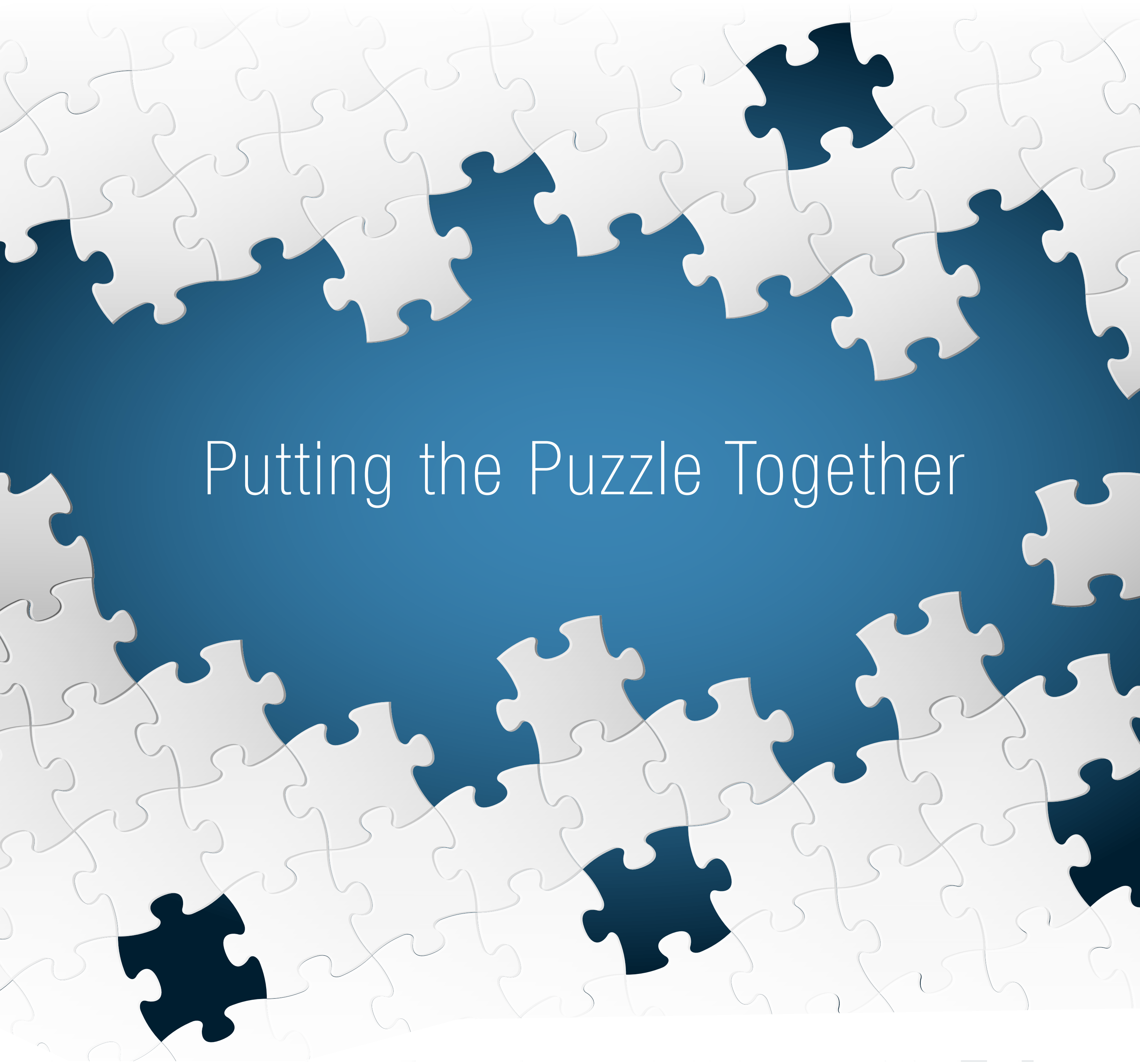


Putting the Puzzle Together

STATE & FEDERAL POLICY DRIVERS FOR GROWING AMERICA'S CARBON CAPTURE & CO_2-EOR INDUSTRY

Introductory Letter

from Governors Bullock and Mead

DECEMBER 2016

WE ARE PLEASED TO PRESENT THIS NEW REPORT—*PUTTING THE Puzzle Together: State & Federal Policy Drivers for Growing America's Carbon Capture & CO_2-EOR Industry*—which outlines growing opportunities for capturing carbon dioxide for use in enhanced oil recovery (CO_2-EOR).

This report results from the research, study and collaboration of the State CO_2-EOR Deployment Work Group, consisting of representatives from 14 states, leading private sector stakeholders and CO_2-EOR experts. The Work Group launched last year and this report contains its detailed analyses and recommendations.

CO_2-EOR enhances our nation's energy and economic security by lessening our dependence on foreign oil, often imported from unstable and hostile areas, and reducing our trade deficit by keeping dollars currently spent on oil imports at work in the U.S. economy. Production of coal, oil and natural gas plays a vital role in the economies of most states participating in this Work Group. These states and the nation benefit from all sectors involved in CO_2-EOR.

CO_2-EOR provides a long-term low-carbon path to production of abundant fossil energy resources. This industry can grow and protect jobs and investments in traditional energy and industrial sectors—which face regulatory requirements to reduce their emissions—by providing a practical, technology-based solution for lowering their carbon footprint. Jobs will be added, as workers will be needed across the CO_2-EOR value chain—building and operating CO_2 capture systems, constructing new pipeline networks to transport CO_2, and retrofitting and giving new life to existing oil fields. The incentives for CO_2 capture recommended in this report present an opportunity for states and the federal government to stimulate new economic activity and realize additional revenue at a time when most governments face fiscal challenges. CO_2-EOR will also safeguard existing industries and enable new production from existing oilfields.

The United States leads the world in commercialization of carbon capture, utilization and storage. We can and should remain on the cutting edge of global leadership in carbon capture and storage research, technology demonstration, hydrocarbon recovery and related manufacturing, and engineering and other services. We look forward to continuing bipartisan work with our fellow governors and state and federal policy-makers to implement this robust package of state and federal incentives to help grow this critically important industry.

Sincerely,

Steve Bullock, Governor
STATE OF MONTANA

Matt Mead, Governor
STATE OF WYOMING

Acknowledgements

While the final recommendations of this report represent the joint conclusions of state officials in the State CO_2-EOR Deployment Work Group, participating state officials want to recognize the contributions of leading private sector stakeholders and CO_2-EOR experts who lent their expertise and guidance to the effort. In particular, these individuals enriched Work Group meetings and conference calls, dedicated extensive time and organizational resources to modeling, provided critical information and perspective in their areas of expertise, and reviewed and provided valuable input during the drafting of the report. The state representatives extend their thanks to all who contributed to this report, and to the Hewlett Foundation for the funding that made this work possible.

Contents

Executive Summary 2

Introduction..14

Growing State Support for Co_2-Enhanced Oil Recovery:
Policy Resolutions from Governors and Other State Policy-makers...............................16

Overview of State Co_2-EOR Deployment Work Group..18

Co_2-EOR is More Than a Niche:
A National Energy, Economic & Environmental Solution 21

Federal Incentives to Spur Carbon Capture Deployment.. 30

Analyzing the Impact of Federal Policy Changes 42

Complementary State Tax Incentives to Spur Development
of Carbon Capture, Utilization & Storage 47

Other Policy Considerations for State Policy-makers.. 56

Need for a Balanced, Cost-effective Approach:
Accelerating Ccus Deployment is the Other Piece of the Puzzle.................................. 59

Conclusion.. 62

Glossary 64

Appendices.. 68

Executive Summary

The Case for Federal, State Support of CO_2-EOR

CARBON DIOXIDE-ENHANCED OIL RECOVERY (CO_2-EOR) offers extraordinary benefits for our nation. Capturing CO_2 from power plants and industrial facilities for use in EOR increases American oil production, while simultaneously reducing carbon emissions and enabling continued use of our domestic fossil energy resources. Producing more oil in the United States through EOR also further displaces heavier, more carbon-intensive imported crudes from the domestic marketplace and lowers our trade deficit by reducing expenditures on oil imports. Additionally, installing carbon capture facilities, building CO_2 pipelines and reworking mature oil fields to revitalize their production through CO_2-EOR bring jobs and investment to key energy and industrial sectors of the U.S. economy.

CO_2-EOR is not a new technology, but is a technique that has been utilized for nearly a half-century. It currently represents approximately four percent of domestic oil production, and industry has decades of commercial carbon capture experience across myriad industrial sectors. With respect to capturing CO_2 from power plants, the first commercial-scale project started last year in Canada, and two more are slated to begin operation in the U.S. in the next few months.

Market forces, federal policies and some state policies are driving the energy industry to reduce carbon emissions. Carbon capture with CO_2-EOR compares cost-effectively with other forms of zero- or low-emission generation. Accordingly, it must become an integral part of our future energy system and of a diverse energy portfolio.

However, further deployment of carbon capture faces challenges, including high capital costs, low revenues from CO_2 sales due to low oil prices, limited availability of debt and equity for projects due to policy uncertainty and market risk.

A targeted package of federal incentives will help address these challenges, including:

- Improving and expanding an existing tax credit for storage of captured CO_2;
- Deploying a mechanism to stabilize the price paid for CO_2—and carbon capture project revenue—by removing volatility and investment risk associated with CO_2 prices linked to oil prices; and
- Offering tax-exempt bonds and master limited partnership status to provide project financing on better terms.

States can also assist by optimizing existing tax and other policies to complement federal incentives in helping carbon capture projects achieve commercial feasibility.

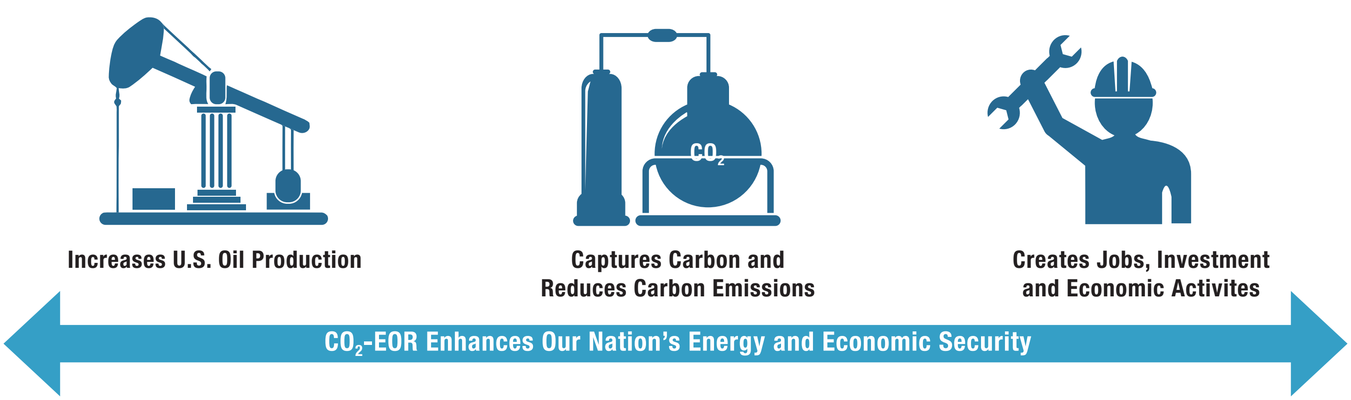
Complementary federal and state incentives will narrow the gap between the cost of carbon capture and revenue received from the sale of CO_2 for EOR, spur commercial project deployment by enticing private investment in projects, and bring down the cost of carbon capture technology. This will help our nation better utilize domestic resources, create and maintain good-paying jobs, realize additional economic benefits and reduce emissions.

Market forces, federal policies and some state policies are driving the energy industry to reduce carbon emissions. Carbon capture with CO_2-EOR compares cost-effectively with other forms of zero- or low-emission generation. ”

INTRODUCTION

Putting the Puzzle Together: State and Federal Policy Drivers for Growing America's Carbon Capture & CO_2-EOR Industry provides an in-depth look at CO_2-EOR while explaining the current policy landscape and recommendations for future action. The report provides the rationale for the capture of CO_2 from power plants and industrial facilities and its use and storage through EOR as a key component of a U.S. and global energy strategy that can provide economic, environmental and energy and national security benefits.

Carbon capture and storage, or CCS, describes the process of capturing and preventing the release of man-made or anthropogenic CO_2 into the atmosphere and then ensuring its permanent storage in an oil and gas field, deep saline formation or other geologic formation. Carbon capture, utilization and storage, or CCUS, reflects the commercial use of CO_2 prior to permanent geologic



storage through its injection into oil fields to recover additional crude through CO_2-EOR.

CO_2-EOR represents a well-understood and commercially successfully technique for oil production that enables cost-effective recovery of remaining crude from mature oil fields. In the early or primary phase of traditional oil production, the extraction of oil and gas decreases the fluid pressures in a reservoir. Typically, a secondary phase involving injection of water to restore reservoir pressure has followed the primary phase, enabling production of still more of the original oil in place. Eventually, water flooding reaches a point of diminishing economic returns. Then, some fields are suitable for a tertiary phase of production that commonly involves CO_2 injection—commonly referred to as "CO_2 floods"—to recover still more of the remaining oil.

This report and its recommendations focus on CO_2-EOR due to the ability to generate revenue to offset some of the cost of carbon capture through the sale of CO_2 for oil production, and the potential to scale up CO_2-EOR to play a meaningful role in national energy production and emissions reductions. Current federal EPA regulations recognize CO_2-EOR as a valid and proven pathway to secure geologic storage of power plant and industrial CO_2 emissions, along with the storage of CO_2 in saline formations.

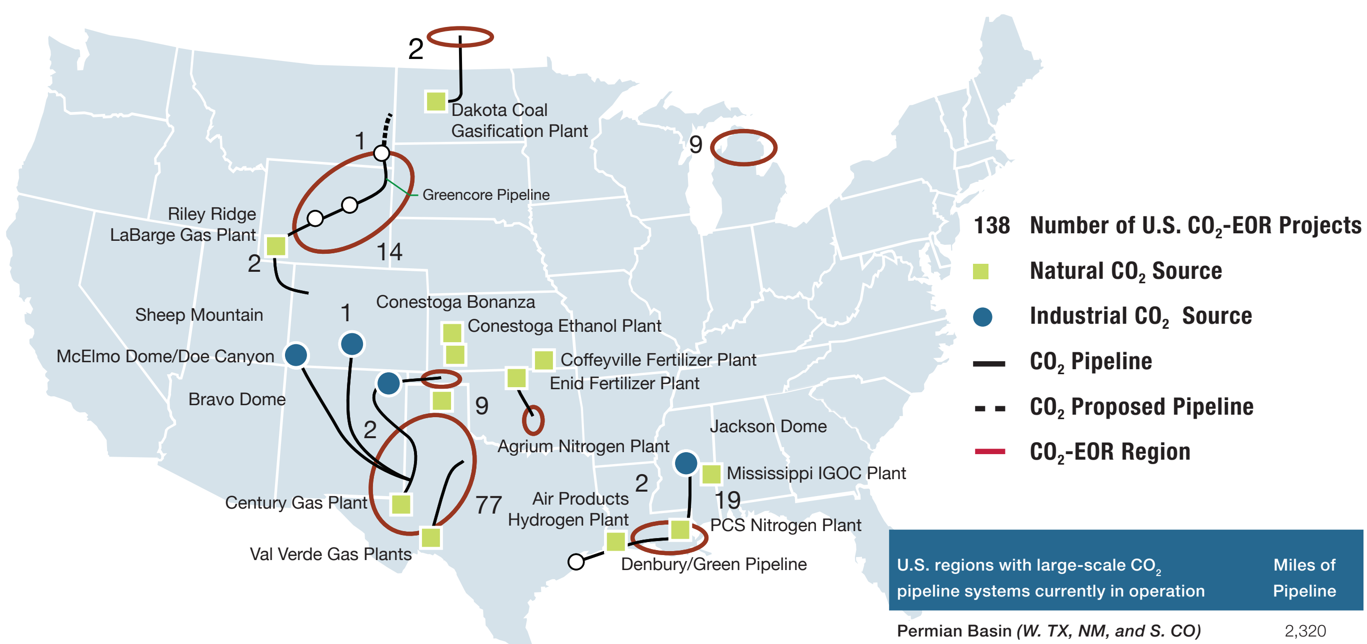
The report also takes a detailed look at the current policy landscape and then evaluates and recommends several key federal and state policy options that will enhance the further commercial deployment of CO_2-EOR. In addition, an inventory with information on existing state-level laws and policies related to CO_2-EOR has been prepared for the work group and is provided at: (insert web link).

GROWING STATE SUPPORT FOR CO_2-ENHANCED OIL RECOVERY

Over the past year, state officials from across the U.S. have signaled growing support for capturing CO_2 from power plants and industrial facilities for use in EOR to increase domestic oil production while reducing overall emissions. State officials have also endorsed the need for federal action to provide incentives to accelerate commercial deployment of carbon capture, utilization and storage (CCUS).

In 2015, the Western Governors Association (WGA) and the Southern States Energy Board (SSEB) adopted

FIGURE ES-1: Current CO_2-EOR Operations & Infrastructure



U.S. regions with large-scale CO_2 pipeline systems currently in operation	Miles of Pipeline
Permian Basin *(W. TX, NM, and S. CO)*	2,320
Rocky Mountains *(N.CO, WY and MT)*	810
Gulf Coast *(MS, LA, and ETX)*	740
Mid-Continent *(OK and KS)*	480
Other *(ND, MI, Canada)*	215

Source: Quadrennial Energy Review: Energy Transmission, Storage, and Distribution Infrastructure, April 2015.

resolutions in support of CO_2-EOR, and in early 2016 the National Association of Regulatory Utility Commissioners (NARUC) adopted a similar resolution.

The WGA resolution recognizes the economic and environmental benefits of CO_2-EOR and calls on Congress and the Administration to enact CCUS incentives. In June 2016, the WGA also wrote to members of Congress in support of bipartisan legislation to extend and strengthen the Section 45Q tax credit for the capture and storage of CO_2 through EOR and other geologic storage.

The SSEB resolution also emphasizes the need for federal financial incentives and state policy measures to accelerate deployment of CO_2 capture at power plants and industrial facilities, citing the increased energy security of the nation, reduction in the dependence on foreign oil sources, and the creation of high quality jobs and additional economic benefits.

The nation's utility commissioners approved the NARUC resolution to highlight the economic, energy production and carbon mitigation benefits of CO_2-EOR, and the importance of state and federal action.

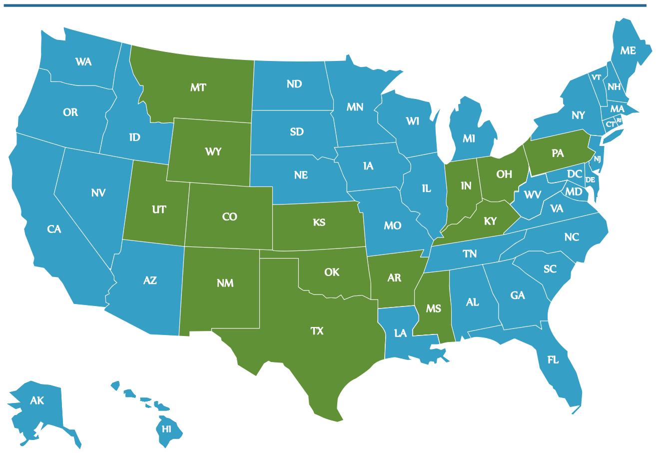
> State officials from across the U.S. have signaled growing support for capturing CO_2 from power plants and industrial facilities for use in EOR to increase domestic oil production while reducing overall emissions.”

STATE WORK GROUP

Governors Matt Mead (R-WY) and Steve Bullock (D-MT) jointly convened the State CO_2-EOR Deployment Work Group as a key follow-up to the June 2015 WGA Enhanced Oil Recovery Policy Resolution. The group began meeting in September 2015, and the state officials were joined by leading enhanced oil recovery, electric power, coal industry, regulatory and NGO experts in their desire to highlight and encourage policies that will accelerate deployment of CO_2-EOR in the country.

Fourteen states now participate in the Work Group: Arkansas, Colorado, Indiana, Kansas, Kentucky, Mississippi, Montana, New Mexico, Ohio, Oklahoma, Pennsylvania, Texas, Utah and Wyoming. State participation varies by state and includes governors' staff, cabinet secretaries/deputy secretaries, utility commissioners and agency and commission staff.

FIGURE ES-2: CO_2-EOR State Deployment Work Group – Participating States



Participating States

Non-participating States

The Work Group identified three principal roles for its work, including analysis and policy identification, development of recommendations for state and federal policy makers, and support for implementation of those policy recommendations. The Work Group objectives are:

1. Help policy-makers and stakeholders better understand states' potential for CO_2-EOR (both in oil production and supplying CO_2), and evaluate which strategies and state and federal policies can best achieve that potential;

2. Make recommendations to states and the federal government;

3. Support state policy-makers in implementing strategies and policies developed through Work Group analysis and deliberations, including multi-state efforts; and

> CO_2-EOR turns carbon dioxide from a liability into a valuable commodity.

4. Encourage enactment of federal policies that complement state priorities through coordinated efforts of governors, other state policy-makers and stakeholders.

CO_2-EOR A PROVEN NATIONAL ENERGY, ECONOMIC AND ENVIRONMENTAL SOLUTION

CO_2-EOR using anthropogenic CO_2 offers extraordinary benefits for our nation. Capturing CO_2 from power plants and industrial facilities for use in EOR increases American oil production, while simultaneously reducing carbon emissions and enabling continued use of our domestic fossil energy resources. Producing more domestic oil through EOR also further displaces heavier and more carbon-intensive imported crude oil and lowers our trade deficit by reducing expenditures on oil imports. Additionally, installing carbon capture facilities, building CO_2 pipelines and reworking mature oil fields to revitalize their production through CO_2-EOR brings jobs and investment to key energy and industrial sectors of the U.S. economy.

CO_2-EOR is a proven commercial process that has been utilized for nearly a half-century, and currently represents approximately four percent of domestic oil production. It turns CO_2 from a liability into a valuable commodity with potential for enhancing oil production by five to fifteen percent, and potentially extending production for up to 30 years. CO_2-EOR therefore can provide relatively stable energy production, employment and benefits to local economies. In addition, CO_2-EOR offers rates of return that compare favorably with other oil production projects, provided the CO_2 can be delivered at an affordable price.

> The U.S. has the potential to produce an estimated 28 billion barrels of economically recoverable oil with today's industry best practices.

CO_2-EOR can become a game changer, both for U.S. domestic energy production and for managing carbon emissions. According to 2013 analysis from the U.S. DOE's National Energy Technology Laboratory, the U.S. has the potential to produce an estimated 28 billion barrels of economically recoverable oil from conventional oil fields with today's industry best practices, and next generation techniques have the potential to yield an estimated 81 billion barrels. For comparison, total U.S. proven reserves of oil stood at just under 40 billion barrels in 2014.

The carbon storage potential of CO_2-EOR is equally vast. For every 2.5 barrels of oil produced, CO_2-EOR in a conventional oil field can safely and permanently store an average of one metric ton of CO_2 underground. For example, if the estimates cited above for current and next-generation economically recoverable oil production through EOR were achieved using anthropogenic CO_2, approximately 11 to 24 billion metric tons would be geologically stored—the equivalent of 35 years' worth of CO_2 capture from 55 to 120 GWs of coal-fired power generation.

These estimates merely reflect conventional oil fields. When unconventional oil resources such as residual oil zones or tight hydrocarbon shales are included, estimates of total oil production and carbon storage potential for CO_2-EOR increase substantially.

In addition, EOR using CO_2 captured from anthropogenic sources results in net emissions reductions from a full life cycle standpoint. A recent study by the International Energy Agency finds that a barrel of oil produced through EOR using anthropogenic CO_2 emits 37 percent less net CO_2 (including emissions from combustion of the oil itself) than a barrel of oil produced without CO_2-EOR.

However, for this full oil production and carbon storage potential to be realized, more CO_2 is needed from power plant and industrial sources, as just over 75 percent of CO_2 used in EOR currently comes from geologic sources. Toward that end, further technology demonstration and innovation will reduce the cost and financial risk of carbon capture in electric power generation and industrial processes such as cement, refining and steel production.

Fortunately, we have nearly a half century of successful commercial-scale carbon capture technology deployment to build on that spans myriad industry sectors, including natural gas processing, fertilizer production, hydrogen production, steam methane reforming, ethanol production and gasification to produce a range of energy and industrial products.

With respect to power plant CO_2 capture, the world's first commercial-scale CO_2 capture project at a power plant commenced operation last year at SaskPower's Boundary Dam plant in Saskatchewan, Canada. Two additional projects will start in the next few months: one at an existing coal-fired power plant operated by NRG near Houston, Texas and a new lignite-fueled integrated gasification-combined cycle power plant being built by Southern Company in Kemper County, Mississippi. Importantly, the key challenge to further deployment of this first-generation commercial carbon capture technology is primarily one of technology transfer, innovation and cost reduction, not new technology invention. Therefore, the federal and state financial incentive policies recommended in this report can play a critical role in scaling up carbon capture.

Other energy technologies, such as wind and solar power faced similar challenges of higher costs, policy uncertainty and investment risk for project developers. Robust federal and state policies to spur development of wind and solar played a major role in scaling up the commercial deployment of these technologies, improving performance and significantly reducing costs.

JOBS AND FISCAL BENEFITS OF CO_2-EOR DEPLOYMENT

CO_2-EOR deployment directly supports high-paying jobs that extend across a range of sectors, including oil and gas production, pipelines and other energy infrastructure, manufacturing, construction, engineering and other services. Over the longer term, carbon capture can help safeguard the viability of existing fossil energy production, electric power generation, and industrial production by providing a cost-effective carbon management solution for traditional energy producing and energy intensive sectors of our nation's economy.

