


Capturing and Utilizing CO_2 from Ethanol:

Adding Economic Value and Jobs to Rural Economies and Communities While Reducing Emissions

White paper prepared by the
State CO_2-EOR Deployment Work Group

December 2017

Acknowledgements

The final recommendations of this white paper represent the joint conclusions of state officials in the State CO_2-EOR Deployment Work Group. However, participating state officials want to recognize the contributions of leading private sector stakeholders in CO_2-enhanced oil recovery, carbon storage and ethanol industry experts who lent their expertise and guidance to the effort. The state representatives extend their thanks to all who contributed to this white paper, and to the Hewlett Foundation and the MacArthur Foundation for the funding that made this work possible. This white paper draws on research being conducted in collaboration with the Kansas Geological Survey as part of a DOE-funded CarbonSAFE project.

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About the State CO_2-EOR Deployment Workgroup

Wyoming Governor Matt Mead (R) and Montana Governor Steve Bullock (D) jointly convened the State CO_2-EOR Deployment Work Group in September 2015 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 Great Plains Institute (GPI) provides coordination and staffing of Work Group activities.

Thirteen states currently participate in the Work Group: Arkansas, Colorado, Illinois, Indiana, Kansas, Louisiana, Mississippi, Montana, Pennsylvania, Ohio, Texas, Utah and Wyoming. State participation varies by state and includes governors' staff, cabinet secretaries, utility commissioners, and agency and commission staff. Some state representatives participate at the direction of the governor; others do not. State representatives were joined by leading enhanced oil recovery, electric power, coal industry, regulatory and NGO experts.

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.

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.

The Work Group released a comprehensive set of federal and state policy recommendations in December 2016 – Putting the Puzzle Together: State & Federal Policy Drivers for Growing America's Carbon Capture & CO_2-EOR Industry, a white paper outlining recommendations for national CO_2 pipeline infrastructure in February 2017 - 21st Century Energy Infrastructure: Policy Recommendations for Development of American CO_2 Pipeline Networks and a report recommending policies to enable power plants with carbon capture to compete cost-effectively in wholesale power markets entitled Electricity Market Design and Carbon Capture Technology: The Opportunities and the Challenges in June 2017.

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Acronym Guide

45Q	Section 45Q Tax Credit for Carbon Dioxide Sequestration
ARB	California Air Resources Board
CapEX	Capital expenditure
CO_2	Carbon dioxide
DOE	Department of Energy
EOR	Enhanced oil recovery
IEA	International Energy Agency
LCFS	Low carbon fuels standard
MGY	Million gallons per year
MT	Metric ton
NETL	National Energy Technology Laboratory
PAB	Private Activity Bond
OpEX	Operating expense
QM	Quantification methodology`

Executive Summary

As the world leader in demonstrating carbon capture technologies in multiple industries, the U.S. is well-poised to expand commercial deployment and bring down the costs of CO_2 capture, compression and pipeline transport. With its high-purity and low-cost biogenic CO_2 derived from ethanol fermentation, the biofuels industry can play a key role in scaling up carbon management for energy production and geologic storage.

Carbon capture technology and the use and geologic storage of CO_2 through enhanced oil recovery (CO_2-EOR) have a successful history of commercial deployment going back nearly a half century. While roughly 80 percent of CO_2 used in EOR is sourced from geologic domes, a commercial market for the sale of large volumes of captured CO_2 from industrial facilities has existed for decades in the U.S. because the oil industry purchases it for injection into existing fields to recover additional crude. Storing CO_2 in saline geologic formations—a process that does not involve oil production—is more recent, with the first commercial scale demonstration dating back to the mid-1990s.

In this paper, the State CO_2-EOR Deployment Work Group explores the opportunities for energy production, expanded economic development and emissions reduction potential from capturing and utilizing CO_2 from ethanol production. The paper also describes the federal and state policies needed to foster further commercial deployment. The Work Group turns to this topic as a follow-up to its December 2016 report recommending federal and state carbon capture deployment incentives. These incentives are essential to enabling private investors to finance carbon capture at ethanol facilities, power plants and other industrial facilities, as well as pipelines to transport the CO_2 to oilfields and saline formations where it can be used and stored.

The ethanol industry already supplies roughly 270,000 MT of CO_2 annually for EOR in Kansas and Texas, and ADM expects to inject up to 1.1 million MT annually for saline storage in Illinois. For comparison, Occidental Petroleum, the world leader in CO_2-EOR, injects 47 million MT of CO_2 annually. The ethanol industry has a strategic opportunity to deploy technology and infrastructure that would both increase its revenue and beneficially reduce carbon emissions.

The biofuels industry has a history of innovation to reduce energy and water use, drive down costs, generate new sources of revenue from value-added byproducts, and lower the carbon intensity of ethanol. As it has improved energy efficiency and lowered emissions, the industry has sought new revenue opportunities from products that add value beyond the ethanol itself. Fermentation in ethanol production yields 99.9 percent pure CO_2, which can become an additional value stream; [1] in fact, the industry has sold biogenic CO_2 to the EOR industry for nearly a decade.[2]

Further deployment of carbon capture presents a significant economic opportunity for the ethanol industry through the oil industry's purchase and beneficial use of CO_2. Proposed federal and state financial incentives and credits obtained by storing CO_2 geologically through EOR or its injection into saline formations could provide additional economic value. Moreover, when the carbon accumulated in corn or other biomass feedstocks through photosynthesis is captured during fermentation, rather than released back to the atmosphere, even deeper reductions in lifecycle carbon emissions can be achieved. This, in turn, enhances the value of the ethanol produced in key markets where public policy increasingly demands reductions in carbon intensity.

Net lifecycle emissions reductions from the capture of biogenic CO_2 from ethanol fermentation can be significant.[3] The application of carbon capture to corn-ethanol plants in the U.S. has the potential to reduce the carbon intensity of resulting biofuels production by upwards of 40 percent, if the captured CO_2 is stored in saline geologic formations.[4] In the case of storing

1 While the CO_2 stream from fermentation is of high purity, equipping an ethanol plant for carbon capture requires investments in the fermenters for capture and in equipment to compress and dehydrate the CO_2 prior to pipeline transport.

2 See Figure 1 for a timeline and description of carbon capture projects in the ethanol industry.

3 Lindfeldt, Erik G., and Mats O. Westermark. 2008. "System Study of Carbon Dioxide (CO_2) Capture in Bio-Based Motor Fuel Production." Energy 33 (2):352–61. https://doi.org/10.1016/j.energy.2007.09.005. Laude, A., O. Ricci, G. Bureau, J. Royer-Adnot, and A. Fabbri. 2011. "CO_2 Capture and Storage from a Bioethanol Plant: Carbon and Energy Footprint and Economic Assessment." International Journal of Greenhouse Gas Control 5 (5):1220–31. https://doi.org/10.1016/j.ijggc.2011.06.004.

4 McCoy, Sean T. 2017. "The Value Proposition for Combining CCS and Ethanol Production." presented at the Capturing Value from Biogenic CO_2: Opportunities for Ethanol and Other Industries, Johnston, Iowa, 2 August 2017. http://www.betterenergy.org/sites/default/files/McCoy-%20Ethanol%20and%20CCS_v1.pdf.

captured CO_2 in oilfields through EOR, large net emissions reductions still result, even after accounting for the additional oil produced. Recent analysis from the International Energy Agency (IEA) shows that, after accounting for the additional oil produced and global market effects, every ton of anthropogenic CO_2 delivered for CO_2-EOR results in a 63 percent emissions reduction.[5]

This paper focuses on commodity use and geologic storage of CO_2 from ethanol production through EOR, the most commercially-ready pathway that could scale rapidly with policy reform, as well as on storage in saline formations. However, other innovative technologies and processes are under development to transform CO_2 directly into valuable fuels, chemicals and other valuable products. These alternative utilization options will benefit from the policies discussed in this paper, and they also have the potential to add value to ethanol producers, while reducing carbon emissions.

Public policy is needed to overcome challenges to commercial deployment of carbon management in the biofuels industry. At today's low oil prices, the cost of carbon capture, compression, dehydration and pipeline transport from ethanol fermentation exceeds revenue from selling that CO_2 to the oil industry. While the costs of carbon capture from ethanol are low compared to most other industries, the heartland of U.S. ethanol production in the Central Plains, Upper Midwest and Midwest is geographically distant from large oil basins with the greatest potential for EOR and storage. This requires investment in large-volume, high-pressure pipelines needed to transport CO_2 over long distances. Some ethanol production does occur in close proximity to suitable saline reservoirs, but saline storage provides no revenue from CO_2 sales for EOR, offsetting the financial advantage of avoiding major pipeline investments.

Fortunately, economic analysis completed for the Work Group suggests that federal and state financial incentives under consideration could help bridge the current cost gap in the marketplace and mitigate investment risk by incenting private capital to invest in carbon capture at ethanol plants and pipeline corridors to serve ethanol-producing regions.

The Great Plains Institute and Improved Hydrocarbon Recovery, LLC modeled CO_2 capture, dehydration, compression, and pipeline transport from Midwestern ethanol plants to oilfields for EOR under two illustrative scenarios: a pipeline network connecting 15 ethanol plants in Nebraska and Kansas to multiple oilfields in Kansas; and a regional-scale pipeline network linking 34 of the largest Upper Midwestern ethanol plants to the Permian Basin in Texas. The analysis finds a CO_2 price in the range of \$42 and \$60 per metric ton (MT) is required across the two scenarios to cover CO_2 capture, dehydration, compression and pipeline transport. The results of this analysis show that federal and state policies under consideration, coupled with revenue from the sale of CO_2 for EOR, could help make deployment of carbon capture from ethanol production and CO_2 pipeline infrastructure commercially feasible.

The Work Group's highest policy priority is extension and reform of the federal Section 45Q Tax Credit for Carbon Dioxide Sequestration, and legislation introduced in Congress to accomplish this enjoys unprecedented bipartisan support. The Carbon Capture Act in the U.S. House (H.R. 3761) and the FUTURE Act in the U.S. Senate (S. 1535) would provide investment certainty, increase the financial value, and enhance the eligibility and flexibility of a tax credit awarded for every ton of CO_2 captured from industrial facilities and power plants and then stored geologically, or used beneficially in other ways that reduce emissions. Importantly, 45Q is performance-based, meaning that credits under the legislation can only be claimed for CO_2 successfully stored in oilfields and other suitable geologic formations or otherwise put to beneficial use.

While extension and reform of the 45Q tax credit is essential, other bipartisan legislation in the U.S. House and Senate would provide valuable complementary incentives to help deploy carbon capture in ethanol production and other industries. The Carbon Capture Improvement Act (S. 843 and H.R. 2011) would make carbon capture and utilization eligible for tax-exempt private activity bonds (PABs), and the Master Limited Partnership (MLP) Parity Act (S. 2005 and H.R. 4118) would extend eligibility for tax-advantaged MLPs to renewable fuels and to carbon capture and utilization.

