.

Another issue that needs to be addressed is the Marine Protection, Research and Sanctuaries Act of 1972, also referred to as the "Ocean Dumping Act," which regulates the transportation and dumping of any material into ocean waters. The Act requires the issuance of permits for the disposal of waste and other matter at sea, including industrial waste. Although not explicitly named in the Act, the term "industrial waste" has commonly been interpreted to include CO_2 generated through industrial processes. Under such an interpretation, CO_2 on the OCS would require a permit from EPA, subject to public comment and hearings, to evaluate the environmental impact of such activity. This regulation is duplicative of the environmental impact assessment procedures

24 43 U.S.C. Section 1337 (p)(1)(A).

that already apply to BOEM OCS leasing program. The international community has recognized this unintentional barrier to offshore storage of CO_2 and explicitly exempted CO_2 from the list of prohibited materials for disposal in the OCS.[25]

5. Regulatory Authority for Permitting of CO_2 Pipelines

The ability to transport very large volumes of CO_2 by pipelines, or a network of interconnected pipelines, from sources to sequestration sites will be crucial to the deployment of CCUS at-scale. Existing pipeline infrastructure will need to be expanded at least ten-fold to accommodate the volume of CO_2 transport at that level. Beyond any financial support that might be needed from the government to offset early deployment costs, nonfinancial incentives, such as streamlining and/or expediting permitting applicable to both power and industrial CCUS projects, can play an important role.

Although the Federal Energy Regulatory Commission (FERC) has jurisdiction to regulate the transmission and sale of natural gas for resale in interstate commerce under the Natural Gas Act, it has disclaimed jurisdiction to regulate CO_2 based on a finding that CO_2 is not a natural gas under the Natural Gas Act. The Surface Transport Board (STB), which is an independent federal administrative agency within the DOT, is responsible for economic regulation of certain common carrier interstate transportation, primarily related to railroad transportation, but also including interstate transportation of pipeline commodities “other than water, gas, or oil” with the term “gas” undefined. However, the STB’s predecessor agency, the Interstate Commerce Commission, found that CO_2 is a gas and therefore nonjurisdictional under the Interstate Commerce Act when transported by pipeline. If STB followed this precedent, it would not regulate CO_2 pipelines either. However, they have neither disclaimed jurisdiction in the same manner as FERC, nor asserted jurisdiction over CO_2 pipelines to date.

At present, the only federal agency that has exercised any sort of authority over CO_2 pipelines siting and rates is the Bureau of Land Management (BLM), which is one of the federal agencies with authority to grant right-of-way across federal land. BLM imposes the equivalent of a common carrier obligation on CO_2 pipelines crossing federal lands on the basis that CO_2 is a natural gas within the meaning of the Mineral Leasing Act.

6. Long-Term Liability

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

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

Generally, operators are potentially liable until the statutes of limitations expire, and regulatory requirements cease to apply. Beyond ongoing responsibilities for monitoring, potential liabilities associated with a CO_2 storage facility may include responsibility for mitigation and remediation of any leaks; recapture of incentives associated with CO_2 that ceases to be stored; risks of subsurface trespass that entails migration to pore space for which storage rights were not acquired; and potential litigation for personal or property damage. These may result from situations in or out of the operator’s control and are similar to those encountered during typical oil and natural gas operations.

A key distinction between EOR operations and CO_2 storage operations is that, whereas oil and natural gas operators may or may not be required to cover liabilities after operations cease, a CO_2 storage operation has obligations imposed by regulation during the post-injection site care period even though the fluid pressures are greatest, and the CO_2 is most mobile (and potentially able to escape quickly) during the injection of CO_2. Over time, the CO_2 dissolves, precipitates, or becomes trapped and the pressure dissipates, which implies that proper monitoring and

25 See Resolution LP.1(1) on the Amendment to Include CO_2 Sequestration in the Sub-Seabed Geological Formations in Annex 1 to the London Protocol, http://www.imo.org/en/KnowledgeCentre/IndexofIMOResolutions/London-Convention-London-Protocol-(LDC-LC-LP)/Documents/LP.1(1).pdf.

injection design is needed for the duration of the project, but not necessarily long afterwards.[26] When operations cease, the operator generally maintains responsibility for overseeing a site for some amount of time and remains liable for legal violations until statutes of limitations expire. For example, under Class VI permitting for saline storage, the default requirement for monitoring is 50 years, or at the discretion of the EPA administrator, whereas under California's Low-Carbon Fuel Standard CCS Protocol, the default requirement is 100 years. These potential long-term liabilities and responsibilities can have a detrimental effect on project development. Thus far, there are no insurance products available to appropriately cover these long-term, low-risk scenarios.

Several options have been proposed to address long-term liability concerns. Some have advocated that long-term liabilities should be handed over to state or other governmental agencies once it has been demonstrated the plume is stable. Others have advocated for only partial transfer of liability. Today, only a few states have defined a process to manage some initial, limited liability for CO_2 injection, including long-term liability (described in more detail below). However, because no commercial storage operations in the United States have entered the post-injection site care phase, long-term liability transfers have yet to be tested, so questions remain regarding the evolution of the current legal standards for post-injection site closure and liability management.

An example of options to address long-term liability for geologic storage of CO_2 is a "layered approach" as described in Eames and Anderson.[27] This approach creates cooperative agreements between operators and the government, which are used to pool resources, and sets up a layered responsibility approach, with each layer having set limits. In the event of an incident requiring remediation, the operator/site owner has the first layer of responsibility at any point in the site life, up to a per-incident dollar limit. If this is exceeded, the second layer cost is shared by those in the cooperative agreements. The third layer is backstopped by the government, and any remaining fourth layer costs are borne by the site owner/operator. This proposal is intended to limit liability during the formative stages of the CCUS industry while leaving operators with enough potential liability to encourage responsible behavior.

A recent paper by the Global CCS Institute[28] discusses the common perceptions regarding risk and approaches adopted by different jurisdictions that have been used globally and finds "the availability and benefits of transfer provisions in some jurisdictions have proven particularly significant, with some proponents highlighting their beneficial impact upon project investment decisions." The paper also highlights the mechanisms that have been employed to date including CCUS under existing liability schemes, transfer of liability to a governmental body, and upfront detailed requirements on site selection, monitoring, and verification. They also identify the need for further engagement of the insurance sector for the development of effective and affordable products for entities that cannot self-insure as an option for handling long-term liability.

There are some policies that allow long-term liability to be transferred to the government after a period of time. This has been adopted by four states: Texas (for state-owned offshore acreage), Illinois (for the FutureGen project to the extent damages exceed $100 million), North Dakota, Louisiana, and some federal governments of other countries. For example, Australia provides for a statutory indemnity. The Commonwealth must indemnify against liability if the formation was specified under the GHG license, a site closing certificate is in force, a closure assurance period (CAP) has been declared, and if: the liability is a liability for damages; the liability is attributable to an act done, or omitted to be done, in the carrying out of operations authorized by the license in relation to the formation; and the liability is incurred or accrued after the end of the CAP. If the CAP has been declared and the license holder subsequently ceases to exist, the Crown assumes

26 Blunt, M., "Carbon Dioxide Storage," Grantham Institute for Climate Change, Briefing Paper No. 4, Imperial College, London, December 2010.

27 Eames, F., and Anderson, S., "The Layered Approach to Liability for Geologic Sequestration of CO_2," 2013, Environmental Law Institute, Washington, DC, https://www.huntonak.com/images/content/3/4/v2/3463/Layered_Approach_to_Liability_Geologic_Sequestration_of_CO2.pdf.

28 Global CCS Institute, "Lessons and Perceptions: Adopting a Commercial Approach to CCS Liability," August 14, 2019.

liability for damage and losses, for which it would have indemnified the former licensee. These policies generally transfer stewardship, monitoring, and remediation requirements to a government entity, with the operator paying a fee into a trust or stewardship fund throughout the operations and/or at the time of liability transfer to defray the government's expenses. Assuming trust fund requirements are not excessive or too low, these liability transfers are beneficial because they put the site in the hands of a government entity that can assure the stewardship responsibilities are met, whereas private entities may or may not exist in perpetuity and/or the long time frames associated with CO_2 storage.

However, even these transfers may not protect an operator from damage claims in perpetuity. Due to societal unfamiliarity with the risks and benefits of CO_2 storage, litigation risks pose a threat to operators regardless of the validity of damage claims.

7. Power Market Challenges

CCUS will be needed in the power sector to achieve rapid, large-scale, and cost-effective decarbonization of the electric system without sacrificing reliability.[29] Fossil fired generation with CCUS can provide low-carbon emissions reliability services in the form of system inertia, black start capability, and ability to load follow as a result of fluctuations in power generation from renewables.

The power sector is highly complex. Each state is effectively a unique market with its own laws and regulations. In a few states, power remains fully regulated. Other states have deregulated power markets, known as competitive markets, and some states have a blend of the two types of markets. Overlaid on the states in which generation participates in a competitive market are independent system operators, which add a layer of unique rules, from wholesale market design to plant dispatch algorithms. Additionally, the federal government, through FERC, oversees the wholesale markets as well as interstate transmission. When deciding how best to achieve deployment of CCUS in the power sector, all of these differences need to be considered. For purposes of this report, a simplifying assumption has been made—electricity markets are either fully regulated (i.e., a monopoly utility that owns/operates its own facilities and makes its own investment decisions with state regulatory oversight) or deregulated (i.e., generation competes in a wholesale market and investment decisions are not made by utilities with primarily federal regulatory oversight).

29 IPCC, 2014: Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, R.K. Pachauri and L.A. Meyer (eds.)]. IPCC, Geneva, Switzerland.

Regulated markets are simpler to understand, yet difficult for the federal government to change. Fully regulated utilities remain outside of the independent system operators' involvement and largely beyond FERC regulation. Some regulated markets also have generation technologies imposed upon them via their state's legislature, most commonly in the form of Renewable Portfolio Standards (RPS). An RPS mandates how much of the power generation mix must be renewable. In addition to RPS, states have also enacted "must run" policies that require all energy from renewables to be prioritized over other forms of power generation. A recent trend is for states to dramatically increase the required amount of power supplied from renewables to reach targets of 50% or higher. However, without adequate energy battery storage, which comes at a cost, or fossil fired generation to back up renewables, the reliability of the grid will be jeopardized.

Deregulated markets are more complex. They are generally within the purview of the federal government, making implementation of any federal policy more straightforward.[30] The wholesale markets commonly pay power generators for: (1) the generation of energy (the commodity), (2) the generation capacity (the right to use that capacity),[31] and (3) reliability services needed to maintain the grid. For example, in addition to energy and capacity, PJM[32] also pays for reserves, regulation, and black start service. Renewables

30 Note that even in deregulated markets, the states can and do mandate generation technologies.

31 ERCOT in Texas is the exception to this rule.

32 PJM is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia.

generally cannot provide reliability services, whereas fossil fuel plants are ideally suited for this purpose. The energy payment to a specific plant depends upon whether the plant is dispatched by the independent system operators in any given period, which is driven by the plant's bid. If the plant is not dispatched, it does not generate electricity and therefore does not get paid nor generate revenue. Similarly, the capacity payment depends upon whether the plant's capacity is selected in a capacity auction. This requires bidding the plant's capacity in at a price no higher than the highest bidder selected. Similar to energy, if the plant is not selected in the auction, it does not collect a capacity payment. (Note that capacity auctions address no more than a few years at a time.)

The two challenges to achieving rapid decarbonization in the power sector regardless of the market structure are (1) the need to do so at a reasonable cost while (2) maintaining the high reliability of the grid. These challenges become even more critical when considering the goals of electrification of parts of other sectors of the economy that rely on fossil fuels today (e.g., transportation). Wind and solar energy sources create new operational requirements. They do not contribute to meeting demand when there is no wind or sun but can lead to over-generation when they are abundant. Their variations need to be managed. Plants with CCUS can help meet these challenges. An existing fossil plant retrofitted with CCUS is significantly less expensive than installing a mix of solar generation with long-term battery storage.[33] CCUS plants can also be dispatched as needed, thereby compensating for the weather dependency of renewables while simultaneously adjusting output for the fluctuations of load, they also provide long-term (months) of support that batteries cannot.

III. ENABLING WIDESPREAD CCUS DEPLOYMENT

Achieving widespread deployment of CCUS will require establishing an adequate level of financial incentives through government policy underpinned by a durable regulatory and legal environment. A policy and regulatory framework should be implemented in a phased approach, based on economic efficiency and ease of implementation. The following three phases of implementation (activation, expansion, and at-scale) are intended to detail the policy and regulatory improvements needed to enable increasing levels of CCUS deployment, with a goal of achieving at-scale deployment (i.e., ~500 Mtpa) within 25 years.