CO_2-EOR also provides fiscal benefits at a time when the federal government and many states face budget challenges. Installing carbon capture at power plants and industrial facilities increases the supply of CO_2 available, thus enabling additional domestic oil production that results in new revenue to federal and state governments. In fact, these additional direct federal and state revenues from new oil production can, over time, pay for the cost of incentives recommended by the Work Group in this report.

CO_2-EOR also provides fiscal benefits at a time when the federal government and many states face budget challenges. Installing carbon capture at power plants and industrial facilities increases the supply of CO_2 available, thus enabling additional domestic oil production that results in new revenue to federal and state governments.”

In addition to direct revenues, it is important to consider the indirect federal and state tax revenue associated with economic activity stimulated by CO_2-EOR deployment, as well as the important role that carbon capture can play in preserving the existing tax base by allowing existing energy production and industrial activities to continue even as public policy and market forces require reductions in carbon emissions.

Federal Incentives

Financing the deployment of carbon capture projects currently faces challenges. Capital costs of CO_2 capture, compression and pipeline transport remain relatively high

> “CO_2-EOR deployment directly supports high-paying jobs that extend across a range of sectors, including oil and gas production, pipelines and other energy infrastructure, manufacturing, construction, engineering and other services.

in relation to available revenues. Additionally, the currently low and historically volatile nature of oil prices challenges revenue from the sale of CO_2 for EOR. Finally, availability of debt and equity for carbon capture projects is limited and terms are poor.

The current mix of federal tax incentive and other policies for CO_2-EOR projects have generally failed to provide adequate financial certainty or value for private investors, and they are too cumbersome for project developers to utilize effectively.

A targeted package of federal incentives that are more robust and easier to use by the private sector would help mitigate the risk and uncertainty that currently impedes efforts to develop commercial carbon capture projects and spur private investment in the industry. In order of priority, the Work Group recommends that Congress:

1. **Extend, reform and expand the existing Section 45Q Tax Credit for Carbon Dioxide Sequestration to increase its value, make it financially certain and provide for greater flexibility for carbon capture project developers;**
2. **Establish federal price stabilization contracts, or contracts for differences (CfD), for the CO_2 sold from capture facilities to EOR operators in order to eliminate the risk of price volatility that deters private investment in carbon capture projects; and**
3. **Make carbon capture eligible for tax-exempt private activity bonds (PABs) and for master limited partnerships (MLPs) in order to provide debt and equity, respectively, on more favorable terms.**

Bipartisan legislation has been introduced in the House and Senate to enact each of these measures.

SECTION 45Q CARBON STORAGE TAX CREDITS

The Section 45Q tax credit is an existing tax credit awarded for every ton of CO_2 captured and stored through EOR or other geologic storage. 45Q is completely performance-based, meaning that credits can only be claimed for tons of CO_2 that have been successfully captured and injected into an oilfield or other suitable geologic formation.

Legislation has been introduced in the House and Senate to extend and reform the current 45Q tax credit, and each of these bills and a related Senate amendment enjoy broad, bipartisan co-sponsorship and the support of leaders from both political parties. The legislation addresses fundamental flaws in the original 45Q program that have prevented it from playing a meaningful role in stimulating private investment in new carbon capture projects. These flaws include:

- Only $10 credit per metric ton of CO_2 used in EOR, and $20 per metric ton for non-EOR storage, which does not cover the current gap between the cost of carbon capture and revenue from selling CO_2 for EOR;
- The program is capped at 75 million metric tons, available first-come, first-serve and over half the credits have been claimed, so investors have no certainty that the credit will be available for their project;
- A requirement that the owner of the power plant or industrial facility that emits the CO_2 also own the carbon capture equipment, prevents tax-exempt municipal utilities and electric cooperatives from utilizing the credits and reduces the flexibility and economic value of the credits for other project developers; and
- A minimum facility eligibility threshold of 500,000 tons of CO_2 capture annually all but precludes some industry sectors such as ethanol from participating and could exclude early commercial demonstration of carbon capture technology in a range of sectors.

The Work Group supports legislative efforts in Congress to institute the following reforms:

- **Extend and uncap the program, so that CCUS project investors have the financial certainty and confidence that the tax credit and associated revenue would be available to them;**
- **Increase the value of the tax credit to a level of $30/ton or more to help close the cost gap and justify private investment in commercial carbon capture projects;**
- **Specify that the entity claiming the credit is the owner of the carbon capture equipment, giving developers flexibility to involve outside investors that can utilize the tax credits; and**
- **Reduce the facility eligibility threshold to 100,000 tons of CO_2 captured annually.**

CONTRACTS FOR DIFFERENCES

The Work Group recommends establishing CfDs at the federal level for CO_2-EOR projects. Traditionally, CO_2 prices in contracts with EOR operators have been indexed to the price of oil. Historic volatility in oil prices, coupled with current and projected low market prices, creates market risk and earnings uncertainty for carbon capture projects, keeping potential lenders and investors on the sidelines. The current Senate Energy bill contains a provision directing the U.S. Department of Energy (DOE) to study and report back to Congress on how a program for CfD contracts could be established.

A CfD would provide a single uniform oil price over the term of the contract, based on Congressional Budget Office (CBO) or Energy Information Agency (EIA) forecasts. When oil prices are low (and hence oil-indexed CO_2 prices are low as well), the federal government would make up the difference to achieve the target price; when oil prices are high, the carbon capture project would be required to return any excess above the level target price. This program could be designed to be revenue-neutral for the federal Treasury.

PRIVATE ACTIVITY BONDS

The Work Group supports legislation that would make tax-exempt private activity bonds available to power and industrial facilities that capture CO_2 emissions and store them through EOR or other geologic storage.

The federal government currently allocates to the states permission to issue approximately $33 billion of private activity bonds (PAB) annually, making the PAB tax-exempt bond market large, well-understood and accepted by financial markets and investors. If carbon capture projects were allowed to participate in the PAB market, a long-term debt market for these projects will be created that can be expanded to accommodate the expanding industry. PABs do not conflict with receipt of a federal grant, and they have limited fee payments until bonds are placed with investors, which reduces project development risk. The Work Group is not recommending an increase in the existing allocation of PABs to states, and projects that utilize PABs must reduce certain other tax deductions, so federal budget experts have concluded that allowing carbon capture facilities to be financed by PABs would entail only a modest additional cost to the Federal Treasury.

MASTER LIMITED PARTNERSHIPS

The Work Group recommends that Congress extend eligibility for master limited partnerships (MLP) to carbon capture projects in order to help reduce the cost of equity. MLPs have a lower cost of equity than conventional corporations. This allows the project to raise larger amounts of money on more favorable terms from equity investors.

An MLP combines the benefits of a partnership and a corporation. The partnership itself pays no tax—instead, each partner receives a tax statement showing their pro rata share of the profits or losses from the MLP, to combine with their other gains or losses. Like a corporation, equity in MLPs can be issued and traded in markets, facilitating the raising of private capital.

PRIORITIZING FEDERAL POLICY RECOMMENDATIONS BASED ON MODELING AND QUALITATIVE EVALUATION

On the basis of modeling results and qualitative criteria described in detail later in this report, the Work Group

has identified the extension, reform and expansion of the Section 45Q tax credit as its top federal priority for stimulating commercial CCUS deployment, followed by the establishment of a federal CfD mechanism through DOE. Analyses completed for the Work Group suggest that CfDs could yield financial benefits comparable to 45Q tax credits for carbon capture projects, and potentially on a revenue neutral basis, but final congressional action on CfDs is considered unlikely in the near future.

In addition, the Work Group concluded that making carbon capture projects eligible for PABs and allowing them to form MLPs constitute important supplementary policies that, while insufficient in their own right, can help additional commercial CCUS projects achieve financial feasibility in combination with revamped 45Q tax credits and/or CfDs. PAB and MLP policies have the added benefits of costing the federal government relatively little and, unlike tax credits, can help build a long-term foundation for the industry, as they do not include a sunset or binding limit.

ANALYZING THE IMPACT OF FEDERAL POLICY CHANGES

In crafting its recommendations, the Work Group reviewed two types of analysis, micro-level modeling of project financial feasibility and macro-level modeling of industrywide deployment.

> "Analysis done for the Work Group suggests that states, in conjunction with improved federal policy, can positively affect the overall feasibility of CCUS projects by optimizing a suite of traditional taxes common to most oil and gas-producing states.

First, Stanford University undertook individual project-level analyses of the federal incentives described above. This analysis measured the impact of various incentives, individually and in combination, to determine what is needed to successfully finance a carbon capture retrofit of an existing power plant.

Given low oil prices and other market conditions that prevail today, the retrofit of existing power plants for carbon capture is not commercially viable for a private investor without incentives. This does not mean that capture facilities are too expensive to build, but rather that the returns are too low and uncertain to attract private investment.

The project finance modeling results strongly suggest that a combined package of incentives will be needed to achieve carbon capture deployment commensurate with our nation's energy production and carbon storage potential, with a reformed Section 45Q tax credit and/or a CfD mechanism serving as the major contributor to enhancing financial feasibility and other complementary incentives such as PABs and MLPs playing supporting roles in helping a commercial project to reach financial close.

Second, the Work Group reviewed macro-level, industrywide economic analysis prepared by the U.S. Department of Energy (DOE) with the National Energy Modeling System (NEMS). The results of DOE modeling highlight the fact that Congress can make a meaningful down payment on early deployment of carbon capture projects between now and 2030 by enacting a single major incentive, the Work Group's priority recommendation to extend and strengthen the existing Section 45 Tax Credit. DOE's NEMS analysis of 45Q tax credits at $35 per MT for EOR storage and $50 per MT for saline storage shows just over 50 million MT of annual CO_2 capture coming on line by 2030, or about 10 GW of power plant carbon capture capacity installed.

Finally, available funding limited the Work Group's analysis of deployment to power plants. However, one can assume that the modeled deployment impacts of incentives would be even more favorable for a number of industrial sectors that feature high-purity sources of CO_2 and often lower costs of carbon capture, such as natural gas processing or ethanol production.

The full report and relevant appendices provide detailed analytical results, including scenarios showing the impact of various combinations of incentives on project financial feasibility.

State Incentives

States have implemented three broad categories of policies to provide financial support to CO_2-EOR deployment:

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

In this report, the Work Group focused on the first category of tax policy and will address the other two topics at a later date.

Analysis done for the Work Group suggests that states, in conjunction with improved federal policy, can positively affect the overall deployment of CCUS projects by optimizing a suite of traditional taxes common to most oil and gas-producing states. Indeed, the Work Group finds that relatively modest changes to a wide spectrum of relevant tax policies can have a large beneficial impact that may appeal to states with a long-term interest in development and use of their energy resources. This report frames these state policies as complementary to federal policies, as the latter can clearly offer more assistance for commercial carbon capture projects in the current environment of low oil prices and high capital costs. However, even with robust federal policies, unfavorable state policies could hinder an otherwise feasible project.

The state work group reviewed the following state taxes:

- Sales taxes on equipment purchased to build a carbon capture facility;
- Property taxes on the carbon capture facility;
- Sales taxes on equipment acquired to adapt an oilfield to CO_2-EOR operations; and
- Oil and gas taxes, such as production and severance taxes.

Based upon life-of-project modeling of the carbon capture and oil recovery portions of integrated CCUS projects (i.e. a project that controls the full value chain from carbon capture facility to oilfield injection), it appears that certain targeted reductions in state taxes can have a beneficial impact on project economics that is equivalent to roughly an $8 per barrel increase in the price of oil, which is significant compared to existing federal incentives. In all cases, the types of state tax changes considered for this report are consistent with existing precedents.

Sales Tax on Carbon Capture Equipment

Many states impose sales taxes on the purchase of equipment used in manufacturing and utility operations, similar to sales taxes paid by individual consumers. However, many other states provide targeted exemptions for emissions control equipment used by utilities for a variety of purposes, including for carbon capture equipment, air pollution control equipment, and equipment designed to remove pollutants harmful to human health.

State and Local Property Taxes on Carbon Capture Plants

Many states and local governments impose property taxes on the value of real property, including land, buildings and equipment that is affixed to the property. There is precedent for considering a targeted property tax exemption for certain types of facilities. Many states have exempted pollution control equipment from these taxes. This could provide a template for exemption of carbon capture equipment, and has been done in some states.

In addition, some states exempt specific facilities, air pollution equipment, or equipment required to meet other state or federal regulations.

Sales Tax on CO_2-EOR Equipment

While some states exempt manufacturing equipment from state sales taxes, extractive industries such as oil and gas are typically not considered within the definition of manufacturing processes. In other cases, some states extend their state sales tax exemption to oil extraction equipment. The underlying reasons for exempting manufacturing equipment, which vary by state, may also be relevant to CO_2-EOR equipment.

State Taxation of Oil and Gas Production

Most states impose taxes, often over and above normal corporate income or franchise taxes, on production of oil, gas, coal and other types of mining and extractive industries. In many examples reviewed for the Work Group, states reduce or mitigate taxes on oil and gas operations that engage in secondary or tertiary production, perhaps because those operations involve higher capital and operating expenses. States rationalize applying a lower tax rate to a larger (and potentially otherwise unreachable) increment of oil and gas production, rather than maintain a higher rate applied to diminished production. Some states specifically identify CO_2-EOR as qualifying for the reduced rate, while some include CO_2-EOR recovery as a tertiary extraction. Many states offer no such exemption or reduced rate of taxation.

> "Capturing power plant and industrial CO_2 for use in EOR represents a critical pathway for enabling the continued use of America's abundant domestic energy resources, extending the economic life of existing energy and industrial assets, and sustaining an energy and industrial jobs base.

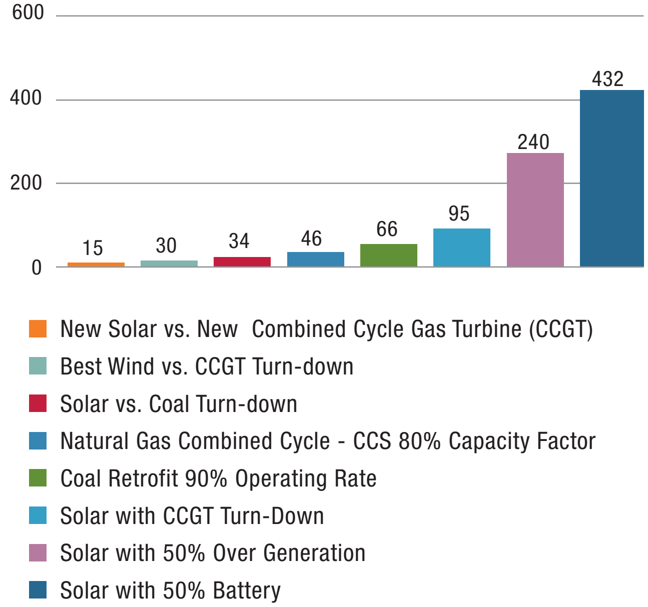
Types of capture plants differ widely, as do types of CO_2-EOR operations. Further, state sales, property and extraction tax regimes are complex and vary significantly. The Work Group's recommendations are intended to be general and individual jurisdictions will consider these recommendations in view of their particular needs. The report merely shows that state-controlled policy tax levers are available to encourage or discourage commercial deployment of carbon capture, and are more powerful than many might have assumed. Closer analysis by interested states of their particular circumstances can help them refine their own incentives to complement improved federal policies for CO_2-EOR deployment.

Conclusion: Achieving Policy Parity for CCUS

In recommending a framework of complementary federal and state incentives to help carbon capture projects achieve financial feasibility, the Work Group maintains that CCUS merits federal and state policy support to accelerate its commercial deployment, as has been done successfully for other energy technologies. As public policy and market conditions drive industry to look for ways to reduce emissions, CCUS deserves equivalent support as a critical component of a broader, cost-effective portfolio of carbon mitigation options.

Indeed, on the basis of cost per ton of CO_2 emissions avoided, carbon capture at power plants with EOR already compares cost-effectively with other options, especially at higher levels of emission reductions. The retrofit of an existing coal plant for carbon capture and EOR lands in the middle of the cost curve for a number of low- and zero-carbon power generation options, as displayed in Table ES 1.

TABLE ES-1: Cost per Ton CO_2 Reductions



Beyond considerations of comparative cost-effectiveness in reducing emissions, there clearly remains a "policy parity" case for CCUS in a broader energy security and economic context: Capturing power plant and industrial CO_2 for use in EOR represents a critical pathway for enabling the continued use of America's abundant domestic energy resources, extending the economic life of existing energy and industrial assets, and sustaining an energy and industrial jobs base. Toward that end, a package of targeted federal and state incentives can become the catalyst for urgently needed commercial CCUS project deployment.

Introduction

PUTTING THE PUZZLE TOGETHER: STATE & FEDERAL Policy Drivers for Growing America's Carbon Capture & CO_2-EOR Industry offers readers both an in-depth look at carbon dioxide enhanced oil recovery, while explaining the current policy landscape and recommendations for future action.

The report first provides background information on the formation of the Work Group and the process utilized to develop this report.

The next section of the report provides the rationale for the capture of carbon dioxide from power plants and industrial facilities and its use and storage through enhanced oil recovery as a key component of a U.S. and global energy strategy with the potential to provide economic, environmental and national security benefits.

The subsequent sections take a detailed look at the current policy landscape and several core state and federal policy options.

The report concludes with a glossary and detailed appendices that provide state-level information on existing laws and policies related to CO_2 EOR.

Carbon capture and storage, or CCS, describes the process of capturing and preventing the release of man-made or anthropogenic CO_2 into the atmosphere and then ensuring its permanent storage in an oil and gas field, deep saline formation or other geologic formation. Carbon capture, utilization and storage, or CCUS, reflects the commercial use of CO_2 prior to permanent geologic storage through its injection into oil fields to recover additional crude through CO_2-EOR. In addition to CO_2-EOR, there is growing interest in other forms of CO_2 utilization to produce useful products, including chemicals, plastics, liquid fuels, cement substitutes, or growing algae with CO_2 to produce biofuels. These other forms of utilization may not result in geologic storage, but they could yield a final product that prevents all or some of the original CO_2 from being released back to the atmosphere, and/or that results in a net reduction in emissions.

This report and its recommendations focus on CO_2-EOR due to nearly half a century of successful commercial experience, the ability to generate revenue to offset some of the cost of carbon capture through the sale of CO_2 for oil production, and the potential to scale up CO_2-EOR to play a meaningful role in national energy production and emissions reductions. Current federal EPA regulations recognize CO_2-EOR as a valid and proven pathway to secure geologic storage of power plant and industrial CO_2 emissions, along with the storage of CO_2 in saline formations.

Growing State Support for CO_2-Enhanced Oil Recovery

Policy Resolutions from Governors and Other State Policy-Makers

OVER THE PAST YEAR, STATE OFFICIALS FROM ACROSS the U.S. have signaled growing support for capturing carbon dioxide from power plants and industrial facilities for use in enhanced oil recovery (CO_2-EOR) to increase domestic oil production and reduce emissions through the safe and permanent geologic storage of that CO_2 through the process of oil recovery. State officials have also endorsed the need for federal action to provide incentives to accelerate commercial deployment of carbon capture, utilization and storage (CCUS).

In 2015, the Western Governors Association (WGA) and the Southern States Energy Board (SSEB) adopted resolutions to that effect, and in early 2016 the National Association of Regulatory Utility Commissioners (NARUC) followed suit with a similar resolution.

The Western governors' resolution recognizes the economic and environmental benefits of CO_2-EOR and calls on Congress and the Administration to enact CCUS incentives. Eight states represented in WGA are already home to active CO_2-EOR projects, while five additional states have EOR potential.

The WGA followed up with a letter to members of Congress in June communicating support for bipartisan legislation to extend and strengthen the critically important federal Section 45Q tax credit for the capture and storage of CO_2 through EOR and other geologic storage.

The SSEB resolution from governors, state officials and legislators also emphasizes the many benefits of CO_2-EOR and the need for federal financial incentives and state policy measures to accelerate deployment of CO_2 capture at power plants and industrial facilities. Their resolution urges Congress and the Administration to "rapidly act . . . in order to increase the energy security of our nation, to reduce the dependence on unstable foreign oil sources, and to create high quality jobs and additional economic benefits."

In the NARUC resolution, our nation's utility commissioners similarly highlight the economic, energy production and carbon mitigation benefits of CO_2-EOR and the importance of both state and federal action:

- "support[ing] States and groups of States developing financial and other policies that encourage the cost-effective use of CO_2 from power plants for EOR;" and
- "urg[ing] Congress and the Administration to support legislation and budget measures that provide assistance to the development and deployment of cost-effective carbon capture/EOR technology."

Overview of State CO_2-EOR Deployment Work Group

WYOMING GOVERNOR MATT MEAD (R) AND MONTANA Governor Steve Bullock (D) have jointly convened the State CO_2-EOR Deployment Work Group as a key follow-on to the Western Governors Association resolution calling for federal incentives to accelerate the deployment of carbon capture from power plants and industrial facilities and increase the use of CO_2 in enhanced oil recovery, while safely and permanently storing the CO_2 underground in the process.

THE CO_2 EOR WORK GROUP AIMS TO FOSTER:

- Expansion of CO_2 capture from power plants and industrial facilities;
- Buildout of pipeline infrastructure to transport that CO_2; and
- Use of CO_2 in oil production, along with its safe and permanent storage.

Launched in September 2015, state representatives were joined by leading enhanced oil recovery, electric power, coal industry, regulatory and NGO experts.

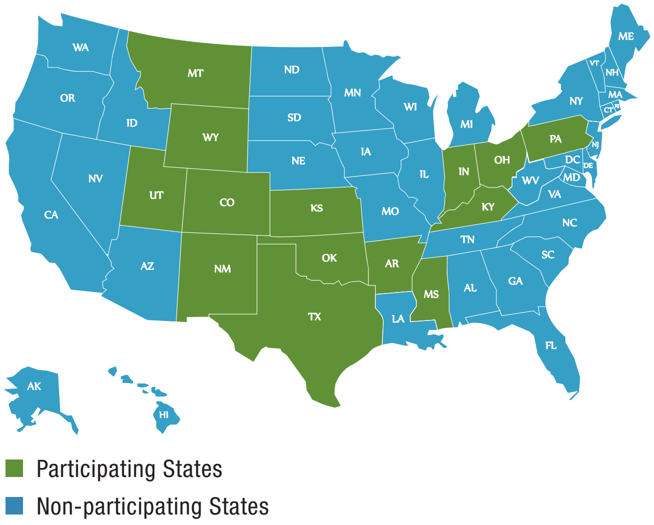
Fourteen states now participate in the Work Group: Arkansas, Colorado, Indiana, Kansas, Kentucky, Mississippi, Montana, New Mexico, Pennsylvania, Ohio, Oklahoma, Texas, Utah and Wyoming. State participation varies by state and includes governors' staff, cabinet secretaries/deputy secretaries, utility commissioners and agency and commission staff. Some state representatives participate at the direction of the governor; others do not.

The Work Group identified three principal roles for its work, including modeling analysis and policy identification, developing recommendations for state and federal policy makers, and supporting the implementation of those policy recommendations.

STATE WORK GROUP OBJECTIVES

1. **Help policy-makers and stakeholders better understand states' potential for CO_2-EOR (both in oil production and supplying CO_2) and evaluate which strategies and state and federal policies can best achieve that potential;**
2. **Make recommendations to states and the federal government;**
3. **Support state policy-makers in implementing strategies and policies developed through Work Group analysis and deliberations, including multi-state efforts; and**
4. **Encourage enactment of federal policies that complement state priorities through coordinated efforts of governors, other state policy-makers and stakeholders.**

FIGURE 1: CO_2-EOR State Deployment Work Group – Participating States



The Great Plains Institute facilitates and staffs the Work Group with funding from the Hewlett Foundation and with technical support from partners at the Stanford Graduate School of Business, Center for Climate & Energy Solutions, Charles River Associates and Clean Air Task Force. Industry, NGO and other stakeholders participate and provide input at the invitation of state representatives and are listed below. The scope of work, deliverables and decisions of the Work Group are determined solely by the state representatives.

Putting the Puzzle Together: State & Federal Policy Drivers for Growing America's Carbon Capture & CO_2-EOR Industry represents the culmination of a diverse group of state officials and key stakeholders and experts learning and working together over the course of one year, five in-person meetings and multiple conference calls. Work Group participants jointly reviewed the experience of industry and states with CO_2-EOR in the U.S. to date, as well as its future energy production, economic and carbon management potential; helped inform and evaluated modeling of existing and proposed state and federal incentive policies and their potential for helping carbon capture and EOR projects reach commercial feasibility; and jointly refined the federal and state incentive policy recommendations contained in this report.