Passage of this legislation would benefit the biofuels industry. House and Senate 45Q bills pending in

5 International Energy Agency, *Storing CO_2 through Enhanced Oil Recovery, combining EOR with CO_2 storage (EOR+) for profit*, 2015.

Congress would provide $35 per MT for CO_2 stored through EOR and $35 or $50 per MT stored through saline storage.[6] Based on the Work Group's analysis of the costs of CO_2 capture, dehydration, compression and pipeline transport from fermentation, these credit values could have a significant impact on a typical ethanol plant's ability to capture carbon and participate in EOR markets and, potentially, to store CO_2 in saline formations without revenue from sale of CO_2 to the oil industry. In addition, access to tax-exempt PABs and the MLP business structure could further enhance the commercial feasibility of deployment.

The absence of pipeline infrastructure in key states and regions poses a further obstacle to scaling up carbon management in ethanol production. The Work Group released a paper earlier this year recommending that Congress and the Administration incorporate and prioritize the buildout of long-distance, large-volume CO_2 pipelines as part of a broader national infrastructure agenda; help finance increased capacity for priority trunk pipelines in states and regions not currently served by such infrastructure; and identify and foster the development of five priority CO_2 pipeline corridors through support for planning, permitting, and financing.

At the state level, policies to reduce the carbon intensity of transportation fuels, particularly low-carbon fuel standard (LCFS) policies, could complement federal incentives in stimulating private investment in carbon capture and CO_2 pipeline infrastructure. In some cases, such as California's LCFS, carbon credits valued at approximately $80 per MT could drive project deployment, with or without additional federal policy. The relative impact and benefit of LCFS policies in California and other jurisdictions depends largely on the regulatory framework that accompanies their implementation. The Work Group has significant concerns that proposed regulatory requirements in the California Air Resources Board's (ARB) current rulemaking would make it impossible for the ethanol and EOR industries to establish a viable carbon management business model based on LCFS compliance.

While the ethanol and oil industries traditionally have different interests in energy and environmental policy, Work Group participants believe important common ground can be forged around expanding the capture and beneficial use of biogenic CO_2 from ethanol production and its associated carbon management through EOR and saline storage.

Federal policies recommended by the Work Group in this paper are not expected to spur construction of new corn ethanol plants or increase overall production. However, working in partnership with the EOR operators, ethanol producers and their investors could harness a revamped 45Q tax credit, together with PAB and MLP eligibility, to tap into evolving low-carbon fuel product and credit markets, positioning them to capture financially the added environmental value inherent in producing fuels with a lower carbon footprint. These policies would also foster a market-based approach to American energy independence and job creation by producing oil here at home through CO_2-EOR, helping to displace current imports of more carbon-intensive imported crude and significantly reducing total emissions in the process.

Federal legislative action is critical. As this paper's analysis of the economics of carbon capture from ethanol production shows, widespread deployment will not occur without financial incentives to enhance financial feasibility and reduce market risk to investors and project developers. Carbon capture merits federal incentives and other policies comparable to those that have proven highly-effective in fostering private investment in early commercial deployment of wind, solar and other low and zero-carbon energy technologies and in achieving innovation and cost reductions.

6 The FUTURE Act in the Senate would increase the value of the 45Q tax credit from the current $10 per MT of CO_2 for EOR storage and $20 per MT for saline storage to $35 and $50 per ton, respectively. By contrast, the Carbon Capture Act in the U.S. House would increase the credit value uniformly to $35 per MT for all types of geologic storage.

Introduction

CO_2-EOR has a history of commercial deployment going back nearly a half century. While roughly 80 percent of CO_2 presently used in EOR is naturally occurring and sourced from geologic domes, a commercial market for captured CO_2 from industrial facilities has existed for decades in the U.S., where it is purchased by the oil industry for injection into existing fields to recover additional crude.

Experience with geologic storage of CO_2 in saline geologic formations is more recent, having first been demonstrated successfully at commercial scale in the mid-1990s. Despite the lack of revenue from selling CO_2 to the oil industry, future opportunity exists for a market to emerge for carbon capture and geologic storage in saline formations as well, potentially driven by public policies under consideration in the U.S. at the federal and state levels. In addition, oilfields with potential for CO_2-EOR and saline formations suitable for geologic storage sometimes occur in the same location. This creates the potential for oil production and geologic storage through EOR to expand or shift to include saline storage in the future, thereby taking economic advantage of existing carbon capture, CO_2 pipeline and other infrastructure.

The commercial capture of CO_2 from ethanol production for sale to the EOR industry first began in 2009 with the Arkalon plant, followed by the Bonanza plant in 2012. Both facilities are located in Kansas. Injection of CO_2 from fermentation into saline formations for geologic storage first began in 2011, when ADM initiated its Illinois Basin–Decatur Project, capturing and storing 1,000 MT per day for three years from its corn processing plant. This year, ADM formally commenced an even larger carbon capture and saline storage project at its Decatur facility (Figure 1).

Net lifecycle emissions reductions from the capture of biogenic CO_2 from ethanol fermentation can be significant.[7] The application of carbon capture to corn-ethanol plants in the U.S. has the potential to reduce the carbon intensity of resulting biofuels production by upwards of 40 percent, if the captured CO_2 is stored in saline geologic formations.[8] Recent analysis from the International Energy Agency shows that, after accounting for the additional oil produced and global market effects, every ton of anthropogenic CO_2 delivered for CO_2-EOR results in a 63 percent emissions reduction.[9]

Further deployment of carbon capture presents a significant economic opportunity for the ethanol industry. It creates another value-added revenue stream from the oil industry's purchase and beneficial use of CO_2 as a commodity byproduct. Additionally, there are potential federal and state financial incentives and carbon credits obtained by storing CO_2 geologically through the process of EOR or its injection into saline formations. Moreover, when the carbon accumulated in corn or other biomass feedstocks through photosynthesis is captured from fermentation, rather than released back to the atmosphere, even deeper reductions in lifecycle carbon emissions can be achieved. This, in turn, enhances the value of the ethanol produced in key markets where public policy increasingly demands reductions in carbon intensity. Thus, the ethanol industry has the potential to expand its revenue base while meeting growing policy and market expectations for lower carbon fuels.

Accomplishing this win-win requires a framework of federal and state policy incentives described in this paper that can attract private capital investment in:

- Carbon capture, compression and dehydration equipment at ethanol plants; and
- CO_2 pipeline networks linking numerous ethanol plants located in key corn and biomass-producing regions to oilfields and other reservoirs for geologic storage.

The federal and state policies recommended by the Work Group are not expected to result in construction of new biofuels facilities or to increase overall ethanol production. However, the scaling up of carbon management infrastructure in the industry would enable ethanol producers to tap into evolving low-carbon fuel product and credit markets, positioning the biofuels industry, in partnership with EOR operators, to capture financially the added value inherent in producing fuels with a lower carbon footprint. It also offers a strategic, market-based opportunity to enhance broader American energy independence by producing oil here at home that displaces current

7 Lindfeldt, Erik G., and Mats O. Westermark. 2008.

8 McCoy, Sean, 2017.

9 IEA, Storing CO_2 through Enhanced Oil Recovery, 2015.

Figure 1: Carbon Capture Works Across Multiple Industries

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

- **1972**: Terrell gas processing plant in Texas - A natural gas processing facility (along with several others) 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 oilfields in southern Oklahoma.
- **1986**: Exxon Shute Creek Gas Processing Facility in Wyoming – This natural gas processing plant serves ExxonMobil, Chevron, Denbury and Anadarko Petroleum CO_2 pipeline systems to oilfields in Wyoming and Colorado and is the largest commercial carbon capture facility in the world at 7 million tons 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. It has supplied over 30 million tons 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**: Conestoga Energy Partners' Arkalon Bioethanol plant in Kansas – The first ethanol plant to deploy carbon capture, it supplies 170,000 tons of CO_2 per year, originally to Chaparral Energy and now to Perdure Petroleum, which uses it for EOR in Texas oilfields.
- **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.
- **2011** Illinois Basin – Decatur Project in Decatur, Illinois – The CO_2 stream is captured from ethanol fermentation at the ADM corn processing plant. Approximately 1,000 MT per day was captured and injected into a saline reservoir 7,000 feet beneath the surface. A total of 1 million MT was stored over three years.
- **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/Petro Santander Bonanza Bioethanol plant in Kansas – This ethanol plant captured and supplies roughly 100,000 tons of CO_2 per year to a Kansas EOR field.
- **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 oilfield in Montana via Denbury Resources' Greencore pipeline.
- **2013**: CVR Energy Coffeyville Gasification Plant in Kansas – The CO_2 stream (approximately 850,000 tons per year) from a nitrogen fertilizer production process based on gasification of petroleum coke is captured, compressed and transported to an oilfield in northeastern Oklahoma originally operated by Chaparral Energy and now by Perdure Petroleum.
- **2013**: Antrim Gas Plant in Michigan – CO_2 from a gas processing plant owned by DTE Energy is captured at a rate of approximately 1,000 tons per day and injected into an oilfield operated by Core Energy in the Michigan Basin.
- **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.
- **2015**: Shell Quest project in Alberta, Canada – Shell began operations on a bitumen upgrader complex that captures approximately one million tons of CO_2 annually from hydrogen production units and injects it into a deep saline formation.
- **2017**: NRG Petra Nova project in Texas – NRG commenced 240 MW slipstream of flue gas from the existing WA Parish plant. The CO_2 is transported to an oilfield nearby.
- **2017**: ADM Illinois Industrial Carbon Capture & Storage Project – Archer Daniels Midland began capture from an ethanol production facility in April 2017, sequestering it in a nearby deep saline formation. The project can capture up to 1.1 million tons of CO_2 per year.

imports of more carbon-intensive imported crude in the U.S. marketplace, while significantly reducing total emissions in the process.

Traditionally, the ethanol and oil industries have often had divergent interests in federal and state energy and environmental policy. Yet, Work Group participants believe that important common ground can be forged around the mutual opportunity of expanding the capture and beneficial industry use of biogenic CO_2 accomplished through EOR and saline storage.

The State CO_2-EOR Deployment Work Group is turning to this topic as a follow-up to our December 2016 report recommending federal and state financial incentives to attract private investment in commercial carbon capture at ethanol facilities, power plants and other industrial facilities. In this paper, we explore the specific opportunities for energy production, economic development and emissions reductions from capturing and utilizing CO_2 from ethanol production and describe the needed federal and state policies.

CO_2-EOR: Background and How It Works

While this paper also considers the capture of CO_2 for geologic storage in saline formations, CO_2-EOR provides the most commercially-ready pathway for geologic storage that could scale rapidly with policy reform. CO_2-EOR represents a well-understood and long-standing technique for oil production that enables cost-effective recovery of remaining crude from mature oilfields. In the early or primary phase of traditional oil production, the extraction of oil and gas decreases the fluid pressures in a reservoir. Traditionally, a secondary phase involving injection of water to restore reservoir pressure 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. oil and gas industry has turned the practice into a robust 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 potential liability into a valuable commodity with remarkable properties 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 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 that ultimately results in safe and permanent geologic storage.