A. Activation Phase — Clarifying Existing Tax Policy and Regulations

The United States currently has approximately 25 Mtpa of CCUS capacity. Clarification of existing tax policy and regulations could drive an additional 25 to 40 Mtpa of CCUS capacity deployment within the next 5 to 7 years, as illustrated in Figure 3-3. These improvements could be achieved without Congressional action. It is important to note, however, that because the cost curve assumes a 20-year project life, capacity potential in this phase may be optimistic. Deployment will likely remain limited to the lower end of the range in this phase as a result of the current 12-year duration of the Section 45Q tax credit.

As described in Chapter 2, "CCUS Supply Chains and Economics," this near-term additional capacity is likely to be deployed where large high-concentration CO_2 sources are in reasonable proximity to suitable storage locations or an existing CO_2 pipeline.

Clarification within three key areas—45Q tax policy, access to federal and state lands, and Class VI well permitting—could quickly enable projects to move forward and potentially double the existing CCUS capacity in the United States. In addition, opportunities to leverage the existing loans available under the DOE Advanced Guarantee Loan Program, and loans available under the USDA Consolidated Farm and Rural Development Act, should be explored.

1. Clarifying 45Q Tax Credits

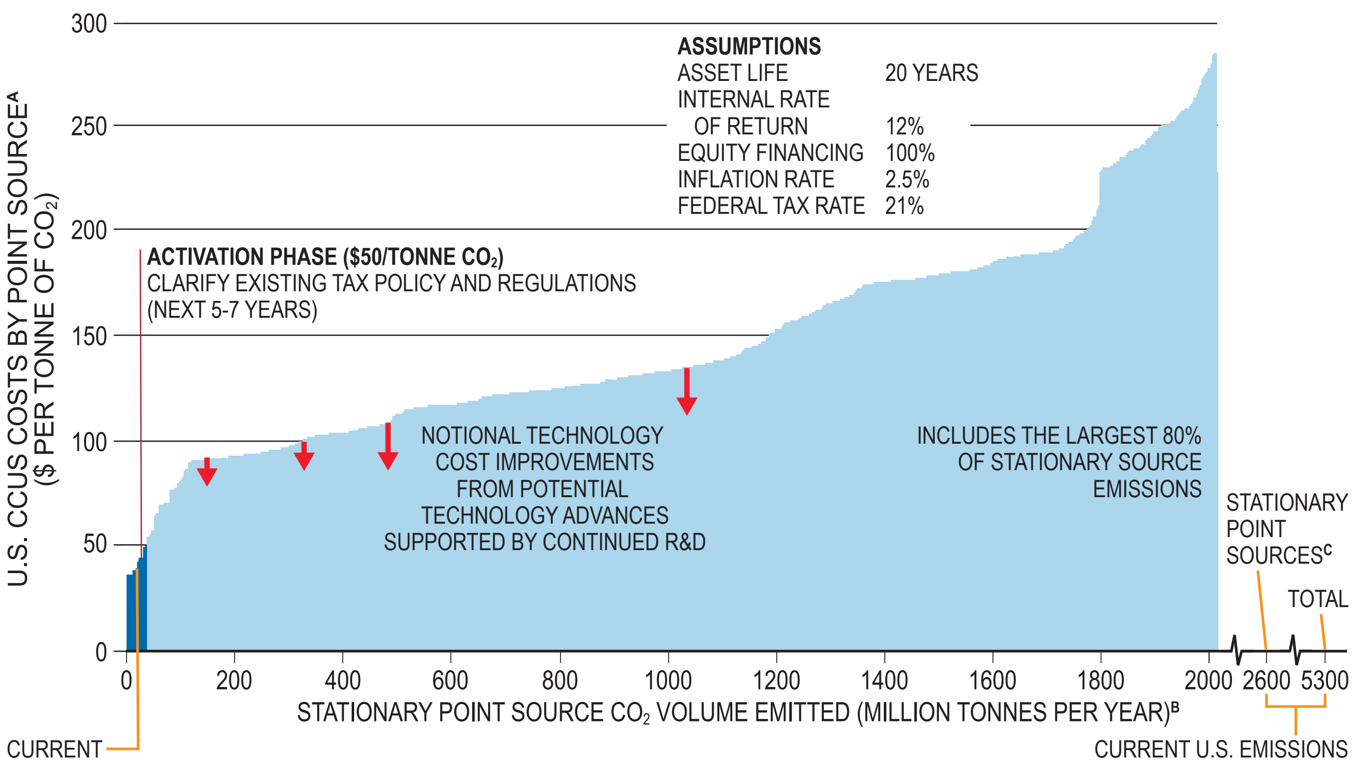
A significant issue in implementing the 45Q tax credit revolves around the demonstration of

33 State CO_2 EOR Deployment Work Group. (2017). "Electricity Market Design and Carbon Capture Technology: The Opportunities and the Challenges," State CO_2 EOR Deployment Work Group, June 2017, https://www.betterenergy.org/wp-content/uploads/2018/01/Electric_Markets_and_CCS_White_Paper.pdf.

"secure geological storage." To date, the IRS has yet to establish regulations as required by the original Energy Improvement and Extension Act of 2008 (amended 2009) and the BBA of 2018 for determining secure geologic storage. This has led to confusion, uncertainty, and controversy in the application of the 45Q tax credit. IRS clarifications, through guidance or regulations, could provide investors certainty in the near term.

Since its original enactment in 2008, Section 45Q has included a requirement that the Treasury, in consultation with the EPA, DOE, and DOI, issue regulations related to claiming these tax credits. The Treasury issued guidance in 2009 but has not yet issued regulations. As a result, the requirements necessary to access the 45Q tax credits have been unclear. On June 5, 2019, the IRS issued Notice 2019-32 stating that the Treasury and IRS intend to issue regulations under Section 45Q and solicited public comments on many aspects of the credit, including secure geological storage, start of construction, transferability, recapture, and "economic substance doctrine" which were top priorities identified by this study.

For example, clarity has been needed since 2009 on options for demonstrating "secure geological storage" for CO_2 used in EOR. This concern continues post-BBA and requires a flexible framework that can be implemented by taxpayers as documentation on the amount of CO_2 being securely stored during EOR operations. The International Standards Organization (ISO) Technical Committee 265 on CCUS has issued an international standard on CO_2-EOR, published in January 2019, ISO 27916. This standard provides a sound basis for demonstrating secure geologic storage. To implement this path forward, the American National Standards Institute (ANSI) has authorized the creation of an American Standard using the ISO 27916. Utility of the standard



Cost Curve Notes:

A. Includes project capture costs, transportation costs to defined use or storage location, and use/storage costs; does not include direct air capture.

B. This curve is built from bars each of which represents an individual point source with a width corresponding to the total CO_2 emitted from that individual source.

C. Total point sources include ~600 Mtpa of point sources emissions without characterized CCUS costs.

Figure 3-3. *CCUS Cost Curve Highlighting Activation Phase Deployment Volume* for 45Q purposes has more to do with implementation than with the substance of the standard.

Clarification is also needed regarding how credits can be transferred between parties, what constitutes "beginning construction," and recapture of tax credits. As noted previously, the 45Q tax credit is earned by the taxpayer who owns the carbon capture equipment. The ability to obtain financing for such projects requires some certainty regarding the value and duration of the tax credits. In most cases, however, the owner of the capture equipment is not the entity that utilizes or stores the CO_2. Lack of clarity regarding the transfer of credits between parties and recapture provision has the potential to create a barrier to financing for the owner of the capture equipment. The tax credit should be transferable, in full or in part, to any party that has a vested interest in the capture project including project developer, the party capturing the CO_2, or the entity that stores the CO_2. Further investment also requires that the tax credit cannot be subject to recapture for a time period inconsistent with IRS audit requirements or similar to the recapture period for other tax credits, i.e., no longer than 3 years[34] after the time of injection. The recapture terms should require that the taxpayer continues to comply, either directly or by contract, with a Treasury recognized method for demonstrating secure geologic storage and has a plan to remediate leaks of CO_2 should they occur.

In order to obtain maximum value for the credit, the term "beginning construction" should be defined to be consistent with accepted precedents for wind and solar tax credits while acknowledging the size and complexity of CCUS projects. Additionally, carbon capture projects may be economically attractive when tax credits are considered, but may have negative operating profits in the absence of consideration of tax credits, thus creating a challenge unless the IRS clarifies that its "economic substance doctrine" does not apply.[35] Resolving these requirements through new rules provided by the IRS will reduce uncertainty for investors, helping to enable the development of CCUS projects needed to begin widescale deployment.

The NPC recommends that the IRS clarify the Section 45Q requirements, specifically:

1. Establish that "beginning construction" is satisfied when the taxpayer has spent or incurred 3% of the expected total expenditure and construction continues without interruption for 6 years.
2. Clarify options for demonstrating secure geological storage as it relates to CO_2 via EOR. One potential option that has attracted significant stakeholder interest is ISO 27916. Utility of the standard for 45Q purposes has more to do with implementation than with the substance of the standard. The IRS should assess implementation issues and potential utility of this standard.
3. Make credit transferable to encourage tax equity investment. The tax credit should be transferable, in full or in part, to any party that has a vested interest in the capture project including project developer, the party capturing the CO_2, or the entity that stores the CO_2.
4. Provide that the tax credit will not be subject to recapture for longer than 3 years[36] after the time of injection, to encourage financing and investment, with the requirement that the taxpayer continues to comply, either directly or by contract, with a Treasury recognized method for demonstrating secure geologic storage and has a plan to remediate leaks of CO_2 should they occur.
5. Clarify that additional carbon dioxide capture capacity placed in service after the BBA should be based on the delta between the new capacity and the average of the amount of CO_2 captured in the 3 years prior to the enactment of the BBA or the facility's nameplate annual capacity.
6. The IRS should also specifically provide that the economic substance doctrine and provisions of Section 7701(o) will not be deemed relevant to a transaction involving the 45Q credit that is consistent with the congressionally

34 Where: Current year (time of injection) + 2 = 3 years.

35 Recently filed comments of Hunton AK law firm for 45Q, on page 12/17 and 13/17.

36 Where: Current year (time of injection) + 2 = 3 years.

mandated purpose of the credit, capture, and geological storage or utilization of CO_2.

The NPC recommends that DOE, with EPA and Treasury, begin to develop a robust life-cycle analysis framework with common parameters to support technology development and direct RD&D funding.

2. Access to Pore Space on Federal and State Lands

Access to pore space on federal and state lands will be important in early deployment of CCUS. Federal and state lands can have a significant advantage over privately owned lands because large areas of land are owned by one party. Federal lands have long been used for commercial activities such as oil and natural gas production, mining, farming, logging, livestock grazing, and public recreation. Accordingly, government statutes and regulations have been developed to manage these activities. There are, however, no current government mechanisms to grant access to, and use, of pore space rights on federal or state lands, except in Montana, North Dakota, and Wyoming. Formulating these regulations is critical to unlocking much of the CO_2 storage capacity in the United States.

As noted previously, the United States has vast CO_2 geologic storage potential. However, access to this storage, especially for saline formations, can be challenging due to the complexity of securing the rights to use the pore space from multiple property owners. In most of the United States, the land (surface) owner also owns the subsurface pore space in which CO_2 can be stored. For saline formation CO_2 storage projects, securing access rights to a large subsurface storage area might require agreement from hundreds if not thousands of landowners.

The NPC recommends that DOI and individual states adopt regulations to enable access to, and use of, pore space for geologic storage of CO_2 on federal and state lands similar to the approach under the Mineral Leasing Act where parties can join together and collectively operate under a cooperative or unit plan of development where it is determined by the Secretary of the Interior to be necessary or advisable in the public interest.

3. Class VI Well Program

As described earlier in this chapter, the Class VI permit process shown in Figure 3-2 requires numerous steps, from submission of a complete application, issuance by EPA of authority to drill under a Final Permit, submission by the permittee of a Well Completion Report, and finally, issuance by EPA of an Authorization to Inject.

As of mid-2019, EPA had issued only six Class VI well permits (Permits to Drill) and only two Authorizations to Inject. The time it took to receive a final Permit to Drill was ~3 years for the two active Illinois wells and 18 months for the four inactive permits (also in Illinois). The process from drilling the well to the issuance of an Authorization to Inject took an additional 2 to 3 years for the two wells that have injected CO_2 for a total of 6 years.[37] Four permits were issued in 18 months for the FutureGen 2.0 project but were never used because the project ran out of time to use federal funding.

The Class VI permitting process poses significant project risk because there is a high degree of variability in how long the timing will be between submission of a complete Class VI application and issuance of an Authorization to Inject, which may not be able to be determined up front. The Class VI wells are not as routine as other classes of wells because: (1) the Class VI requirements are more complicated than other classes, and (2) the Area of Review calculation is significantly different than other classes. Industry can help to reduce the time required for permitting by submitting complete applications and well-characterized geologic storage reservoirs. EPA can help reduce the timing by implementing program improvements noted in the recommendations.