CO_2-EOR State Deployment Work Group Participant List

Representatives of Co-Convening Governors

- Matthew Fry, Policy Advisor
  Office of Wyoming Governor Matt Mead
- Dan Lloyd, Business Development Specialist
  Office of Montana Governor Steve Bullock

Participating State Officials

- Rex Buchanan, Kansas State Geologist (retired)
- Stuart Ellsworth, Engineering Manager,
  Colorado Oil & Gas Conservation Commission
- Michael Kennedy, Assistant Director,
  Kentucky Energy & Environment Cabinet
- Shawn Shurden, Commission Counsel,
  Mississippi Public Service Commission
- Heather McDaniel, Deputy Director,
  Policy Office of the Governor of New Mexico
- Patrick McDonnell, Secretary,
  Pennsylvania Department of Environmental Protection
- Leslie Savage, Chief Geologist,
  Railroad Commission of Texas
- Rob Simmons, Energy Policy & Law Manager,
  Utah Governor's Office of Energy Development
- Michael Teague,
  Oklahoma Secretary of Energy & Environment
- Ted Thomas, Chairman,
  Arkansas Public Service Commission
- Robert Worstall, Deputy Chief, Division of Oil & Gas Resources, Ohio Department of Natural Resources
- Tristan Vance, Director, Indiana Office of Energy Development

Participating Stakeholders & Experts

- Shannon Angielski, Executive Director, Coal Utilization Research Council
- Jeff Brown, Lecturer in Management,
  Stanford University Graduate School of Business
- Steven Carpenter, Director,
  Enhanced Oil Recovery Institute, University of Wyoming
- Al Collins, Senior Director for Regulatory Affairs,
  Occidental Petroleum Corporation
- Ben Cook, Visiting Assistant Professor,
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  Office of Fossil Energy, U.S. Department of Energy
- Julio Friedmann, Senior Adviser for Energy Innovation,
  Lawrence Livermore National Laboratory
- Scott Hornafius, President, Elk Petroleum
- Rob Hurless, Deputy Director,
  Enhanced Oil Recovery Institute, University of Wyoming
- Dina Kruger, Principal, Kruger Environmental Strategies
- Sasha Mackler, Vice President,
  Summit Power Group (now at Enviva LP)
- Steve Melzer, Geological Engineer and Principal,
  Melzer Consulting
- Julie Moore, Senior Director, State Government Affairs,
  Occidental Petroleum Corporation
- Deepika Nagabhushan, Policy Associate,
  Clean Air Task Force
- Jim Orchard, Vice President for Marketing and Government Affairs, Cloud Peak Energy (retired)
- John Thompson, Director, Fossil Transition Project,
  Clean Air Task Force
- Keith Tracy, Director of CO_2 Midstream Operations,
  Chaparral Energy

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- Brad Crabtree, Vice President for Fossil Energy
- Patrice Lahlum, Program Consultant
- Doug Scott, Vice President for Strategic Initiatives

Carbon Dioxide-Enhanced Oil Recovery is More Than a Niche

A National Energy, Economic & Environmental Solution

EOR USING ANTHROPOGENIC CO_2 OFFERS EXTRAORDINARY benefits for our nation. Capturing CO_2 from power plants and industrial facilities for EOR increases American oil production, while simultaneously reducing carbon emissions and enabling continued use of our domestic fossil energy resources. Producing more domestic oil through EOR also further displaces more carbon-intensive imported heavier crudes and lowers our trade deficit by reducing expenditures on oil imports.

Additionally, installing carbon capture facilities, building CO_2 pipelines and reworking mature oil fields to revitalize their production through CO_2-EOR bring jobs and investment to key energy and industrial sectors of the U.S economy.

While our nation's policy-makers, the media and the general public are only beginning to appreciate the array of benefits and enormous opportunity of CO_2-EOR, it is nonetheless a proven, long-established and commercially-successful practice with the potential to be scaled up significantly with the right federal and state policy framework in place.

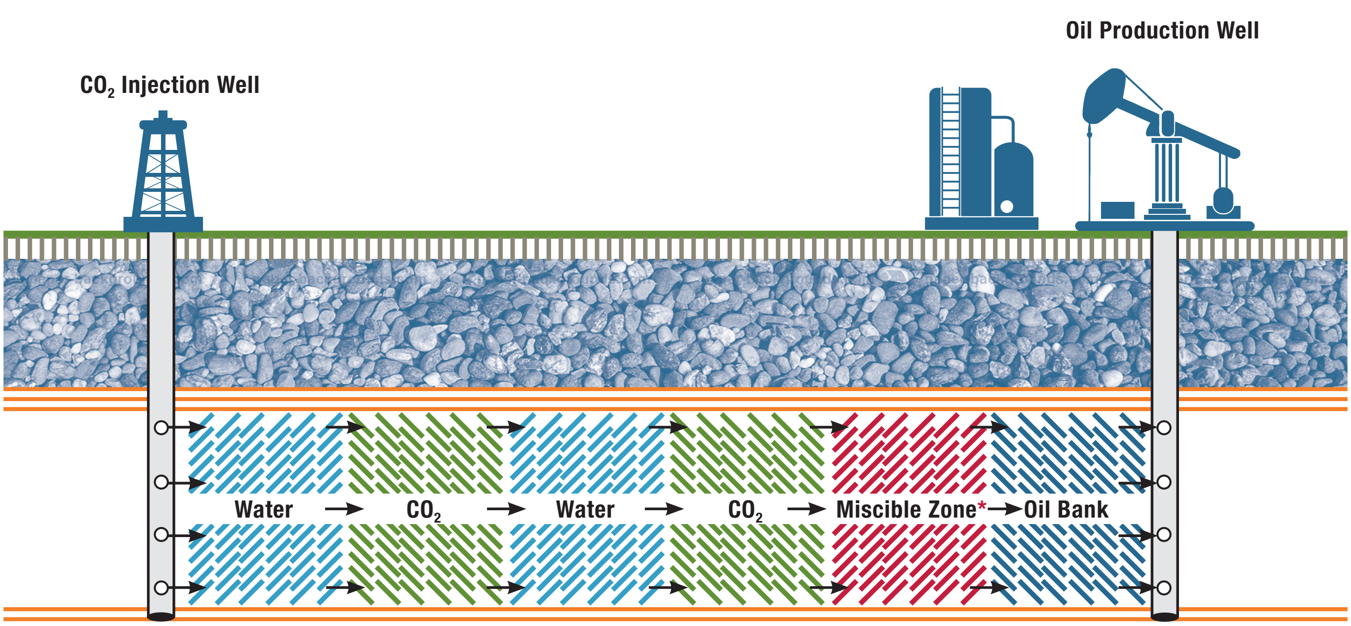
CO_2-EOR: Background and How It Works

CO_2-EOR represents a well-understood and commercially successfully technique for oil production that enables cost-effective recovery of remaining crude from mature oil fields. In the early or primary phase of traditional oil production, the extraction of oil and gas decreases the fluid pressures in a reservoir. Typically, a secondary phase involving injection of water to restore reservoir pressure has followed the primary phase, enabling production of still more of the original oil in place. Eventually, water flooding reaches a point of diminishing economic returns. Then, some fields are suitable for a tertiary phase of production that commonly involves CO_2 injection—commonly referred to as "CO_2 floods"—to recover still more of the remaining oil.

Commercial CO_2-EOR was pioneered in West Texas in 1972. In the ensuing four and one-half decades, the U.S. independent oil and gas industry has turned the practice into a robust and growing industry that accounts for approximately four percent of domestic oil production. The first two large-scale CO_2-EOR projects in the United States (SACROC and Crossett in West Texas) remain in operation today.

Capturing, compressing and transporting CO_2 via pipeline to an oilfield transforms CO_2 from a liability into a valuable commodity with remarkable properties and potential for enhancing oil production. When injected into an existing oilfield, CO_2 lowers the viscosity of the remaining oil, reduces interfacial tension, and swells the oil, thereby allowing oil affixed to the rock and trapped in pore spaces to flow more freely and be produced through traditional means. A majority of injected CO_2 remains in the reservoir

FIGURE 2: How Carbon Dioxide and Water Can Be Used to Flush Residual Oil



*Miscible Zone = Injected CO_2 encounters trapped oil → CO_2 and oil mix → Oil expands and moves towards producing well

Source: Carbon Dioxide Enhanced Oil Recovery Untapped Domestic Energy Supply and Long Term Carbon Storage Solution, National Energy Technology Laboratory, Department of Energy.

in the first pass; that CO_2 which does return to the surface with the produced oil is then separated, compressed, and reinjected. This process results in only *de minimis* emissions from what constitutes a closed-loop system from CO_2 source to oilfield sink.

As oil fields continue to mature, EOR presents a key opportunity to capture carbon emissions from power plants and industrial facilities that would otherwise be vented to the atmosphere and instead put that CO_2 to productive use, harvesting additional domestic oil to displace crude we likely would otherwise import, while safely and permanently storing that captured CO_2 geologically in the process.

Since CO_2 as a purchased commodity is more expensive than water, CO_2 flooding has historically followed water flooding in a tertiary phase of production. However, the EOR industry is exploring the use of CO_2 in primary and secondary production, especially with unconventional reservoirs such as residual oil zones and tight hydrocarbon shales. Successful commercialization of CO_2-EOR in unconventional formations would lead to substantial increases in domestic oil production and carbon storage potential, as well as continued reductions in the import of more carbon-intensive heavy crudes.

CO_2-EOR projects offer longevity and a more complete utilization of existing assets and investments not always associated with other oil production opportunities. Taken together, primary and secondary phases of oil production in conventional fields typically yield a third to half of the original oil in place. By producing additional incremental oil in a tertiary phase, CO_2-EOR can further increase a formation's yield by roughly 10-20 percent of the original oil in place.

While CO_2-EOR operators must inject CO_2 for approximately one year before a formation will yield additional oil, the resulting production may continue for up to 30 years, usually peaking for 10 years (between years 5-15). CO_2-EOR therefore can provide relatively stable energy production, employment, and benefits to local economies. In addition, CO_2-EOR offers economic opportunities for producing oil that compare favorably with other oil production techniques, provided that CO_2 can be delivered at an affordable price.

CO_2-EOR is National in Scope

Until recently, CO_2-EOR was often seen as a useful niche opportunity, but not something with potential to be scaled up as a national energy and environmental solution. However, continued growth of the industry and ongoing analysis and real-world demonstration of the oil production and carbon storage potential of CO_2-EOR are changing that perception.

Since the first oil was produced commercially with CO_2 in West Texas, over 130 additional EOR projects have been developed in 10 U.S. states. They produce roughly 400,000 barrels per day utilizing CO_2, representing over four percent of domestic production, delivered by over 4,500 miles of pipelines. CO_2 pipeline infrastructure today spans 12 states and five geographic regions, including the Permian Basin of Texas and New Mexico, the Northern Rockies and Plains, the Gulf Coast, the Southern Plains and northern Michigan. At one end of the spectrum, the Permian Basin has a 2,470-mile integrated pipeline network, whereas infrastructure in Michigan is limited to a 14-mile pipeline transporting CO_2 from a natural gas processing plant to local oilfields. Nationally, the system as a whole supplies over 70 million tons of CO_2 per year for EOR.

From the map of U.S. CO_2 pipelines in Figure X, one can readily envision an integrated national pipeline network emerging over time, especially with the implementation of federal and state incentives for carbon capture and infrastructure deployment recommended in this report. Indeed, the opportunity for the capture and transport of power plant and industrial CO_2 for EOR and geologic storage is truly national in scope—24 states have CO_2-EOR production potential and still more have industries that could supply CO_2 commercially to the EOR industry (see map of states with EOR potential in Figure 3 below).

Oil Production and Carbon Management Potential of CO_2-EOR

CO_2-EOR has the potential to become a game changer, both for domestic energy production and for management of U.S. carbon emissions. According to analysis by Advanced Resources International (ARI) for the U.S. DOE's National Energy Technology Laboratory, the U.S. has the potential to produce an estimated 28 billion barrels of economically recoverable oil from conventional onshore and offshore fields with today's EOR industry best practices, and

TABLE 1: Economically Recoverable Domestic Oil & CO_2 Storage Capacity, State of Art (SOA) and "Next Generation" CO_2-EOR Technology

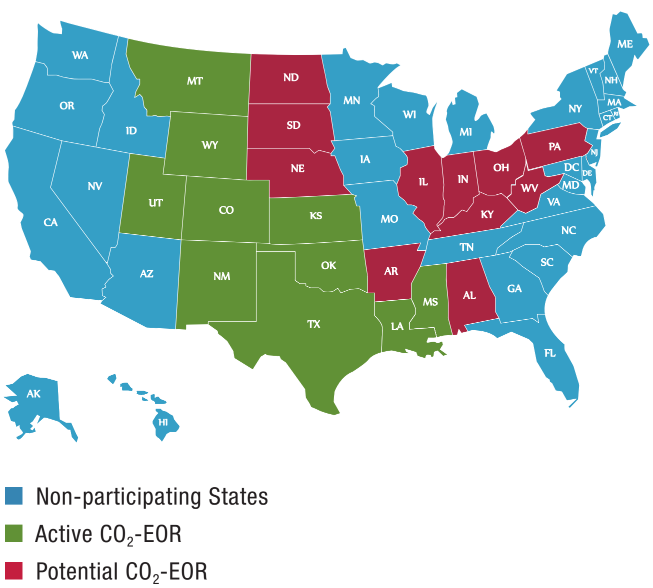
	Economically Recoverable Oil[b] (Billion Barrels)		Economically CO_2 Demand/Storage[b] (Million Metric Tons)	
Basin/Area	SOA	"Next Generation"	SOA[b]	"Next Generation"
Main Pay Zone CO_2-EOR				
Lower-48 Onshore	24.3	60.5	8940	17,340
Alaska	2.6	5.7	1,490	2,330
Offshore GOM	0.8	14.9	310	3,910
Total	**27.7**	**81.1**	**10,740**	**23,580**

a Includes 2.6 billion barrels already produced or placed in reserves with miscible CO_2-EOR.

b At an oil price of \$85 per barrel and a CO_2 cost of \$40 per metric ton with ROR at 20% before tax.

Source: Advanced Resources International/DOE/NETL-2011/1504, July 2011 and DOE/NETL-2014/1631,2014

FIGURE 3: U.S. States with Active CO_2-EOR & Potential for CO_2-EOR



Source: C2ES

next generation EOR techniques have the potential to yield an estimated 81 billion barrels of economically recoverable oil.[1] For comparison, total U.S. proven reserves of oil stood at just under 40 billion barrels in 2014.

The carbon storage potential of CO_2-EOR is equally vast. Over the life of an EOR project, for every 2.5 barrels of oil produced from a conventional oilfield, it is estimated that EOR can safely store on average one metric ton of CO_2. ARI estimates a potential market demand for CO_2 of 11 to 24 billion metric tons from EOR in conventional oil fields based on the estimates cited above for economically recoverable oil production.[2] If this CO_2 were supplied by existing coal-fired power plants retrofitted for carbon capture, it would facilitate the continued operation of roughly 55 to 120 GWs of coal generation over 35 years. In this context, CO_2-EOR offers a market and technology-based carbon management solution that can enable the continued productive use of our nation's abundant energy resources and of our existing energy and industrial assets.

1 For an updated summary of ARI's analysis, see CO_2 Building Blocks: Assessing CO_2 Utilization Options, National Coal Council, Washington, DC, August 2016, pp. 30-32.

2 *CO_2 Building Blocks: Assessing CO_2 Utilization Options*, p. 32, Table E-5.

TABLE 2: U.S. Regional CO_2 Utilization/Storage and Oil Recovery Potential
The CO_2 Utilization/Storage and Oil Recovery Potential of Nine Lower 48 Onshore Regions

Region	Oil Reservoirs Favorable for CO_2-EOR	CO_2 Demand *(MMmt)*				Oil Recovery *(Billion Bbls)*			
		Technical		Economic[d]		Technical		Economic[d]	
		SOA	"Next Generation"	SOA	"Next Generation"	SOA	"Next Generation"	SOA	"Next Generation"
Appalachia	103	520	1,160	10	290	1.1	3.4	*	1.3
California	89	1,30	2320	480	1,760	3.1	7.9	1.2	6.7
East/Central Texas	193	4,120	6,040	2,120	3,620	11.1	20.9	5.9	13.5
Michigan/Illinois	148	660	1,050	330	570	1.8	3.0	1.1	1.8
Mid-Continent[a]	183	4,220	6,530	2,120	3,270	12.9	22.5	6.6	12.0
Permian Basin[b]	217	6,070	8,620	2,690	4,750	13.6	24.0	6.4	14.6
Rockies[c]	146	1,930	2,790	710	1,270	4.5	9.7	1.9	4.7
Golf Coast	209	2,590	3,390	290	1,440	5.4	10.1	0.9	4.8
Williston	86	820	1,150	130	360	2.1	4.0	0.3	1.3
Total	**1,374**	**22,270**	**33,050**	**8,880**	**17,330**	**55.6**	**105.5**	**24.3**	**60.7**

a Includes 0.1 billion barrels already produced or proved with CO_2-EOR.
b Includes 2.2 billion barrels already produced or proved with CO_2-EOR.
c Includes 0.3 billion barrels already produced or proved with CO_2-EOR.
d Evaluated using an oil price of \$85/B, a CO_2 cost of \$40/mt and a 20% ROR, before tax.
Source: Advanced Resources International.

Table 2 illustrates the geographic distribution of the oil production and geologic storage potential of CO_2-EOR in the lower 48 states.

When including unconventional oil resources such as residual oil zones or tight hydrocarbon shale formations, estimates of oil production increase substantially. And, our understanding of recovery techniques and these formations' production potential are only beginning to be understood. For example, a 2015 study by ARI of residual oil zones concluded that approximately 26 billion barrels of oil could technically be recovered through CO_2-EOR and 17 billion tons of CO_2 stored in just a four-county region of the Permian Basin in West Texas alone.[3]

Some have questioned the net emissions benefit of geologic storage through CO_2-EOR because of the fact that more oil is produced in the process. However, EOR using CO_2 captured from anthropogenic sources results in a net emissions reduction from a full lifecycle standpoint. Analysis published last year by the respected International Energy Agency finds that a barrel of oil produced through EOR using anthropogenic CO_2 emits 37 percent less net CO_2 than a barrel of oil produced without CO_2-EOR. Importantly, this analysis includes a full range of factors, including the emissions that result from combustion of the oil produced, as well as the price impact that EOR production has on broader oil markets.

3 ARI's residual oil zone estimates summarized in *CO_2 Building Blocks: Assessing CO_2 Utilization Options*, p. 29, Table E-3.

FIGURE 4: The CO_2-EOR Barrel

Royalities	$12
State Tax	$3
CO_2 Purchase Cost	$15
Capital & Operating Costs	$25
Income Tax	$5
Net Income to EOR Company	$10
TOTAL COST	**$70**

Source: National Coal Council's CO2 Building Blocks Report, Table E-7.

Jobs and Fiscal Benefits of CO_2-EOR Deployment

At a time when federal and state policy-makers and the public are concerned about maintaining quality jobs in the U.S., CO_2-EOR deployment represents a compelling opportunity to sustain and expand our domestic energy and industrial jobs base. Immediate direct benefits include high-paying jobs that extend across a range of sectors, including oil and gas production, pipelines and other energy infrastructure, manufacturing (carbon capture and oilfield equipment, steel pipe, and other components), construction, engineering and other services.

Over the longer term, CCUS can also help safeguard the viability of existing fossil energy production, electric power generation, and industrial production. As the U.S. DOE points out in a recent white paper, electric power generation and liquid fuels industries employed 1.6 million Americans in 2015, of which 1 million of those jobs depended on existing fossil power generation and the mining and extraction of fossil fuels. In addition, U.S. manufacturing provided 8.5-9 percent of total U.S. employment, yet the sector was responsible for 31 percent of total energy consumption. Both these examples underscore the crucial role that carbon capture can play by providing a cost-effective carbon management solution for traditional energy producing and energy intensive sectors of our nation's economy.

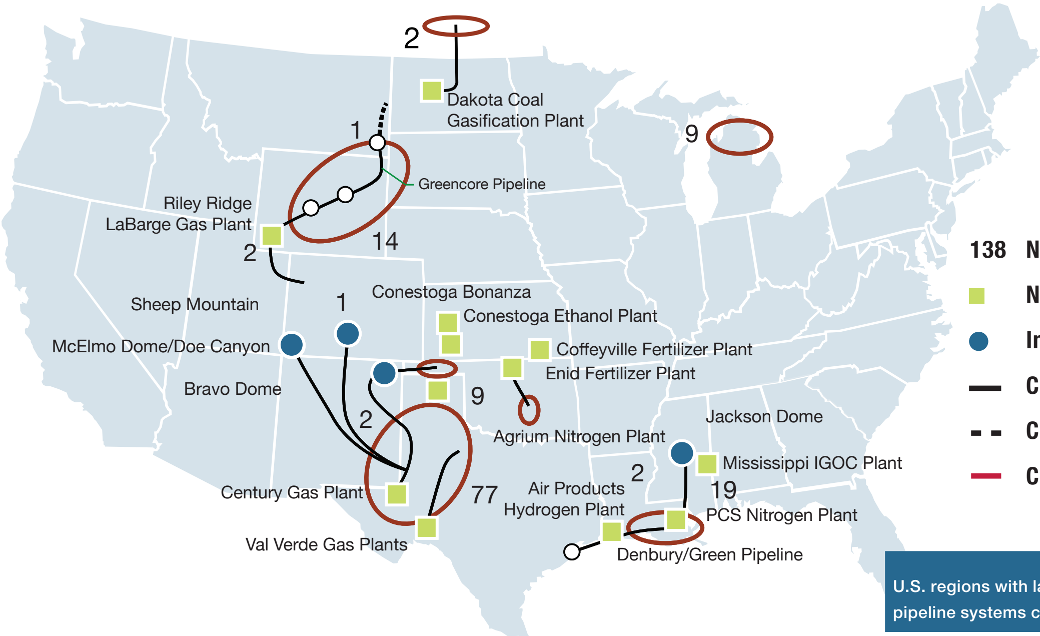
CCUS deployment also provides fiscal benefits at a time when the federal government and many states face budget challenges. Installing carbon capture at power plants and industrial facilities increases the supply of CO_2 available for the oil industry to purchase for EOR, enabling new domestic oil production that would otherwise not occur. This additional production, in turn, results in direct revenue to the federal and state governments in the form of taxes on oil extraction and taxes paid by oil companies and mineral owners, not to mention royalty revenue paid to the federal government in the case of EOR production on federal lands. In fact, these additional direct federal and state revenues from new oil production can, over time, pay for the cost of incentives recommended by the Work Group in this report.

The direct revenue benefits of CO_2-EOR do not factor in additional indirect federal and state revenues that CCUS deployment can stimulate through economic activity associated with carbon capture, CO_2 pipeline deployment and revitalization of existing oilfield production. Additionally, it does not reflect the important role that CCUS can play in preserving existing federal and state tax base by allowing existing energy production and industrial activities to continue even as public policy and market forces require reductions in carbon emissions.

The Need for More CO_2 to Realize CO_2-EOR's Potential

To realize our nation's full oil production, carbon storage and jobs potential from CO_2-EOR, we will need much more CO_2—captured, compressed, transported via pipeline and delivered to oil-bearing formations suitable for injection. The current estimate of CO_2 use in EOR is 72 million metric tons per year; 55 million metric tons of which comes from geologic sources, and 17 million metric tons come from anthropogenic sources. Yet, natural geologic supplies of CO_2 are constrained, so the potential to grow the EOR industry hinges upon increasing the supply of anthropogenic CO_2, thereby also contributing to meeting national CO_2

FIGURE 5: Current CO^2-EOR Operations & Infrastructure



U.S. regions with large-scale CO_2 pipeline systems currently in operation	Miles of Pipeline
Permian Basin *(W. TX, NM, and S. CO)*	2,320
Rocky Mountains *(N.CO, WY and MT)*	810
Gulf Coast *(MS, LA, and ETX)*	740
Mid-Continent *(OK and KS)*	480
Other *(ND, MI, Canada)*	215

Source: Quadrennial Energy Review: Energy Transmission, Storage, and Distribution Infrastructure, April 2015.

emissions reduction goals. The federal and state incentive recommendations offered by the Work Group in this report are intended to help increase that CO_2 supply by accelerating the deployment of carbon capture at power plants and industrial facilities across the country.

Status of Commercial Carbon Capture Technology Deployment

Contrary to common misconceptions, carbon capture is not a new technology, nor is it something that applies only in the context of coal-fired power plants. Actually, carbon capture has been commercially deployed for decades—the first commercial EOR projects in Texas in the early 1970s obtained CO_2 from natural gas processing plants that separate CO_2 from natural gas—and is widespread in certain industrial sectors. In fact, CO_2 appears as a contaminant in some industrial processes that must be scrubbed out or separated as part of normal operations.

There are many examples of industrial processes that demand separation of CO_2 in order to make a particular product or that render much simpler and more cost-effective the separation and treatment of CO_2 prior to compression and pipeline transport for EOR and geologic storage. Examples include natural gas processing, hydrogen production, steam methane reforming, fermentation and gasification. In some cases, CO_2 is captured and used inside a plant. In others, CO_2 is vented to the atmosphere, and in still others CO_2 has been sold for CO_2-EOR or for more scale-limited commercial applications, such as the food and beverage industry.

In the natural gas industry, the raw natural gas produced is frequently contaminated with naturally-occurring CO_2, and gas processing plants must separate and remove CO_2 prior to pipeline transport. Thus, although there is no emissions-based regulatory requirement to do so, natural gas processors strip out the CO_2, and if they are near CO_2 pipeline infrastructure and EOR operations, they attempt to sell into EOR markets.

In the same vein, the process to make urea fertilizer from natural gas feedstock requires capturing a portion of CO_2 in the first stage of the process (making hydrogen), then making ammonia in the second stage, and using that CO_2 in the third stage of the process (urea production). The fertilizer plants typically have a flexible process allowing them to capture more or less CO_2 depending upon the breakdown between urea versus ammonia fertilizers to be sold to customers.

The production of hydrogen represents another area where industry has long been expert at removing CO_2. The principal process for making hydrogen is steam methane reforming, which heats natural gas and steam to create an output of CO_2 and hydrogen gas, which is also the first step in a typical nitrogen fertilizer plant. The hydrogen gas is separated from the CO_2, with the hydrogen being sold to customers, and the CO_2 can be captured and sold as well. The ease or difficulty of obtaining pure CO_2 depends upon the configuration of each hydrogen plant.

Ethanol production represents yet another sector that has effectively demonstrated commercial capture of CO_2 for EOR storage and geologic storage, with the first project coming on line in 2009 in Kansas. CO_2 obtained from

FIGURE 5: Past Commercial CCUS Deployment Milestones

Successful commercial-scale CCUS deployment has a long history through the capture, compression and pipeline transport of CO_2 for EOR with geologic storage, especially in the U.S. Industrial processes where large-scale carbon capture is demonstrated and in commercial operation include natural gas processing, fertilizer production, coal gasification, ethanol production, refinery hydrogen production and, most recently, coal-fired electric power generation.