As oilfields continue to mature, CO_2-EOR presents a key opportunity to capture carbon emissions from ethanol plants, power plants, and other industrial facilities that would otherwise be vented to the atmosphere and instead puts 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 costs more 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, 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.

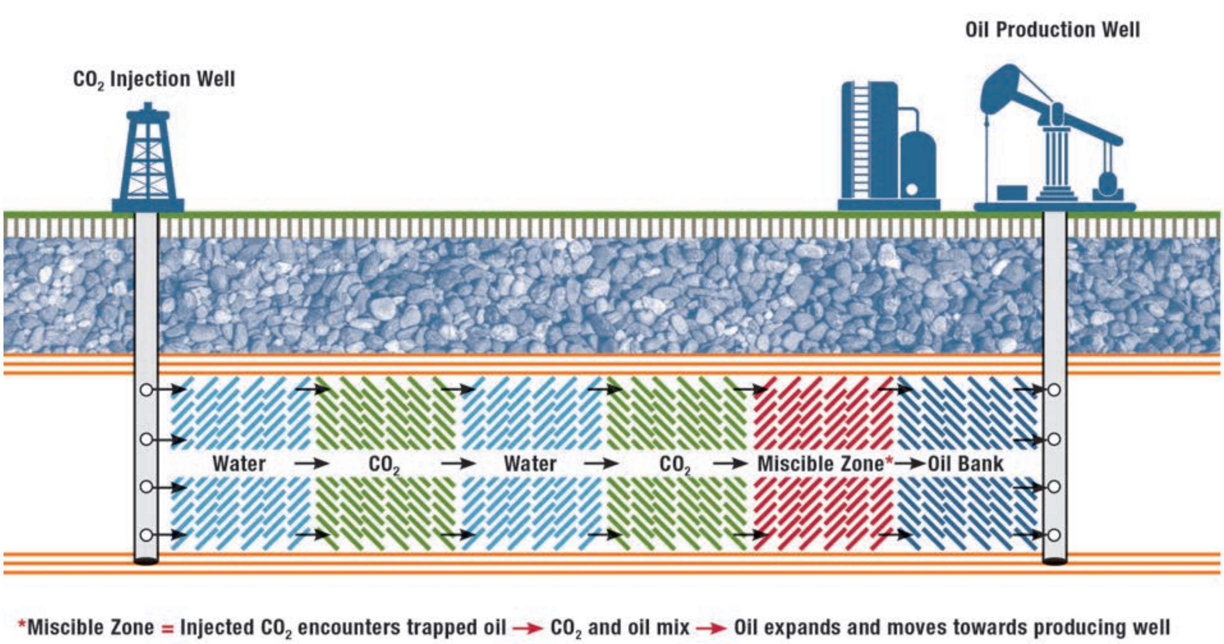
While CO_2-EOR operators must inject CO_2 for approximately one year before a formation will yield additional oil, the resulting production may continue for up to 30 years, usually peaking for 10 years (between years 5-15). CO_2-EOR therefore can provide relatively stable energy production, employment, 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 captured, compressed and delivered by pipeline at an affordable price. The fermentation of corn and biomass to produce ethanol provides a 99.9 percent pure stream of biogenic CO_2 from which only excess water must be removed prior to compression and pipeline transport. This process aligns well with the need for affordable and readily available CO_2.

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 (MT) per year; 55 million MT of which comes from geologic sources, and 17 million MT come from manmade or anthropogenic sources. Yet, natural geologic supplies of CO_2 are constrained and gradually depleting, so the potential to grow the EOR industry hinges upon increasing the supply of anthropogenic CO_2, thereby also reducing net carbon emissions. In that context, low-cost, high-purity biogenic CO_2 from fermentation in ethanol production represents a key early target for making additional anthropogenic CO_2 available for EOR and thus enabling domestic production of lower-carbon oil.

CO_2-EOR & Ethanol: Opportunities & Challenges Explained

Carbon capture, compression and dehydration systems were installed at the Arkalon and Bonanza ethanol plants in Kansas in 2009 and 2012, respectively, together with the construction of pipelines to transport the CO_2 to Texas and Kansas for use in EOR. These commercial operations continue successfully today. However, a combination of conditions made these projects feasible in the market

Figure 2: How Carbon Dioxide and Water Can Be Used to Produce Residual Oil



place—close proximity to suitable oilfields and higher oil prices—that cannot be replicated elsewhere today. For production of biogenic CO_2 from the fermentation of ethanol to expand and become a major source of supply for oil production with geologic storage, that CO_2 must be delivered to the oilfields at a market price compatible with the economics of EOR projects.

Similarly, ADM's current efforts at its Decatur ethanol facility in Illinois to capture CO_2 and store it in a saline formation depends on federal funding provided by the U.S. Department of Energy (DOE) for the purposes of first-time commercial-scale demonstration. Red Trail Energy in Richardton, ND, also plans to store 180,000 MT of CO_2 annually from ethanol fermentation in the Broom Creek saline formation by 2020.[10] However, further commercial-scale deployment of saline storage of CO_2 from ethanol production will be challenged without financial incentives.

Proposed federal incentives described in this paper, such as the extension and reform of the Section 45Q Tax Credit for Carbon Dioxide Sequestration, coupled with complementary policies such as tax exempt private activity bonds (PABs) and tax-advantaged master limited partnership (MLP) structures, will bring down the cost of carbon capture, compression and pipeline transport enough to enable widespread deployment and competitive delivery of anthropogenic CO_2 from ethanol into existing and emerging EOR markets. Furthermore, in some geographic locations, proposed federal incentives could facilitate biogenic CO_2 from ethanol production being captured, transported and stored in saline geologic formations, even without the need for revenue from the sale of CO_2 to the oil industry.

Large reserves of domestic oil exist in the lower 48 states that could, through expanded CO_2-EOR with storage, reduce the trade deficit and our need for foreign oil, while generating significant employment, tax revenue and emissions reductions.[11] To date, the production of mature U.S. oilfields is being extended by decades through the injection of CO_2. A near-term opportunity exists to enhance domestic energy production and generate federal and state revenue from oil production, while simultaneously reducing millions of tons of annual CO_2 emissions. By enacting the 45Q tax credit, PAB and MLP incentives, we can drive investment in carbon capture at ethanol plants and pipeline infrastructure to increase the market supply of anthropogenic CO_2 available to the U.S. EOR industry.

Carbon Capture and Utilization: The Next Step in Adding Value to the Ethanol Industry

The ethanol industry has a history of innovation to reduce energy and water use, drive down costs, generate new sources of revenue from value-added byproducts, and lower the carbon intensity over time. Numerous studies have documented the steady progress in improving the efficiency of energy use in ethanol production.[12]

As the ethanol industry has improved energy efficiency and lowered emissions, it has also sought new opportunities for revenue from different products, in addition to ethanol. Each 56-pound bushel of corn produces about 17 pounds of dried distillers grains, now widely marketed as animal feed. Wet mill ethanol plants produce a variety of food and bio-based chemical products. Many dry mill ethanol plants are exploring strategies for extracting additional value from distillers grains, including extracting corn oil for food and biodiesel production, and extracting cellulosic fiber for ethanol production. Recovery of these value-added byproducts has contributed to the lowering of ethanol's carbon intensity over time. In the context of

10 Lisa Gibson (2017), Red Trail Energy moves forward with carbon capture research, Ethanol Producer Magazine. Available at: http://www.ethanolproducer.com/articles/14428/red-trail-energy-moves-forward-with-carbon-capture-research [Accessed July 3, 2017]

11 For example, Advanced Resources International estimates that, using current industry practices, 24.3 billion barrels of additional oil could be economically recovered through CO_2-EOR from U.S. onshore fields in the lower 48 states, while storing 8.9 billion MT of CO_2. With the adoption of next generation techniques, those estimates rise to 60.7 billion barrels of economically recoverable oil and 17.3 billion MT of CO_2, respectively. See ARI analysis in *CO_2 Building Blocks: Assessing CO_2* Utilization Options, National Coal Council, 2016, Appendix 2, p. 96.

12 As an example, see research from Argonne National Laboratory, as cited in https://www.usda.gov/oce/climate_change/mitigation_technologies/USDAEthanolReport_20170107.pdf

ongoing byproduct innovation and marketing, high purity biogenic CO_2 produced during fermentation represents yet another value stream that the ethanol industry can take advantage of to the benefit of carbon management.

This paper focuses on the commodity use and geologic storage of CO_2 through EOR, as well as storage in saline formations, but there are other distinct and innovative utilization options. Ethanol plants constitute the largest single-sector source of CO_2 for U.S. merchant gas markets, and the CO_2 produced enters a wide variety of markets, including food, beverage and dry ice applications.[13]

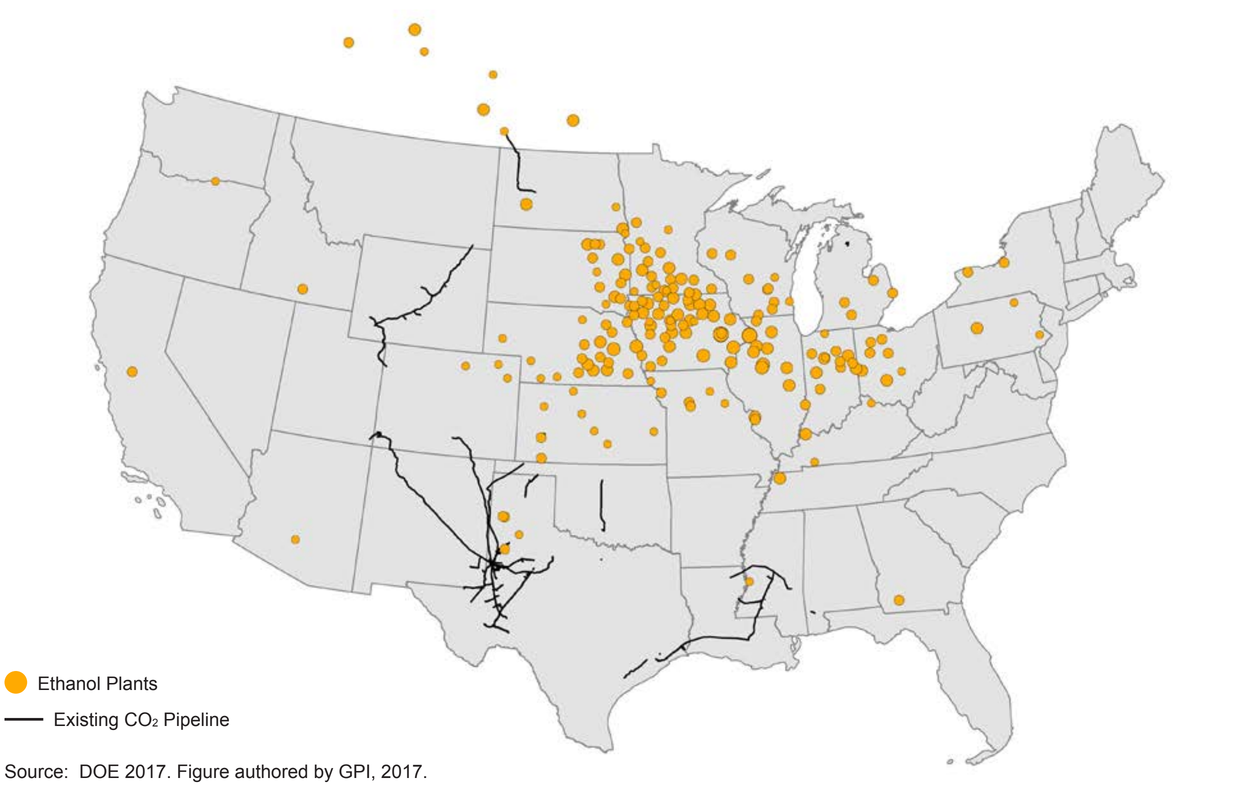
At least one ethanol plant in Iowa utilizes CO_2 from fermentation for algae production, and a range of new technologies are under development to transform CO_2 directly into valuable fuels and chemicals. These technologies would all benefit from the policies discussed in this paper, and they have future potential to provide additional value to ethanol producers while reducing carbon emissions.