When the Class VI regulations were promulgated, EPA acknowledged the limited information available at that time and emphasized the benefit of having "an adaptive approach" to enable EPA

37 ADM's Illinois Basin – Decatur Project and Illinois Industrial Sources Project.

"to incorporate new research, data, and information about geologic storage and associated technologies (e.g., modeling and well construction)." To use this information, EPA announced its "plans, every six (6) years, to review the rulemaking and data on GS projects to determine whether the appropriate amount and types of information and appropriate documentation are being collected, and to determine if modifications to the UIC Class VI requirements are appropriate or necessary."[38]

As discussed in the Storage Cost Assessment section of Chapter 2, "CCUS Supply Chains and Economics," it is assumed that after its 6-year review, the EPA adopts the following recommendation of moving to a site-specific, performance-based approach to the ratio of monitoring to injection wells and number of seismic surveys (versus the NETL CO_2 Saline Storage Cost Model).

The time required to complete the process would be improved through clear and consistent procedures for reviewing permit applications, improved interactive communications with applicants, and more efficient resolution/dispensation of comments and/or challenges to the permit applicants.

The NPC recommends that the EPA undertake the planned periodic review of the Class VI rules, guidance, and implementation so that they are aligned with a site-specific and performance-based approach. Specifically, EPA should use the experiences and learnings since the program was promulgated to:

- Consider how the program could be modified to better incorporate a site-specific, performance-based approach
- Review guidance documents to be sure they reflect the latest technical and financial information, and they are consistent with the regulations. Include clarity regarding which aspects of the guidance documents are requirements versus recommendations.

38 EPA 40 CFR Parts 124, 144, 145, 146, and 147 Federal Register/ Vol. 75, No. 237/Friday, December 10, 2010/Rules and Regulations, https://www.govinfo.gov/content/pkg/FR-2010-12-10/pdf/2010-29954.pdf.

This program review should be done in consultation with DOE, a national association of state groundwater agencies like the Ground Water Protection Council, the Interstate Oil and Gas Compact Commission (IOGCC), and relevant industry partners, including former and prospective Class VI permit applicants.

The NPC recommends that the EPA issue a Permit to Drill within six months. The NPC further recommends that upon receipt of a Well Completion Report, the EPA should review, make any necessary modifications, and issue a Permit to Inject within six months.

The NPC further recommends that Congress, through its agency oversight process, emphasize to the EPA the importance of accelerating the review of states' applications seeking primacy to implement the Class VI program.

Under the Class VI UIC regulations, computational modeling must be performed to support reduction in the default 50-year PISC period. In the final rule, the EPA established an option for demonstrating "an alternative post-injection site care timeframe other than the 50-year default" based on extensive additional data collection, technical analysis, and computational modeling. Although these expectations were designed for large, commercial projects, the EPA has applied it universally. As a result, smaller research and development projects have incurred significant redirection of financial and technical resources to make such demonstrations.

The NPC recommends that the EPA adjust its computational modeling requirements for post-injection site care requirements with respect to small demonstration projects to make them fit for purpose.

4. R&D for Class V CO_2 Injection

The effort to apply the Class VI provisions to smaller scale R&D projects has imposed permitting and regulatory compliance costs that far exceed any real or potential benefits in terms of environmental protection. In particular, the administrative and permitting costs have limited the scientific content of projects on fixed budgets to the long-term detriment of advances in scientific knowledge and CCUS technologies.

The NPC recommends that the EPA amend the regulation to allow pilot and demonstration projects to be permitted under the UIC Class V program as experimental technology wells, which give the agency much greater flexibility to tailor permit requirements to the individual project. DOE should consult with the EPA to determine what additional research is needed to allow the EPA to better define the scale of research projects that can be permitted as Class V experimental.

B. Expansion Phase — Expanding Policies and Addressing Regulatory Needs

By the end of the activation phase, Treasury should have completed Section 45Q tax credit regulations governing secure geologic storage, start of construction, transferability, and recapture, and developed a robust life-cycle analysis framework to allow taxpayers to claim credits for utilization of CO_2 so that these are no longer barriers. As shown in Figure 3-4, extending and expanding current policies to achieve a combined level of ~$90/tonne and further developing a durable legal and regulatory framework would incentivize an additional 75 to 85 Mtpa of capacity, bringing the total U.S. capacity to approximately 150 Mtpa. This deployment level could be achieved in the next 15 years. These policy changes will likely require congressional action as well as rulemaking by U.S. federal agencies.

This additional capacity is likely to be deployed where large high-concentration CO_2 sources can be connected to suitable storage locations that are economically accessible and, in certain circumstances, where lower-concentration CO_2 sources can take advantage of infrastructure that has been developed because of high-purity source CCUS deployments.

1. Financial Incentives

a. Extend and Expand 45Q Tax Credits

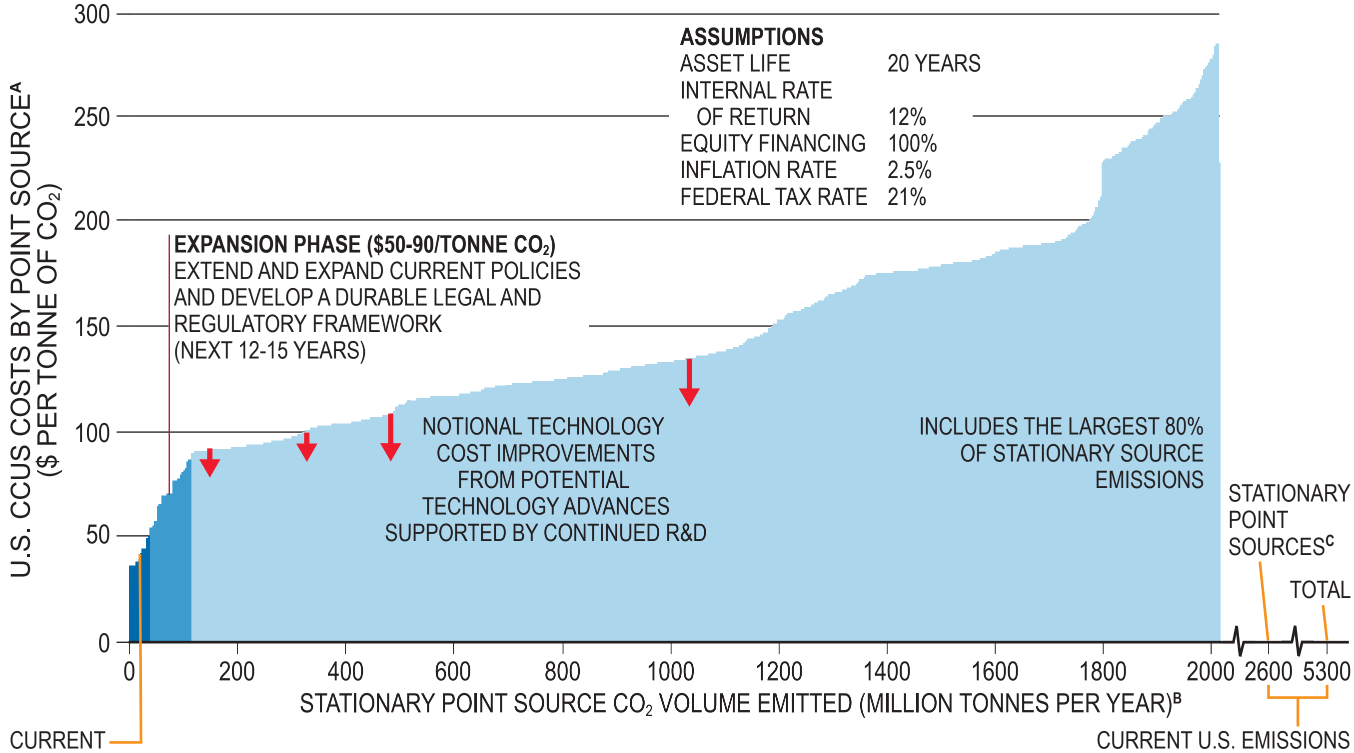
Under the current 45Q tax credit, the deadline to begin construction by January 1, 2024, will limit the near-term deployment of CCUS projects. In general, the time needed to identify, prove, plan, acquire access to and permit a CCUS project is more than 3 years. The project development timeline might be longer if there are complex commercial arrangements between multiple parties, a need for tax equity, pore space negotiations, and the structuring of insurance and liabilities. Unless a project was already in some stage of development when the Bipartisan Budget Act of 2018 passed, it will be challenging for CCUS project developers to accomplish the necessary tasks in time to qualify for the deadline.

Over the next decade, 45Q tax credits will need to be extended and expanded. As currently designed, the amount and the length of the tax credits are likely insufficient to encourage significant deployment. Qualified projects are eligible to receive the credit for a 12-year period from the date the capture equipment is originally placed in service. In most cases, the total value of the tax credit during this period will be insufficient to incentivize investment. In addition, approximately 56% of electricity-generation units, and 27% of industrial sources, do not generate sufficient CO_2 each year to meet their respective minimum size requirements for 45Q as currently written.

Recommendations on other aspects are discussed below.

The NPC recommends that Congress amend Section 45Q such that it will:

1. Extend the deadline (January 1, 2024) for beginning construction to 2030.
2. Lengthen the duration the credit pays out to a project from 12 to 20 years.
3. Lower the project size thresholds to 25,000 tonnes for industrial facilities, 100,000 tonnes for power plants, and 1,000 tonnes for use per year per site to accommodate smaller installations that may not qualify for the credit.
4. Increase the value of the credit for storage and use applications by notionally $5 per tonne as the current value of the credit is often less than the costs for such projects. The actual adjustment should be based on economic conditions at the time of reassessment.



Cost Curve Notes:

A. Includes project capture costs, transportation costs to defined use or storage location, and use/storage costs; does not include direct air capture.

B. This curve is built from bars each of which represents an individual point source with a width corresponding to the total CO_2 emitted from that individual source.

C. Total point sources include ~600 Mtpa of point sources emissions without characterized CCUS costs.

Figure 3-4. *CCUS Cost Curve Highlighting Expansion Phase Deployment Volume*

b. Amend Section 43 Tax Credit

The Internal Revenue Code Section 43 EOR credit was put in place to incentivize investment in EOR projects during periods of low activity (e.g., periods of low oil price). At current oil prices, with the current reference price of $28 per barrel (adjusted for inflation), the credit will be phased out for 2019. Because EOR is an important near-term pathway for CCUS deployment, incentivizing new EOR projects that securely store anthropogenic sources of CO_2 with a 15% tax credit for qualified costs can help drive additional capacity in the near term. Amending Section 43 by raising the reference price to a level sufficient to activate the tax credit (e.g., $50 per barrel) for projects that securely store anthropogenic CO_2, especially when stored in conjunction with the existing Section 45Q incentive, will incentivize new EOR projects.

The NPC recommends that Congress amend the IRS Section 43 tax credit by raising the reference price to a value greater than $50 per barrel of oil for CO_2 EOR projects that securely store anthropogenic CO_2.

c. Expand Other Financial Incentives to CCUS

Currently, the Section 48A and 48B tax credits are only available to coal-based power generation technologies and integrated gasification combined cycle projects, and requirements for the existing program create challenges. Expanding access to investment tax credits like Section 48 to all CCUS projects would likely incentivize multiple projects that currently remain uneconomic with current policy.

The NPC recommends that Congress enact legislation to expand Section 48 of the tax code to create 48C for industrial sources and natural gas fired electricity generating technologies.

As noted earlier in the chapter, private activity bonds are a way to provide financial support for projects that are deemed to be in the public good.

The NPC recommends that legislation be enacted to allow CCUS projects access to private activity bonds.

Current MLPs are not allowed to own and receive single-taxation benefit on the income from carbon capture projects. Even if all CO_2 capture projects were deemed qualified, it still may not make sense for an MLP to own CCUS assets. This is because MLP unitholders likely could not benefit from the full value of Section 45Q tax credits. The value of a Section 45Q tax credit would be limited to the taxable income generated by the partnership that could be offset, before being passed through to unitholders. Said otherwise, in the event the tax credit exceeded the partnership's taxable income, unitholders would not be able to apply the excess credit against their taxable income. Addressing this issue would make MLPs an attractive vehicle for CCUS investment and an ideal mechanism to disburse the 45Q tax credits.

The NPC recommends that Congress enact legislation providing CCUS projects access to the use of master limited partnership structures and that the MLP be structured in a way that allows the Section 45Q tax credit to be passed through and applied toward an individual's income.

To advance CCUS, a substantial amount of CO_2 pipeline infrastructure will need to be built. An option for the government to support infrastructure needs for CCUS would be to expand the TIFIA program to include CO_2 pipeline infrastructure.

The NPC recommends that Congress enact legislation to allow CO_2 pipelines to qualify under TIFIA and provide the budget authority for the expanded program.