1972: Val Verde gas processing plants in Texas Several natural gas processing facilities began supplying CO_2 in West Texas through the first large-scale, long-distance CO_2 pipeline to an oilfield.

1982: Koch Nitrogen Company Enid Fertilizer plant in Oklahoma This fertilizer production plant supplies CO_2 to oil fields in southern Oklahoma.

1986: Exxon Shute Creek Gas Processing Facility in Wyoming This natural gas processing plant serves ExxonMobil, Chevron and Anadarko Petroleum CO_2 pipeline systems to oil fields in Wyoming and Colorado and is the largest commercial carbon capture facility in the world at 7 million MT of capacity annually.

2000: Dakota Gasification's Great Plains Synfuels Plant in North Dakota This coal gasification plant produces synthetic natural gas, fertilizer and other byproducts and has supplied over 30 million MT of CO_2 to Cenovus and Apache-operated EOR fields in southern Saskatchewan as of 2015.

2003: Core Energy/South Chester Gas Processing Plant in Michigan CO_2 is captured by Core Energy from natural gas processing for EOR in northern Michigan, with over 2 million MT captured to date.

2009: Chaparral/Conestoga Energy Partners' Arkalon Bioethanol plant in Kansas The first ethanol plant to deploy carbon capture, it supplies 170,000 MT of CO_2 per year to Chaparral Energy, which uses it for EOR in Texas oil fields.

2010: Occidental Petroleum's Century Plant in Texas The CO_2 stream from this natural gas processing facility is compressed and transported for use in the Permian Basin.

2012: Air Products Port Arthur Steam Methane Reformer Project in Texas Two hydrogen production units at this refinery produce a million tons of CO_2 annually for use in Texas oilfields.

2012: Conestoga Energy Partners/PetroSantander Bonanza Bioethanol plant in Kansas. This ethanol plant captures and supplies approximately 100,000 MT per year of CO_2 to an EOR field in Kansas.

2013: ConocoPhillips Lost Cabin plant in Wyoming The CO_2 stream from this natural gas processing facility is compressed and transported to the Bell Creek oil field in Montana via Denbury Resources' Greencore pipeline.

2013: Chaparral/CVR Energy Coffeyville Gasification Plant in Kansas The CO_2 stream (approximately 850,000 MT per year) from a nitrogen fertilizer production process based on gasification of petroleum coke is captured, compressed and transported to a Chaparral-operated oil field in northeastern Oklahoma.

2014: SaskPower Boundary Dam project in Saskatchewan, Canada SaskPower commenced operation of the first commercial-scale retrofit of an existing coal-fired power plant with carbon capture technology, selling CO_2 locally for EOR in Saskatchewan.

the fermentation of biomass (typically corn in the U.S.) is dehydrated and compressed, rendering it suitable for pipeline transport and further use.

Lastly, there is a worldwide industry that uses gasification to produce hydrogen from solid coal and/or petroleum coke. The pure hydrogen derived from gasification is subsequently used to produce final products such as methanol, synthetic natural gas, polypropylene, and nitrogen fertilizer. Carbon capture is inherent in gasification to produce chemicals and other products, and the commercial-scale use of CO_2 from such facilities has been successfully deployed for many decades. Two such plants in the U.S. sell their already-separated CO_2 to the oil industry, although most such facilities globally still vent their CO_2.

As the milestones in Figure 6 illustrate, there is a long history of successful commercial carbon capture deployment across industry sectors. The specific application of CO_2 capture in various industrial processes to EOR and geologic storage has, in some cases, been the result of intentional federal policies to support research, demonstration and deployment. In other cases, the capture technology was already commercially deployed, and industry principally provided the investment in compression and pipeline transport necessary to cease venting CO_2 and begin putting it to productive use through EOR.

In response to growing interest in reducing industrial and power sector emissions, carbon capture technology has begun entering commercial operation in new industry sectors, boosted by more intentional public support of private sector deployment efforts through a combination of federal and state (or provincial) government grants, financing and incentives. The world's first commercial-scale CO_2 capture project at a power plant commenced operation last year at SaskPower's Boundary Dam plant in Saskatchewan, Canada, with two additional projects starting up this year at an existing coal-fired power plant operated by NRG near Houston, Texas and a new lignite-fueled integrated gasification-combined cycle power plant being built by Southern Co. in Kemper County, Mississippi. In addition, the first commercial-scale capture project at a steel plant is expected to become operational soon in the United Arab Emirates.

In recent years, the US Department of Energy has sponsored a number of first-generation technology commercialization projects in CO_2 capture in the industrial and power sectors. While DOE and industry are also supporting the development and demonstration of important next-generation carbon capture technologies with potential to increase efficiencies and reduce costs, most current commercial deployment efforts involve innovating and improving upon existing technologies and processes to adapt them to electric power generation and other sectors that previously lacked commercial-scale examples of carbon capture for EOR and other geologic storage.

For instance, Mitsubishi Heavy Industries (MHI) has installed a particular type of amine solvent carbon capture system in dozens of fertilizer plants around the world, and MHI is now broadening the market for that system by installing the technology at coal power plants. The first commercial-scale power sector application of this long-standing technology will be demonstrated at NRG's retrofit an existing coal unit soon to come on line in Texas.

Understanding this fundamental point—that key first generation carbon capture technologies work and the immediate deployment challenge is primarily one of technology transfer and cost reduction, not new invention—helps explain why the federal and state financial incentive policies recommended in this report can play such an important role in scaling up carbon capture. Other energy technologies have faced similar early-stage challenges of higher costs, policy uncertainty and investment risk for project developers. For example, not that long ago wind and solar technologies – now mainstream and widely deployed in the U.S. and abroad – were deemed cost-prohibitive and fraught with risk. Their widespread adoption today can be attributed in large measure to robust federal deployment incentives that stimulated commercial technology deployment, leading to reduced costs and performance improvements that, in turn, drove further deployment. Strong, stable and long-term incentives for carbon capture at power plants and industrial facilities can similarly help bridge the cost gap and spur CCUS project deployment.

Federal Incentives to Spur Carbon Capture Deployment

Background

THE STATE CO_2-EOR DEPLOYMENT WORK GROUP HAS analyzed an array of federal and state incentives for carbon capture, utilization and storage (CCUS). Work Group participants and various experts have discussed different technologies available for carbon capture, the CO_2-EOR industry, emerging federal regulation, and current conditions in capital and commodity markets and in the CO_2-EOR industry. Analysis undertaken for the Work Group demonstrates that public policy, both at the state and federal level, can have a major impact upon the feasibility of carbon capture projects.

This chapter focuses on the federal policies that affect the economics of the "value chain" that stretches from the capture of CO_2 from industrial and power plant sources, to utilization and associated geologic storage of CO_2 through EOR.

Summary

This chapter summarizes the recommendations of the Work Group regarding existing and proposed federal incentives. These recommendations are informed by economic modeling of federal incentives. In broad terms, the Work Group concludes that a package of targeted incentives, rather than a single catalyst, will likely be most effective at spurring additional commercial deployment of carbon capture projects. In turn, more rapid and numerous deployment of commercial CCUS projects will drive down construction and operating costs through both learning curve effects and supply chain improvements.

Financing the deployment of CCUS projects currently faces challenges. Capital costs of CO_2 capture, compression and pipeline transport remain relatively high in relation to available revenues. Additionally, the currently low and historically volatile nature of oil prices challenges revenue from the sale of CO_2 for EOR. Finally, availability of debt and equity for carbon capture projects is limited and terms are poor.

In broadest terms, the Work Group examined five different federal incentive policy mechanisms that could help enable a number of CCUS projects to go forward and, evaluated those policies in terms of absolute impact, cost, political viability, and breadth of applicability. Work Group participants came to the following conclusions:

- In order to help CCUS projects close the financial gap in the current environment, any two of the following three federal incentive mechanisms are recommended:
  - An upfront grant or refundable investment tax credit (ITC) of broad applicability, perhaps at the level of 30 percent of capital costs;
  - A higher ($30/MT or more), more flexible and financially certain Section 45Q Tax Credit for Carbon Dioxide Sequestration (referencing section 45Q of the Internal Revenue Code of 1986). Section 45Q is an existing tax credit that pays taxpayers per ton of CO_2 stored, similar to the wind production tax credit that is awarded to generators per Megawatt hour of wind energy produced.
  - A mechanism to stabilize the price at which CO_2 is sold from capture projects to EOR operators (the price of CO_2 is typically linked contractually to volatile oil prices, reducing the ability of carbon capture projects to secure financing and increasing the cost of capital). This mechanism is frequently called a contract for differences or CfD.
- In terms of absolute impact on project economics, political momentum in Congress, and breadth of applicability, extending and strengthening the existing Section 45Q tax credit represents the highest priority for enactment by Congress. A price stabilization mechanism also offers promise for helping more projects reach commercial feasibility, but being less familiar to policy-makers, it faces a potentially longer and more complex path to congressional implementation.
- Master limited partnerships-MLPs (to secure equity investment funding) and tax-exempt private activity bonds-PABs (to provide less expensive, longer-term and fixed-rate debt) have been proposed in Congress and would help increase market access for and reduce the cost of financing CCUS projects, but are not sufficient by themselves to bring a number of new commercial projects online. Both MLPs and PABs would complement and supplement tax credits effectively and at low cost, are well-accepted in financial markets, and are already broadly applied to energy and utility industry projects (though CCUS projects are not eligible for MLPs and PABs under current federal law).

Shortcomings of Existing Federal CCUS Deployment Policies

The current mix of federal policies intended to foster carbon capture deployment have failed to provide adequate financial certainty or value for private investors, and they have proven too cumbersome for project developers to utilize effectively. The various programs adopted were forward-looking and intended to jump-start the industry, but in many cases have not proved to be practically useful.

Federal CCUS Tax Incentives

Current CCUS tax incentives include investment tax credits designed to defray equipment costs and per-ton-based geologic storage credits designed to reward actual performance. While these CCUS tax programs superficially resemble those for renewable energy, when closely compared, they have complexities and weaknesses that have significantly reduced their efficacy. Thus, these programs have not by themselves provided sufficient economic value to attract adequate private investment in carbon capture projects.

Section 48A and 48B Investment Tax Credits. First, the Section 48A and 48B investment tax credit (ITC) programs (referencing the listed sections of the Internal Revenue Code of 1986) were designed to defray the upfront capital costs of clean coal projects (48A) and gasification projects (48B). The total value of 48A and 48B credits appropriated by Congress was $3.15 billion, with most of those funds prioritized for projects that employ carbon capture. It is unclear what portion of those funds has actually been successfully claimed and kept.[4] CCUS project developers have confronted numerous difficulties in utilizing these tax credits, including a rigid five-year deadline for developing, financing and completing carbon capture projects, followed by a five-year recapture period during which the ITC may have to be repaid to the IRS if a project fails to comply with complex technical and operating specifications. Also, when the tax equity market nearly shut down following the financial crisis, Congress made ITCs payable in cash for renewable energy producers under the Section 1603 "grant-in-lieu of tax credit" program, but carbon capture projects were not included.

Section 45Q Tax Credit for Carbon Dioxide Sequestration. The Section 45Q Tax Credit is a federal performance-based incentive awarded per metric ton of CO_2 captured and stored geologically underground, much like the federal wind production tax credit can be claimed for every MWh of wind energy generated. However, while a majority of 45Q tax credits has been claimed in contrast to 48A and 48B ITCs, the program has failed to stimulate private investment in new carbon capture projects due to a number of flaws in how it is structured.

First, under current law, the value of the credit is too low. 45Q provides a $10/MT production tax credit for every ton of CO_2 stored through EOR operations and $20/MT for other geologic storage. As modeling described later in this report shows, these credit values are insufficient to cover the gap between the cost of carbon capture in electric power generation and other industrial sectors and the price the oil industry will pay for CO_2.

Second, the original legislation failed to provide the necessary financial certainty to investors in carbon capture projects. Congress established a total limit of 75 million MT for the Section 45Q program. The tax credits are made available on a first-come, first-served basis, with the program set to expire when the overall tonnage cap is reached. Thus, a potential investor in a carbon capture project has no way to know for certain whether any of the 75 million MT will remain by the time the project begins operations. The IRS recently reported that over half the original pool of credits is already gone, with 44 million credits claimed as of September 2016.[5] Given the timeframe to plan, permit and construct carbon capture projects, this means that if a company begins developing a major carbon capture facility today, there may be no credits left when the project begins commercial operation. Thus, the current 45Q program has already effectively expired in terms of its potential to foster further CCUS project development.

Finally, there are other design flaws in the current 45Q program that further diminish the applicability and value of the tax credit in fostering CCUS project deployment. For example, eligibility to claim the credit is limited to facilities that capture 500,000 MT or more of CO_2 annually. This precludes widespread participation of key industrial sectors that typically have lower total emissions per facility, notably ethanol and fertilizer production, and it makes it more difficult for first-of-a-kind commercial carbon capture technology demonstrations in power generation and other sectors to qualify for the credit. In addition, there are a number of technical difficulties with current law that make 45Q tax equity or leasing transactions nearly impossible for owners of CO_2-emitting plants that are either tax-exempt (such as municipal utilities and generation and transmission cooperatives or otherwise lack the tax appetite to make full use of the 45Q tax credit.

4 For example, of the $350 million from the first round allocation of 48B credits created in 2005, $309.337 million was still available for reallocation as of 2014. See IRS Notice 14-81. In some cases, capture project developers initially claimed the credits and then were forced to repay the IRS after completion lagged past the five-year "placed in-service" deadline.

5 Notice 2016-53: Credit for Carbon Dioxide Sequestration 2016 Section 45Q Inflation Adjustment Factor, Internal Revenue Bulletin 2016-39, September 26, 2016.

Federal Grants

Federal support for CCUS deployment has also included grants for carbon capture projects at industrial and power generation facilities. U.S. DOE grants through the Industrial Carbon Capture and Storage Program (ICCSP) have proven the most effective, helping develop important first-mover projects at industrial facilities, such as ADM's Decatur, Illinois ethanol plant and Air Products' hydrogen plant at a refinery in Port Arthur, Texas. However, DOE's Clean Coal Power Initiative (CPPI) grant program has fallen short relative to the number of commercial projects targeted for development in the electric power sector—in large measure because the above-referenced federal financial incentives have served as ineffective complements to federal grants in helping projects reach financial close and because of adverse market conditions, including low natural gas prices and weak demand for electric power.

Federal Loan Guarantees

The $8 billion in federal loan guarantee program for advanced fossil energy projects administered by DOE has not performed as anticipated. To date, no loans have been closed for any carbon capture projects. Current federal loan guarantees are costly to apply for, limited in terms of the number of projects financeable, burdened by a cumbersome four-year, multi-stage process as required by law, generally trigger a federal environmental impact statement, and require major upfront payments by the project to the U.S. Treasury. Another major problem has been that if a project was the beneficiary of a federal grant under the ICCSP or CCPI programs described above it was rendered ineligible for a loan.

Need for a Comprehensive and Complementary CCUS Incentive Policy Framework

A targeted package of federal incentives that are both more robust and easier to utilize by the private sector would help mitigate the risk and uncertainty that currently stymies efforts to develop commercial CCUS projects and would spur private capital investment in the industry. Targeted policies can help expand and accelerate CCUS deployment in power generation and industrial sectors:

- Closing the remaining gap between cost of capturing, compressing and transporting CO_2 versus the revenue earned from the sale of CO_2 for use in EOR;
- Lowering the high cost of debt and equity project financing; and
- Reducing the market risk and cost of project development.

In today's low oil price environment, carbon capture projects can still cover variable cash expenses via CO_2 sales to the EOR market. However, project developers urgently need a set of incentives to cover the large upfront equipment costs to build these projects. Some funding may come directly from the federal government, in terms of grants or refundable ITCs, but these options typically cover only a fraction of total project costs (e.g., 30 percent of equipment costs with an ITC). Financing the privately-paid balance of remaining costs for large projects typically requires a mix of equity (money from stockholders) and debt (money from lenders), so incentives for private capital need to address the needs of both the equity and debt sides of the financing package.

The U.S. has successful precedents for providing a multi-faceted package of federal incentives that serve to help jumpstart an energy industry. For example, the nation's first large solar projects received substantial federal funding through refundable tax credits, favorable DOE loan rates without upfront payments, and long-term fixed price contracts triggered by state renewable portfolio standard policies. No one magic bullet fostered the solar industry, and no one policy in isolation is likely to do so for CCUS.

Review and Analysis of Various Federal CCUS Incentive Mechanisms

To recap, the Work Group considered five types of federal incentives and prioritized them based on beneficial financial impact on typical projects, fiscal cost, perceived political feasibility, and breadth of applicability to CCUS projects. The prioritization and methodology are described in the section entitled "Ranking of Potential Policies by Priority", below. The five sub-sections that follow describe each of these five incentive policies in more detail and demonstrate their relative contribution to achieving project

TABLE 3: Federal Upfront Policy Tools for CCUS

	"Five Policy Tools"—Purpose of Policy and Program Example	What Would the Policy Accomplish for CCUS?
Grants	1. Government Grants or Cash-Refundable Investment Tax Credit—similar to Section 1603 or CCPI	Government grants for project development increase the number of projects in the pipeline. Grants paid during construction that are firmly committed at financial closing reduce the total amount of private debt and equity needed.
Debt	2. More cash with less commodity price risk (after operating expenses) to pay back debt—some type of CfD program 3. Better terms on the debt—through eligibility for tax-exempt PABs	Both tools (#2 & #3) enable project to raise more longer-term, lower-cost debt. A project with a high, stable operating income stream and low cost of debt can raise larger amounts of debt. The opposite is true for a project with a small, risky operating income stream. It cannot raise much money because of its high cost of debt.
Equity	4. More cash distributable as dividends (after debt service) or tax credits—by extending and reforming Section 45Q tax credits 5. Less expensive equity—through eligibility for MLP tax status	Both tools (#4 & #5) enable a project to raise more equity. A project with a large amount of distributable cash and tax credits and a low cost of equity can raise large amounts of equity. The opposite is true for a project with little distributable cash, no tax credits and a high cost of equity.

financial feasibility.[6] For the purposes of analyzing the financial impact of each policy mechanism, an upfront capital cost of $300 per ton of annual carbon capture capacity for power sector projects is assumed.[7] In other words, an estimated $300 in financing must be produced for each ton of annual carbon capture capacity deployed at a power plant. The only three sources of such funds are government grants, debt, and equity. The debt and equity to be raised is simply the total cost minus any government grants. As shown in Table 3, there are multiple policy tools that can contribute to the upfront funding a CCUS project requires in order to break ground.

Upfront Federal Funding (Grants/Tax Credits)

The federal government has historically awarded upfront financial support to carbon capture projects through grant or ITC programs, and the Work Group recommends continued federal funding in this area. This could include Congress appropriating additional funding to support existing Section 48A ITCs for coal-based power generation carbon capture projects and Section 48B ITCs for gasification projects with carbon capture, or establishing a new ITC that is refundable for cash as proposed for power plant carbon capture projects in President Obama's FY 2016 and 2017 budgets.[8]

6 The order in which each of the policy mechanisms is described in this section does not reflect the Work Group's prioritization, rather they are ordered functionally according to the particular role that each incentive can play in helping a project developer close financing on a project.

7 The $300 per ton is illustrative for post-combustion capture of CO_2 from existing, conventional pulverized coal or natural gas combined cycle (NGCC) power plants. In actuality, the capital cost per ton for coal is in the $250-300/ton range and the cost for NGCC is in the $325-350 range. Cost quotes vary widely depending on vendors, location, status of the existing plant, etc. Thus the $300 is an approximation used to benchmark the efficacy of the various incentives.

8 it is important to note that an ordinary tax credit, such as an Investment Tax Credit (ITC) does not produce cash directly. An ordinary ITC can produce cash indirectly, but only if the project (or its owners, if it is a partnership or LLC) is currently paying cash taxes to the IRS—in that case, tax payments are reduced, and more cash remains in the company (or owners') bank account(s). An ordinary ITC is not helpful, if the project does not owe any cash tax payments to the IRS as a consequence of large early-year interest and depreciation deductions (the case with most capital intensive industrial projects). A refundable ITC avoids this problem. If a project does not owe cash taxes to the IRS, it can surrender its tax credit to the IRS and receive a cash payment for the same dollar amount.

While the Work Group supports the continuation and enhancement of 48A and 48B ITCs, it is important to note that they differ substantially from the familiar ITCs available for renewable energy technologies in ways that make it more difficult to finance CCUS projects. First, the 48A and 48B credits are awarded via competitive application, and certain projects, in certain amounts, are certified on technical and programmatic metrics by U.S. DOE and then awarded credits by the IRS. By comparison, a solar ITC is available to any and all solar projects that meet the required eligibility definition. Second, 48A and 48B ITCs (under the terms of existing law), once finalized, have a very short in-service timeframe, given realistic project development, financing, and construction schedules for such projects. For these reasons, these incentives are not prioritized as highly by the Work Group in its recommendations for congressional action.

Nevertheless, as the Work Group's analysis shows, any federal program that provides either cash or a refundable tax credit upfront provides value to CCUS projects.

Here is a simple example of how a refundable ITC could work to benefit a project. The arithmetic is simple, though there are a few complexities that must be mentioned:

1. **Project costs $200 million. (Assuming 100 percent of project is qualifying equipment.)**
2. **ITC will provide 30 percent x $200 million = $60 million in cash at the tax in-service date.**
3. **The project can most likely obtain a bank loan, or a "bridge loan," for the $60 million immediately, which will then be repaid with funds from the federal government at project completion. Cash refundability of the ITC is key, because a bridge loan can only be repaid with cash, not an ordinary ITC.**
4. **This means the project needs only $140 million of permanent debt and equity capital, instead of $200 million.**
5. **Therefore, if the CRF (Capital Recovery Factor)[9] is 15 percent, the annual funds that need to be generated after covering operating expenses will be reduced 15 percent x $60 million = $9 million.**
6. **If the annual capacity of the project is 750,000 tons per year (tpy), the $9 million works out to a $12 per tpy reduction in the revenues required for the project to close the economic gap ($9mm/yr reduction / 750,000 tpy = $12/ton).**

Price Stabilization Contracts or Contracts for Differences (CfDs)

In its analysis of the industry, the Work Group explored how CO_2 contracts have traditionally been indexed to the price of oil. That is, a ton of CO_2 is typically priced at approximately 30 to 40 percent of the price per barrel of domestically produced oil.[10] Given the link between CO_2 revenues and oil prices, CCUS projects are currently especially challenged. First, spot oil price levels have recently been extremely low. Second, both oil forecasts (what is projected) and oil futures markets (what traders will pay) tend to be low in the early years and higher in the future. So, rather than starting with a $100/bbl oil prices rising towards $120/bbl in the future (as was the case two years ago), CCUS project developers now confront a world of $40/bbl oil rising to roughly $70/bbl. Even if those forecasts prove correct, project developers face a financial challenge in the early years of operation. This makes borrowing difficult because lending decisions rely heavily on what a project will earn early on, rather than in later years.

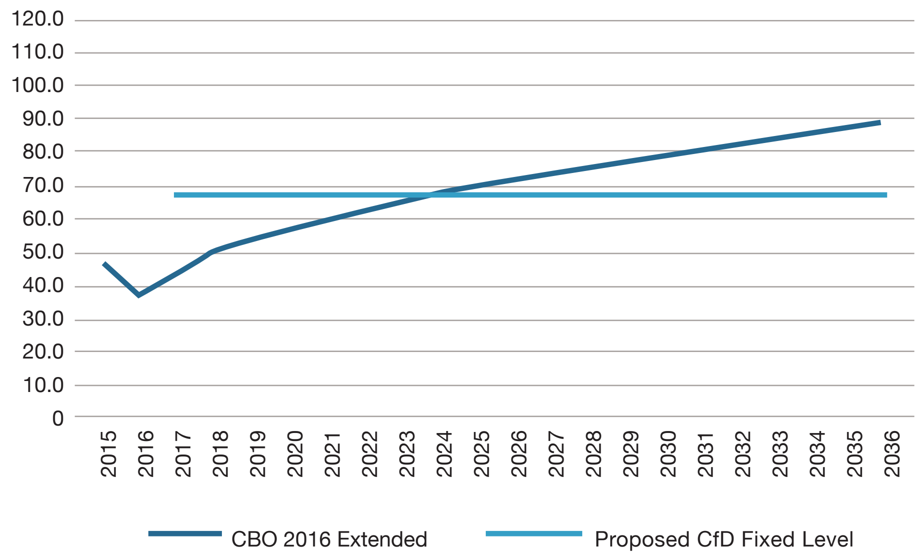
To address this challenge, the Work Group recommends establishing price stabilization contracts or contracts for differences (CfDs) for CCUS projects. At the writing of this report, a provision in the Senate Energy bill—the North American Energy Security and Infrastructure Act of 2016 (S. 2012)—directs DOE to study and report back to Congress how a program could be established to provide CfDs to CCUS project developers. This provision was offered and approved as bipartisan amendment (SA 3174).

A CfD intended to stabilize CO_2 revenue would provide a single uniform CO_2 price over the term of the contract by stabilizing the underlying oil price to which CO_2 prices are linked. CfDs are not designed simply to pay carbon capture projects an above-market high price in the low oil price world of today. Instead, a CfD approach would provide

9 A Capital Recovery Factor is a measure of the total dollars that will need to be generated, after all other cash expenses are paid, in order to cover cash taxes, principal and interest owed to lenders, and dividends and return of capital for the owners. So, a project that costs $100 with a CRF of 15 percent has to generate $15 of cash annually after all other cash expenses are paid.