As previously noted, the ethanol industry already supplies roughly 270,000 MT of CO_2 annually for EOR in Kansas and Texas, and ADM expects to inject up to 1.1 million MT annually for saline storage in Illinois. For comparison, Occidental Petroleum, the world leader in CO_2-EOR, injects 47 million MT of CO_2 annually. The ethanol industry has a strategic opportunity to deploy technology and infrastructure to both increase its revenue and beneficially reduce carbon emissions.

Near-term market opportunities are motivating the ethanol industry to explore potential carbon capture and CO_2 pipeline projects and to organize and engage with the EOR industry and other stakeholders in support of federal incentives. Unfortunately, challenges to this sector's widespread participation in carbon management markets are significant. U.S. ethanol production in the Central Plains, Upper Midwest and Midwest is geographically distant from large oil basins with the greatest potential for EOR and storage (Figure 3). Additionally, large-volume, high-pressure pipelines needed to transport CO_2 from ethanol over long distances are expensive. Although some U.S. ethanol production occurs near reservoirs

13 http://ethanolproducer.com/articles/14122/ethanol-industry-provides-critical-co2-supply

Figure 3: Ethanol Plants and Existing CO_2 Pipelines



Source: DOE 2017. Figure authored by GPI, 2017.

suitable for saline storage, the financial benefit of not needing major investment in new pipeline infrastructure is offset by the lack of a revenue stream from selling CO_2 to the EOR industry.

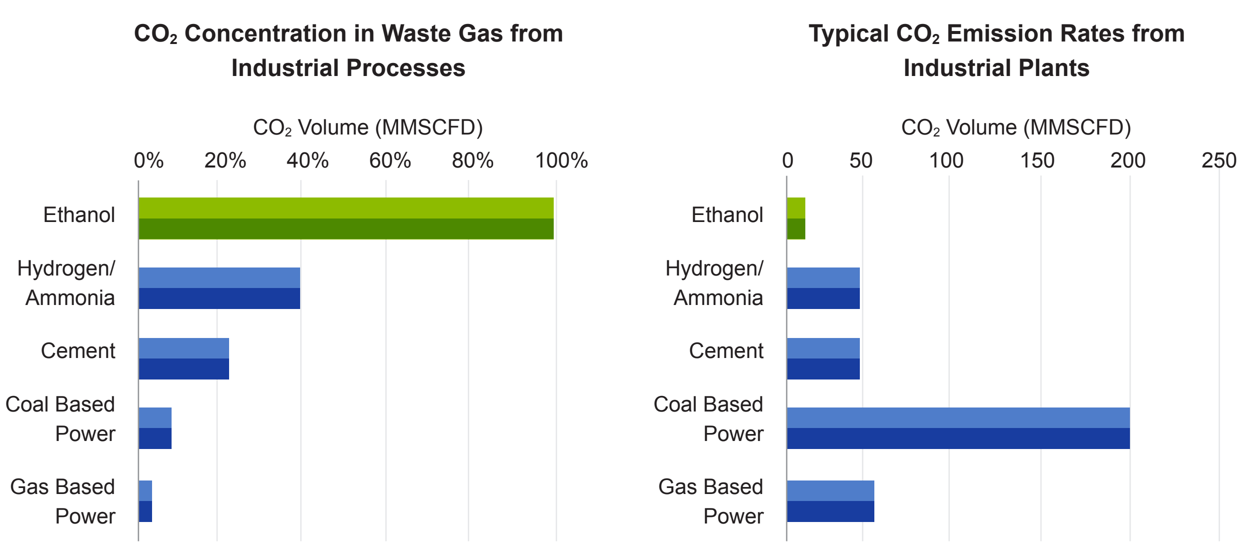
Additionally, ethanol plants produce small volumes of CO_2, compared to a typical coal-fired power plant or many other industrial facilities. Thus, individual ethanol plants must be aggregated along a common trunk pipeline and connected by feeder lines, not only to realize economies of scale associated with transportation infrastructure costs, but also to provide a large and dependable supply of CO_2. Figure 4 illustrates the relative concentration and volume of CO_2 from ethanol refineries compared to other industrial sources.

Therefore, at current lower oil prices, it is unlikely that significant additional carbon capture and CO_2 pipeline infrastructure serving the ethanol industry can be financed with private capital, absent additional policy incentives. In addition, investments in EOR operations are long term, generating cash flow over decades. However, it typically requires several years of CO_2 injection before significant increases in oil production materialize, meaning that initial investors bear greater risk up front. In the current market environment, investing in oil production from shales offers greater returns with a shorter pay-off, thus diverting capital away from longer-term EOR and associated carbon capture and pipeline investments. The availability of federal incentives could change that by helping to bridge the current cost gap in the marketplace and mitigating investment risk, thereby incenting private capital to invest in capture, compression and dehydration equipment at ethanol plants and CO_2 pipeline corridors to ethanol-producing regions.

In addition to analysis prepared for the Work Group of carbon capture and pipeline transport deployment for EOR with geologic storage (see Technical Evaluation of the Ethanol Opportunity below), separate modeling of deployment for the purposes of saline storage illustrates that, as incentives for ethanol producers to store CO_2 increase (due to tax credits or emissions reduction credits), the number of plants equipped with carbon capture grows, along with number of miles of pipeline built and geologic storage sites developed.[14] This growth is facilitated by development of large-volume CO_2 trunk pipelines, which allows more distant ethanol plants to economically transport CO_2 to storage. This analysis underscores the critical role that financial incentives can play in leveraging private sector investment in carbon management infrastructure to serve the ethanol industry. Combining such incentives with federal and state policies to facilitate development and siting and permitting of long-distance, large-volume CO_2 trunk pipelines with feeder lines aggregating multiple ethanol plants (as

14 D.L. Sanchez, N. Johnson, S. McCoy, P.A. Turner, K.J. Mach. “Near-term deployment of carbon capture and storage from biorefineries in the United States” Manuscript in preparation.

Figure 4: Biogenic and Anthropogenic CO_2 Sources

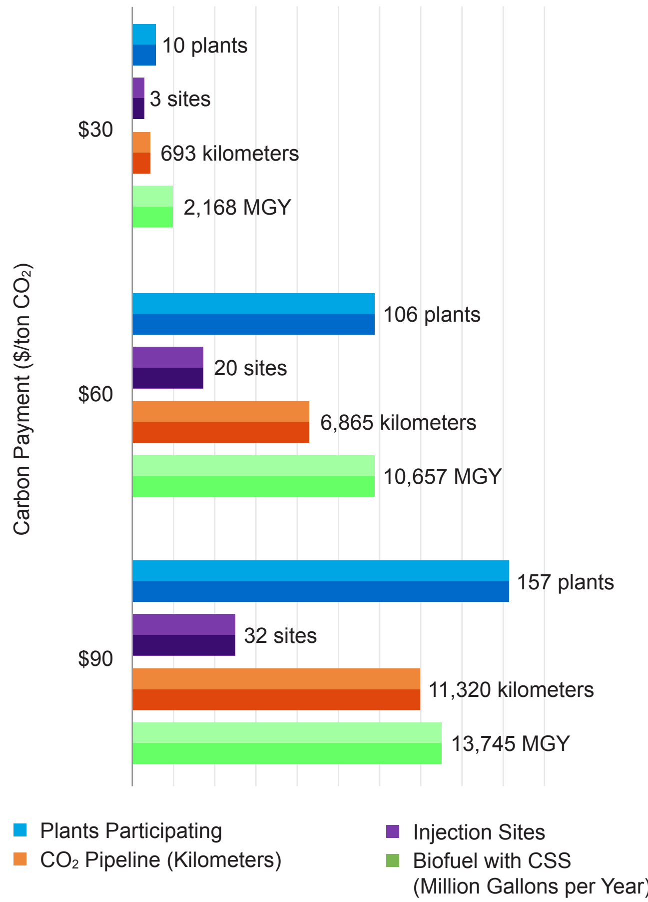


recommended in a previous Work Group paper), can improve the feasibility of carbon capture and CO_2 pipeline infrastructure deployment.

Federal policies currently under consideration in Congress, and endorsed by the Work Group, could help foster such deployment. For example, pending bills to extend and reform the federal 45Q tax credit—the FUTURE Act, S. 1535, in the U.S. Senate and the Carbon Capture Act, H.R. 3761, in the U.S. House—would provide credit values of $35 per MT for CO_2 stored through EOR and $35 or $50 per MT stored through saline storage.[15] Passage of this legislation could enhance a typical ethanol plant's ability to capture carbon and participate in EOR markets, and potentially to capture and store CO_2 in saline formations as well.

At the state level, low-carbon fuels policies such as California's LCFS have the potential to drive broader carbon capture and CO_2 pipeline development in the ethanol industry. Currently, carbon credit prices of around $80 per MT in the state's LCFS market would make the capture and storage of CO_2 from fermentation economically attractive for those producers selling ethanol into the California market, but only if the current rulemaking being undertaken by the California Air Resources Board (ARB) establishes a regulatory framework conducive to commercial participation by the industry (a more detailed discussion of the California LCFS occurs later in this paper).

Figure 5: Biofuel Carbon Capture Grows with CO_2 Payment



Source: D.L. Sanchez, N. Johnson, S. McCoy, P.A. Turner, K.J. Mach. "Near-term deployment of carbon capture and storage from biorefineries in the United States" Manuscript in preparation.

Technical Evaluation of the Ethanol Opportunity

Coinciding with the writing of this paper, research team members are engaged in an ongoing collaboration with the Kansas Geological Survey as part of a DOE-funded CarbonSAFE project. An economic analysis of CO_2 capture, compression, and pipeline transportation from Midwestern ethanol plants was conducted by GPI and Improved Hydrocarbon Recovery, LLC (IHR). The analysis considered a variety of scenarios for capture and transportation of large CO_2 volumes in the Midwest and Central Plains. Two of these scenarios are presented here as a case study. The second scenario is a regionwide pipeline network to carry CO_2 from ethanol production across the Upper Midwest and Central Plains. This pipeline network follows one of the Work Group's previously-recommended CO_2 pipeline corridors.