2. Regulatory Improvements

a. Underground Injection Control Program and Class II Transition to Class VI

In the expansion phase, traditional EOR operators or others may be interested in considering how to optimize CO_2 storage versus conducting EOR operations for the primary purpose of producing oil. Some may be interested in exploring CO_2 storage in depleted oil fields where it is no longer economical to produce oil and natural gas with current methods. Any optimization of CO_2 storage by design and intent that does not result in a more efficient recovery of hydrocarbons would also need to be properly vetted to ensure that the mineral estate and the surface estate interests are both considered.

The question of whether a well should transition from Class II to Class VI should not focus on the activity but rather on the physical parameters of the proposed operating regime and associated risk. As stated by the EPA, "The most direct indicator of increased risk to USDWs is increased pressure in the injection zone related to the significant storage of CO_2. Increases in pressure should first be addressed using tools within the Class II program. Indirect methods that could indicate such a pressure increase or show the movement of the CO_2 plume may also be used. Transition to Class VI should only be considered if the Class II tools are insufficient to manage the increased risk."[39] Given the complexities of determining when such a transition is appropriate, it is important that the decision rest with the state primacy agency because they have the greatest familiarity with the relevant information about the reservoir characteristics, the pressure and volume of CO_2 injected, and the production rates for EOR processes in a given field.

The NPC recommends that the EPA, in consultation with DOE, academics, Class II state directors, the IOGCC, nongovernmental organizations (NGOs), and industry develop a process for determining maximum pressure threshold or ratio, and/or maximum injection rates or volumes, above which the risk is such that the injection should transition from Class II to Class VI. At a minimum, EPA should codify the statements in its memo to Regional Directors "Key Principles in EPA Underground Injection Control Program Class VI Rule Related to Transition of Class II

39 Memo to EPA Regional Directors: "Key Principles in EPA Underground Injection Control Program Class VI Rule Related to Transition of Class II Enhanced Oil or Gas Recovery Wells to Class VI," April 23, 2015.

Enhanced Oil or Gas Recovery Wells to Class VI" April 2015.

b. Class VI Program Review

i. Risk-Based Approach to Endangerment

EPA's regulations limit even inconsequential migration of fluids and constituents into a USDW. The SDWA defines endangerment in terms of health-based considerations, and EPA has recognized that an endangerment standard is inherently linked to the assessment and management of risk.[40] Such an approach facilitates a far more realistic and scientific assessment, as well as management, of public health risks related to geologic storage operations.

The NPC recommends that the EPA apply a risk-based approach when implementing the standard for endangerment and in the implementation of all aspects of the Class VI program.

ii. Flexibility with Risk-Based Monitoring

Under the Class VI regulations, monitoring is required to track the injected CO_2 plume. However, determining the exact location of the CO_2 plume may not be the most efficient way to determine containment, and monitoring strategies should evolve as the project evolves. Additionally, the requirement for in-zone monitoring may be interpreted as an additional well, requiring penetration of the reservoir cap rock and creating an additional potential leakage pathway. The Class VI regulations allow indirect methods of monitoring the extent of the CO_2 plume and the presence of the associated pressure front, but only in addition to direct methods. Careful site selection and indirect monitoring can be adequate to monitor the extent of the carbon dioxide plume and the presence of the associated pressure front, while avoiding the unnecessary penetrations into the injection zone created by direct methods. The director should have the necessary flexibility to allow the use of indirect monitoring methods only, when appropriate.

The NPC recommends that the Class VI regulations be amended to allow indirect monitoring through perimeter and above zone monitoring of storage reservoirs to ensure containment.

iii. Financial Responsibility

The Class VI regulations base financial responsibility on the applicant's "detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), post-injection site care and site closure, and emergency and remedial response."[41] Yet EPA review of Class VI permit applications has imposed prescriptive approaches to estimating costs. A risk assessment/management approach should be allowed for both scaling to fit the size of the project and for consideration of site-specific factors.

The NPC recommends that the EPA, in consultation with experts in the field and stakeholders, clarify what information, including financial estimates for emergency and remedial response, should be provided to support a risk-based approach when evaluating financial responsibility.

iv. Post-Injection Site Care

The Class VI permittee is required to petition for site closure via a non-endangerment finding by the delegated regulatory agency. Although the default PISC period specified in the regulation is 50 years, guidance has been provided by EPA that includes considerations and recommendations to help owners or operators petition for an alternate PISC during permitting, to revise the PISC time frame during the injection operation, and to make a non-endangerment demonstration for revision of the PISC and Site Closure Plan at the discretion of the EPA administrator. The default 50-year PISC period is overly conservative and longer than it needs to be for some well-chosen sites and imposes a substantial burden for permit applicants. This flexibility should be included in UIC permits so that shorter PISC time frames can be specified with the possibility of adjustment depending on actual site conditions.

The NPC recommends that the EPA amend the UIC Class VI regulations to allow the PISC time

40 42 USC §300h(d); (Miami-Dade County v. USEPA, 2008).

41 40 CFR §146.85(c).

frames to be set based on actual site conditions by using a risk-based approach for the duration of the PISC period.

v. Area of Review

Revising the AoR framework would reduce the cost of regulatory compliance while ensuring that the objective of protecting USDWs is preserved. Separating the AoR into subareas would lead to a tiered AoR definition in which the projected region of CO_2 plume extent would have appropriately focused regulatory standards regarding site characterization, monitoring, and corrective action than the larger pressure plume: (1) the region of CO_2 plume extent would have the highest regulatory standards regarding site characterization, monitoring, and corrective action, and (2) the pressure plume part of the AoR would focus on major pathways for brine leakage, such as unplugged wellbores and transmissive faults. Alternatively, the AoR reevaluation could be conducted pursuant to certain performance-based triggers derived from monitoring and operating conditions rather than according to a rigid fixed schedule.

The NPC recommends that the Class VI regulations be amended to allow the Area of Review to be separated into different subareas that are focused on whether the primary concern is free-phase CO_2 or pressure-driven upward brine leakage.

vi. Class VI Primacy

Under the UIC program, EPA established "minimum requirements for effective programs to prevent underground injection which endangers drinking water sources" with states intending to adopt and administer UIC programs that meet these requirements. States that receive approval to implement primary enforcement responsibility of their UIC programs are called "primacy" states. State primacy for Class VI implementation can be a more effective means for advancing CCUS in states that have existing CO_2 management and natural resource conservation programs.

To obtain primacy for the Class VI UIC program, a state is required to demonstrate that its program is "at least as stringent as" the federal requirements, although the regulations also specify that "States need not implement provisions identical to the[se] provisions." EPA provided for state primacy for the Class VI UIC program separate from primacy for the other classes of injection wells. EPA has outlined a process for states seeking UIC primacy. North Dakota was the first state to receive Class VI UIC program in April 2018. The process from application submittal to approval took almost 5 years.

The NPC recommends that, to facilitate state primacy for the Class VI program, Congress enact statutory changes for approval of state primacy of the Class VI program under the Section 1425 standard of equal effectiveness, similar to the Class II UIC program.

vii. Funding for UIC Class Program

Increased project activity as a result of increased deployment of CCUS with respect to both Class II and Class VI will require additional funding. The level of federal funding for the UIC program has remained at approximately $10.5 million for the past 16 years, and has, in effect, been diminished by inflation. During that time, the EPA and state agencies responsible for the UIC program have faced increased compliance and reporting requirements and significantly more program implementation expenses.

The NPC recommends that Congress increase the funding to EPA and the states by $20 million for UIC Class II and $50 million for Class VI to support EPA's and the states' anticipated increase in workload in the expansion phase to review permit applications, to provide any additional training, and support state Class VI primacy applications and EPA's review of those primacy applications.

viii. Flexibility with Aquifer Exemption

The SDWA directed EPA to develop regulations "to prevent underground injection which endangers drinking water sources."[42] To implement the SDWA, EPA promulgated the UIC program regulations authorizing state UIC program directors to "identify aquifers and portions of aquifers which are actual or potential sources of drinking

42 42 U.S.C. § 300h(b)(1).

water" by applying criteria relating to the ability of a geologic formation to produce water that can reasonably be expected to supply a "public water system" as defined by rule.[43] The UIC regulations established a two-part process under which the term "underground source of drinking water" is defined (1) by using broad criteria to identify aquifers that may potentially be capable of producing water for drinking, and then (2) by using the process for identifying exempted aquifers to exclude such aquifers from the definition if they have no real potential to be used as a drinking water source. Class VI prohibits the use of the two-part test established under the UIC regulations. As a result, two DOE-funded projects failed to obtain Class VI permits. These provisions appear in 40 CFR §§144.7(a) and 146.4. In both cases, the normally applicable criteria for designating exempted aquifers might have confirmed that such formations are not USDWs. This provision undercuts the carefully designed process for identifying USDWs and exempted aquifers built into the original UIC regulations. EPA's Class VI regulations also limit the use of aquifer exemptions available to wells transitioning from Class II to Class VI. This prohibition has already prevented the permitting of at least one important scientific research project designed to further the development of CCUS technologies.

The NPC recommends that the EPA amend the UIC Class VI regulations to allow the use of the UIC two-part process for exempting aquifers.

c. Storage in Federal Waters

One of the largest opportunities for saline storage in the United States can be found offshore in federal and state waters, particularly in the Gulf of Mexico. Offshore formations are typically not near underground sources of drinking water, the pore space rights are not dispersed among large numbers of owners (as is typical onshore), and the leasing, permitting, and regulation could be managed by a single entity (i.e., DOI). For these reasons, among others, there could be significant advantages to offshore storage.

However, as noted previously, the OCSLA language bars the storage of CO_2 on the OCS from the majority of industrial sources of CO_2, which would be a major impediment to widespread deployment of CCUS. Although there is an argument that other language in the OCSLA could authorize DOI to grant leases for offshore storage of CO_2 supporting the "exploration, development, production, or storage of oil or natural gas," this language is something less than explicit for that purpose and would not apply to CO_2 from non-oil and natural gas-related industries.[44] This ambiguity will continue to hinder investment, development, and deployment of offshore CCUS opportunities.

Similarly, the interpretation of CO_2 as industrial waste with respect to the Ocean Dumping Act has resulted in the unintended consequence of creating a barrier to offshore storage of CO_2.

The NPC recommends that Congress amend the OCSLA or enact a separate statute explicitly authorizing the issuance of leases, easements, and rights-of-way for facilities used to transport and inject CO_2 in the OCS without respect to the origin of the CO_2. Further, the DOE, Bureau of Ocean Energy Management, and Bureau of Safety and Environmental Enforcement should establish processes to enable access to pore space in federal waters and regulate CO_2 storage in those waters.

The NPC recommends that Congress amend the Ocean Dumping Act to explicitly exempt CO_2 from the list of prohibited materials for disposal in the OCS.

d. Regulating CO_2 Pipelines

In an optimal situation, buildout and access to future CO_2 pipeline capacity would be driven by the market. If common carrier pipelines are constructed with private funds, it seems logical the project will be developed with source and sink well understood, and contract terms for capacity and length identified upfront. In this situation, reservation of capacity by various shippers would not leave a lot of spare capacity for new shippers. Those who commit to the project early, which is the economic backbone of the pipeline, must have assurance that the pipeline will have space to move their captured CO_2 volumes to the sink.

43 40 CFR §§ 144.1(g) & 146.4(c).

44 43 U.S.C. Section 1337 (p)(1)(A).

However, open access on CO_2 pipelines could eventually lead to venting from all sources using the pipeline in the event of over subscription for service (proration). Under both scenarios, transportation rates for "cost of service" should be fairly straightforward using in-service cost, capacity, annual operating expense, rate of return, and project life for economic payout.

In addition, deployment of CCUS at scale will require significant expansion of CO_2 pipeline infrastructure, which will require access to the necessary property for pipeline construction, sometimes through eminent domain. Eminent domain is the power of government to take private land for public use. This power is limited by the federal Constitution and by state constitutions. In the United States under the Fifth Amendment to the Constitution, the owner of any appropriated land is entitled to reasonable compensation, usually the fair market value of the property. Eminent domain has been used traditionally to facilitate transportation, supply water, construct public buildings, and aid in defense readiness. Although federal Fifth Amendment protections apply to all exercises of the power of eminent domain, each state has its own laws and regulations that govern takings within the state. State governments have delegated the power of eminent domain to their political subdivisions, such as cities and counties. In some states, eminent domain is delegated to certain public and private companies, typically utilities, such that they can bring eminent domain actions to run telephone, power, water, or gas lines. Eminent domain law and legal procedures vary, sometimes significantly, between jurisdictions.

Both the interstate and intrastate pipeline permitting processes are complex and can involve multiple federal, state, and local agencies, as well as the public. An applicant may be required to comply with other federal regulations, such as the Clean Air Act, Clean Water Act, National Historical Preservation Act, and Endangered Species Act. In addition, projects may be subject to the National Environmental Policy Act (NEPA), which may require the preparation and coordination of extensive environmental impact assessments. And, the applicant may be required to comply with various state regulations.

In addition, several factors can affect the time frame for the permitting process of a given project, including different types of federal permits or authorizations, delays in the reviews needed by governmental stakeholders, and incomplete applications. For example, state and local permitting and review processes can affect federal decision-making time frames because some federal agencies cannot issue their permits until state and local governments have completed their own permitting processes.