10 Technically, a thousand cubic feet of CO_2 (1 MCF) is often priced at approximately 2 percent of the prevailing WTI price per barrel. Since 17.5 MCF of CO_2 weighs 1 ton, this works out to CO_2 priced per ton at 35 percent of WTI (2 percent x 17.5 = 35 percent).

FIGURE 7: CBO Forecasts vs. Proposed CfD Fixed Price



CCUS project investors a stable average CO_2 price that is fixed for the long-term. That average price would be based upon the U.S. government's own forecasts of future oil prices, such as the Congressional Budget Office (CBO) forecasts used to create the federal budget, or the U.S. Energy Information Agency's (EIA) forecasts. When oil prices are low (and hence oil-indexed CO_2 prices paid by EOR operators are low as well), the federal government would make up the difference to achieve the level fixed price. When oil prices are high (and oil-indexed CO_2 prices paid by EOR operators are high) the project would be required to give back any excess above the level fixed price.

Such a CfD program could be designed to be revenue neutral based on the government's own oil price projections. In other words, the total amount of money paid by the government in low-price years would be expected, based on the government's own forecasts, to be offset by the amount of money received by the government in high-price years.

Figure 7 below depicts the comparison between CBO forecasts for oil prices and a proposed CfD fixed price. Assuming a CfD began in 2017, with CO_2 prices indexed to a level $70 oil price, the government expects to be out of pocket in early years through 2024, and then expect to receive funds back thereafter—based on the CBO's own forecast. The actual calculation of the fixed rate in our example takes account of the government's cost of funds, using a four percent discount rate.[11] That means the CfD is designed to correct for the time-value-of-money problem of the government paying money out initially and having to wait several years before getting money back. Note that the CBO only publishes a 10-year forecast, so years 2027 and beyond are extrapolated for illustrative purposes.

Tax-Exempt Private Activity Bonds

The Work Group supports legislation introduced by Senator Michael Bennet (D-CO) and Senator Rob Portman (R-OH) that would make tax-exempt private activity bonds available to power and industrial facilities that capture CO_2 emissions and store them through EOR or other geologic storage.

The federal government allocates to states the ability to issue $33 billion of PABs annually, making the PAB market for tax-free bonds large, well-understood and accepted by financial markets and investors. An important current eligible application of PABs falls under the "solid waste exemption" in which tax-exempt bonds pay for facilities that treat the byproducts of coal plant emissions control systems, including ash from baghouses and gypsum from wet SO_2 scrubbers, but CO_2 is not a "solid waste", leaving

11 See Federal Reserve Statistical Release H.15 for government bond rates. The 30-year government bond rate yielded 2.71 percent as of April 27, 2016, so the 4 percent discount rate applied to positive and negative cash flows in the CfD fixed rate determination is reasonably advantageous to the government vs. the Treasury's actual borrowing costs. http://www.federalreserve.gov/releases/h15/update/default.htm

TABLE 4: **Private Activity Bonds vs. Other Debt Alternatives for Carbon Capture Projects**

	Long Maturities Available	Fixed Rate Available	Construction Risk OK?	Single Project Risk OK?	Sub-Investment Grade Ratings OK
Project Bond Market	Yes	Yes	Yes	Yes	NO
Insurance Private Placement	Yes	Yes	Yes	Yes	NO
Bank Term Loan	NO	NO	Yes	Yes	Yes
Foreign Export Credit Bank Loan	NO	NO	Yes	Yes	Yes
High Yield Bonds	NO	Yes	NO	NO	Yes
Term Loan B	NO	NO	NO	Yes	Yes
Tax Exempt PAB	Yes	Yes	Yes	Yes	Yes

carbon capture facilities ineligible the PAB market. Thus, if CCUS projects were allowed to participate, a long-term debt market for loans to CCUS projects will be created that can be expanded to accommodate the capture projects that will be needed as the industry matures and technology and project development costs are reduced.

PABs offer several advantages for debt structuring in a CCUS project. PABS do not conflict with the receipt of a federal grant, whereas projects that have received a federal grant are not allowed to use federal loan programs. In addition, PABs have limited fee payments until bonds are placed with investors, which reduces project development risk. PABs also offer a long-term incentive solution because, unlike DOE's loan program, they are not limited to the first few carbon capture projects involving a given technology, nor are they subject to a programmatically defined limit. Finally, the Joint Committee on Taxation in Congress has determined that CCUS projects could be made eligible for PABs at a very low fiscal cost to the Treasury.[12]

In practice, a developer of a carbon capture project would be pleased to get a federal loan and/or PAB financing, as compared to other less desirable alternatives presently available in the commercial debt markets. The table below lays out the challenges of commercial debt markets for carbon capture projects ("NO" marks issues that preclude entry into the particular market for a carbon capture project). Fundamentally, a carbon capture project:

i. Needs fixed-rate and long-term debt;

ii. Is unlikely to be investment grade (unless the price stabilization or CfD concept described elsewhere is executed); and

iii. Suffers both construction risk and single-asset project risk.

12 There are several reasons why PABs would be a low-cost CCUS incentive, with the most significant being stretched out depreciation deductions and smaller interest deductions for projects that use PABs. Also, the federal government does not authorize use of tax-exempt bond markets; rather it would be up to individual states to decide whether to prioritize CCUS projects with their existing annual allocation of PABs from the federal government. Each state is authorized to issue only a certain amount of PABs, based on state population, via a system called the State Volume Cap. PABs for CCUS facilities, however, like certain other types of PABs, will only require $1 of volume cap per $4 of PABs issued. Nonetheless, no PAB could be issued in a particular state for a CCUS project without specific state and local actions, all as set forth in current law dating back to the 1986 Tax Act.

Getting (i) from commercial investors despite (ii) and (iii) turns out to be virtually impossible, other than through either the PAB market or a federal loan.

Carbon Storage Tax Credits (Section 45Q)

The Work Group recommends that Congress extend and reform the current federal Section 45Q Tax Credit for Carbon Dioxide Sequestration, and legislation has been introduced in the U.S. House and Senate in 2016 to accomplish that, including Mike Conaway's (R-TX) Carbon Capture Act (H.R. 4622) and Senator Heidi Heitkamp (D-ND) and Senator Sheldon Whitehouse's (D-RI) Carbon Capture Utilization and Storage Act (S. 3179). Both of these bills, and a related Senate amendment (S.A. 3645), enjoy broad support and co-sponsorship from both political parties and from members in congressional leadership.

A more robust and improved 45Q tax credit would provide CCUS projects with the financial certainty needed to attract private investment, greater value in helping to close the remaining cost vs. revenue gap, and more flexibility to accommodate different business models, assisting project developers with little or no ability to utilize traditional tax credits.

Just as importantly, a revamped 45Q program would be responsive to growing concerns of policy-makers and the public over taxpayer accountability. As a functional equivalent of a production tax credit, 45Q is completely performance-based. This means that the tax credit can only be claimed for every ton of CO_2 that has been successfully captured, compressed, transported by pipeline and injected into an oilfield or other suitable geologic formation, thus protecting U.S. taxpayers by ensuring that public dollars only go to projects that accomplish the energy production and carbon storage purposes of the 45Q program.[13]

13 These are large fixed rate bond issues that do not require Securities and Exchange Commission (SEC) registration, by virtue of being offered only to large, sophisticated, Qualified Institutional Buyers (QIBs) pursuant to the SEC's Rule 144A. This is a big, liquid, attractive market, but a market that requires investment grade ratings from project credits (Baa3/BBB- or better).

Key Reforms Needed for 45Q

Given the deficiencies in the existing 45Q program, the Work Group supports current legislative efforts in Congress that, to varying degrees, would institute the following reforms:

- Extend and uncap the program, so that CCUS project investors would have the financial certainty and confidence that the tax credit and associated revenue will be available to them in the future once their project is successfully placed in service and begins capturing and storing CO_2;
- Increase the value of the tax credit to a level that helps close the cost gap and justifies private investment in CCUS projects;
- Specify that the entity claiming the tax credit is the owner of the carbon capture equipment and does not require the owner to be the day-to-day operator, thereby maximizing the flexibility of developers to involve outside investors that can easily utilize tax credits, while also enabling municipal or cooperative entities to benefit from this credit; and
- Reduce the eligibility threshold for industrial facilities and electric generating units to 100,000 tons of CO_2 captured annually to enable the participation of additional industries, expand the states and regions that benefit from the program, and eliminate unnecessary impediments to technology innovation.

Master Limited Partnerships

The Work Group recommends that Congress extend eligibility for MLPs to carbon capture projects in order to help reduce their cost of equity. The principal federal legislative effort to accomplish that is the bipartisan Master Limited Partnerships Parity Act introduced by Senator Chris Coons (D-DE) and Senator Jerry Moran (R-KS) in the Senate (S. 1656) and Representative Ted Poe (R-TX) and Representative Mike Thompson (D-CA) in the House (H.R. 2883).

This legislation seeks to expand the types of enterprises eligible to be treated as MLPs under the tax code. As described below, MLPs have a lower cost of equity than conventional corporations (called "C" corporations in the tax code). The reason for the lower cost of equity is that MLPs are not subject to "double taxation." With a lower cost of equity, a carbon capture project can successfully raise larger amounts of money from equity investors for any given stream of distributable cash.

An MLP combines the benefits of both a partnership and a corporation:

- A partnership is tax-efficient for investors. The partnership itself pays no tax. Instead, each partner receives a tax statement from the partnership showing the partner's pro rata share of the gains and losses of the partnership. When calculating its annual taxes, the partner combines those taxable gains and losses from the partnership with all its other taxable business activities. However, for a variety of state law and investor preference reasons, it is extremely difficult for a partnership (often a limited liability corporation or LLC) to successfully garner a listing on a major stock exchange. Therefore, a partnership is good for tax purposes, but not for raising money.
- A "C" corporation is tax-inefficient for investors. It creates "double taxation". First, if the company is profitable, it pays corporate taxes on its income. Then, with the remaining after-tax profit, it distributes dividends to shareholders. Then, if the shareholder is subject to tax, the shareholder must list that dividend on his personal tax return and pay tax again. However, profitable, growing corporations have an easy time financing growth by listing on a major stock exchange and selling shares to the public and institutions. Thus, in contrast with a partnership, a "C" corporation is bad for tax purposes, but good for raising money.
- An MLP combines the two worlds. Like a partnership or LLC, the MLP is a "flow through entity," never paying taxes itself and merely reporting tax information to its owners (typically called unit holders). Like a corporation, the MLP can list on a stock exchange and sell units to the public. Unit holders can trade in and out of MLP units in the same way as they trade shares of listed corporations.
- Since the MLP has the good points of both (tax-efficient and access to large public securities markets) investors demand a lower rate of return from an MLP, compared to returns demanded from ordinary partnerships or listed corporations.

Lower investor returns demanded means more money upfront to build projects. The amount of money an enterprise can raise is very much determined by its cost of equity capital. For example, a share or unit that pays $1.00 a year of dividends for fifty years is worth $9.91 if investors demand a 10 percent return, but only worth $4.99 if investors demand a 20 percent return.

Only certain types of business activities can be conducted by MLPs under current federal tax law. To retain tax status as a MLP, at least 90 percent of the MLP's income must be from "qualifying sources"—and qualifying sources have not included electric power projects of any type, whether renewable or fossil, with or without carbon capture.[14]

Some types of companies involved in carbon capture can be MLPs today, but without legislation, the situation remains murky. For instance, a fertilizer plant using natural gas to make fertilizer, and that separates out CO_2 in the process, would likely have 100 percent qualifying income. A natural gas power plant with carbon capture—which effectively makes two products, electricity and CO_2—likely would not because electric power sales is not a qualifying source. The desired change sought by current federal legislation is to amend the qualifying source definition to include both sales of electricity (energy, capacity, etc.) and byproducts obtained from gasification or post-combustion.

Ranking of Potential Policies by Priority

The description of each federal incentive above followed a commonsense order based on what role a particular policy tool plays in the capital structure of a project. Before presenting the results from modeling the financial impact of the various incentives, it is important to review the quantitative and qualitative factors that inform the prioritization of policies to be adopted. Looking forward using middle-of-the road forecasts by respected government and private energy market analysts, CCUS projects are primarily jeopardized by the lack of an adequate, stable income stream. And even if the project were to garner such an income stream, CCUS project development would remain constrained by the lack of

14 In general, "Qualifying income includes, among other things, income and gains derived from the exploration, development, mining or production, processing, refining, transportation (including pipelines transporting gas, oil or products thereof) or the marketing of any mineral or natural resource, as well as certain passive-type income including interest, dividends and real property rents." In turn, the term "mineral or natural resource" means "fertilizer, geothermal energy and timber, as well as any product from which a deduction is allowable, which includes oil, gas, and oil-and-gas related products. Typically, anything that is mined or pumped out of the ground qualifies, which includes coal, lignite, potash, salt, aggregates, limestone, sand and many other hard rock minerals." Excerpted from Master Limited Partnerships-101, Latham & Watkins LLP, accessed online November 3, 2016 @ https://www.lw.com/MLP-Portal/101#assettypes

efficient financing tools to turn that adequate, stable income stream into cash at financial closing.

Of the five policy tools discussed above, to narrow meaningfully the project feasibility gap, two out of the following three federal incentive policies would need to be adopted. By order of preference, they are:

i. **Reformed and strengthened Section 45Q tax credit;**

ii. **CfD or price stabilization mechanism; and**

iii. **Refundable ITC.**

These three tools would increase project feasibility, even without better debt and equity terms. Nevertheless, there are some major qualitative differences among these three tools.

Key Criteria for Prioritizing Federal Incentive Policies: 45Q, CfD and Refundable ITC

The Work Group used the following criteria to prioritize the first three recommended federal incentive policies:

- **General applicability vs.** one-off selection process. Section 45Q tax credits would be universally available to any industrial or electric industry carbon capture project meeting minimum criteria and capable of commencing construction prior to the applicable statutory deadline—it is a tax credit of general applicability that does not require an application to a federal agency to secure approval under a particular federal program. Similarly, the CfD is conceptualized as a broadly available program for industry participants. This would make both the 45Q and CfD programs broadly more stimulative than a program such as the Administration's proposed refundable ITC for electric generation capture projects that has a fixed dollar cap, prescribed subcategories and would require an application for approval.

- **Broad, bipartisan political support.** Section 45Q has considerable momentum, being broadly sponsored in the House and Senate by members from across the political spectrum and every region of the country and supported by senior congressional leaders in both chambers. The CfD concept has been vetted in policy circles, has many domestic, foreign, and capital markets analogues, and DOE has been directed to study the concept in the current Senate energy bill now in House-Senate conference. While the Administration's proposed ITC in both the FY 2016 and 2017 budgets has made a major contribution to elevating interest in and support for federal CCUS incentives, there is political opposition to making a tax credit refundable, despite the inherent attractiveness of refundability to CCUS project developers.

- **Likely cost to the Treasury.** The working group recognizes the importance of public investments in CCUS technology but also understands the need to be fiscally responsible and keep costs to the Treasury on par with the public benefits received. Two of the proposals have been scored fiscally, with the Section 45Q likely in the approximately $1.5-3 billion range (depending on the House and Senate versions), and the refundable ITC scored at $2 billion. However, the 45Q score is for a program applicable across industries that can capture CO_2 (not just electric power generation), whereas the $2 billion ITC is sufficient for only a few projects. For its part, a CfD program, if structured to set a contract price at the average of the government's own oil forecasts, could score quite low, despite being a powerful incentive for project development.

- **Impact across the entire capital structure versus limited impact.** If properly constructed, the CfD is likely to have positive impacts on many fronts. Recall that the CfD is not designed to raise the total lifetime income of the project, but rather to average the same dollars into a stable, predictable revenue stream. The revenue predictability means the project can obtain significantly more debt because it will not have to show feasibility in worst case market scenarios. Eliminating worst case scenarios lets the project secure a more cost-effective financing package, using more of the less costly debt and allowing the more expensive equity component of project finance to shrink. At the same time, since the project's earnings will be more stable under the CfD contract, it will garner higher credit ratings and pay lower interest rates. Finally, more predictable revenues and better debt also means a more predictable residual stream of income for stockholders, thereby opening up new investor markets to carbon capture projects. By contrast, though the ITC shrinks the total amount of capital needed, likely being a dollar-for-dollar reduction in equity, it has no direct impact upon debt. Similarly, the 45Q credit is good for equity, but provides no extra cash flow to service debt or to pay operating expenses in a stress situation. Hence, on this criterion, a CfD approach is far superior to the other two.

Role of PABs and MLPs

In addition to the three priority policy tools just discussed, the Work Group's analysis shows that CCUS projects need to tap more attractive and efficient sources of equity and debt. Though better debt and equity tools for project deployment are insufficient by themselves, making carbon capture projects eligible for PABs and allowing them to be set up as MLPs can magnify the beneficial impacts of other policies. For example, the stable revenue stream resulting from a CfD contract helps a project get more and lower cost debt, but the addition of PABs provides access to ultra-low interest rates and very long maturities, thereby increasing the benefit.

PABs and MLPs also help build a long-term foundation for the industry because these tools represent efficient finance mechanisms available to all qualifying industry participants, without a sunset or binding limit.[15] PAB and MLP policies will continue to provide benefits to the industry long after other incentives programs such as 45Q or CfDs may have lapsed or been reduced. Both have been scored fiscally, with the PAB legislation costing only an estimated $128 million over a 10-year period according to Congress' Joint Committee on Taxation. Similarly, the entire MLP Parity Act, which includes wind, solar, batteries, and a host of other alternative energy sources, scored at just $1.3 billion, and only a small part of the legislation's fiscal score relates to carbon capture. Thus, these two policies should be viewed as cost-effective, long-term and complementary to and reinforcing the benefits of 45Q tax credits, CfDs and refundable ITCs.

15 Most PABs are subject to annual limitations in volume under the "State Volume Cap Allocations." However, the current legislation requires only $1 of volume cap allocation per $4 of debt, so the PABs for carbon capture projects would be much less burdened by volume cap issues than other types of private activity bonds might be.

Conclusions Regarding Prioritization

The quantitative analysis shows that individually, any one of the three major incentive policy tools—45Q tax credits, CfDs, or ITCs—could have an impact that closes 40-50 percent of the funding gap in carbon capture project feasibility. However, on the basis of a qualitative evaluation, extending and reforming the Section 45Q tax credit and establishing a federal CfD program merit prioritization over enactment of a refundable ITC for the purposes of fostering CCUS deployment. Finally, relatively less costly PABs and MLPs offer strong reinforcement to an incentive package and provide a final boost to achieve financial viability for carbon capture projects.

Analyzing the Impact of Federal Policy Changes

THE WORK GROUP RELIED ON TWO TYPES OF ANALYSES to evaluate the impact of federal financial incentives on the financial feasibility of commercial CCUS deployment.

First, project level analysis was undertaken to evaluate a typical power plant's operations, additional costs for carbon capture and CO_2 revenues to find out whether and to what degree proposed incentives improve the financial feasibility of a carbon capture project. This method provides a detailed view of any gaps there might be in reaching financial close, and it also helps us understand how much impact on dollar basis each incentive has at a project level.

Second, the Work Group reviewed macro-level industrywide analyses prepared by the U.S. Department of Energy (DOE) with the National Energy Modeling System (NEMS).

Both the project and macro-level analyses reveal similar insights and help confirm the value of federal CCUS deployment incentives recommended in this report.

Finally, available funding limited the Work Group's analysis of deployment to power plants. However, one can assume that the modeled deployment impacts of incentives would be even more favorable for a number of industrial sectors that feature high-purity sources of CO_2 and lower costs of carbon capture, such as natural gas processing or ethanol production.

Project Level Analysis

OVERVIEW OF MODELING PURPOSE AND RESULTS

This section describes the project-level analysis undertaken to determine what combination of the five policy tools described in the prior section would help finance successfully a carbon capture retrofit of an existing power plant, with a retrofit being the relevant case since there is so much existing fossil fuel coal and NGCC capacity. Detailed results from the modeling can be found in Appendix A.

The first basic conclusion is that *without any incentives,* given current carbon capture capital equipment costs, low revenues from CO_2 sales (because oil prices are low), and no regulatory requirement to use CCUS, carbon capture facilities will not be feasible for a private investor. Note that this is different than saying "CCUS is too expensive." CCUS may well be a very cost-effective means for society to reduce CO_2 emissions, relative to other technologies, while at the same time failing to provide adequate cash to reward a private owner's investment. Given current oil prices, especially since lenders use even lower "sensitivity prices" to establish size of a projects credit lines, it is likely no debt can be obtained (without some incentive). Some equity can be obtained, depending on the degree of optimism inherent in an investor's price view—but nowhere near enough to reach financial close on a project.

The second basic conclusion is that, *if we add incentives*, it is likely to take a number of the options presently under consideration to close the financial gap. A properly crafted package of incentives must address the needs of different capital providers—lenders only like cash, whereas owners/stockholders like tax incentives. Lenders are extremely worried about commodity risk avoidance, whereas owners/stockholders are more optimistic. Some incentives work not by changing cost of debt or equity, but rather by permitting a higher proportion of the relatively cheaper debt to be used in creating the proposed project's balance sheet.

MODELING METHODOLOGY

The Work Group utilized a simplified model built by Stanford University for this report, with that simplified model having been extracted from Stanford's more detailed project finance models of the same technologies, prices, and incentives. All scenarios assumed the lack of a regulatory mandate to use carbon capture and the lack of a market-derived price for CO_2 that might result from a regulatory requirement to reduce carbon emissions. To simplify the analysis, all results were scaled down to a unit size of one ton captured per year.

Since the incremental asset being financed is the capture plant only, modeled scenarios require a carbon capture plant to survive solely on sales revenues from CO_2 sold to the oil industry, plus any government policies designed to enhance project feasibility.[16] The basic economic unit examined is a post-combustion capture unit at a conventional coal or natural gas power plant, with capital costs of \$300 per ton of annual carbon dioxide capture capacity (\$300/tpyc). So, a plant that can capture 2 million tons per year of CO_2, with equipment cost of \$300/tpyc, needs to raise \$600 million. The model sums present values of all costs, revenues, payments to debt and equity, tax credits, and taxes to generate the theoretical value of the project on the day of financial closing. On the day of financial closing, the project needs to raise \$300/tpyc to build the plant. If the project can raise more than the needed \$300/tpyc, it is financially viable and can be built; it the project can't raise the \$300/tpyc, it will be abandoned.

In a profitable business, operating revenues are higher than operating costs, leaving an operating profit. That operating profit can be used to pay back principal and interest on loans and to pay dividends to shareholders.

By contrast, in the current world of CCUS, when adding a carbon capture system to an existing power plant, it turns out that operating revenues (from sale of captured

16 In a different world, the assumptions might be different. For instance, if a coal plant were extremely profitable, as it might be in a world where the coal fuel costs were \$20 per MWh and gas fuel costs were \$50 per MWh, while at the same time that profitable coal plant was being forced to shut down because of lack of CO_2 emissions compliance, then the coal plant owner would be happy to pay a large ~\$30/MWh service fee to the CO_2 capture equipment owner. However, coal plants today are struggling to compete with gas plants on a straight cash cost of production basis (both coal and gas plants have variable production costs in the ~\$20-\$25/MWh range) and there is no operative federal CO_2 reduction mandate for existing plants.

CO_2) just manage to cover operating costs (parasitic power consumption, wear and tear, and replacement of chemicals). For example, even using today's NYMEX strip prices for oil, CO_2 sales revenues are estimated at about $20/ton vs. operating costs of $18/ton. Thus, there is almost nothing left to repay the lenders and stockholders who paid for the capture facility.

Thus, the goal of various policy incentives is to create a combination of cost-effective incentives that can supplement cash flows to the point of satisfying providers of capital.

MODEL SCENARIOS WITHOUT INCENTIVES

Based on the modeling undertaken for the Work Group, oil prices alone will not drive commercial CCUS deployment. Table 5 below summarizes Scenarios A through D from the model. In these scenarios, oil price forecasts are varied, but there are no additional policy incentives. None of these scenarios generates the $300/tpyc at financial closing that would be required to build a plant. Note that lenders are not required to use the same forecasts as equity investors. Lenders universally opt to use a more conservative forecast than the NYMEX futures (resulting in not much debt being raised for a CCUS project today), while the equity investors use a more middle-of-the road forecast—hence Scenario A below that uses NYMEX futures prices to estimate amount of debt is too aggressive and is for reference only. The forecasts referred to in the table—the NYMEX futures strip, the Lender Survey Stress Case, the CBO's forecast, and the U.S. EIA Annual Energy Outlook forecast—show 2020 WTI prices per barrel of $56, $41, $56 and $78, respectively. Obviously, the U.S. EIA forecast is the outlier, but even if potential stockholders used that forecast, less than half the required funds could be raised.

The key results of these no incentives cases are portrayed graphically below (Figure 8). The red bar portrays the funding gap for each case.