In the first scenario, a pipeline network (Figure 6.1) would transport 4.3 million MT of CO_2 per year from Nebraska ethanol plants into Kansas oilfields for EOR at a projected cost of $42 to $53 per MT. This could increase Kansas oil production by 10 million barrels

15 The FUTURE Act in the Senate would increase the value of the 45Q tax credit from the current $10 per MT of CO_2 for EOR storage and $20 per MT for saline storage to $35 and $50 per ton, respectively. By contrast, the Carbon Capture Act in the U.S. House would increase the credit value uniformly to $35 per MT for all types of geologic storage.

per year (a 28 percent increase).[16] In the second scenario, a larger pipeline network (Figure 6.2) would gather 9.85 million MT of CO_2 annually and link Upper Midwestern ethanol plants to an existing CO_2 pipeline network in the Permian Basin of Texas and New Mexico at a projected cost of $47 to $60 per MT.

The costs in this study include both capital and operating expenses for capture and compression at the ethanol plants, as well as for CO_2 pipeline construction and operation. Although the range of estimated costs of $42 to $60 per MT across both scenarios is not competitive with the current West Texas CO_2 market for EOR, financial incentives such as the proposed 45Q tax credit ($35 per MT), credit generation in California's LCFS, and revenues from the sale of CO_2 to EOR producers would present economic opportunities that may justify investment in the deployment of capture and pipeline infrastructure to serve ethanol plants.

CO_2 Pipeline Assumptions and Cost Model

GPI and IHR utilized the National Energy Technology Laboratory's (NETL) CO_2 Transport Cost Model[17], modified by GPI for this application, to calculate detailed breakdowns of capital and operating costs of CO_2 pipelines in two scenarios.[18] A detailed description of the methodology and assumptions can be found in the Appendix.

Scenario 1: Fifteen Nebraska and Kansas ethanol plants to Kansas oilfields

An efficiently planned, regional-scale pipeline system would connect 15 of the larger ethanol plants in Nebraska and Kansas and transport CO_2 to multiple oilfields in Kansas. A primary trunk line runs from Blair, NE, through Columbus, NE, down to the Huffstutter oilfield in Kansas, then further southwest to the Pleasant Prairie field area of Kansas. Ethanol plants are connected to the trunk through feeder lines, resulting in a total pipeline network length of 737 miles. Aggregating the 15 plants' yields, a total capacity of 1,575 million gallons per year (MGY) of ethanol would yield CO_2 production of about 4.3 million MT net CO_2 per year, assuming 90 percent of gross CO_2 is captured. Calculated minimum pipeline diameters ranged from four inches for feeder lines to 12 inches for the trunk line.

Pipeline costs determined by the NETL CO_2 Transport Cost model are a $642 million capital investment and $16 million in annual operating expenses. An additional $364 million is required for capital equipment at ethanol plants as well as $37 million in annual operating expenses for capture. This results in a total capital investment of about $1 billion and annual expenses of $53 million.

Assuming a 10 percent cost of capital, the investment requires a CO_2 price of about $42 per MT, while a 15 percent return on investment requires a CO_2 price of about $53 per MT.

Scenario 2: Large scale Midwestern pipeline network to Permian Basin

To capture the full potential of CO_2 capture from Central Plains and Upper Midwestern ethanol and maximize economic opportunities for the biofuels and EOR industries, and for large-scale carbon management, an even larger scale, multistate pipeline network is necessary. The second scenario considers a pipeline network designed to connect 34 of the largest ethanol plants throughout the region with feeder lines along a trunk pipeline that would link up with existing pipelines in the Permian Basin.

The 34 ethanol plants considered here could produce 9.85 million MT of net CO_2 per year (90 percent of gross) and would require about 1,546 miles of pipeline ranging in diameter from four inches for feeder lines and 20 inches for the main trunk. This large pipeline network could enable additional capture from other large CO_2 sources such as Westar's Jeffrey Energy Center (2.5 million MT per year) and the CHS McPherson refinery (0.75 million MT per year), depending on economic feasibility at those plants.

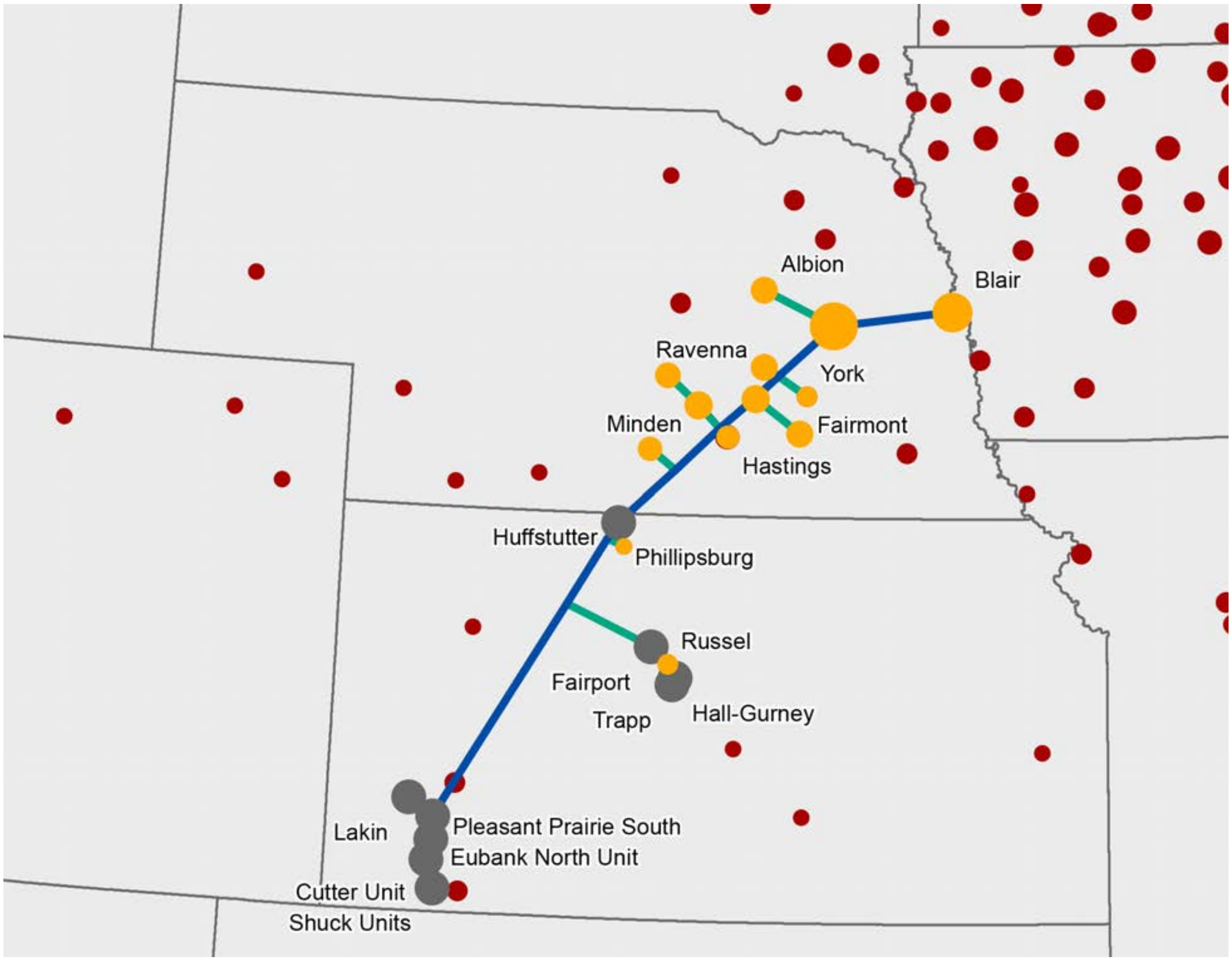
Adding CO_2 from these plants would increase source diversity and overall reliability, expand delivered volume, and potentially improve systemwide economics. As designed, capture and transportation of 9.85 MT of CO_2 from ethanol fermentation would require capital investments of $809 million for capture and compression at the 34 ethanol plants and $1.86

16 Martin Dubois, Kansas CO_2 Enhanced Oil Recovery History and Potential, presented at CCUS in Kansas, Wichita KS, September 21, 2017.

17 Timothy Grant & David Morgan, National Energy Technology Laboratory. *FE/NETL CO_2 Transport Cost Model.* DOE/NETL-2014/1667. July 11, 2014.

18 Martin Dubois, Dane McFarlane and Tandis Bidgoli, CO_2 Pipeline Cost Analysis Utilizing and Modified FE/NETL Cost Model Tool, poster presented at the Carbon Storage and Oil and Natural Gas Technologies Review Meeting, Pittsburgh PA, August 3, 2017.

Figure 6.1: Scenario 1



- Ethanol Plants (Capture Occuring)
- Ethanol Plants (Not Initially Participating)
- Oil Fields / Storage Sites
- Other Energy Facilities with Potential Capture
- CO_2 Trunk Pipeline
- CO_2 Feeder Lines
- Existing CO_2 Pipeline