The need for pipelines to be built to connect sources of CO_2 to EOR or storage locations in the activation phase, and to ultimately achieve widescale deployment, makes this recommendation of critical importance.

The NPC recommends that DOE create a CO_2 pipeline working group to study how to: harmonize federal/state/local permitting processes; establish tariffs, grant access, and administer eminent domain; establish the authority to issue certificates of public convenience and necessity; and to facilitate corridor planning. The working group should be made up of relevant federal and state regulatory agencies such as FERC, the IOGCC, or the Environmental Council of the States, representatives of local governments and communities, industry, and interested NGOs. The working group should be established concurrently with the activation phase.

e. Addressing Long-Term Liability

During CO_2 injection operations—which may last for a period of 10 years to more than 60 years—the operator generally holds and provides financial assurance for liabilities. These financial assurance mechanisms may cover responsibility for monitoring, mitigation, and remediation of any leaks; paying back incentives associated with CO_2 that ceases to be stored; risks of subsurface trespass, which entails migration to pore space for which storage rights were not acquired; and potential litigation for personal or property damage.

When operations cease, the operator generally maintains responsibility for overseeing a site for some amount of time and remains liable for legal violations until statutes of limitations expires.

These potential long-term liabilities and responsibilities have a detrimental effect on project development. Some have advocated that long-term liabilities should be handed over to state or other governmental agencies once it has been demonstrated that storage is secure. Others have advocated for only partial transfer of liability. Today, only a few states have defined a process to manage liability for CO_2 injection, including long-term liability. However, because no commercial storage operations in the United States have entered the post-injection site care phase, long-term liability transfers have yet to be tested, so questions remain regarding the evolution of the current legal standards for post-injection site closure and liability management.

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

- Applicability and limitations of private insurance
- Government assumption of liability for early mover project to incentivize and de-risk market creation[45]
- Transfer of liability risk and oversight to the government when secure geologic storage is demonstrated, likely with operators paying a fee into a stewardship or trust fund
- Layered responsibility approach for risk pooling among operators and government
- When evaluating damage claims, consider the societal benefit of CO_2 storage.

45 Under the Anti-Deficiency Act, the United States may not agree to open-ended indemnification arrangements absent specific Congressional authorization. See 31 U.S.C. 1341(a)(1)(B). Such authorizations have rarely been granted due to their inherent open-ended risk to the federal government and taxpayers. Accordingly, sound public policy and legislative precedent counsel that authority to indemnify be strictly limited to activities of absolutely vital national security interests, and then only when private insurance is unavailable (e.g., agreements indemnifying Department of Energy contractors for liability arising out of nuclear incidents; and agreements indemnifying certain Department of Defense contractors). See Pub. L. No. 85-804 (codified as 50 U.S.C. § 1431 et seq.); the Price-Anderson Act, 42 U.S.C. § 2210; and Hercules Inc. v. United States, 516 U.S. 417, 426-29 & n.11 (1996).

f. Pore Space Access — Private Lands

In the longer term, to progress secure geologic storage at levels necessary to achieve widespread deployment of CCUS, it will become important for projects to access pore space on privately held land. As such, commercial viability of CCUS may depend on whether and how property rights issues are resolved.

The NPC recommends that state policymakers enact legislation enabling access to storage resources on private lands, including pore space ownership, setting a threshold and process for forced unitization and fair compensation.

g. Power Market Incentives

Investments in power plants with CCUS will remain economically challenged unless there are some changes in public policy both at the state and federal level. Mandates and subsidies of non-fossil favored supply resources, and the failure to charge the market for all relevant costs, are generating distorted market outcomes and producing negative economic impacts that disproportionately suppress economic incentives to deploy fossil-fueled generation resources with CCUS.

A wide range of possibilities could be considered to address this issue including legislated capacity markets, portfolio standards similar to RPSs that include CCUS, Clean Energy Standards, feed-in-tariffs, contracts for differences,[46] or some other form of long-term market construct such as those described in a publication by Energy Innovation[47] including offtake agreements and power purchase agreements. Recently, the UK CCUS Advisory Group (CAG) released a report on various business

46 A Contract for Difference (CFD) is a market mechanism that is currently being utilized in the United Kingdom. A CFD is a contract between a low-carbon electricity generator and the government. A generator party to a CFD is paid the difference between the strike price—a price for electricity reflecting the cost of investing in a particular low-carbon technology—and the reference price, a measure of the average market price for electricity in the market. It gives greater certainty and stability of revenues to electricity generators by reducing their exposure to volatile wholesale prices, while protecting consumers from paying for higher support costs when electricity prices are high.

47 Energy Innovation Policy and Technology LLC. (June 2019). “Wholesale Electricity Market Design for Rapid Decarbonization,” https://energyinnovation.org/publication/wholesale-electricity-market-design-for-rapid-decarbonization/.

models to underpin investment in CO_2 capture in power and energy intensive industries along with CO_2 transport and infrastructure.[48] The various business models are designed to provide options for managing risks. For the power sector, the CAG focused on variants of a contract for difference (CFD). In terms of power, the report recommended a new "dispatchable CFD," which would include fixed and variable payments and would be designed to bring forward investment in dispatchable low-carbon power generation capacity. The design of the dispatchable CFD is intended to ensure that electricity plants with CCUS would dispatch ahead of unabated gas-fired plants, but behind renewables and nuclear generation. Note in the United States, the states still retain authority to make their own independent generation technology choices, which could work against any federal policy. As discussed here, multiple policies will likely need to be implemented to adequately incentivize the building and operation of power plants with CCUS. The options presented are just a few of the possibilities. Since the options that will be selected have important and long-lived implications, further focused study is strongly recommended to advance the thinking. Encouraging the generation mix to be the most economically reliable is the proper focus.

The NPC recommends that DOE conduct a study exploring the range of options to determine how to address CCUS dispatch and available capacity in the most cost-effective manner with input from Electric Power Research Institute, Edison Electric Institute, independent system operators, NGOs, FERC, National Association of Regulatory Utility Commissioners, the utilities, and independent power investors and industry. The study should begin concurrently with the activation phase.

C. At-Scale Phase — Achieving At-Scale CCUS Deployment

Achieving at-scale CCUS deployment will require substantially larger economic incentives than those recommended in the activation and expansion phases. As shown in Figure 3-5, policies that support financial incentives of ~$110/tonne, could enable an additional 350 to 400 Mtpa of CCUS capacity within 25 years, bringing total U.S. capacity to ~500 Mtpa. At this level, CCUS would be deployed on nearly 20% of current U.S. stationary emissions, which is a level the NPC defines as at-scale deployment.

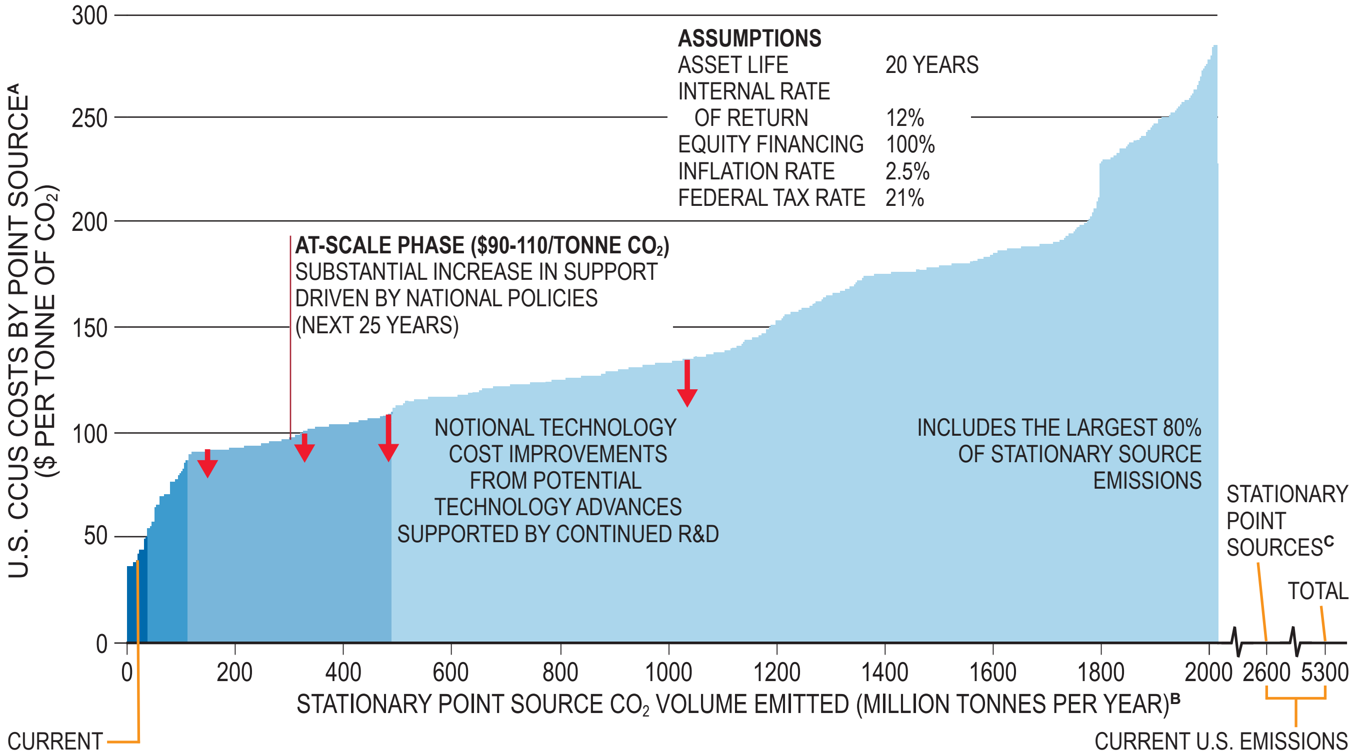
At this level of incentives, the additional CCUS capacity could be deployed in industries such as power generation, refining and chemical manufacturing, and cement and steel. As described in Chapter 2, "CCUS Supply Chains and Economics," these industries typically have low concentrations of CO_2 (e.g., less than 15%) and, as a result, the highest cost to capture and separate. Achieving this level of deployment will also require substantial industry support for, and investment in, pipeline and storage infrastructure.

The following section describes three broad policy frameworks that have been implemented at the federal and state level in the United States and globally to address GHG emissions reductions:

- Standards and mandates (e.g., renewable portfolio standards)
- Financial incentives (e.g., tax incentives)
- Market-based mechanisms (e.g., carbon tax or cap and trade).

Each of the three policy frameworks applies a different methodology for addressing CO_2 emissions. Standards and mandates, such as efficiency standards and technology mandates, establish a set of required actions or technologies designed to reduce emissions. Financial incentives provide value, usually in the form of tax benefits, to individuals or companies for implementing or using certain technologies designed to reduce emissions. A market-based mechanism, such as a carbon tax or cap-and-trade system, places either a cost or a cap on CO_2 emissions, and requires an emitter to either pay the cost of their emissions or meet certain emissions levels, respectively. Although any policy framework can be implemented effectively, the ultimate success or failure of an emissions control program depends upon the basic design and the details of implementation.

48 CCUS Advisory Group. (2019). "Investment Frameworks for Development of CCUS in the UK," CCUS Advisory Group, July 2019, http://www.ccsassociation.org/files/4615/6386/6542/CCUS_Advisory_Group_Final_Report_22_July_2019.pdf.



Cost Curve Notes:

A. Includes project capture costs, transportation costs to defined use or storage location, and use/storage costs; does not include direct air capture.

B. This curve is built from bars each of which represents an individual point source with a width corresponding to the total CO_2 emitted from that individual source.