Model Scenarios with Various Incentives

It is possible to close the gap with a carefully crafted package of incentives. Table 6 shows a combination of incentives being used. In all cases that lack a stabilizing CfD, the Lender's Stress Case was used to estimate maximum potential debt raised and the CBO's oil forecast was used as a baseline oil price view for equity (Scenarios D & E). Of course, if a CfD is executed (Scenarios F, G & H), then the future oil price is known, and the CfD price is used by both debt and equity. The conclusions suggested by this table are as follows:

- The three most powerful tools in contributing to reaching the $300/tpyc goal are the refundable ITC, the reformed and strengthened Section 45Q tax credit, and a CfD program for price stabilization. Two of these three tools would be needed to get close to attaining the goal (e.g., Scenarios F & G). Scenario E, with only a refundable ITC,

TABLE 5: Capital Cost vs. Funds Raised—No Incentives

	Oil prices used for debt calculation	Oil prices used for equity calculation	Funding gap vs. target of $300/ tpyc
Scenario A	NYMEX (too aggressive)	NYMEX	**$260 gap**
Scenario B (BASE)	Lender Sensitivity[a]	NYMEX	**$268 gap**
Scenario C	Lender Sensitivity	CBO[b]	**$255 gap**
Scenario D	Lender Sensitivity	USDOE/EIA[c]	**$184 gap**

a Quarterly Energy Lender Price Survey for Q2, 2016, Macquarie Capital, undated. http://static.macquarie.com/dafiles/Internet/mgl/com/energy-ad/publications/energy-lender-price-survey/2016Q2.pdf?v=5

b An Update to the Budget and Economic Outlook: 2016 to 2026, Congressional Budget Office, www.cbo.gov/publication/51908, Tab 2. Calendar Year, Refiners' Acquisition Cost of Crude Oil, Imported. (WTI not supplied at mid-year update.)

c Annual Energy Outlook 2016, US Energy Information Agency, downloaded May 17, 2016, ref 2016 d032316a, reference case WTI in nominal $.

offers insufficient incentive; but Scenarios F and G, each of which combine two strong incentives, move projects close to closing the gap, with Scenario F showing $0.50 ahead and Scenario G a small gap of $5.75/tpyc, respectively.

- If there is strong cash flow available for debt (based on the CfD), plus storage tax credits (45Q) for equity, then the tools that lower the cost of debt (PABs) and lower the cost of equity (MLP status) produce even more money up front from the identical cash flows and tax credits (e.g., Scenarios H and I). Given the current CBO forecast being used for CFDs, Scenarios H and I actually bring the project well over the $300/tpyc goal line; but we would caution against viewing that result as evidence of excessive support. The most recent Section 45Q legislative proposal has a hard sunset date, and any DOE CfD program would need to be renewed. The PAB and MLP tools could be viewed as the longer-term underpinnings of the industry, even if other programs expire later on.

The key results of these incentivized cases are portrayed graphically in Figure 8. Each scenario shows the contribution of each policy to closing the financial gap. As the graph shows, there are a number of policy combinations that could successfully reach the goal line (i.e., the red bar disappears and the total of funding available exceeds the height of the "Capital Cost" bar).

FIGURE 8: Capital Cost vs. Funds Raised—No Incentives

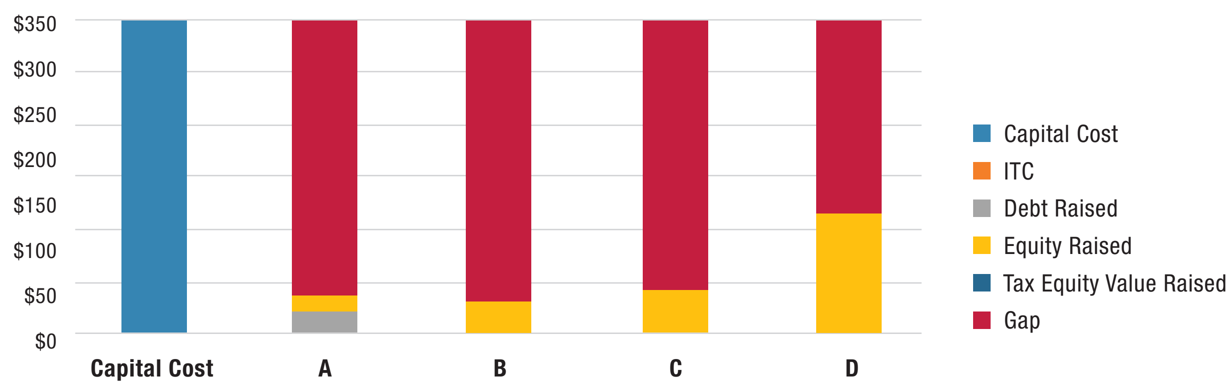
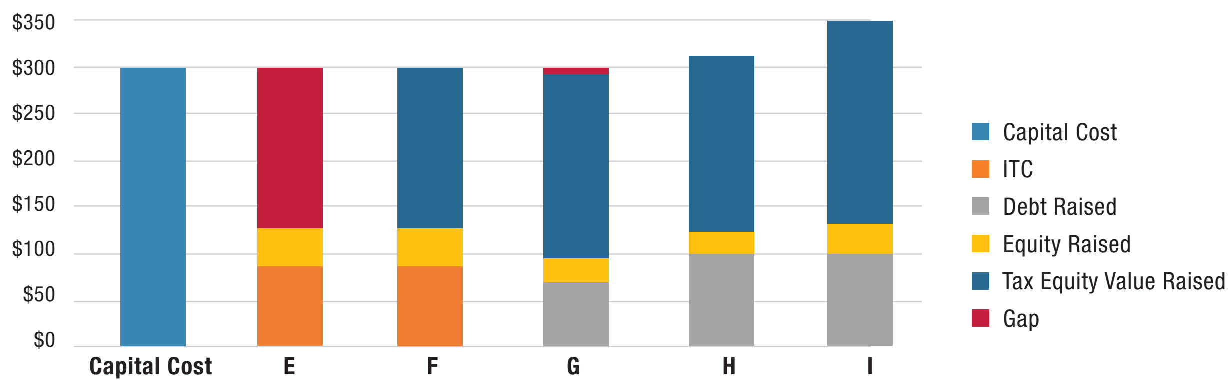


TABLE 6: Summary Table of Incentivized Price Scenarios[a]

	Refundable ITC	CfD for Stabilization (at present value of USIEA forecast)	Private Activity Bonds	45Q Tax Credit @ $35/ MT for 12 years	Full MLP Eligibility	Funding gap vs. target of $300/tpyc (figures in parentheses are a shortfall)
Scenario E	YES	—	—	—	—	($172.15)
Scenario F	YES	—	—	YES	—	+$0.50
Scenario G	—	YES	—	YES	—	($5.75)
Scenario H	—	YES	YES	YES	—	+$17.17
Scenario I	—	YES	YES	YES	YES	+$52.16

a Scenarios E and F use the same price configurations as Scenario C (Lender Stress for Debt and CBO year-by-year forecast for equity). Scenarios G, H and I all have CfDs and use CfD fixed price—a contractual number rather than a forecast for both debt and equity.

FIGURE 9: Capital Cost vs. Funds Raised with Incentives



Macro-level analysis

MODELING OVERVIEW AND RESULTS

The Work Group reviewed macro-level, industrywide NEMS analysis prepared by DOE. Due to the nature of the model employed and different assumptions, DOE's results are more favorable regarding the impact of federal financial incentives on carbon capture deployment than the micro-level project modeling undertaken for the Work Group by Stanford University. For example, DOE's modeling of an extended and strengthened Section 45 Tax Credit at $35 per metric ton for EOR storage and $50 per metric ton for saline storage (as in S. 3179 introduced by Senator Heitkamp) results in just over 50 million MT of annual CO_2 capture coming on line by 2030, or about 10 GW of power plant carbon capture capacity installed.

For a description of DOE's NEMS modeling methodology and more detailed results, please see DOE's recent white paper entitled, *Carbon Capture, Utilization and Storage: Climate Change, Economic Competitiveness, and Energy Security.*[17]

17 Carbon Capture, Utilization and Storage: Climate Change, Economic Competitiveness, and Energy Security, U.S. Department of Energy, 2016, pp. 8-10.

Complementary State Tax Incentives to Spur Development of Carbon Capture, Utilization & Storage

Background

THIS CHAPTER FOCUSES ON THE STATE POLICIES THAT affect the economics of the value chain that stretches from the capture of CO_2 from industrial and power plant sources through to utilization and associated geologic storage of CO_2 through EOR.

The following section summarizes the recommendations of the Work Group regarding state taxation of CCUS activities. While changes to federal policy will have the biggest overall impact on commercial CCUS deployment, state policies can play an important role in complementing federal policy to help projects cover the cost gap and reach financial close.

Scope of Work

There are three broad categories of policies that states have implemented to provide financial support for CCUS:

1. Changes in state taxes that provide incentives for the capture of CO_2 from power plant and industrial sources, and/or for the use of captured CO_2 to produce oil through EOR;

2. State portfolio requirements and mandatory power purchase or offtake agreements for power plants and facilities that have carbon capture; and

3. State regulatory and other policies and strategies to facilitate CO_2 storage, project development and pipeline transport.

For the purposes of this initial report, the Work Group focused on the first category of tax policy and sought to understand the degree to which state tax policy can influence commercial CCUS project deployment. The Work Group will address the second and third topics at a later date.

Summary

Analysis done for the Work Group suggests that states, in conjunction with improved federal policy, can positively affect the overall feasibility of CCUS projects by optimizing a suite of traditional taxes common to most oil and gas-producing states. Indeed, the Work Group finds that relatively modest changes to a wide spectrum of relevant tax policies can have a large beneficial impact and may appeal to states with a long-term interest in development and use of their energy resources. This report frames these state policies as "complementary" to federal policies because, compared to individual states, the federal government can offer relatively more support in the form of incentives for commercial CCUS projects in the current environment of low oil prices and high capital costs.[18] However, even in the context of robust federal policies, unfavorable state tax policies could hinder an otherwise feasible project.

The economic context, analytic approach and conclusions regarding the impact of state tax policies described in this section of the report are summarized as follows:

- The economic "value chain" of CCUS addressed in this report encompasses the capture of anthropogenic CO_2, oilfield injection of the CO_2 for EOR, and the pipeline infrastructure to transport the CO_2 in between. These individual components of the value chain sometimes operate independently; in other cases, the entire value chain is owned by a single integrated operator.

- To determine the feasibility of projects, CO_2 capture operators tend to look at *CO_2 prices* (which are often directly linked to oil prices), whereas the EOR operators look at *oil prices*. At current costs and product prices (of both CO_2 and oil) there is an economic gap at both the capture and oilfield ends of the value chain that needs to be addressed by incentives:

  - Total CO_2 capture costs (fixed capital, fixed operating, variable operating, tax and insurance) are about \$60/ton CO_2 in the power sector.[19] Current revenues earned by a capture plant through the sale of captured CO_2 to EOR operators (generally indexed to oil prices) are on the order of \$15-20/ton, leaving a ~\$40-45/ton CO_2 price gap.

  - CO_2-EOR revenues based on ~\$40-50/bbl oil are too low to commence new CO_2 floods with the likely break-even level nearer to the \$70-80/bbl area, hence a ~\$30/bbl oil price gap.

- Using CO_2 prices as a metric, a number of different types of incentives being actively considered on the federal level have incentive benefits that could reduce the ~\$40-45/ton gap on the carbon capture side by \$5-\$20 per ton of CO_2, depending on the particular incentive.

- The Work Group examined state tax policies relating to the two most capital intensive portions of the CCUS value chain, the carbon capture system and the CO_2-EOR operation.

18 Carbon capture technology has existed and has been used in non-power industrial applications for decades, but the commercial-scale application of capture technologies to commercial coal and natural gas power plants, is new and faces high capital costs. With relatively few working examples in the field, designs have not been standardized and the supply chain is inefficient.

19 This is a general cost estimate based on typical costs for retrofit of a modern, reasonably efficient pulverized coal plant with a solvent-based post combustion capture system that is operating at a reasonably high capacity factor.

- In the aggregate, it appears that the combined impact of adopting the most favorable structures and rates of the various taxes levied by states could be on the order of:
  - ~\$4/ton of CO_2 for a standalone CO_2 capture operation;
  - ~\$5/bbl for a standalone CO2-EOR operation; and
  - ~\$8/bbl for an integrated operation that owns both capture plant and oilfield.[120]

Review of and Need for Incentive Mechanisms

The particular state taxes reviewed by the Work Group are:

i. Sales taxes on equipment purchased to build a carbon capture facility;

ii. Property taxes on the carbon capture facility;

iii. Sales taxes on equipment acquired to adapt an oilfield to CO_2-EOR operations; and

iv. Oil and gas taxes, such as production and severance taxes.

In addition, a research team has assembled an inventory of existing state CCUS policies, including these four different types of state taxes. This inventory will provide state-by-state detail to supplement the general recommendations in this report, as well as help inform comparative analysis of policies by interested state agencies or legislators.

Since oil prices are the principal and most volatile determinant of the feasibility of both carbon capture plants and CO_2-EOR operations, analysis undertaken for the Work Group quantified the disparate impacts of different tax policies in terms of equivalent changes in oil prices. This analysis examined potential profitability for a CCUS project developer in cases where all four taxes were set at the high-end of the typical range across states vs. when all four taxes were set at the low-end of that range—following the model of states that have sought to promote CCUS deployment.

TABLE 7: State Tax Policies

	High Tax	Low Tax
Sales tax on capture equipment	8%	0%
Property tax on completed capture plant	1%	0%
Sales tax on CO2-EOR equipment	8%	0%
Severance tax on oil value	5%	1.25%
WTI price/bbl to reach economic feasibility	\$69/bbl	\$61/bbl

Based upon full life-of-project economic modeling of both the carbon capture and oilfield sides of the CO_2-EOR business, it appears that certain targeted reductions in state taxes can have a beneficial impact to CCUS project feasibility that is economically equivalent to roughly an \$8 per barrel increase in oil prices. This is considerable when compared to impacts of current federal incentives. A rule of thumb is that one ton of CO_2 injected will conservatively yield an incremental two barrels of oil. The current federal Section 45Q tax credit is \$10 per metric ton of CO_2 stored, thus about \$9 per ton of CO_2. Using the 1:2 ratio, that particular federal incentive would be \$4.50 per barrel of oil produced.

In all cases, the types of state tax changes considered by this analysis are in line with existing precedents. For instance, many states exempt pollution control equipment from sales taxes, so why not CO_2 capture equipment? As another example, many states have lower oil taxation on secondary and tertiary oil recovery operations, providing a rational to treat CO_2-EOR operations similarly.

In the four subsections that follow, we summarize each tax, its economic value, the rationale for considering lightening the tax burden on CCS-related activities or property, some examples of state policies, and the individual impact of changes in the particular tax.

20 In an integrated operation, there is no 3rd party sale of CO_2, and the only revenues come from oil sales. All the CO_2 captured by the capture operation and sold (revenue for the capture plant) is offset as a cost to the EOR operation. Thus, incentives for an integrated operation really should be considered in the context of equivalent oil prices.

EXAMPLE OF IMPACT OF SALES TAXES ON CAPTURE EQUIPMENT

- Total installed cost at capture plant of $300 per ton of annual carbon capture capacity (referred to as $300/tpyc).
- Of the $300/tpyc, approximately $150/tpyc is likely to represent sales-taxable equipment. Costs such as construction labor, engineering, or interest during construction (all of which are part of the $300 total) are not typically subject to sales taxes.
- If the tax rate were 8 percent, the upfront cost would be increased by $12/tpyc ($150/tpyc x 8 percent sales tax rate).
- If the annual combined financing cost of debt and equity is 10 percent, then the sales tax paid upfront would create the need for an extra $1.20 per annual CO_2 ton captured ($12 upfront cost added to total funds raised x 10 percent annual financing rate).
- Since current CO_2 prices are in the range of ~$15-20/ton, this $1.20 is not an insignificant amount.
- Since a typical CO_2 pricing formulation might be CO_2 price per ton = ~35 percent of oil price, then oil prices might need to rise $3.43 per bbl to make CO_2 prices rise $1.20 per ton in order to cover the annual cost of the extra money raised to pay sales tax when the capture plant was built.

State Sales Taxes on Carbon Capture Equipment

Many states impose sales taxes on the purchase of equipment used in manufacturing and utility operations. In those states, the purchase of carbon capture equipment for a power plant or industrial facility is taxed at more or less the same rate as retail sales taxes levied on purchases by individual consumers.

In terms of amounts involved, in keeping with the earlier examples of federal tax policy, the Work Group looked at the assumption of a carbon capture operation that costs $300 per ton of annual CO_2 capture capacity.

It is not unreasonable or unprecedented to consider such a targeted sales tax exemption. For example, many states have exempted from sales tax the purchase by utilities of equipment such as sulfur dioxide scrubbers for coal-fired power plants with the rationale that, rather than new equipment bought for a lucrative business venture, this equipment represents a pure cost to utilities and ratepayers imposed by changes in environmental law. So, it may be politically palatable to create similar exemptions for CO_2 following the same line of argument.

Actual practice varies across states. Some states have exemptions specifically for CO_2 capture equipment. For example, Texas enacted H.B. 469 in 2009 to provide a complete sales tax exemption for all equipment used to separate, capture, transport and geologically inject CO_2.[21]

Many other states have similar exceptions intended to apply to air pollution equipment, though the exact rationale, mechanisms, and applicability varies:

- Some states exempt any equipment installed to control emissions of a substance that federal or state law treats as a pollutant (Mississippi and Indiana), and Kansas has a similar law, but a project must apply for the actual exemption;
- Others exempt equipment that is designed to remove pollutants that are harmful to the health of the state's citizens (Kentucky);
- North Dakota has a sales tax exemption for capture equipment at oil refineries and gas processing plants, but not power plants;
- Others exempt equipment financed with tax-exempt pollution control bonds (California, though not relevant unless Congress authorizes the use of federal private activity bonds for CO_2 capture projects);
- Still others exempt all utility equipment; and finally,
- Some states, such as Nebraska and New Mexico levy full state sales taxes on all power plant and pollution control equipment (presumably including CO_2 capture equipment).

A pro forma model prepared for the Work Group estimates that imposing an 8 percent sales tax versus 0 percent sales tax (an exemption for CO_2 capture equipment) lowered the annual returns on equity to a standalone carbon capture project by approximately 1 percent, with all other factors remaining constant. Again, in the context of

21 Tex. Tax Code Ann. §151.334, "Components of Tangible Personal Property Used in Connection with Sequestration of Carbon Dioxide. http://www.statutes.legis.state.tx.us/Docs/TX/htm/TX.151.htm

EXAMPLE OF IMPACT OF STATE & LOCAL PROPERTY TAXES CARBON CAPTURE PLANT

- Total installed cost at capture plant of $300 per ton of annual carbon capture capacity (referred to as $300/tpyc).
- Property taxes are typically applied against the full value of the industrial plant, i.e. the entire $300/tpyc.
- If the annual tax rate were 1 percent, the annual cash operating costs would be increased by $3/tpyc.
- Since a typical CO_2 pricing formulation might be CO_2 price per ton = ~35 percent of oil price, then oil prices might need to rise $8.57 per bbl to then make CO_2 prices rise $3.00 per ton in order to cover the annual property tax bill.

the financial decision of whether to build a carbon capture facility, this is meaningful because such decisions are often ruled by some minimum financial return rate, often called a "hurdle rate." If the projected return on the project falls below the hurdle rate, the project is not undertaken.

State & Local Property Taxes on Operating Carbon Capture Plants

Many states (and localities subject to the constraints of each state's constitution) impose property taxes on the value of real property, typically including the full value of land, buildings, and equipment. Equipment used in manufacturing is commonly taxed at some version of depreciated cost or replacement value. Sometimes property taxes are subdivided between portions that secure government borrowing, and cannot be forgiven or mitigated, versus those portions that provide general government revenues and can be forgiven or mitigated.

In terms of amounts involved, in keeping with the earlier examples on federal tax policy, the Work Group looked at the assumption of a carbon capture operation that costs $300 per ton of annual CO_2 capture capacity.

There is precedent for considering such a targeted property tax exemption. As with sales taxes on pollution control equipment (as defined under the particular state law), many states have also exempted from property tax the installed property value of items such as sulfur dioxide scrubbers for coal-fired power plants. Again, the rationale is that rather than being new equipment bought for a lucrative business venture, this equipment imposes a pure cost on utilities and ratepayers due to changes in environmental law. Another consideration may be that the addition of CCS equipment to an existing plant, such as a large coal plant located in a rural county, may turn out to be a critical factor in keeping the host coal plant running, thereby preserving the property tax revenues of the host coal plant, even if the capture plant is exempted. Thus, it may be politically feasible to create property tax exemptions for CO_2 capture equipment similar to those on other pollution control equipment based on the same general argument.

As with sales taxes on capture equipment, actual practice varies across states, with some states giving specific exemption, others providing exemptions for "pollution control", some limiting exemptions to state or federally-mandated pollution control, and others giving no exemption:

- Texas, has specifically made carbon capture equipment eligible to receive ten-year abatements of property taxes with approval of the government of the county in which the capture plant is located, and Montana has a specific 50 percent reduction for CO_2 capture equipment;
- Some states appear to exempt specific facilities without specifically naming them, such as North Dakota (coal conversion facilities such as Dakota Gasification) or Mississippi (Mississippi's Kemper power plant); and
- A number of states categorically exempt or permit local exemptions for state or federally-mandated pollution equipment (with the open question being whether CO_2 controls fit under the relevant statutes), including Alabama and Ohio (for "air pollution"), Arkansas (for state-required equipment), and Indiana (provided required by local, state, or federal regulations).

The pro forma model prepared for the Work Group estimates that imposing a 1 percent annual property tax versus 0 percent property tax (an exemption for CO_2 capture plants) lowered the annual returns on equity to a standalone carbon capture project by approximately 2.5 percent, all other factors remaining constant. It is worth noting that in some states that have relatively low or no personal or corporate income taxes, property taxes tend to be relatively high, sometimes approaching 2 percent. Hence, the absolute dollars involved can be very large—a $600 million value carbon capture plant (2 million tpyc) could be paying $12 million per year in property taxes, if not exempted.

Again, in evaluating whether to build a particular carbon capture facility, this 2.5 percent equity return differential is important because of the minimum financial return rate, or "hurdle rate", that governs such decisions. If the projected return falls below the investor's hurdle rate, the project is not undertaken.

State Sales Taxes on CO_2-EOR Equipment

Many states impose sales taxes on the purchase of equipment used in virtually every industry. In some states there is a "manufacturing exemption" on equipment going into a factory that makes goods. However, extractive industries, such as oil and gas production or mining, are generally not treated as "manufacturing."

In terms of amounts involved, in keeping with the earlier examples on federal tax policy, the Work Group examined a CO_2-EOR operation producing approximately 4 million bbl per year and injecting approximately 2 million tpy of purchased CO_2 using an installed plant worth $400 million. Thus, its upfront cost was approximately $100 per annual barrel. These are illustrative figures and not intended to be exact.

EXAMPLE OF IMPACT OF SALES TAXES ON CO_2-EOR EQUIPMENT

- Total installed cost of surface equipment (such as oil, water, and CO_2 separation), pumping, revamped wells, etc. assumed to be $100/bbl of annual oil production capacity.
- Of that $100/bbl per year of capacity, approximately 75 percent or $75/bbl per year is likely to represent sales-taxable equipment. Costs such as construction and oilfield labor are not typically subject to sales taxes.
- If the sales tax rate were 8 percent, the upfront cost would be increased by $6/bbl per year ($75/bbl per year x 8 percent sales tax rate).
- If the annual combined financing cost of debt and equity is 20 percent (the oilfield typically has little debt and very high equity costs), then the sales tax paid upfront would create the need for an extra $1.20/bbl per year.

Sales taxes are often abated with a so-called "manufacturing exemption" in various states based on the premise that sales taxes are ultimately paid by final consumers of goods and that previously taxing purchases of equipment or raw materials used at factories therefore amounts to double taxation. However, states often exclude extractive industries from such manufacturing exemptions. Here are a few examples of the varied tax treatment of equipment used for CO_2-EOR:

- Some states have a manufacturing exemption, but have interpreted the exemption to exclude the upstream oil industry, including Oklahoma, Pennsylvania ("predominant use" must be manufacturing), and Mississippi; and
- Arkansas has an exemption that appears to recognize machinery used for "extracting" oil, as does Kentucky.

States may wish to consider a targeted sales tax exemption for equipment used for injection and recycling of CO_2 in secondary or tertiary oilfield operations, given that CO_2-EOR resembles manufacturing in terms of a long-term commitment of large amounts of capital. The same rationale for could also apply to other alternative injectants used to increase oil production, including water, steam, nitrogen, caustics, surfactants, and polymer compounds. However, non-CO_2 injectants do not provide the additional public benefit of anthropogenic CO_2 capture and storage offered by CO_2-EOR, which might serve to distinguish CO_2 from other tertiary methods.

A pro forma model prepared for the Work Group estimates that imposing an 8 percent sales tax versus 0 percent sales tax (an exemption for CO_2-EOR equipment) lowers the annual returns on equity to a standalone CO_2-EOR operation by approximately 0.5 percent, all other factors remaining constant.

State Taxation of Oil and Gas Production

Most states impose taxes, often above and beyond normal corporate income or franchise taxes, on production of oil and gas, coal, and other types of mining and extractive industries. The particular nomenclature varies widely from state to state, but the typical taxes are based upon some percentage of wellhead value of oil and gas produced, often with adjustments for non-state severance taxes or royalties. However, some states, like California, instead impose a state property tax upon the value of reserves in the ground.

In many examples reviewed for the Work Group, states reduce or mitigate taxes on oil and gas operations that engage in secondary or tertiary production. The general concept is that significantly higher capital and operating expenses are required to conduct secondary or tertiary oil production. If taxes were applied at the same high rates as for primary production, secondary and tertiary production would not be undertaken by mineral owners or their lessees. Therefore, states rationalize applying a lower production tax rate to a large increment of new oil production, rather than to maintain a higher production tax rate and possibly get very little or no additional production. Some states specifically identify CO_2-EOR as qualifying for a reduced rate of taxation, whereas other states simply include CO_2-EOR in the same reduced-taxation category as other "tertiary" methods.[22]

Some examples follow:

- Texas specifically focuses on CO_2, cutting the normal 4.6 percent severance tax to 2.3 percent for CO_2-EOR and to 1.15 percent for CO_2-EOR that utilizes anthropogenic CO_2 (apparently the only state specifically identifying anthropogenic CO_2-EOR)[23];
- Some states abate for a specified time: North Dakota and Oklahoma abate their normal severance (5 and 7 percent, respectively) for 5 years for secondary production and 10 years for tertiary production, without distinguishing among types of tertiary production;
- Kansas appears to permanently abate its 8 percent tax for tertiary production;
- Other states assess lower rates, with Wyoming formerly cutting its 6 percent rate to 4 percent for all tertiary oil production (since expired), and Mississippi halving its 6 percent rate for all EOR; and
- Some states do not appear to make any tax reductions relating to EOR methods.