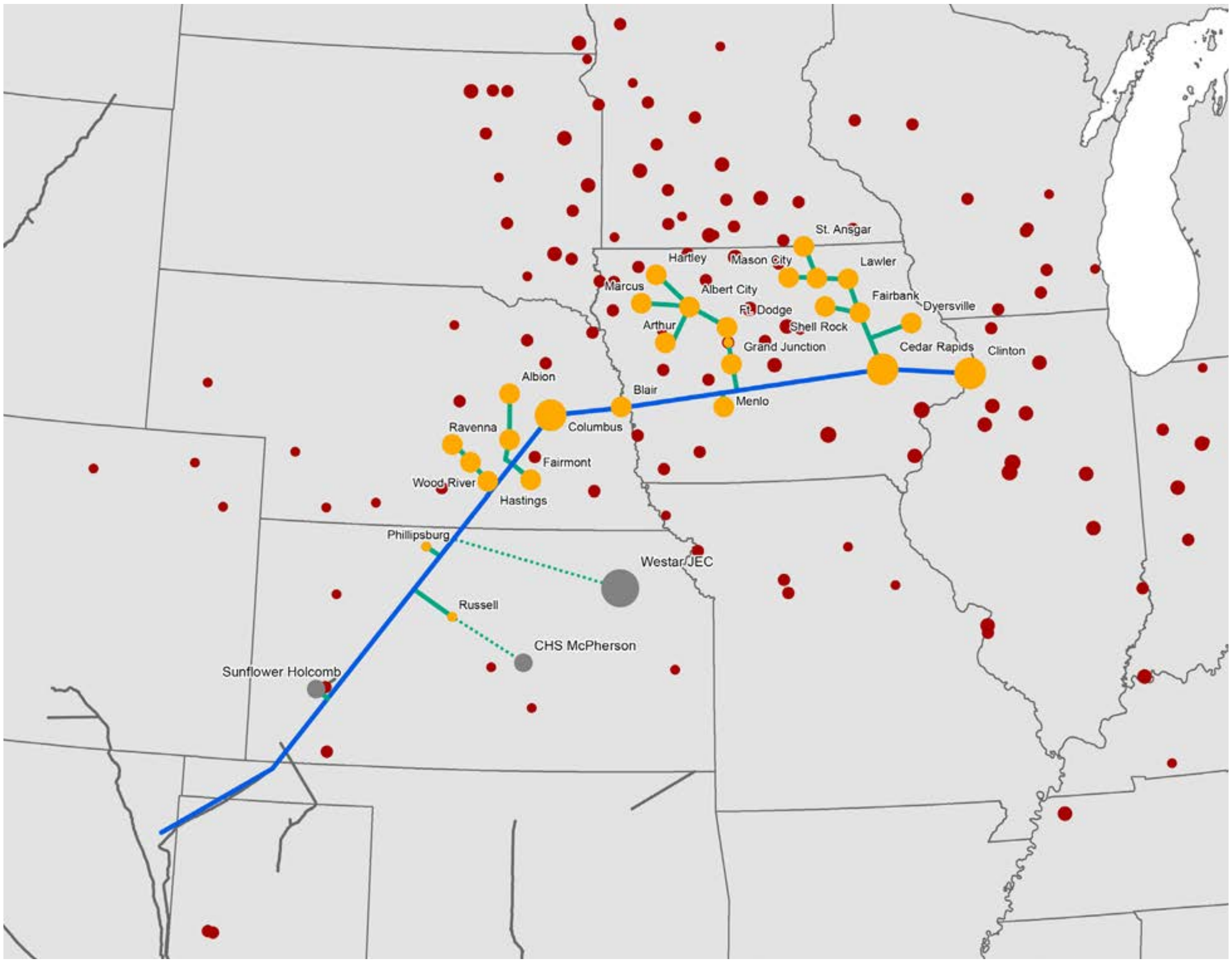
Ethanol plant production capacity is represented by the size of each circle (orange) from 40 to 350 million gallons per year.

Source: DOE, GPI, IHR, 2017. Figure authored by GPI, 2017.

Table 1.1: Scenario 1 Costs and Required CO_2 Price

	Plant Capture	Pipeline Transport	Total	Required CO_2 Price for ROI 10%	Required CO_2 Price for ROI 15%
CapEx	$364	$642	$1,006	$42	$53
Annual OpEx	$37	$16	$53		
	$ million			$ / metric ton	

Figure 6.2: Scenario 2



- Ethanol Plants (Capture Occuring)
- Ethanol Plants (Not Initially Participating)
- Oil Fields / Storage Sites
- Other Energy Facilities with Potential Capture
- CO_2 Trunk Pipeline
- CO_2 Feeder Lines
- Existing CO_2 Pipeline

Ethanol plant production capacity is represented by the size of each circle (orange) from 40 to 350 million gallons per year.

Source: DOE, GPI, IHR, 2017. Figure authored by GPI, 2017.

Table 1.2: Scenario 2 Costs and Required CO_2 Price

	Plant Capture	Pipeline Transport	Total	Required CO_2 Price for ROI	
				10%	15%
CapEx	$809	$1,857	$2,667	$47	$60
Annual OpEx	$85	$47	$131		
	$ million			$ / metric ton	

billion for the 1546-mile pipeline network. Annual operating expenses are estimated to be $85 million for capture and compression and $47 million for the pipeline system.

The $2.67 billion capital investment and $131 million in annual operating costs would require a CO_2 price of $47 per MT for a 10 percent return on investment and $60 per MT for a 15 percent return.

Conclusion: Incentives Can Enhance Ethanol Carbon Capture Feasibility

The two large-scale capture and transportation systems described in the scenarios above would require an oilfield CO_2 price ranging from $42 to $60 per MT in order to recover capital and operating costs, plus a reasonable return on investment.

Determining the actual economic feasibility of projects such as those analyzed in this paper involves more than simply comparing modeled cost estimates against projected CO_2 sales and the value of potential incentives. Project development costs and uncertainties and market and investment risk not captured by the modeling will influence a developer's decision whether to pursue a project and investors' willingness to finance it and on what terms.

However, within the context of existing demand for CO_2 in the EOR industry, this analysis suggests that the economic viability of large-scale ethanol CO_2 capture and transportation would be significantly enhanced by enactment of incentives such as a revamped federal 45Q tax credit currently proposed in Congress and potentially California's LCFS policy, subject to the outcome of the ARB's current rulemaking.

Federal Policy Overview

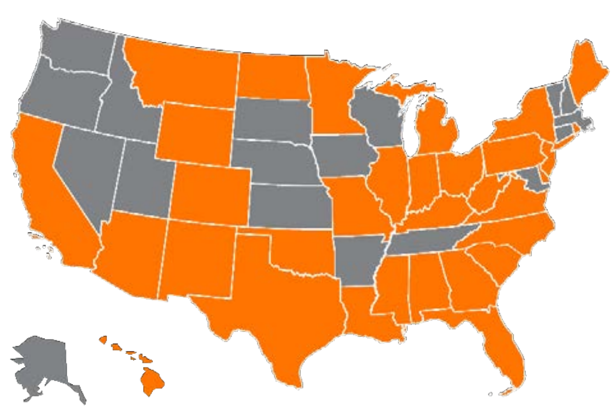
In analysis released last month, the IEA estimates that $850 billion was invested globally in low-carbon energy in 2016, but only $1.2 billion of that investment flowed into carbon capture.[19] In the U.S. and other countries, carbon capture lacks incentives and other policies that have proven highly-effective in fostering private investment in commercial deployment of wind, solar and other low and zero-carbon energy technologies, resulting in ongoing innovation and cost reductions.

As the world leader in demonstrating carbon capture technologies in multiple industries, the U.S. is well-poised to scale up commercial deployment and bring down the costs of CO_2 capture, compression and pipeline transport. However, as analysis of the economics of carbon capture from ethanol production in this paper shows, widespread deployment will not occur without the benefit of robust financial incentives and other policies to help bridge the cost gap and reduce the commercial risk to investors and developers of carbon capture and pipeline projects. Fortunately, passage of bipartisan legislation introduced in both the U.S. House and the Senate would go a long way toward providing carbon capture with financial incentives comparable to those that have long benefitted other low and zero-carbon energy technologies.

Section 45Q Tax Credit

At the federal level, the most important financial incentive for carbon capture under consideration is the Section 45Q Tax Credit for Carbon Dioxide Sequestration, which is awarded for every ton of CO_2 captured and stored through EOR or other geologic storage. The 45Q tax credit is completely performance-based, meaning that credits can only be claimed for tons of CO_2 that have been successfully captured, injected into an oilfield or other suitable geologic formation, and stored.

Figure 7: States with Congressional Sponsors of 45Q Legislation



19 *Five Keys to Unlock CCS Investment*, International Energy Agency, 2017, p. 3.

However, the existing 45Q tax credit has never worked as originally intended. Credit values of $10 per MT for CO_2 stored through EOR and $20 per MT for saline storage provide too little financial incentive to stimulate private investment in new carbon capture projects. The credit is also poorly designed. For a facility to be eligible, it must capture 500,000 MT or more of CO_2 annually, a scale far beyond all but a handful of ethanol plants, as well as many facilities in other industries. Other requirements make it difficult or impossible for project developers to monetize the tax credit, especially cooperatives that play an important role in the ethanol industry. To make matters worse, the current 45Q program is capped at 75 million MT and will soon expire, as over two-thirds of available credits had already been claimed as of May 2017.[20] This means that any carbon capture project initiated today, whether at an ethanol plant or other industrial facility, will not benefit from the tax credit, thus providing no financial certainty to investors.

20 *Internal Revenue Bulletin: 2017-22*, Internal Revenue Service, May 30, 2017.

Fortunately, legislation with extensive bipartisan support has been introduced in Congress. The FUTURE Act, S. 1535, introduced by U.S. Senators Heidi Heitkamp (D-ND), Shelley Moore Capito (RWV), Sheldon Whitehouse (R-RI) and John Barrasso (R-WY) and co-sponsored by 21 other senators—five Republicans, 19 Democrats and one Independent—together represent one-fourth of the Senate. In the U.S. House, a bipartisan companion bill introduced by Representative Mike Conaway (RTX), the Carbon Capture Act, H.R. 3761, has 44 cosponsors, 32 Republicans and 12 Democrats. Supporters of these bills hail from thirty-two states.

The FUTURE Act and the Carbon Capture Act would extend and reform the Section 45Q tax credit in the following key ways (see Figure 8 for details):

Figure 8: Key Elements of 2017 45Q Legislation

House: Carbon Capture Act
H.R. 3761

Specifications

- Keeps existing 45Q in place for current projects.
- Credit for EOR storage and saline storage increases to $35 per metric ton. There is only one credit.
- Ramps credit for 10 years.
- Reduces facility eligibility threshold from 500,000 to 100,000 tons of annual CO_2 capture for all facilities–was 150,000 in last year's bill.
- Includes stronger transferability provision in last year's Senate bill.
- Authorizes program for projects that commence construction within 7 years.
- Credic can be claimed for 15 years once placed in service.
- Provides eligibility for new forms of CO_2 utilization beyond EOR at $35 per ton.
- Adds language to allow corbon monoxide capture and direct air capture to get the credit.
- Credit authorization language is changed to allow all projects that "have never received 45Q tax credit before" to qualify.