C. Total point sources include ~600 Mtpa of point sources emissions without characterized CCUS costs.

Figure 3-5. *CCUS Cost Curve Highlighting At-Scale Phase Deployment Volume*

1. Standards and Mandates

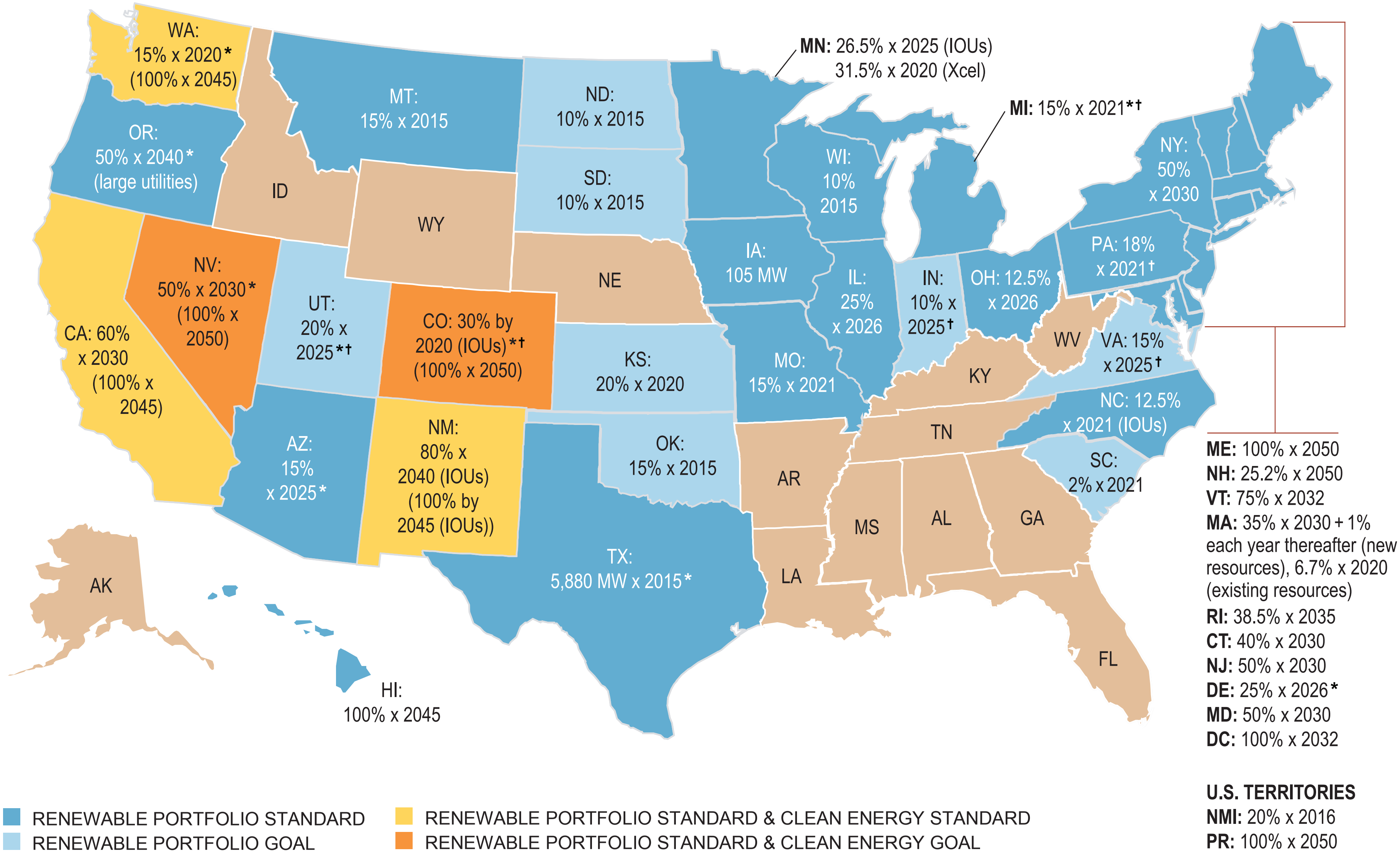
The U.S. government and many states have implemented some combination of standards and mandates that require certain products and technologies be used and/or establish a performance standard that certain technologies must achieve. For example, the federal Renewable Fuel Standard requires that specified volumes of biofuels be blended into U.S. transportation fuels. Figure 3-6 shows the current U.S. states and territories with renewable and clean energy standards and goals.

At the state level, a range of policies have been put in place to drive emissions reductions. One of the most common state policies is a renewable portfolio standard (RPS) requiring that certain amounts of electric capacity come from renewable sources or alternative energy sources. Twenty-nine U.S. states, Washington, D.C., and three territories have adopted an RPS, while eight states and one territory have set renewable energy goals. RPS mandates have created strong demand for renewable power. It is estimated that 58% of all renewable capacity in the United States installed from 1998 to 2014 is being used to meet RPS targets (excluding hydropower).[49] Currently, electric power associated with CCUS technology is not eligible under RPS policies.

While these approaches can be effective at driving deployment of targeted technologies, they can also be economically inefficient. According to a recent study by the Energy Policy Institute at the University of Chicago, RPS policies "come at a very high cost to consumers and are inefficient at reducing carbon emissions."[50] The study

49 Wiser, R., et al., "A Retrospective Analysis of the Benefits and Impacts of U.S. Renewable Portfolio Standards," National Renewable Energy Laboratory, January 2016.

50 Greenstone, M., and Nath, I., "Do Renewable Portfolio Standards Deliver?" Energy Policy Institute Working Paper No. 2019-62, May 2019, https://epic.uchicago.edu/wp-content/uploads/2019/07/Do-Renewable-Portfolio-Standards-Deliver.pdf.



Notes: 29 states and D.C. have a Renewable Portfolio Standard, 3 states have a Clean Energy Standard (8 states have Renewable Portfolio Goals, 2 states have Clean Energy Goals).
* Extra credit for Solar or Customer-Sited Renewables.
† Includes Non-Renewable Alternative Resources.

Source: Dsireusa.org, June 2019.

Figure 3-6. *U.S. Renewable and Clean Energy Standards and Goals* concluded that although the RPS had the intended effect of increasing renewable power generation, and thereby reducing the carbon intensity of the electricity generation, the estimated impact on consumers is a 17% increase in retail electricity prices over a period of 12 years, and across the 29 states studied, a cumulative effect of $125 billion more for energy than they would have paid in the absence of the policy, with an average cost of $130 per tonne of CO_2 abated.

A similar study was published in 2018 by the National Bureau of Economic Research in conjunction with Yale and Harvard Universities that assessed the cost of a range of policies designed to reduce greenhouse gas emissions. By compiling and analyzing a number of other economic studies that looked at the cost per tonne of CO_2 abated, the report estimates the range of policies to be between $10 and $1,000 per tonne, with most standards and mandates policies ranging from $50 to $500 per tonne of CO_2.[51]

Fundamentally, a standards and mandates approach will likely be the most difficult to implement in a manner that yields the most emissions reduction for the least cost. This is because in a complex system, it is difficult for the standard-setter to be able to identify and then specify the precise economic optimum and to continually update the standards as technology develops, market conditions change, or to adjust for other factors in the economy.

2. Financial Incentives

As shown in the cost curve in Figure 3-5, CCUS deployment in the at-scale phase will require incentives at a greater level than has been provided to date. The activation and expansion phases focus primarily on clarifying and then extending and expanding access to existing financial incentives that have been detailed in the previous two sections of this chapter. This third phase of deployment will require an increase in the absolute value of such incentives.

As described earlier in the chapter, there are three types of policy driven financial incentives available to CCUS projects—investment incentives, production or operations incentives, and financing support. By increasing the value of the existing incentives, a broader range of CCUS projects become economic, making them more attractive to investment. For many projects, it will be necessary to combine available incentives to make a project viable. The amount of incentive and level of support needed will vary based on each company's ability to finance and take advantage of certain tax credits, gain access to pipelines, generate revenue from the sale of CO_2, and other factors. Ultimately, that combined level of incentives needs to reach approximately $110/tonne to achieve at-scale deployment of CCUS.

The renewable energy industry provides an example of how policy can incentivize at-scale deployment of technology. Between 2005 and 2015, the federal government provided $51.2 billion in financial incentives in support of solar and wind power development, and tax incentives provided 90% of that amount. Those financial incentives, when combined with a range of renewable energy standards and other supportive policies at the federal and state level, helped established the renewable energy industry. Today, more than 7% of U.S. electricity is supplied by wind and solar energy.

However, financial incentives have similar limitations to those described in the standards and mandates framework in that they place government in the position of choosing which technologies to incentivize (i.e., picking winners and losers). One risk of relying solely on financial incentives to drive CCUS deployment is the uncertainty regarding the life of the incentive. As governments and societal expectations change, policy priorities and programs will change. Uncertainty is a key issue for project developers and investors.

3. Market-Based Mechanisms

For more than a decade, there has been considerable discussion in the United States regarding a national price on CO_2 emissions to incentivize deployment of lower emissions technologies. Putting a price on CO_2 emissions is generally referred to as a price on carbon. There are two main types of carbon pricing: carbon taxes and

51 Gillingham, K., and Stock, J., "The Cost of Reducing Greenhouse Gas Emissions," August 2, 2018, https://scholar.harvard.edu/files/stock/files/gillingham_stock_cost_080218_posted.pdf.

emissions trading systems (e.g., cap and trade). In the United States, several states and regions have cap-and-trade programs in place, including California, Massachusetts, and 10 Northeast and Mid-Atlantic states participating in the Regional Greenhouse Gas Initiative.

Both cap-and-trade and tax programs attempt to overcome the difficulty of identifying and specifying the economic optimum by employing market mechanisms, which in theory combine the knowledge of many participants and evolve over time. Both systems function by establishing a cost for emitting. A tax program has a theoretical advantage over cap and trade for reducing GHG emissions because a tax should produce a more predictable price and has broader application and provides a stable planning basis for the large capital investments necessary to make a significant reduction in GHG emissions over many decades. A cap-and-trade system conversely subjects the participants to more price volatility and is less transparent to the public. Under either approach, studies suggest that the most effective system would impose a gradually increasing real carbon cost over time.

One market-based policy approach that could incentivize CCUS is the implementation of a Clean Energy Standard (CES). A CES typically refers to a technology-neutral portfolio standard that requires that a certain percentage of utility sales be met through clean zero- or low-carbon resources, such as renewables, nuclear energy, coal or natural gas fitted with carbon capture, and other technologies. Similar to an RPS, eligible technologies are awarded credits per MWh of generation that can be traded, which provides an efficient, market-based solution to meet a standard.[52] The CESs that exist today are at the state level and do not recognize CCUS as a low-carbon technology. However, federal CES legislation has been proposed recognizing CCUS as a low-carbon resource.

A CES offers the potential to achieve an equivalent level of emissions reductions as an RPS at lower cost. Having a greater number of technologies in competition to reduce emissions can increase market efficiency and lower overall compliance costs for a given level of emissions reduction. In addition, the inclusion of a broad range of zero- and low-emitting technologies as compliance options for a clean energy standard can also increase ambition with respect to emissions reductions.

Previous research done by Resources for the Future, an independent research nonprofit organization, suggests that further efficiency gains are possible by using a credit system based on emissions rates rather than technology type. This credit system would encourage emissions reductions through changes in dispatch or investments at a facility, consequently further reducing emissions and lowering costs by allowing low-carbon technologies to participate.[53]

In the near-term, incentives will likely be a more effective way to drive deployment. In the long-term, however, a market-based approach is likely a much more economically efficient way of reducing CO_2 emissions than standards and mandates or financial incentives. Various articles have been written detailing the benefits and drawbacks of incentive-driven programs versus market-based approaches. Most economists agree that a market-based approach is a more effective approach for reducing emissions and more efficient for the overall economy.

The NPC recommends that to achieve at-scale deployment of CCUS, congressional action should be taken to implement economic policies amounting to about $110 per tonne. The evaluation of these policies should occur concurrently with the expansion phase.

IV. RESEARCH, DEVELOPMENT, AND DEMONSTRATION FUNDING

The United States has benefited from a more than 20-year history of DOE leadership, funding support, and public-private partnerships between government, academia, and industry. Between 2012 and 2018, Congress provided more than $4 billion in appropriations for CCUS R&D through DOE's Office of Fossil Energy. In

52 Cleary, Kathryne, et al. (2019). "Clean Energy Standards," Issue Brief 1901, Resources for the Future, January 2019, https://www.rff.org/publications/issue-briefs/clean-energy-standards/.

53 Cleary, Kathryne, et al., 2019.

addition, since 2010, $60 million per year of funding has been provided for technological advances in CO_2 EOR in unconventional reservoirs. As a result, the United States is currently the leader in CCUS technology and deployment capability. To retain this leadership position, RD&D funding must continue and, in some cases, increase to continue driving technology forward and costs to levels that will incentivize widespread deployment of CCUS. Increased RD&D will unlock opportunities by helping to enable the development of lower cost technologies, thus reducing investment uncertainty and the financial incentives necessary to enable substantial deployment of CCUS.

Commitment to research and development and expansion of academic and industry research for carbon capture across multiple innovation pathways is required to enable continued cost reductions, create competition, and help accelerate innovation. As noted in Chapter 5, "CO_2 Capture," in Volume III of this report, capture technologies have been demonstrated at several commercial projects. Many of these projects were successful in part because of governmental support through, among other things, research funding. For example, Petra Nova received up to $190 million in cost share from DOE, and Air Products received a $284 million contribution from DOE.

The DOE Office of Fossil Energy is responsible for research, development, and demonstration efforts on CCUS, among other areas of power generation. Current federal CCUS research and development is housed in two main areas: DOE's Office of Fossil Energy and the Advanced Research Project Agency–Energy (ARPA-E). The Fossil Energy Research and Development (FER&D) program offices advance transformative science and innovative technologies that enable the reliable, efficient, affordable, and environmentally sound use of fossil fuels. FER&D conducts R&D on advanced fossil energy systems, crosscutting fossil energy research, and CCUS technologies, including CO_2 EOR on unconventional reservoirs.[54] DOE's research and development efforts over the last eight years (2012 to 2019) are outlined in Table 3-2.