EXAMPLE OF IMPACT OF SEVERANCE TAX REDUCTIONS FOR CO_2-EOR

- A state charges a state severance tax of 5 percent of wellhead value of oil for primary production.
- The state reduces the rate to 1.25 percent for production using anthropogenic CO_2.
- Thus, the difference in taxation is 3.75 percent of wellhead value.
- At $50/bbl the incremental difference is $1.875/bbl, and at $100/bbl the incremental difference is $3.75/bbl.
- The value of this policy depends upon the oil price, so the exact rate of return value to an oilfield owner depends on the precise oil forecast used.

Different and lower rates of oil extraction and other taxes are common and economically justified for producers using more capital intensive and costly means of oil production. Compared to other methods of recovery, CO_2-EOR has greater environmental and, potentially, regulatory value for a state, making it appropriate to consider incentivizing the practice further. Toward that end, Texas distinguishes between incremental CO_2-EOR production that is elicited with naturally occurring geologic CO_2 versus anthropogenic CO_2 from industrial and power plant sources. The normal severance tax in Texas is 4.6 percent, which is reduced to half that level with geologic CO_2 usage and to one-quarter of the normal level with use of anthropogenic CO_2.[24]

Using a $75/bbl oil price, the Work Group finds an approximate 2.2 percent difference in the equity rate of return for a standalone CO_2-EOR operation triggered by reducing the severance tax as shown in the boxed example above. That is, an oilfield earning a 20 percent rate of return under the lowered 1.25 percent severance tax rate would only earn 17.8 percent rate of return under the normal 5 percent severance tax rate.

22 Most of the time, CO_2-EOR is a tertiary method of production, with a well going through primary production, then secondary production with water flooding, followed by CO_2-EOR. However, in the real world, CO_2-EOR is typically "WAG" or water alternating with "gas", the gas being CO_2. So, it is quite possible the CO_2-EOR can be a secondary method of production. Meanwhile, in certain geologic formations such as residual oil zones or ROZs, it appears that CO_2-EOR may be the best primary production method. Hence, tax distinctions between primary, secondary and tertiary don't strictly catch all the nuances of producing oil with the aid of CO_2, which state policy-makers should consider in formulating their own state policies in order to accommodate different potential oil production and carbon storage opportunities offered by CO_2-EOR.

23 Texas Tax Code Ann. §202.0545.

24 Provision of Texas HB 469 enacted in 2009.

Combining Carbon Capture and CO_2-EOR in a Vertically Integrated Operation

For this report, the Work Group has looked at four different categories of state tax policy. All four had medium-sized impacts upon the oil prices required to earn adequate returns, with the first two taxes affecting the carbon capture side of the CCUS value chain and the second two influencing the CO_2-EOR side of the equation. In practice, the carbon capture and CO_2-EOR operations may be owned by the same entity. In that case, we can look at the financial impact of tightening or easing the rates of taxation at all four levels discussed above.

It bears emphasizing that there is no easy way to add up all the illustrative examples shown previously. For instance, since the CO_2-EOR operation needs only a few dollars' worth of CO_2 to produce many dollars' worth of oil, the relative importance of the carbon capture operation is disproportionately small in the combined operation. In other words, since one ton of CO_2 that costs ~1/3 of the price of a barrel of oil actually produces 2 or more barrels of oil to be sold, the capture business represents only about one-sixth of the revenues of the oil business that uses all of its CO_2 output.

The full analysis of the combined easing or optimization of all four levels of taxation shows it to be worth the equivalent of an $8 per barrel increase in the price of oil to a vertically-integrated CCUS project. The analysis assumed a vertically integrated business that combined both a carbon capture plant that produced X tons of CO_2 a year plus a CO_2-EOR flood that fully utilized those X tons of CO_2. Under high tax conditions, meaning that all four taxes considered were at the high end of the ranges discussed above, the operation needed a $69/bbl oil price to meet all operating expenses, debt service, dividends to stockholders, and federal and state tax. On the other hand, if all four taxes were at the low end of their ranges, only $61/bbl was needed to break even. The comparison is summarized in the table below:

Preliminary Conclusions

Both simple illustrations and full project models of carbon capture plants, CO_2-EOR operations, and vertically-integrated combinations of the two demonstrate that state taxes can have a meaningful impact upon project financial feasibility.

Taxation regimes clearly vary widely from state to state, with some states heavily dependent on one form of taxation (such as Texas, which has no individual income tax and thus depends heavily on property taxes) and other states in the opposite camp (such as California, which is very constrained on residential property taxes and thus has very high sales, income and property taxes imposed on oil reserves). Even within the same type of taxation (e.g. production taxes on oil wellhead value) rates of taxation and types of exclusions and exemptions vary widely.

Nonetheless, we have identified four types of taxes that are commonly levied in many oil and gas-producing states. In most cases, there already exist precedents or an economic rationale for reducing these taxes to benefit commercial CCUS project deployment.

Since both carbon capture operations and CO_2-EOR operations are largely driven by oil prices, we appropriately used oil price-equivalent changes to create a common yardstick for measuring the impact of tax changes at the state level. The combined possible impact of changes was significant at $8/bbl.

State Fiscal Issues

Throughout this report, the Work Group has offered a rationale for more favorable state tax treatment of carbon capture or CO_2-EOR. Work Group participants recognize and appreciate that most states confront fiscal challenges, and granting tax benefits to any industry is often very difficult. Nonetheless, it is worth exploring the reasoning for optimizing taxation of CO_2-EOR.

For example, in the case of exempting or reducing property taxes on CO_2 capture equipment, some may suggest that doing so erodes the local tax base. On the other hand, an existing facility may face closure because the expense of installing CO_2 capture equipment erodes the economics of the plant. Property tax exemption, or permitting local jurisdictions the option of allowing such exemption, may in fact help preserve the local property tax base.

In the case of sales taxes upon equipment used in carbon capture and CO_2-EOR operations, an argument can be made that the capital investment required CO_2-EOR is far more like "manufacturing" than is primary oil production, given the long-term commitment of capital required by projects.

Finally, many states recognize that secondary and tertiary methods of oil recovery, and especially CO_2-EOR, are qualitatively different from primary production, often involving a complete rework of the original production wells, construction of surface compression and oil/water/gas separation facilities, power production, and installation of other equipment that can cumulatively cost hundreds of millions of dollars. In the absence of such operations making financial sense, CO_2-EOR projects will not proceed and incremental oil production will be zero. In this context, the case can be made to state policymakers that having a lower severance tax rate on a large new volume of production is preferable to maintaining a high severance tax rate on little or no new production.

Caveats and Follow Up

Types of capture plants differ widely, as do types of CO_2-EOR operations. Further, state sales, property, and oil severance tax regimes are complex and variable. The Work Group's recommendations are intended to be general and to be subsequently tailored to the particular needs of individual jurisdictions. The investigation outlined above primarily aims to show that the state-controlled tax policy levers available to encourage or discourage commercial deployment of carbon capture and CO_2-EOR are more powerful than many observers might have imagined. Work Group participants believe that closer analysis by interested states of their particular circumstances can help them refine their own incentives to complement improved federal policies for CCUS deployment also recommended in this report.

Other Policy Considerations for State Policy-Makers

As this report and the preceding analysis demonstrates, there is an urgent need to provide an effective framework of federal and state incentives to help CCUS projects bridge the current cost gap and secure private financing. Therefore, the Work Group's first set of policy recommendations appropriately focuses on the suite of needed federal incentives complemented by optimized state tax policies.

However, there remains a host of additional policies that merit consideration as well, both in the interest of meeting broader emissions reduction objectives and ensuring the continued diversity, reliability and affordability of our broader energy system. The Work Group, for its part, will take up additional state and federal policies in future recommendations. Meanwhile, this report provides a comprehensive inventory of state tax and non-tax policies related to CCUS that has been prepared by partners at the Center for Climate & Energy Solution and Stanford University. Policy matrixes and feature polices organized by state and category can be found here, with brief descriptions and online links and/or citations for each policy.

Other CCUS Policies Available to States/Federal Policymakers

Beyond the tax policies discussed in this report, states have adopted a number of additional measures to support CCUS deployment and ensure economic development and job benefits for traditional industries within their jurisdictions. From the perspective of CCUS project developers, the three policies with the most significant financial impact are the adoption of clean energy standards that include CCUS as an eligible technology or resource, state direction to utilities to enter into long-term offtake agreements for power generated by facilities incorporating CCUS technology, and allowing utilities cost recovery for CCUS. With respect to particular projects, states can also provide financial assistance in the form of grants, bonds, loans and loan guarantees.

It should also be noted that the Federal Energy Regulatory Commission (FERC) has a substantial role to play in the determination of wholesale power markets, and of what states are allowed to do with respect to incentives that affect those markets. As discussed in the section below, having a financially viable power sector carbon capture project on paper does not conclude the discussion, as power must be sold into a market, and the cost of that power determines whether a particular generation unit will dispatch at any given time. Incentives utilized by states that affect the wholesale market (as administered by regional transmission organizations (RTOs), independent system operators (ISOs) or balancing authorities) thus come under FERC jurisdiction, so attention must be paid to their rulings.

Some states have opted not to implement utility portfolio standards and other binding requirements that support the development of renewable energy and energy efficiency and provide preferential treatment to these resources in the marketplace. However, for those states that do have such policies for renewables and efficiency, reframing them as broader clean energy policies to include CCUS and CO_2-EOR will help achieve policy parity and a more level playing field for all zero and low carbon energy technologies.

Taking a longer view, establishing a forward-looking framework for CCUS and CO_2-EOR can help position states strategically to encourage deployment of these technologies. States have an important role to play in clarifying property rights and liability regimes related to CO_2 pipeline infrastructure and geological storage of CO_2. Specifically, states can clarify pore space ownership and ownership of captured and injected CO_2. States can also declare geologic storage of CO_2 to be in the public interest and authorize the exercise of eminent domain for construction of CO_2 pipeline infrastructure in a manner similar to other linear projects. Finally, states can also establish financial requirements of CO_2 storage facility operators, set up a state trust fund for management of CO_2 storage sites, and assume long-term liability for CO_2 stored. These policies mitigate the uncertainties that have inhibited financial investment in CCUS and CO_2-EOR. As noted, examples of all of these state polices can be found here.

It can be expected that state and regional planning of CO_2-EOR infrastructure will increase in importance if federal incentives are extended and expanded and as carbon capture from industrial facilities increases in priority. Capturing CO_2 from most industrial facilities costs less than from power plants, but a hub and trunk line approach to pipeline infrastructure for CO_2-EOR is needed to accommodate the economics of gathering and transporting what are typically lower volumes of CO_2 obtained from each industrial facility, such as an ethanol or fertilizer plant. In this way, a networked approach brings together multiple CO_2 emitters and multiple oilfields using shared pipeline infrastructure.

Ensuring the Viability of Power Plants with Carbon Capture in Regional Power Markets

Policies, regulations and procedures that determine how and when electric generators dispatch and sell power into the marketplace represents a final important realm of policy for carbon capture projects in the power sector that these recommendations do not address, and one with which CCUS project developers, policy-makers and stakeholders have only begun to grapple.

Depending on the relative cost of power from various electric generating units operating in a specific location at a given time, a power plant equipped with carbon capture technology may not be allowed to dispatch and sell power into the market, thus affecting its financial feasibility—even if the facility has access to the financial incentives and policy tools recommended in this report.

In much of the U.S., power is sold into a regional grid operated by a RTO or ISO. In other locations, the tasks performed by RTOs and ISOs are performed by entities known as balancing authorities. The mission of the RTOs and ISOs is to balance power needs in a geographic area with the supply of power available to that area. Their actions are subject to FERC jurisdiction, as described above, and decisions that affect wholesale prices are not only subject to rules of the dispatch authority, but of the FERC as well. Recently, FERC has been very attentive to looking at state actions that influence the wholesale power markets. A generator that has power available, but at too high a cost, may not be allowed to sell into the market.

Many nuclear plants and coal plants (without carbon capture) already confront this challenge as their bids increasingly do not "clear" in a marketplace increasingly dominated by lower-cost natural gas generators and by renewable generators with more favorable policy, regulatory and marketplace treatment. Generators that find themselves out of the market can lower their bids in the short term, dispatch and sell power at a loss, but that obviously cannot be sustained over the long term.

In summary, these regional power market dynamics will need to be taken into account in order to ensure that power plants equipped with carbon capture and selling CO_2 for EOR have the opportunity to compete and dispatch. RTOs and ISOs must operate the grid and establish market rules and procedures consistent with state and federal policy. Therefore, it is possible to craft policies that recognize and reward the emissions reduction and other benefits provided by power plants with CO_2 capture, relative to other generation technologies. It is the intention of Work Group participants to explore this issue in more depth in the future and potentially make additional recommendations to state and federal policy-makers in that regard.

Need for a Balanced, Cost-effective Approach

Accelerating CCUS Deployment is the other piece of the puzzle

IN RECOMMENDING A FRAMEWORK OF COMPLEMENTARY federal and state incentives and modeling their potential to enhance the financial feasibility of carbon capture projects, the Work Group has broadly discussed how CCUS merits policy treatment to accelerate its commercial deployment, as has been done successfully for other energy technologies. There is clearly a case to be made for such “policy parity” in the broader energy security and economic context: Capturing power plant and industrial CO_2 for use in CO_2-EOR is a pathway for enabling the continued use of America’s abundant fossil energy resources, extending the economic life of existing energy and industrial assets, and sustaining an energy and industrial jobs base.

However, the policy parity argument for CCUS deployment makes sense even from the narrower standpoint of cost-effectiveness in reducing CO_2 emissions when compared with other available options.

How should the cost-effectiveness of carbon capture paired with CO_2-EOR be measured? We can begin by identifying the least expensive carbon mitigation options on the basis of cost per ton of CO_2 emissions reduced or avoided, recognizing that taxpayers and customers ultimately pay for the reductions. Doing so requires evaluating the cost of integrating a particular emission reduction option into the broader energy system over time at progressively higher levels of deployment.

Too often, cost analyses treat new projects and resources in isolation and/or consider their integration only at early stages of deployment, a context in which power plant carbon capture with CO_2-EOR initially looks relatively expensive.[25] However, as we demand greater emissions reductions from the energy system, carbon capture becomes increasingly cost-effective relative to other options.

The cost case for including carbon capture as part of a broader electric generation portfolio rests on the fact that supplying power to the modern grid increasingly depends upon a diversity of generation types, with each having different production, cost, and reliability characteristics. Disproportionate reliance on any single type of generation will ultimately lead to consequences for the system as a whole that must then be managed to ensure electricity supply and reliability, thereby increasing costs.[26] We are already beginning to see such system effects with curtailment of wind power in some regions and growing economic challenges faced by existing nuclear plants in particular power markets. Thus, at higher levels of emissions reductions, a diversified portfolio of low-carbon generation options—including carbon capture from coal and natural gas-fired power plants—becomes a critical hedge against rising costs.

Figure 10 illustrates what portfolio diversity and the inclusion of CCUS deployment means from a comparative emissions reduction cost standpoint. It shows where carbon capture retrofits of existing coal and natural gas power plants falls along the spectrum of avoided CO_2 emissions costs—more or less in the middle—underscoring the financial and economic benefits of an all-of-the-above approach to carbon mitigation. On the lower-cost left side of the chart, wind and solar cost less in early stages of deployment, when they displace generation from coal-fired power plants. On the higher-cost right side of the chart, solar at higher penetration rises significantly in cost when it begins displacing highly efficient combined cycle natural gas plants, especially in cases of solar over-generation and curtailment, or of the need to deploy battery storage. The key take-away is that although generation hardware, whether a solar photovoltaic array or a power plant carbon capture system, may remain physically unchanged and have unchanged operating costs, relative costs of CO_2 reductions to taxpayers and consumers when deployed on an integrated power system change markedly at higher levels of grid penetration and greater overall emissions reductions targets.

While differences in the cost per ton of CO_2 reduction between these examples are large, they were generated using standard cost estimates and comparing the cost of a proposed low-carbon option to a business as usual option under various operating rates.[27]The avoided cost figures are not unusual—a major study performed for California's

How does one calculate the cost of avoiding one ton of CO_2 emissions to decide whether carbon capture is cost-effective? The answer is the same for carbon capture as for any other proposed option:

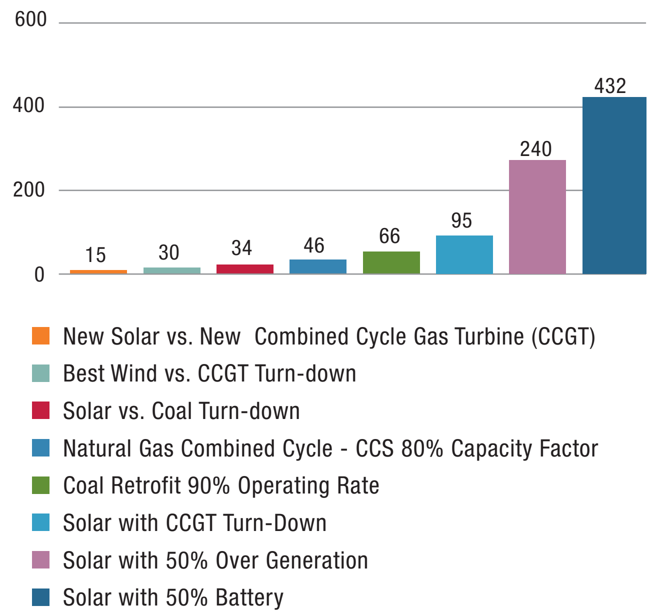
- Measure how much extra you have to pay for the same amount of electricity from the new option compared to under Business As Usual (BAU)—that's the incremental cost.
- Measure how much less CO_2 is emitted generating the same amount of electricity from the new option compared to business as usual—that is the incremental CO_2 reduction.
- Divide the extra cost by the tons saved, and you have cost per ton of emissions avoided.

25 For a static analysis see *Pathways to a Low-Carbon Economy, Version 2 of the Global Greenhouse Gas Abatement Cost Curve,* McKinsey & Company, 2009, p. 63. For cautions about this type of analysis see *Marginal Abatement Cost Curves: A Call for Caution,* Paul Elkins et al, University College London, April 2011, pp. 4-5.

26 For study of abatement costs ($403-$1,020/MT) under various 50 percent renewables scenarios see *Investigating a Higher Renewables Portfolio Standard in California, Energy+Environmental Economics* (E3), January 2014, Figure 38, p. 144.

27 *Lazard's Levelized Cost of Energy Analysis-Version 9.0*, Lazard Freres, November 2015 for renewables and combined cycle natural gas. *Lazard's Levelized Cost of Storage Analysis-Version 1.0*, Lazard Freres, November 2015 for battery costs. *Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 23*, National Energy Technology Laboratory, DOE/NETL-2015/1723, July 6, 2015 various cases for carbon capture, supplemented by industry estimates and interviews.

FIGURE 10: Cost per Ton CO_2 Reductions



four largest utilities by an internationally-respected energy consulting firm projected that as the state moves from 40 to 50 percent renewable generation, and in the absence of power plant carbon capture and/or new nuclear generation (which were not considered), the incremental avoided cost of CO_2 would range from $403-$1,020 per MT, depending on the particular strategy chosen.[28] In the study, the principal driver of these high costs is over-generation of solar, especially during spring and fall, often exacerbated by high wind generation when peak wind occurs simultaneously with peak solar generation.[29]

In summary, a portfolio of low- or zero-carbon generation technologies will be needed to accomplish deeper emissions reductions cost-effectively. Federal and state policy-makers should ensure parity for CCUS through a balanced approach to incentives and other policies that encourage additional commercial carbon capture technology deployment, along with other options.

28 E3 study, page 144.

29 *Overgeneration from Solar Energy in California: A Field Guide to the Duck Chart*, Paul Denholm et al, National Renewable Energy Laboratory, Technical Report NREL/TP=6A20-65023, November 2015, pp. 3-4, chart on p. 22. *Market Performance Report August 2016*, California ISO, October 7, 2016, Figures 17 & 18, p. 18 of 43. http://www.caiso.com/Documents/MarketPerformanceReportforAug2016.pdf

Conclusion

CARBON DIOXIDE-ENHANCED OIL RECOVERY (CO_2-EOR) offers extraordinary benefits for our nation. Capturing CO_2 from power plants and industrial facilities for use in EOR increases American oil production, while simultaneously reducing carbon emissions and enabling continued use of our domestic fossil energy resources. Over the past year, state officials from across the U.S. have signaled growing support for capturing CO_2 from power plants and industrial facilities for use in EOR to increase domestic oil production while reducing overall emissions. State officials have also endorsed the need for federal action to provide incentives to accelerate commercial deployment of carbon capture, utilization and storage (CCUS).

CO_2-EOR can provide stable energy production, increased employment and benefits to local economies. In addition, CO_2-EOR offers rates of return that compare favorably with other oil production projects, provided the CO_2 can be delivered at an affordable price. Installing carbon capture facilities, building CO_2 pipelines and reworking mature oil fields to revitalize their production through CO_2-EOR bring jobs and investment to key energy and industrial sectors of the U.S. economy.

Carbon capture technology in certain industry sectors and the use of CO_2 in EOR has a long and successful history of commercial deployment in the U.S. going back nearly a half century. However, further deployment of carbon capture faces important challenges, including high capital costs, low CO_2 prices at current low oil prices, limited availability of debt and equity for CO_2-EOR projects due to policy uncertainty and market risk and, for carbon capture projects at power plants, potential difficulty of selling electricity into the market because of higher costs.

A targeted package of federal incentives will help address these challenges. These include improving and expanding an existing tax credit for storage of captured CO_2; deploying a mechanism to stabilize the price paid for CO_2—and carbon capture project revenue—by removing volatility and investment risk associated with CO_2 prices linked to oil prices; and offering tax-exempt bonds and master limited partnership status to provide project financing on better terms.

States can also assist by optimizing existing tax and other policies to complement federal incentives in helping carbon capture projects achieve commercial feasibility. Analysis done for the Work Group suggests that states, in conjunction with improved federal policy, can positively affect the overall feasibility of CCUS projects by optimizing a suite of traditional taxes common to most oil and gas-producing states.

Complementary federal and state incentives will narrow the gap between the cost of carbon capture and revenue received from the sale of CO_2 for EOR, spur additional commercial project deployment by enticing private investment in CO_2-EOR projects, and bring down the cost of carbon capture technology. In addition, CCUS merits policy treatment from the federal government and states to accelerate its commercial deployment, as has been done successfully for other energy technologies. As public policy and market conditions drive industry to look for ways to reduce emissions, CCUS deserves equivalent support as a critical component of a broader, cost-effective portfolio of carbon mitigation options.

The federal and state financial incentive policies recommended in this report can play a critical role in scaling up carbon capture, which in turn will help our nation better utilize domestic resources, create and maintain good-paying jobs, realize additional economic benefits and reduce emissions.

Glossary

Anthropogenic CO_2	Anthropogenic refers to carbon dioxide that is produced or released as a result of human activity, as distinct from naturally-occurring CO2 that is released or obtained from geologic sources.
ARI	Advanced Resources International (ARI) is a consulting, research and development firm providing services related to unconventional gas (gas shales, coalbed methane and tight sands), enhanced oil recovery (EOR), and carbon capture, utilization and storage (CCUS).
BAU	Business as usual in this report refers to a modeling scenario or case that assumes no change in policy beyond what already is and will be required by existing law or regulation and assumes no change in technology or markets beyond mid-range forecasts.
Bbl	The abbreviation for barrel, a unit of volume for crude oil and petroleum products.
CfD	A contract for difference (CfD) creates a contract between two parties based on the movement of an asset price. Parties execute a contract to exchange the difference in value of a particular currency, commodity or index between the time at which a contract is opened and the time at which it is closed. If the asset rises in price, the buyer receives cash from the seller, and vice versa. In the context of this report, a CfD would establish a target price for oil (to which the CO_2 prices is contractually linked) based on an oil price projection over the life of the contract. If the oil price were to fall below the target price, the federal government would provide the difference to a CO_2 capture project, and if the price of oil were to rise above the target price, the CO_2 capture project would pay the federal Treasury the difference.
CCS	Carbon capture and storage, or CCS, describes the process of capturing and preventing the release of man-made or anthropogenic CO_2 into the atmosphere and then ensuring its permanent storage in an oil and gas field, deep saline formation or other geologic formation.
CCUS	Carbon capture, utilization and storage, or CCUS, reflects the commercial use of CO_2 prior to permanent geologic storage through its injection into oil fields to recover additional crude through CO_2-EOR.
CO_2-EOR	Carbon dioxide enhanced oil recovery, or CO_2-EOR describes the process of injecting CO2 into an oil field, usually in a tertiary phase of production, to increase the amount of crude oil that can be extracted. The commercial purpose of CO_2-EOR is to increase oil production, but permanent geologic storage of the injected CO2 in the formation is an incidental result of the process.
Conventional reservoir	A conventional reservoir is an oil and gas formation in which buoyant forces keep hydrocarbons in place below a sealing caprock. Reservoir and fluid characteristics of conventional reservoirs typically permit oil or natural gas to flow readily into wellbores to be produced through traditional means, as distinguished from shales, ROZs, and other unconventional reservoirs, which require special techniques to mobilize and produce hydrocarbons in commercial volumes.