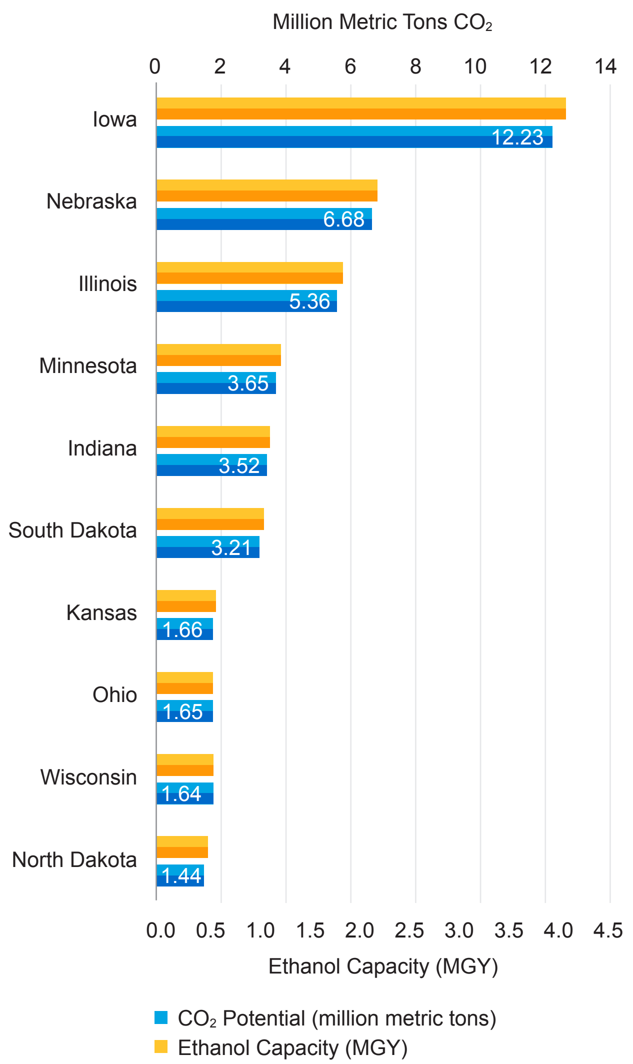
Senate: FUTURE Act
S. 1535

Specifications

- Keeps existing 45Q in place for current projects.
- Credit for EOR storage and saline storage increases to $35 per metric ton.
- Ramps credit for 10 years.
- Reduces 500,000 ton thresholdto 100,000 for industrial and 25,000 threshold for non-EOR utilization. Retains 500,000 threshold for electric generating units.
- Includes stronger transferability provision in last year's bill.
- Authorizes program for projects that commence construction within 7 years.
- Credic can be claimed for 12 years once placed in service.
- Provides eligibility for new forms of CO_2 utilization beyond EOR at $35 per ton.
- Adds language to allow corbon monoxide capture and direct air capture to get the credit.
- Credit authorization language is changed to allow electric power projects that "have never received 45Q tax credit before" to qualify.

- Increase the incentive value of the credit from $10 to $35 per MT for EOR storage, and from $20 to $35 per MT for saline storage in the House bill and to $50 in the Senate;
- Eliminate the $75 million MT cap, making credits available to any project that commences construction within seven years and providing much needed investment certainty;
- Lowers the eligibility threshold from 500,000 to 100,000 MT of CO_2 captured annually, expanding participation to ethanol plants and many other industrial facilities;

Figure 9: Annual Ethanol CO_2 Capture Potential Top Ethanol Producing States



- Enhances flexibility by allowing different participants in a project to claim the credit, thus accommodating multiple business models and investors; and
- Provides eligibility for other beneficial commodity uses of captured CO_2 beyond EOR and saline storage that reduce carbon emissions.

Based on analyses of the financial feasibility of carbon capture projects, the Work Group identified the extension and reform of 45Q as its highest legislative priority in its major 2016 report recommending federal and state incentives. Much as the federal wind production tax credit and solar investment tax credit have helped to accelerate commercial deployment of those technologies, congressional action to revamp 45Q would make the tax credit a primary driver for carbon capture projects. This would in turn reduce the risk to private capital of investing in pipelines by giving greater assurance of an affordable and growing supply of anthropogenic CO_2 from ethanol production, electric power generation and other industries.

For the biofuels industry, passage of 45Q tax credit legislation will help bridge the current gap between the cost of carbon capture, compression and dehydration from ethanol fermentation and potential revenues from selling commodity CO_2 to the EOR industry. Changing the eligibility threshold to 100,000 MT of annual CO_2 capture will make most of the nation's ethanol facilities eligible for the credit. In addition, by making the tax credit available to any eligible ethanol plant that commences construction within seven years, project developers and investors will have ample time to execute, finance and construct (See Figure 9). Finally, the legislation's flexibility in allowing any entity involved in managing the CO_2 to claim the credit will enable negotiations between ethanol producers, investors, pipeline owners, EOR operators and technology vendors to identify the party best positioned to take advantage of the tax credit and benefit the project economics.

Federal Incentives to Complement 45Q: Private Activity Bonds and Master Limited Partnerships

While the extension and reform of 45Q is essential, other bipartisan legislation would provide additional incentives for carbon capture projects could play a valuable complementary role.

Tax-Exempt Private Activity Bonds

Carbon capture projects should also be made eligible for tax-exempt PABs to lower the cost of capital. To provide that eligibility, the Carbon Capture Improvement Act has been introduced as bipartisan companion bills in the U.S. Senate, S. 843, by Senators Michael Bennet (D-CO) and Rob Portman (R-OH), and in the U.S. House, H.R. 2011, by Congressmen Carlos Curbelo (R-FL) and Marc Veasey (D-TX).

The federal government currently provides allocations to states of approximately $33 billion of PABs issued 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 industry as it grows. 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. Federal budget experts have concluded that allowing carbon capture facilities to be financed by PABs will entail only a modest additional cost of $126 million to the Federal Treasury over ten years.

Master Limited Partnerships

The carbon capture industry, including ethanol projects, would benefit if Congress extends MLP eligibility to carbon capture projects to help reduce the cost of equity. The Master Limited Partnership Parity Act would extend availability of this tax-advantaged business structure to additional energy technologies and resources not currently eligible, including both renewable fuels and carbon capture projects (CO_2 pipelines are already eligible). Bipartisan companion legislation has been introduced in the U.S. Senate, S. 2005, by Senators Chris Coons (D-DE) and Jerry Moran (R-KS) and in the U.S. House, H.R. 4118, by Congressman Ted Poe (R-TX) and Mike Thompson (D-CA).

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. Thus, eligibility for the MLP business structure would allow carbon capture projects to raise larger amounts of money on more favorable terms from equity investors.

Policies to Support the Buildout of CO_2 Pipeline Infrastructure

In addition to the need for federal incentives to finance CO_2 capture, the lack of available pipeline infrastructure in key states and regions poses a major obstacle to scaling up carbon management in ethanol production. While its relative cost of carbon capture from fermentation is low, the biofuels industry faces a greater CO_2 pipeline challenge than many other industry sectors for reasons highlighted by the modeling results presented earlier in this paper. Given the greater distances of most ethanol production from large oilfields suitable for CO_2-EOR, combined with the comparatively smaller volumes of CO_2 produced by each ethanol plant, economies of scale will require financing, permitting and constructing large, long-distance trunk pipelines with feeder lines to aggregate multiple ethanol plants over wide geographic areas.

Federal CO_2 Pipeline Policy Recommendations

Recognizing that the buildout of pipeline networks merits greater attention from federal and state policymakers, the Work Group released a paper on CO_2 pipeline infrastructure earlier this year that makes three principal recommendations:

1. Congress and the Administration should incorporate and prioritize the development of long-distance, large-volume CO_2 pipelines as part of a broader national infrastructure agenda;

2. The federal government should play a targeted role, supplementing private capital, in financing increased capacity for priority trunk pipelines to transport CO_2 from industrial facilities and power plants not currently served by pipeline infrastructure to oilfields for EOR and to other geologic storage sites; and

3. Congress and the Administration should, in consultation with states, tribal governments and key stakeholders, identify and foster the development of five such priority CO_2 trunk pipelines, including support for planning, permitting, and financing.

Developing CO_2 Pipeline Infrastructure Commensurate with Future Carbon Management Potential

In its CO_2 pipeline infrastructure paper, the Work Group identified five potential trunk pipeline corridors that would link key industrial, fossil power-generating, and biofuels-producing regions of the country with the potential to supply significant anthropogenic CO_2 to major hubs of domestic oil production (see map in Figure 10). With the addition over time of several connecting pipelines of modest length, this roughly horseshoe-shaped system would link the Upper and Lower Midwest in the east to the Gulf Coast and the Permian Basin of Texas and New Mexico in the south to the Rockies and Northern Plains of the U.S. and Canada in the west. Note that these illustrative pipeline corridors focus on the transport of CO_2 for use in EOR; depending on available incentives, pipeline infrastructure could be developed to enable saline storage as well.[21]

Each proposed trunk pipeline would be comparable in scale and volume to the 30-inch diameter Cortez pipeline, the world's largest CO_2 pipeline today. The Cortez spans a 500-mile route from southern Colorado, through New Mexico and into the Permian Basin of Texas, and it has the capacity to transport approximately 30 million MT of CO_2 annually.

Three of the five potential priority CO_2 trunk pipeline corridors suggested by the Work Group have particular relevance for the biofuels industry realizing its long-term potential for large-scale carbon management in the context of ethanol production:

- ***Upper Midwest to the Permian Basin.*** Moving CO_2 from ethanol fermentation, fossil power generation, fertilizer production and other industries in the corn-producing heartland of the Upper Midwest into the vast potential and proven reservoirs of the Permian Basin of Texas and New Mexico; and

- ***Illinois Basin-Midwest to the Permian Basin.*** Moving CO_2 from Midwestern ethanol production, fossil power plants and other industries to midcontinent oilfields in Oklahoma, Kansas and Arkansas and the Permian Basin; and

- ***Ohio River Valley-Lower Midwest to Gulf Coast.*** Moving CO_2 from fossil power generation, steel production, ethanol production and other sectors in the industrial and manufacturing heartland of the Lower Midwest to Midwestern oilfields and down to onshore and offshore fields of the Gulf Coast of Alabama, Mississippi and Louisiana.

The private sector in the U.S. has a long history of successfully harnessing private capital to develop and finance pipelines across a range of industries. However, the Work Group recognizes that, to develop trunk CO_2 pipeline corridors and associated feeder networks on a scale consistent with the future potential for carbon capture deployment, initial trunk pipelines will need to be built with extra capacity up front.