A. Technology Readiness and Maturity

Technology maturity levels provide a helpful indicator by which to assess the potential for continuing development and application of CCUS technologies to offer potential for cost reductions, efficiency gains, and performance improvements over time.

Figure 3-7 describes the range of technology readiness levels (TRL) for all of the CCUS technologies described in this study, using the U.S. Department of Energy TRL definitions[55] and assessment from NPC CCUS Technology Task Group members. Each technology is assigned a technology readiness level range that represents its stage of technical development and maturity (vertical axis). The TRL scale ranges from 1 (basic principle observed) through 9 (operational at scale). The higher the TRL level (i.e., >8), the closer a technology is to commercial readiness and deployment.

Chapter 2, "CCUS Supply Chains and Economics," highlights several CCUS technologies that are quite mature, well understood, and have been deployed safely at large-scale in commercial projects for many years. These technologies include absorption capture (via amine scrubbing), CO_2 compression and transport by pipeline, geologic storage in saline formations as well as CO_2 injection, and trapping during Enhanced Oil Recovery, among others. These technologies have TRL ranges in the upper (green) portion of Figure 3-7.

These established technologies have benefited from, decades of research and development, application and deployment, and associated learning-by-doing. As a result, most have experienced reductions in cost and improvements in efficiency and performance. Each of these technologies remains available for further application and deployment as part of future CCUS projects across a range of industries today. However, as

54 U.S. Department of Energy. "Department of Energy FY 2020 Congressional Budget Request," DOE/CF-015, Vol. 3, Part 1, March 2019, https://www.energy.gov/sites/prod/files/2019/04/f61/doe-fy2020-budget-volume-3-part-1_0.pdf.

55 U.S. Department of Energy. "Technology Readiness Assessment Guide," DOE G 413.3-4A, September 15, 2011, https://www2.lbl.gov/dir/assets/docs/TRL%20guide.pdf. Accessed October 2019.

FER&D Coal Program Areas	Program/ Activity	FY2012 ($1,000)	FY2013 ($1,000)	FY2014 ($1,000)	FY2015 ($1,000)	FY2016 ($1,000)	FY2017 ($1,000)	FY2018 ($1,000)	FY2019 ($1,000)
Coal CCS and Power Systems	Carbon Capture	66,986	63,725	92,000	88,000	101,000	101,000	100,671	100,671
	Carbon Storage	112,208	106,745	108,766	100,000	106,000	95,300	98,096	98,096
	Advanced Energy Systems	97,169	92,438	99,500	103,000	105,000	105,000	112,000	129,633
	Cross-Cutting Research	47,946	45,618	41,925	49,000	50,000	45,500	58,350	56,350
	Supercritical CO_2 Technology				10,000	15,000	24,000	24,000	23,430
	NETL Coal R&D	35,011	33,338	50,011	50,000	53,000	53,000	53,000	54,000
	Transformational Coal Pilots							35,000	25,000
Subtotal Coal		**359,320**	**341,864**	**392,202**	**400,000**	**430,000**	**423,800**	**481,117**	**488,180**

Source: U.S. Department of Energy.

Table 3-2. *Funding for DOE Fossil Energy RD&D Program Areas*

a result of their maturity, further cost reductions are expected to be limited.

Figure 3-7 also includes a number of newer CCUS technologies in earlier stages of development (TRL 6 and below). These less mature and emerging technologies offer the greatest potential for a step change in performance and cost reductions, and, through continued public and private investment in RD&D, are likely to deliver the greatest return on that investment.

The technology chapters and appendices in Volume III of this report include an assessment of the maturity of each component technology today and describe what is needed for each to achieve their future potential. As experience and expertise develop, and the market for CCUS matures, existing technologies may move up the TRL scale. In addition, new technologies may be introduced into this portfolio.

B. R&D Policy Parity

Appropriations language in the federal budget provides guidance regarding the allocation of funds for CCUS projects across various industries. From 2017 through 2019, the appropriations language has directed DOE to "use funds from Coal CCS and Power Systems for both coal and natural gas research and development as it determines to be merited, as long as such research does not occur at the expense of coal research and development."[56] And although the language does not prohibit funds to be used for natural gas RD&D, it may be interpreted that way. As a result, relatively little funding has gone into natural gas RD&D. In addition, as shown in Table 3-2, the Fossil Energy program does not have a designated industrial carbon capture program. However, some of the technologies in development through DOE's carbon capture program have either evolved from industrial carbon capture process technologies or can be used in industrial applications. Revising the federal budget appropriations language to allow for all sources and fuel types could encourage broader research and development into new technologies.

The NPC recommends that Congress amend appropriations language to allow for all CO_2 sources and fuel types in the allocation of RD&D funding for CCUS.

56 Department of Energy RD&D Appropriations, Fiscal Year 2017, 2018, 2019.

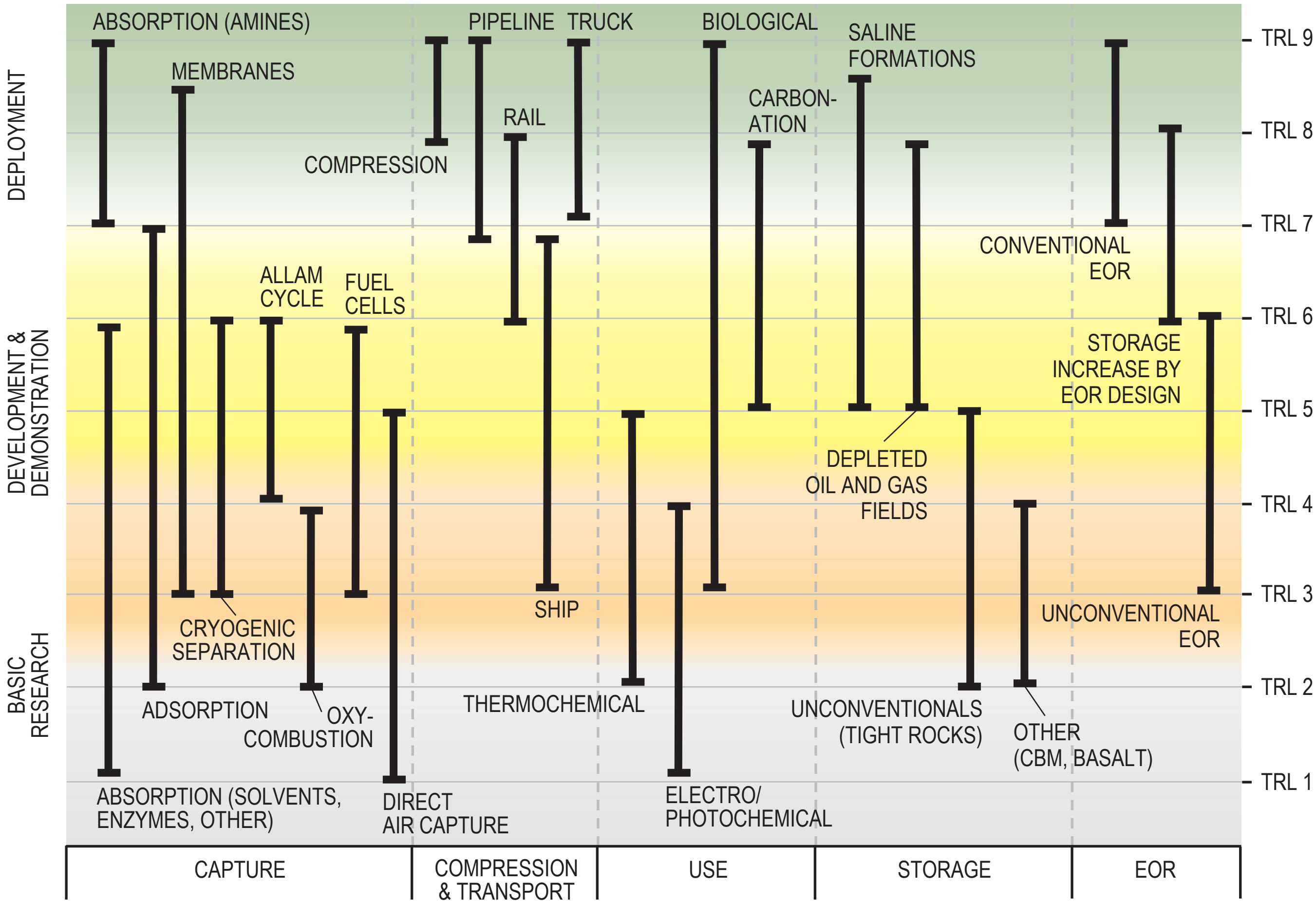


Figure 3-7. *Technology Readiness Level (TRL) Ranges for CCUS Technologies*

C. Increasing Federal Research, Development, and Demonstration Funding

In conjunction with the recommended policy and regulatory support described in this chapter, continued investment in RD&D for existing and emerging technologies will be critically important. Increased RD&D will unlock opportunities by helping to enable the development of lower cost technologies, thus reducing the level of financial incentives needed to enable substantial deployment of CCUS. Achieving more substantive cost reductions and improving the performance of existing technologies for CCUS deployment requires a substantially increased and continued investment in the RD&D of emerging technologies. Table 3-3 details the level of RD&D support needed over the next 10 years across all technology areas. A more detailed description of the specific research and development priorities for each technology follows the table. The NPC recognizes that these funding recommendations represent a substantial increase from current RD&D funding levels. A phase-in over one to two years could provide a pathway to the ultimate levels of support NPC recommends.

The NPC recommends that Congress appropriate the level of RD&D funding detailed in Table 3-3 ($1.5 billion per year) over the next 10 years to enable the continued development of new and emerging CCUS technologies and demonstration of existing CCUS technologies.

This section describes the critical role RD&D has in improving performance, reducing costs, and advancing alternative CCUS technologies, making the case for continued investment by both government and industry in capture technology and methods for identification and characterization of suitable large-scale storage locations. It is anticipated, as with experiences in other areas, that as more CCUS projects are deployed, nominal cost improvements will occur as industry learns by doing. Examples of this may include developing a better understanding of how to integrate new CO_2 capture facilities with existing equipment already on site, and of how to link more effectively to new downstream components of the CCUS chain (e.g., new pipelines to new storage or EOR sites).

1. CO_2 Capture Research and Development

Over the next decade-plus, a combined public/private partnership will be required, which is estimated at $1.6 billion per year. The projected federal R&D investment averages around $1.0 billion per year. Current funding levels from the FY19 enacted budget are $101 million for CO_2 capture and $129 million for advanced energy systems such as pressurized oxy combustion, chemical looping combustion, supercritical CO_2 cycles, and hydrogen generator systems. The proposed capture technology RD&D has the following emphasis:

- Adjust to handle differences between coal flue gas, natural gas flue gas, and industrial CO_2 gas sources, and atmospheric source
- Advance development in solvents, sorbents, membranes, and cryogenic processes for gas separation as well as new energy cycles that would inherently capture CO_2 for storage or utilization
- Develop a baseline against which improvements can be benchmarked and evaluated openly
- Lower the overall cost of capture including capital, operating, and maintenance costs
- Focus on flexibility of operations of the CO_2 capture systems to accommodate ramping cycles
- Test partial capture to find the low-cost minimum for the technologies and sectors to which partial capture would be most applicable.

Specifically, average annual public-private investment into CO_2 capture, including negative emissions technologies, over the next 10+ years are recommended below and detailed in Chapter 5, "CO_2 Capture."

- R&D (includes basic science and applied research, bench-scale, and small pilots): $300 million per year at an 80% federal cost share (i.e., $250 million) for a minimum of 10 years on CO_2 capture and advanced power cycles system development. Typically, the cost share is 80% federal.
- Pilot programs: $300 million per year at 80% federal cost share (i.e., $250 million) over a minimum of 10 years is needed for a large-scale pilot program[57]
- Demonstrations: $1.0 billion annually at a total 50% federal cost share (i.e., $500 million) over

57 Items 1 and 2 are consolidated in Table 3-3 in the column labeled R&D (including pilot programs).

Technology	R&D (including pilot programs)	Demonstrations	Total	10-Year Total
Capture (including negative emissions technologies)	$500 million/year	$500 million/year	$1.0 billion/year	$10 billion
Geologic Storage	$400 million/year		$400 million/year	$4 billion
Nonconventional Storage (including EOR)	$50 million/year		$50 million/year	$500 million
Use	$50 million/year (first 10 years)		$50 million/year	$500 million
Total	**$1.0 billion/year**	**$500 million/year**	**$1.5 billion/year**	**$15 billion**

Table 3-3. *10-Year RD&D Funding Levels Recommended by NPC Study on CCUS*

10 years to support the needed CCUS technology demonstrations.