DOE	The U.S. Department of Energy (DOE) is a federal Cabinet-level department concerned with U.S.' policies regarding energy and safety in handling nuclear material. Its responsibilities include the nation's nuclear weapons program, nuclear reactor production for the U.S. Navy, energy conservation, energy-related research and development, radioactive waste disposal, and domestic energy production.
EIA	The U.S. Energy Information Administration (EIA) is a principal agency of the U.S. Federal Statistical System responsible for collecting, analyzing, and disseminating energy information. EIA programs cover data on coal, petroleum, natural gas, electric, renewable and nuclear energy. EIA is part of the U.S. Department of Energy.
FERC	The Federal Energy Regulatory Commission (FERC) is the U.S. federal agency that regulates the transmission and wholesale sale of electricity and natural gas in interstate commerce, and regulates the transportation of oil by pipeline in interstate commerce. The FERC also reviews proposals to build interstate natural gas pipelines, natural gas storage projects, and liquefied natural gas (LNG) terminals. Finally, theFERC licenses non-federal hydropower projects.
Gasification	Gasification is a long-established process of applying heat and pressure to an organic or fossil fuel-based carbonaceous feedstock, transforming it into carbon monoxide and hydrogen, with a pure stream of carbon dioxide ultimately resulting as a chemical byproduct that can readily be compressed and transported.
Geologic storage	Geologic formations can serve as storage sites for carbon dioxide, which is captured from large point sources, such as fossil fuel power plants and industrial facilities, transported by pipeline to a storage site and injected into the geologic formation. CO_2 has been injected into geological formations for nearly a half century for various purposes, including enhanced oil recovery.
GW	The abbreviation for a gigawatt, or the equivalent of 1,000 megawatts or 1,000,000 kilowatts.
IEA	The International Energy Agency (IEA) is a Paris-based autonomous intergovernmental organization established in the framework of the Organization for Economic Co-operation and Development in 1974 in the wake of the 1973 oil crisis. The IEA was initially dedicated to responding to physical disruptions in the supply of oil, as well as serving as an information source on statistics about the international oil market and other energy sectors, but it is now responsible for a broader portfolio of activities.
IGCC	Integrated gasification combined cycle (IGCC) is a technology that uses a high pressure gasifier to turn coal and other carbon-based fuels into hydrogen and ultimately a synthesis gas (syngas), removes impurities from the syngas, and then combusts the syngas in combined cycle power generation. With additional process equipment, a water-gas shift reaction can convert carbon monoxide to carbon dioxide. The resulting CO_2 from the shift reaction can be separated, compressed, and used for EOR or in other geologic storage.
Industrial CO_2	For the purposes of this report, industrial is meant to distinguish anthropogenic carbon dioxide generated from a wide range of industrial processes and activities from CO_2 produced through electric power generation.
Injectant	An injectant is a fluid or gas that is pressurized and injected into an oil and gas formation for the purpose of increasing hydrocarbon recovery. CO_2 represents one such injectant, traditionally used in a tertiary phase of recovery.

Interfacial tension	*Interfacial tension* is the surface tension separating two non-miscible liquids, or two liquids that do not mix.
ISOs	An independent system operator (ISO) is an organization formed at the direction or recommendation of the Federal Energy Regulatory Commission (FERC). In the areas where an ISO is established, it coordinates, controls and monitors the operation of the electrical power system, usually within a single state, but sometimes encompassing multiple states. RTOs typically perform the same functions as ISOs, but cover a larger geographic area.
ITC	An investment tax credit (ITC) helps defray upfront capital costs by providing a federal tax credit for investments in the development of a qualified project.
Lender Survey Stress Case	A survey published quarterly by the investment bank, Macquarie, that details the typical assumptions about future oil and gas commodity prices used to assess a borrower's ability to withstand prolonged low prices without defaulting on borrowings.
Macro-level modeling	In the context of this report, it is industrywide economic analysis undertaken at the level of an entire economic sector, such as electric power generation.
Manmade CO_2	See anthropogenic CO_2 definition.
Micro-level modeling	In the context of this report, it is financial analysis undertaken at the level of an individual carbon capture project to determine commercial viability.
MLP	In the U.S., a master limited partnership (MLP) is a limited partnership that is publicly traded on an exchange qualifying under Section 7704 of the Internal Revenue Code. It combines the tax benefits of a limited partnership with the liquidity and ability to raise capital of publicly-traded securities.
MT	The abbreviation for metric ton.
MWh	The abbreviation for a megawatt hour, or the equivalent of 1,000 kilowatt hours.
Natural CO_2	Naturally occurring carbon dioxide is CO_2 that is released or obtained from geologic sources, as distinct from CO_2 that is produced or released as a result of human activity.
NEMS	The National Energy Modeling System (NEMS) is an economic and energy model of U.S. energy markets created at the U.S. Department of Energy's, Energy Information Administration (EIA). NEMS projects the production, consumption, conversion, import, and pricing of energy. The model relies on assumptions for economic variables, including world energy market interactions, resource availability (which influences costs), technological choice and characteristics, and demographics.
NYMEX strip prices	The NYMEX Strip, or "12-month strip" is the average of the daily settlement prices of the next 12 months' futures contracts.
PAB	Private activity bonds (PABs) are a type of revenue bond that allows tax-exempt debt to be issued to governments in order to fund the construction of a qualified project.
Primary production	Primary production refers to the production of oil in the initial or primary recovery stage, when production of oil and gas is assisted by natural reservoir pressures. Only about ten percent of a reservoir's original oil in place is typically produced during primary recovery.
Pro forma model	It is a set of equations based upon inputs that are known (like cost of a plant) and are assumed (like cost of fuel or inflation rates) and that will generate a set of projected financial statements for a project year-by-year over a long time horizon.

Residual oil zones	Residual oil zones (ROZs) are areas of immobile oil found below the oil-water contact of a conventional oil formation. These unconventional oil resources have not traditionally been commercially feasible to exploit, but recent experience indicates that ROZs are amenable to CO_2-EOR and contain large volumes of oil and significant potential for CO_2 storage.
RTOs	A regional transmission organization (RTO) in the U.S. is an organization that is responsible for managing the electric grid and the dispatch of generation over large interstate areas and for overseeing the operation of wholesale electricity markets.
Secondary production	Secondary production refers to the production of oil that follows in a second phase following the primary recovery stage. Over the life of a producing well, the pressure will fall due to declining underground pressure to drive oil to the surface. At that point, a secondary recovery method (water injection, natural gas reinjection, etc.) is used to drive oil to the surface, resulting in the recovery of an additional 20-40 percent of the original oil in place.
Section 48A and 48B Investment Tax Credits	Section 48A and 48B reference sections of the Internal Revenue Code of 1986, authorizing federal programs that provide an investment tax credit to defray the upfront capital costs of clean coal projects (48A) and gasification projects (48B). The Section 48A and 48B programs prioritize projects that involve carbon capture.
Section 45Q Credit for Carbon Dioxide Sequestration	26 USC §45Q provides a federal production tax credit of $10 per metric ton of carbon dioxide through enhanced oil recovery or $20 per ton for other geologic storage. Section 45Q was enacted by § 115 of the Energy Improvement and Extension Act of 2008.
Tertiary production	Enhanced, or tertiary production, follows the secondary phase and increases the mobility of the oil in order to increase extraction. Tertiary (or enhanced) production typically begins when secondary recovery declines to the point where production no longer generates sufficient economic return. There are three major categories of enhanced recovery that have found varying degrees of commercial success: thermal injection, gas injection and chemical injection. Gas injection (including CO_2EOR) accounts for nearly 60 percent of the enhanced oil production in the U.S.
tpy	The abbreviation for tons per year.
tpyc	The abbreviation for tons per year of capacity, a measure of a facility's total annual carbon capture capacity.
Viscosity	*Viscosity* is a measure of a fluid's resistance to flow. A fluid with large *viscosity* resists motion because its molecular makeup gives it a lot of internal friction, making it sticky or thick. Conversely, a fluid with low viscosity, such as water, flows freely.
Wellhead value	The value or price less transportation costs charged by the producer for petroleum or natural gas.
144(a) Bonds	The purpose of Rule 144(a) is to provide a mechanism for the sale of privately placed securities that do not have, and are not required to have, a Securities and Exchange Commission registration in place, creating a more efficient market for the sale of said securities. To sell restricted or controlled securities under Rule 144(a), certain conditions must be met.

Appendices

Appendix A: Model Scenarios

MODEL SCENARIO A

No Incentives; NYMEX Strip Used for Debt and Equity

The scenario below shows the shortfall in funding under current market conditions, using the June 2, 2016 NYMEX futures strip as the oil price forecast for both determining amount of debt that can be serviced and for calculating equity returns. No policy incentives are provided. Per annual ton of CO_2 capture capacity, the project needs to raise $300. However, it can only obtain $40, leaving a $260 gap.

Policy Levers	Setting
1. Refundable ITC?	**None**
2. Revenue Stabilization Contract?	**None**
3. Private Activity Bonds?	**None**
4. 45Q Sequestration Credit?	**None**
5. MLP Eligible	**None**

Source/Use of Funds	$ Amounts
Capital Cost Paid	**($300.00)**
less ITC	$0.00
plus ITC Bridge Cost	$-
Net Nedded D or E	**($300.00)**
plus Debt Raised	$23.26
plus NPV of Equity Dividends	$16.39
plus NVP of 45Q Credits to Equity	$0.00
Value of D and E	$39.64
Surplus (+) or Shortfall (–)	**($260.36)**

Use of Oil Price Cases	Forecast Used
Debt Stress Case Used	Strip 6/2/2016
Equity Case Used	Strip 6/2/2016

MODEL SCENARIO B

No Incentives; Lender Stress Used for Debt and NYMEX Strip Used for Equity

The scenario below shows the shortfall in funding with no incentives, the Lenders' Sensitivity Case oil price forecast for debt, and June 2, 2016 NYMEX futures strip to estimate equity that can be raised. No policy incentives are provided. Per annual ton of CO_2 capture capacity, the project needs to raise \$300. However, it can only obtain \$32, leaving a \$268 gap.

Policy Levers	Setting
1. Refundable ITC?	None
2. Revenue Stabilization Contract?	None
3. Private Activity Bonds?	None
4. 45Q Sequestration Credit?	None
5. MLP Eligible	None

Source/Use of Funds	$ Amounts
Capital Cost Paid	($300.00)
less ITC	$0.00
plus ITC Bridge Cost	$-
Net Nedded D or E	($300.00)
plus Debt Raised	$0.00
plus NPV of Equity Dividends	$32.13
plus NVP of 45Q Credits to Equity	$0.00
Value of D and E	$32.13
Surplus (+) or Shortfall (–)	**($267.87)**

Use of Oil Price Cases	Forecast Used
Debt Stress Case Used	Lenders Stress Q2 16
Equity Case Used	Strip 6/2/2016

MODEL SCENARIO C

No Incentives; Lender Stress Used for Debt and CBO Forecast Used for Equity

The scenario below shows the shortfall in funding with no incentives, the Lenders' Sensitivity Case oil price forecast for debt, and August 2016 CBO forecast of US oil prices to estimate equity that can be raised. No policy incentives are provided. Per annual ton of CO_2 capture capacity, the project needs to raise $300. However, it can only obtain $44, leaving a $256 gap.

Policy Levers	Setting
1. Refundable ITC?	None
2. Revenue Stabilization Contract?	None
3. Private Activity Bonds?	None
4. 45Q Sequestration Credit?	None
5. MLP Eligible	None

Source/Use of Funds	$ Amounts
Capital Cost Paid	($300.00)
less ITC	$0.00
plus ITC Bridge Cost	$-
Net Nedded D or E	($300.00)
plus Debt Raised	$23.26
plus NPV of Equity Dividends	$44.40
plus NVP of 45Q Credits to Equity	$0.00
Value of D and E	$44.40
Surplus (+) or Shortfall (–)	($255.60)

Use of Oil Price Cases	Forecast Used
Debt Stress Case Used	Lenders Stress Q2 16
Equity Case Used	CBO Crude August 2016

MODEL SCENARIO D

No Incentives; Lenders' Stress Case Used for Debt, but Highly Optimistic Price Scenario Used for Equity

The scenario below shows the shortfall in funding under current market conditions, the Lenders' Sensitivity Case oil price forecast for debt, and the May 2017 EIA Annual Energy Outlook's forecast of U.S. oil prices to estimate equity that can be raised. This forecast is quite high relative to the others—so it effectively serves as a bookend on optimistic oil prices from responsible forecasters. The purpose is to demonstrate that the funding gap is unlikely to be closed simply by finding a bullish equity investor. No policy incentives are provided. Per annual ton of CO_2 capture capacity, the project needs to raise $300. However, it can only obtain $115, leaving a $185 gap.

Policy Levers	Setting
1. Refundable ITC?	None
2. Revenue Stabilization Contract?	None
3. Private Activity Bonds?	None
4. 45Q Sequestration Credit?	None
5. MLP Eligible	None

Source/Use of Funds	$ Amounts
Capital Cost Paid	($300.00)
less ITC	$0.00
plus ITC Bridge Cost	$-
Net Nedded D or E	($300.00)
plus Debt Raised	$0.00
plus NPV of Equity Dividends	$115.19
plus NVP of 45Q Credits to Equity	$0.00
Value of D and E	$115.19
Surplus (+) or Shortfall (–)	($194.81)

Use of Oil Price Cases	Forecast Used
Debt Stress Case Used	Lenders Stress Q2 16
Equity Case Used	USBA AEO 5-17-16

MODEL SCENARIO E

ITC Incentive Alone; Lenders' Stress Case Used for Debt and CBO Forecast Used for Equity

The scenario below shows the shortfall in funding with an ITC incentive (but nothing else), the Lenders' Stress Case used to establish borrowing capacity, and the January 2016 CBO forecast to estimate amount of equity that can be raised. Unsurprisingly, the result is approximately $90 per ton closer to reaching full funding vs. Scenario C (not exactly $90 because we accounted for the need to pay interest on a bridge loan during construction, since the ITC is only received in cash somewhat after the Commercial Operation Date =~ Tax In-Service Date).

Policy Levers	Setting
1. Refundable ITC?	None
2. Revenue Stabilization Contract?	None
3. Private Activity Bonds?	None
4. 45Q Sequestration Credit?	None
5. MLP Eligible	None

Source/Use of Funds	$ Amounts
Capital Cost Paid	($300.00)
less ITC	$0.00
plus ITC Bridge Cost	$-
Net Nedded D or E	($300.00)
plus Debt Raised	$0.00
plus NPV of Equity Dividends	$32.13
plus NVP of 45Q Credits to Equity	$0.00
Value of D and E	$32.13
Surplus (+) or Shortfall (–)	**($267.87)**

Use of Oil Price Cases	Forecast Used
Debt Stress Case Used	Lenders Stress Q2 16
Equity Case Used	Strip 6/2/2016

MODEL SCENARIO F

ITC Incentive plus Improved Section 45Q; Lenders' Stress Case Used for Debt and CBO Forecast Used for Equity

The scenario below shows the shortfall in funding with both an ITC incentive and an improved Section 45Q storage credit. In terms of prices, we continue to use the Lenders' Stress Case used to establish borrowing capacity, and the January 2016 CBO forecast to estimate amount of equity that can be raised. The combination is very powerful, bringing the project over the goal line (by $0.50/typc). That said, notice that the capital structure of the project is still extremely inefficient from a financial markets point of view—we are still stuck with no debt at all. The ITC provided cash up front, and the 45Q provided tax credits valuable to an equity investor with tax appetite, but nothing improved cash flow available for debt or the cost of debt.

Policy Levers	Setting
1. Refundable ITC?	**Administration**
2. Revenue Stabilization Contract?	**None**
3. Private Activity Bonds?	**None**
4. 45Q Sequestration Credit?	**New 45Q**
5. MLP Eligible	**None**

Source/Use of Funds	$ Amounts
Capital Cost Paid	**($300.00)**
less ITC	$90.00
plus ITC Bridge Cost	$(6.75)
Net Nedded D or E	**($216.75)**
plus Debt Raised	$0.00
plus NPV of Equity Dividends	$44.60
plus NVP of 45Q Credits to Equity	$172.65
Value of D and E	$217.25
Surplus (+) or Shortfall (–)	**$0.50**

Use of Oil Price Cases	Forecast Used
Debt Stress Case Used	Lenders Stress Q2 16
Equity Case Used	CBO Crude August 2016

MODEL SCENARIO G

Improved Section 45Q and CfD; CfD Rate Used for Debt and Equity Returns

The scenario below shows a mix of incentives oriented towards obtaining more debt. We (i) dispense with the refundable ITC, which has had little Congressional support, (ii) continue with the revamped Section 45Q credit, and (iii) also implement a CfD contract. The flat oil price embedded in the CfD is derived by levelizing the CBO forecast at a government bond discount rate of four percent.[30] With the oil price risk taken out of the investment equation, required debt service coverages are reduced, debt interest rates reduced, term of debt extended, and equity discount rates are reduced. By taking out the ITC and putting in the CfD, we are left in more or less the same place. Scenario F (with ITC and without CfD) was $0.50 ahead; Scenario G (w/o ITC and w/ CfD) has a $5.75 gap. The decision might be made based on the relative "scoring" of the ITC vs. the CfD.

Policy Levers	Setting
1. Refundable ITC?	None
2. Revenue Stabilization Contract?	CfD
3. Private Activity Bonds?	None
4. 45Q Sequestration Credit?	New 45Q
5. MLP Eligible	None

Source/Use of Funds	$ Amounts
Capital Cost Paid	($300.00)
less ITC	$0.00
plus ITC Bridge Cost	$-
Net Nedded D or E	($300.00)
plus Debt Raised	$71.87
plus NPV of Equity Dividends	$25.09
plus NVP of 45Q Credits to Equity	$197.29
Value of D and E	$294.25
Surplus (+) or Shortfall (–)	**($5.75)**

Use of Oil Price Cases	Forecast Used
Debt Stress Case Used	CfD rate = PV of CBO
Equity Case Used	CfD rate = PV of CBO

30The CBO only has a ten-year forecast, so we inflated CBO's forecast at 2 percent annually from years 11 onwards. This seems reasonable in terms of keeping up with inflation. The "4 percent government bond rate factor" was used to keep the government whole for the time value of money in the CfD contract. That is, since the CfD is designed to flatten an ascending price forecast curve, the government would tend to pay out in early years and be repaid in late years—so without accounting for interest rates, the Treasury would essentially lose the "float" on those differences.

MODEL SCENARIO H

Improved Section 45Q and CfD; Private Activity Bonds Lower Debt Cost; CfD Rate Used for Debt and Equity Returns

The scenario below shows a mix of incentives oriented towards obtaining even more debt. Scenario F is improved by allowing the better CO_2 revenues consequent to the CfD to be leveraged with lower interest rate/long maturity PAB debt. We get an extra $23 by virtue of the lower financing cost of the debt. Since the PAB alternative was scored at just over $100 million by the Joint Committee on Taxation, this is a relatively low-cost means of improving our situation.

Policy Levers	Setting
1. Refundable ITC?	**None**
2. Revenue Stabilization Contract?	**CfD**
3. Private Activity Bonds?	**PAB**
4. 45Q Sequestration Credit?	**New 45Q**
5. MLP Eligible	**None**

Source/Use of Funds	$ Amounts
Capital Cost Paid	**($300.00)**
less ITC	$0.00
plus ITC Bridge Cost	$-
Net Nedded D or E	**($300.00)**
plus Debt Raised	$100.90
plus NPV of Equity Dividends	$18.98
plus NVP of 45Q Credits to Equity	$197.29
Value of D and E	$317.17
Surplus (+) or Shortfall (–)	**$17.17**

Use of Oil Price Cases	Forecast Used
Debt Stress Case Used	CfD rate = PV of CBO
Equity Case Used	CfD rate = PV of CBO

MODEL SCENARIO I

Improved Section 45Q and CfD; PABs and MLPs Cut Cost of Debt and Equity, Respectively; CfD Rate Used for Debt and Equity Returns

The scenario below shows a mix of incentives oriented towards obtaining even more debt. Scenario G is improved by allowing both PAB eligibility for the debt and MLP treatment for equity. This scenario eloquently illustrates the idea that it will indeed take multiple approaches across all five possible policy levers to deploy CCS projects widely in today's market conditions.

Policy Levers	Setting
1. Refundable ITC?	**None**
2. Revenue Stabilization Contract?	**CfD**
3. Private Activity Bonds?	**PAB**
4. 45Q Sequestration Credit?	**New 45Q**
5. MLP Eligible	**MLP_Parity**

Source/Use of Funds	$ Amounts
Capital Cost Paid	**($300.00)**
less ITC	$0.00
plus ITC Bridge Cost	$-
Net Nedded D or E	**($300.00)**
plus Debt Raised	$100.90
plus NPV of Equity Dividends	$23.20
plus NVP of 45Q Credits to Equity	$288.07
Value of D and E	$352.16
Surplus (+) or Shortfall (–)	**$52.16**

Use of Oil Price Cases	Forecast Used
Debt Stress Case Used	CfD rate = PV of CBO
Equity Case Used	CfD rate = PV of CBO

NOTES

MLP Scoring:

1.1 MLP Renewables Bill Scored at a Modest $1.3 Billion

1.2 Renewable Energy, Tax Policy **20 NOV '13**

Senator Coons (D-DE), the lead sponsor of the Master Limited Partnership Parity Act (S. 795), has received the scoring estimate for that bill from the Joint Committee on Taxation. According to the senator's office, it is scored at a $1.3 billion cost over its first 10 years.1 Ten years is the period used for scoring. One would hope it would be relatively easy to find "revenue raisers" to offset that modest cost. Revenue raisers are often closing what are perceived by the public to be tax loopholes.

The typical cost of a one-year extension of the production tax credit is usually several times the estimate for the permanent legislative changes proposed in the MLP Parity Act; however, tax credits are also far more valuable to the renewables industry than the MLP Parity Act is. See here. Thus, the MLP Parity Act should be passed to give renewables the same tax advantage provided to fossil fuels, rather than as a trade for not extending tax credits for renewables

https://www.akingump.com/en/experience/practices/global-project-finance/tax-equity-telegraph/categories/tax-policy.html

Appendix B

In Figure 10 of the report, all the calculations are fully unsubsidized cost comparisons in order to reveal the cost to society of lower CO_2 emissions, rather than impact of current policies. The basic system costs are derived from public data, including Lazard Freres' renewable electricity and storage reports.

- **New Solar vs. New CCGT (combined cycle gas turbine)—$15 per ton.** This bar seems to show nearly "free" CO_2 reductions. This is a misleading, though frequently cited, comparison of near "grid parity." The bar was derived by comparing the life-cycle cost of a brand new CCGT to the life-cycle cost of a brand new P.V. plant. However, in most states combined cycle gas plants are running at low capacity levels. Comparing a newly-constructed solar plant to a newly constructed gas plant can lead to wrong conclusions about cost because the new gas plant will not be needed in many circumstances.

- **Best Wind vs. CCGT Turn-down—$30 per ton.** This is a meaningful comparison of a new and efficient wind plant which, when windpower is available, will allow the system operator to turn down the operating rate of his gas plant fleet. The wind plant has a lifecycle "levelized cost", assuming wind energy is always usable any time it is generated, of $32/MWh. When a MWh of wind is generated, natural gas plants can run more slowly, saving $20/MWh of fuel and wear and tear. For the $12/MWh extra cost, 4/10ths of one ton of CO_2 emissions is avoided. $30 per ton is derived by dividing the $12/MWh extra cost by 4/10ths ton.

- **New Solar vs. Coal Turn-Down—$34 per ton.** The coal plant already exists, so the cost savings when solar power is available are reduced fuel and wear and tear. The new solar plant is $58/MWh, the dollar savings from turning down the coal plant are $24/MWh, and the CO_2 savings are 1 ton per MWh.

- **NGCC-CCS 80 percent CF—$46 per ton.** This is an existing natural gas combined cycle plant, formerly running at a 50 percent capacity factor. A facility to capture $CO_2$from the exhaust was added, with the CO_2 sold to EOR producers ($22/ton), and the much cleaner facility at ~1/20th ton CO_2 per MWh is now run at near-baseload levels of 80 percent capacity factor. The $46 figure may seem surprisingly low, but remember that fuel costs are substantially offset by revenues from captured CO_2, as well as the much cleaner plant assumed to be dispatched much more frequently (50 percent previously vs. 80 percent post installation of capture equipment).

- **Coal retrofit 80percent OR"—$66 per ton.** This is an existing coal power plant. A facility to scrub CO_2 from the exhaust gas was added, capable of removing 90 percent of carbon from the stack gases produced when the coal plant is running at minimum rates, which it does 90 percent of the time. Again, captured CO_2 is sold for EOR.

- **Solar vs. CCGT Turn-Down—$95 per ton.** This is the situation in many states today, and thus the more representative comparison, rather than the $15 bar to the left. When solar generation is available at an unsubsidized $58/MWh, a natural gas plant is turned down, saving $20/Mwh. For an extra $38/MWh, we save 0.4 tons of CO_2, or $38/0.4 = $95/ton.

- **Solar with 50 percent Over-Generation—$240 per ton.** A number of studies, including by NREL and the noted consulting firm E3, have predicted that as total renewable energy (as percent of total energy consumed) reaches the 40-50 percent level and solar reaches the 20 percent level, newly added solar plants will be turned off about 50 percent of the time. Costs to utilities, and thus to ratepayers, are the same—they just get half the power for the same cost. Further, fuel cost savings for the turned-down gas plants and reduction in associated CO_2 emissions only happen during half the available hours, so the avoided cost of CO_2 more than doubles.

- **Solar with 50 percent Battery—$432 per ton.** This bar is included to address the cost of utilizing the excess solar generation. The fixed capital cost of battery storage, even at extremely low battery prices, is so great that the prior case of 50 percent solar turn-down is more cost-effective.