This type of aggressive RD&D program with a focus on demonstration will enable market driven deployment of CO_2 capture projects in addition to other actions recommended in the activation and expansion phases, to reduce the need for additional environmental regulations or mandates.

a. Industrial Capture R&D

As of the time of this report, the DOE Fossil Energy program did not have a designated industrial CO_2 capture program. However, some of the technologies in development through DOE's CO_2 capture program have either evolved from industrial CO_2 capture process technologies or can be applied to industrial applications. One example of this is the pre-combustion CO_2 capture work that DOE has supported for several years. As many industrial processes require CO_2 to be removed from the gas stream in order to be used or to produce other products, DOE has had a dedicated R&D program to develop new and improved gas processing technologies that are widely used in many different industries. DOE has also supported R&D on air separation systems, which are widely used by industrial gas companies for purifying gas streams.

Some industrial applications of CO_2 capture are complex in that they have more than one exhaust stream resulting from both combustion and process streams from chemical reactions, so the approach to capture is not well defined.

The NPC recommends that DOE undertake a study for industrial CCUS RD&D to determine a uniform approach for addressing CO_2 removal from industrial systems and prioritizing R&D pathways. As part of the effort, DOE should identify how federal investments in CO_2 capture technologies currently in the DOE R&D portfolio can be leveraged with industrial applications of those technologies.

b. Demonstration Programs

The Clean Coal Power Initiative (CCPI) provided direct grants at 50-50 cost share for commercial-scale demonstrations of coal plants with CO_2 capture technologies. The American Recovery and Reinvestment Act of 2009 resulted in almost $1 billion of funding for the CCPI. It was through the CCPI program that the Petra Nova project received a $190 million grant to develop the project. Federal funding has not been appropriated to this program since the 2009 Recovery Act. Continuing to fund CCUS commercial-scale demonstration projects, across all fuel sources, through a direct grant program similar to CCPI, is critical to progressing at-scale deployment.

The NPC recommends that the CCPI program be expanded to include all fuel sources or that Congress authorize a new commercial-scale demonstration program with a new set of criteria to be established and robust federal funding provided.

2. CO_2 Storage — Research and Development

Ramping up CO_2 storage in geologic formations to the gigatonne/year scale is an enormous task. To put this into perspective, 1 gigatonne/year globally (a scale equivalent to approximately 40% of U.S. stationary source CO_2 emissions) would require about a 15-fold increase from the combined existing CO_2-EOR and storage operations taking place globally today. Based on the know-how developed through more than 100 years of oil and natural gas operations and the 20+ years of experience with CO_2 storage, there is enough knowledge today to continue expanding geologic storage projects in both oil and natural gas reservoirs and saline formations. Scale-up will take place gradually with learning-by-doing acting as a key component of capacity building and knowledge generation.

However, if this technology is to expand to achieve at-scale CCUS deployment and beyond, much more intensive use of existing storage resources will be necessary. This will require better information to assess risks, characterize sites, match CO_2 sources with potential sinks, and provide assurances that storage will be safe and effective. Several recent assessments, including the 2018 National Academy of Sciences report on CO_2 Removal and Secure Sequestration and the 2017 Mission Innovation Workshop on CO_2 Capture and Sequestration, detail the research needs. This report focuses on the research and development needs to support the rapid scale-up of CO_2 storage in geologic formations within the United States.

Today a significant amount of experience exists with CO_2 storage projects on the scale of 1 million tonnes/year, and even more with smaller scale pilot tests. As described above, the projects have conformed to performance expectations and as anticipated in the 2005 IPCC Special Report on Carbon Dioxide Capture and Storage, "With appropriate site selection informed by available subsurface information, a monitoring program to detect problems, a regulatory system, and the appropriate use of remediation methods to stop or control CO_2 releases if they arise, the local health, safety and environment risks of geological storage would be comparable to risks of current activities such as natural gas storage, EOR, and deep underground disposal of acid gas."[58]

Challenges associated with larger-scale projects needed to efficiently achieve rapid deployment of CCUS over the coming decades are driven by several factors, including larger quantities of CO_2 injected in hub-scale projects; the presence of multiple CO_2 storage projects in a single basin that may interact with each other through overlapping pressure buildups and potentially, plume co-mingling; choosing new sites in regions with less existing data available to support site characterization; and the need to consider the potential for CO_2 storage in unconventional formations.

To address the challenges, research priorities include:

- Increasing the effectiveness of site characterization and selection methods
- Increase pore space utilization by improving confidence in CO_2 plume immobilization mechanisms and accelerating their speed in immobilizing CO_2
- Improving coupled models for optimizing and predicting CO_2 flow and transport, geomechanics, and geochemical reactions—including leveraging capabilities in the oil and natural gas industry
- Lowering the cost and increasing the reliability of monitoring
- Quantifying and managing the risks of induced seismicity
- Investigating the feasibility of million tonnes/year storage in alternatives to sandstone and carbonate reservoirs, including ultramafic rocks (e.g., basalt) and low permeability rocks (e.g., shale)
- Social sciences research for improving community engagement and informing the public about the need, opportunity, risks, and benefits of CO_2 storage in geologic formations.

Existing R&D programs address both the basic and applied science of storage and field deployment with drilling, site characterization, and pilot- and demonstration-scale CO_2 injection projects. These field projects, supported by basic and applied science R&D, will be most impactful to industry to advance storage technology to widespread deployment. These projects also provide valuable infrastructure used in R&D phases for use in commercial-scale deployment.

Kick-starting CCUS projects through early engagement and characterization is intended to help lower or eliminate project risks and demonstrate the technical and commercial feasibility of CCUS, thus accelerating widespread deployment. Sustaining and increasing support of CarbonSAFE, the Regional Initiative to Accelerate CCUS Deployment, similar initiatives, and other storage-oriented efforts, is vital to facilitating rapid deployment. Increasing support for development and refinement of monitoring techniques will also further reduce implementation cost.

The NPC recommends that Congress increase R&D funding for geologic storage to $400 million per year for the next 10 years. The funding should be allocated as follows: $100 million to the Regional Initiative to Accelerate CCUS Deployment; $100 million for characterization of geologic storage formations, including offshore, that have scale potential through the CarbonSAFE program or similar initiatives; and $200 million per year to enable field-scale projects that collect data and geologic samples used to advance the basic and applied science of long-term storage security.

58 Metz, B., Davidson, O., de Coninck, H., Loos, M., and Meyer, L. (eds.), *Carbon Dioxide Capture and Storage,* IPCC, 2005 – Special Report, Cambridge University Press, UK.

3. Nonconventional Storage (including CO_2 EOR) Research and Development

CO_2 EOR is a mature and well understood process that has been successfully practiced for over 40 years. The first CO_2 EOR floods in the early 1970s operated with a combination of high CO_2 costs and low oil prices.[59] Combined with a limited capability to monitor and control the subsurface movement of the injected CO_2, these circumstances encouraged operators to inject relatively small volumes of CO_2. Advances in monitoring and control techniques, and more readily available volumes of affordable CO_2, have led to the use of larger volumes of CO_2. These injected CO_2 volumes are monitored and controlled to ensure that they contact, displace, and recover oil, rather than simply circulating CO_2 through higher permeability zones of the reservoir.

In addition to larger volumes of injected CO_2, the implementation of tapered water alternating gas injection schemes has become common practice to better control CO_2 mobility, improve conformance and sweep efficiency, and avoid bypassing areas of the reservoir that contain residual oil. These control measures, along with the application of more advanced well drilling and completion strategies to better contact bypassed oil, have led to steady improvements in residual oil recovery efficiencies in today's state-of-the-art CO_2 EOR projects.[60]

To a large degree, the impact of technology on expanding the application of CO_2 EOR in conventional reservoirs will most likely not be through the development of entirely new tools or technologies, but rather through refinement of existing state-of-the-art methods and their broader application to a larger number of reservoirs within basins with existing CO_2 EOR projects and in basins where CO_2 EOR has not yet been implemented.

Two state-of-the-art CO_2 EOR technologies that can benefit from research are (1) vertical and horizontal conformance controls to maximize sweep efficiency, and (2) advanced compositional modeling techniques to better predict and enhance performance.

Unconventional reservoirs account for 50% of U.S. crude oil production. These unconventional reservoirs have ultra-low permeability, which limits a conventional CO_2 flooding process where CO_2 and water are injected into dedicated wells to create a mobile oil bank that travels to producer wells.

The NPC recommends that Congress fund $100 million over the next 10 years for research into methods that can be used to improve effective application of CO_2 EOR for purposes of enhancing storage of CO_2 in conventional residual oil zone reservoirs, for application to unconventional CO_2 EOR reservoirs, and to storage in un-mineable coal deposits and basalts. This is needed so that widespread CO_2 EOR in these reservoirs can begin within 5 to 10 years.

4. CO_2 Use — Research and Development

In the United States, funding levels for CO_2 utilization have been relatively small and an increase in funding is necessary to achieve CCUS at scale. Synergies may exist between the R&D needs of other federal agencies and the use of CO_2. Until recently, CO_2 use (with the exception of EOR) has received very little attention. Over the last 10 years, potentially marketable CO_2 use technologies have been developed with the assistance of government support. Several companies are exploring mechanisms for incorporating CO_2 emission streams for use in manufacturing. Existing commercial uses for CO_2 include the production of methanol, urea, carbonate salts, polycarbonates, and other specialty chemicals. These technologies currently do not sequester CO_2 on the order of magnitudes required for CCUS at scale but have shown promise at a small scale. These technologies can play an important role in emerging energy technologies, such as in

59 While the first patent for CO_2 EOR was granted in 1952, the first large-scale commercial EOR project began operations in 1972 at SACROC field in West Texas (Meyer, J. P., "Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2 EOR) Injection Well Technology," prepared for American Petroleum Institute, https://www.api.org/~/media/Files/EHS/climate-change/Summary-carbon-dioxide-enhanced-oil-recovery-well-tech.pdf).

60 Global CCS Institute. (2017). "The Global Status of CCS: 2017," https://www.globalccsinstitute.com/wp-content/uploads/2018/12/2017-Global-Status-Report.pdf."

the manufacture of electrodes used in batteries and fuel cells.

Fundamental research funding would be very important to advance science and engineering related to these technological areas by providing sufficient government support. Both multi-PI funding and center grants focused on scientific discoveries should be created. Interdisciplinary research is very important for CO_2 technologies since they require expertise in a wide range of fundamental areas including materials, catalysis, and reaction engineering as well as systems engineering. Collaborations between academia and industry should be encouraged via center grants. An earlier version of "ARPA-E type" funding for the acceleration of tech-to-market transitions can provide support for academic researchers to work with industrial partners and the "New ARPA-E type" funding can be given to startup companies.

Among the focus areas for research and development, "the Office of Fossil Energy seeks to develop novel, marketable products using CO_2 or coal as a feedstock. Projects are sought for technologies that show a positive life-cycle analysis; the potential to generate a marketable product; and significant advantages when compared to traditional products."[61]

The NPC recommends that Congress provide $500 million in R&D funding over 10 years for support to basic science. This is particularly important for CO_2 use technologies since many of them are still in low TRL. The design of R&D funding structure should also be unique to the program.

The NPC further recommends that Congress provide an additional $500 million in years 10 to 15 for pilots, demonstration projects, and early deployment support. In order to do so, it is recommended that projects need to be field deployed to at least the level of National Carbon Capture Center, Wyoming Integrated Test Center, or similar practical demonstration environments that use real flue gas from coal and NGCC sources, in an industrial environment.

61 U.S Department of Energy, Office of Clean Coal and Carbon Management, https://www.energy.gov/fe/science-innovation/office-clean-coal-and-carbon-management.

D. Sharing RD&D Information

When researchers and technology providers work together to share information on their research designs, process, and outcomes, while maintaining intellectual property protections, all parties benefit, and RD&D is more effective. Two means of accomplishing this are furthering public-private partnerships that integrate government, academia, and industry, and embracing the concept of open-source technology development. These options to maximize RD&D investment efficiency should be explored.

The NPC recommends that DOE promote public-private partnerships and consider open source approaches to the development of CCUS technologies as appropriate.

V. CONCLUSIONS

As described in Chapter 2, "CCUS Supply Chains and Economics," the United States has had remarkable success to date in deploying CCUS technology. And although the United States leads the world in CCUS today, further deployment opportunities remain limited. Achieving widespread deployment of CCUS will require greater policy support, further development of a clear and durable legal and regulatory framework, and significant increases in funding for research and development. By implementing the recommendations detailed in this chapter and in the "Roadmap to At-Scale Deployment of CCUS for the United States" developed as part of this study, the United States has the opportunity to achieve widespread deployment of CCUS within 25 years and remain the global leader in technology and deployment. Implementing the recommendations in this chapter will depend upon engaging all stakeholders, including policymakers, coalitions, industry and the general public to achieve commitment and support. Chapter 4, "Stakeholder Engagement," describes the process for engaging all stakeholders to enable widespread deployment, and details recommended actions to achieve that commitment and support.

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