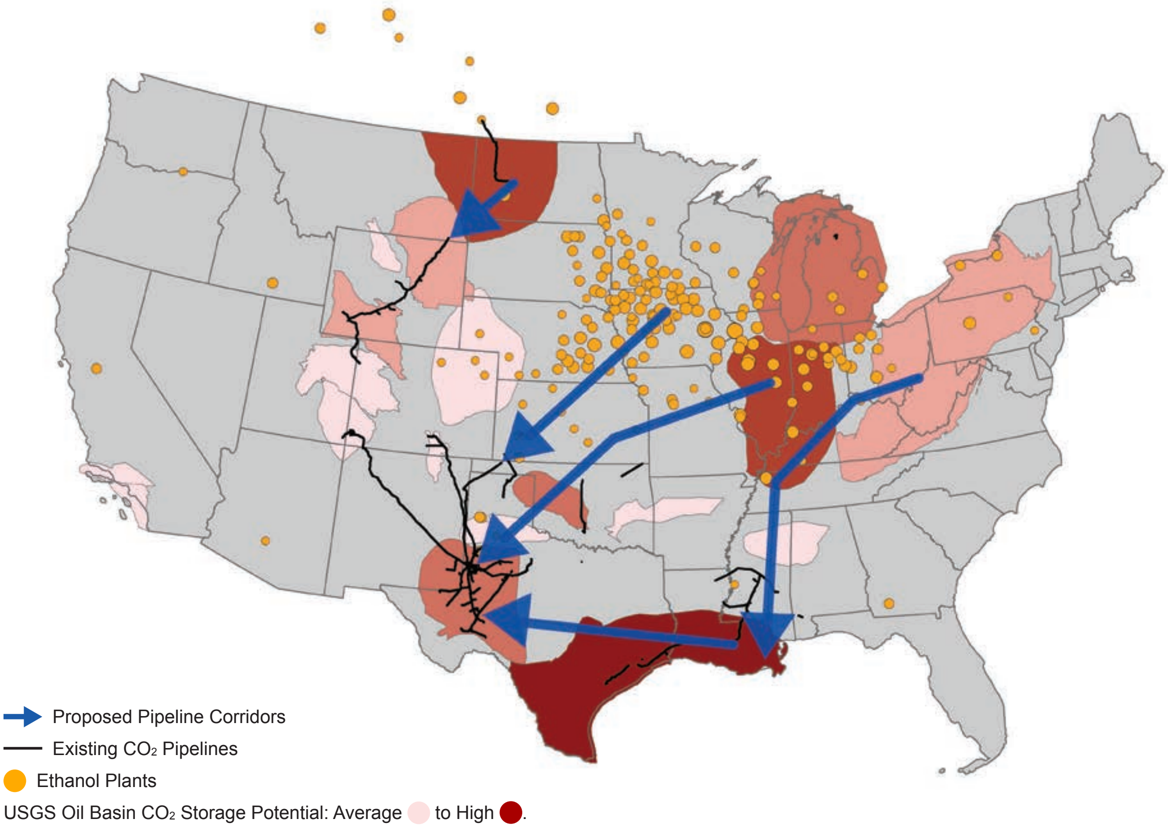
Such "super-sizing" of pipelines would enable developers of future carbon capture projects, EOR operations and other geologic storage sites to proceed with confidence in planning, permitting and financing their projects, knowing that adequate pipeline capacity will be in place to transport the CO_2, once their projects commence commercial operations. This approach has the added benefit of reducing the total cost and footprint of the future infrastructure needed to meet energy production and emissions reduction objectives by reducing the number and miles of pipelines ultimately constructed.

The opportunity to achieve economies of scale is enormous. For example, doubling the diameter of a pipeline quadruples its throughput capacity. Thus, significantly expanding the physical capacity of a pipeline to transport CO_2 constitutes a relatively small proportion of total project development, siting and permitting, construction and other costs.

Since private investors typically finance pipelines that are only large enough to meet contracted market demand, the Work Group recommends that the federal government provide targeted, low-cost financing of extra capacity in a given trunk pipeline adequate to accommodate future projected demand. Toward that end, the Work Group has prepared a menu of federal financing options with analysis of potential economic benefits to CO_2 pipeline projects, and it has presented this menu to members of Congress developing broader federal infrastructure legislation.

21 Note that these illustrative pipeline corridors focus on the transport of CO_2 for use in EOR; depending on available incentives, pipeline infrastructure could be developed to enable saline storage as well.

Figure 10: CO_2 Pipeline Corridors proposed by the State CO_2-EOR Deployment Work Group



Source: USGS 2016, GPI 2017.

State & Provincial Low-Carbon Fuels Standards

State policies that reduce the carbon intensity of transportation fuels, particularly LCFS policies, could complement federal incentives in stimulating private investment in carbon capture and CO_2 pipeline development. In some cases, such as California's LCFS, the potential value of carbon credits from that policy alone could drive project deployment, with or without additional federal policy. In addition, California's LCFS policy and other emerging state and provincial policies could incentivize the deployment of carbon management outside those jurisdictions, especially for ethanol producers that deliver and sell their fuels into California and other markets. The relative impact and benefit of LCFS policies in California and other jurisdictions will depend on the regulatory framework that accompanies their implementation.

California Low Carbon Fuels Standard

California seeks to reduce carbon emissions to 1990 levels by 2020. Subsequent goals for 2030 and 2050 aim to reduce emissions by 40 percent and 80 percent, respectively, relative to 1990 levels. The LCFS program represents one of California's key policy tools to achieve those goals by requiring a 10 percent reduction in the carbon intensity of transportation fuels by 2020, as measured from a 2010 baseline.

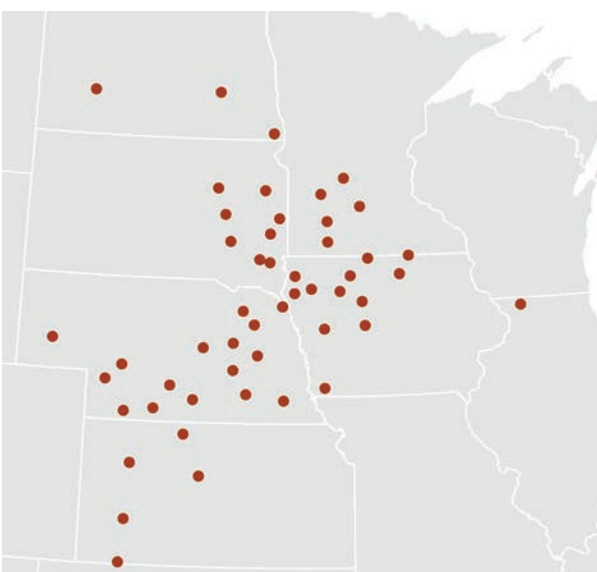
The program provides credits to regulated parties that achieve average fuel carbon intensity lower than the target set by the ARB. In 2016, ethanol generated approximately 40 percent of all credits under the LCFS program. The carbon intensity of transportation fuels in the California market at the end of 2016 was 2.71 percent lower than 2010, indicating that California remains on track to achieve its 2020 target. However, accomplishing the proposed target of 18 percent by 2030 would be more challenging.

Ethanol's contribution to achieving LCFS goals is already large, and biofuels suppliers are uniquely positioned to help California achieve deeper carbon intensity reductions in pursuit of the proposed 2030 target. The carbon intensity score of ethanol in California's program could be lowered substantially, if production facilities were equipped with carbon capture and accompanying geologic storage, thus further reducing net emissions on a lifecycle basis, whether the CO_2 is stored in oilfields or saline formations.

The ARB would help the state meet its proposed 2030 LCFS target cost-effectively by developing a quantification methodology (QM) that enables those ethanol producers selling into the California market to qualify additional reductions in carbon intensity. This is achieved by deploying carbon capture from ethanol fermentation and geologically storing the CO_2 through EOR or in saline formations.

However, capitalizing on this carbon management opportunity requires removing critical regulatory barriers in the proposed QM and the LCFS, which will discourage and potentially preclude commercial development of the best and safest projects to capture and store carbon emissions. The Work Group expressed this concern in formal comments to ARB in September 2017.

Figure 11: Ethanol Plants with Approved ARB Pathways



Source: CARB 2017. Figure authored by GPI, 2017

With the subsequent release of ARB's draft QM, the Work Group continues to have concerns. In particular, the draft proposes to enforce site-selection and monitoring requirements on CO_2 storage projects outside state boundaries. For instance, a Midwestern ethanol producer that captures biogenic CO_2 could not claim lower carbon intensity for its fuel marketed in California, if it sells that CO_2 to an oil company for storage through EOR, unless that company were to meet California's additional requirements—even if its EOR operation complies with existing federal U.S. Environmental Protection Agency requirements to certify secure geologic storage for the purposes of claiming federal tax credits. The same would hold true for a Midwestern ethanol producer seeking to claim credits for capturing and storing CO_2 in a saline formation outside of California.

ARB has also proposed a requirement that geologic storage sites be monitored for 100 years after CO_2 injection has ended, which would be unprecedented, if implemented. This would prevent private investment in carbon capture and storage projects aimed at participating in the California LCFS market, leave millions of tons of potential CO_2 reductions on the table and making California's achievement of its own policy goals more costly and uncertain.

California state leaders are calling for continued progress in reducing our nation's carbon emissions, and numerous ethanol producers have expressed interest in investing in carbon capture and storage with a view toward LCFS compliance, provided that regulatory requirements are commercially feasible. ARB has the strategic opportunity to design a regulatory system that drives industry investment in deployment of large-scale carbon capture and CO_2 pipelines in states that may have different policy priorities from California, but which share a common interest in deploying technology and infrastructure that beneficially reduces emissions, while achieving other energy and economic objectives.

Other State and International Low Carbon Fuels Policies

Other states and international jurisdictions have LCFS policies and are looking to California to inform implementation of their own efforts. Oregon's Clean Fuels Program and British Columbia's Renewable and Low Carbon Fuel Requirement statute represent two additional state/provincial LCFS policies within the same region that present potential additional opportunities to incentivize carbon capture from ethanol production. These jurisdictions will be evaluating ARB's rulemaking for guidance, underscoring how the impact of California's emerging regulatory framework will extend far beyond the state.

Finally, as the largest importer of U.S. ethanol, Canada is currently developing a national Clean Fuels Standard to achieve 30 million MT of annual CO_2 emissions reductions by 2030, which would extend LCFS policies beyond the province of British Columbia[22]. Depending on how Canada implements this national standard, it could serve as an additional market driver for carbon capture deployment in the U.S. biofuels industry.[23]

Conclusion

Widespread deployment of carbon capture represents an important next step in the commercial evolution of the biofuels industry, which has a history of innovation to reduce energy and water use, drive down costs, generate new sources of revenue from value-added byproducts, and lower its carbon intensity. As the industry has improved energy efficiency and lowered emissions, ethanol producers have sought diversity and increased revenue from the development and marketing of byproducts that add value beyond the ethanol itself. Carbon capture presents a further opportunity for the biofuels industry to generate additional economic returns from the oil industry's purchase of CO_2 and from permanent and safe geologic storage of CO_2 through EOR and in saline formations.

However, up-front costs of installing carbon capture, compression, and dehydration and building out new pipeline infrastructure limit further commercial deployment. Federal and state policies could help bridge the financial gap and reduce risk, attracting private capital to invest in carbon capture and CO_2 pipeline projects that serve the ethanol industry, which will in turn foster further innovation and cost reductions.

The results of the analysis in this paper show that revenue from the sale of CO_2 for EOR, combined with the proposed federal 45Q tax credit and complemented by eligibility for tax-exempt private activity bonds and master limited partnerships, could enhance the feasibility of deploying carbon capture from ethanol production and the necessary pipeline infrastructure to transport that CO_2 to oilfields where it can be put to beneficial use and stored. These federal policies also have the potential to support further geologic storage of CO_2 from ethanol in saline formations to achieve even greater emissions reductions.

State low carbon fuels policies such as the California LCFS could also help drive private investment in large-scale carbon management by ethanol producers seeking to comply with LCFS requirements by capturing and storing CO_2 from fermentation. However, California and other jurisdictions need to develop accompanying regulatory frameworks that enable the industry to establish a commercially viable carbon capture and storage business model around LCFS compliance.

The capture of biogenic CO_2 from fermentation in ethanol production can play a key role in scaling up carbon management for domestic energy production and geologic storage, thus contributing to American energy independence, protecting and creating high-paying jobs and significantly reducing net carbon emissions.

Appendix: CO_2 Pipeline Assumptions and Cost Model

GPI and IHR utilized the National Energy Technology Laboratory's (NETL) CO_2 Transport Cost Model[24], modified by GPI for this application, to calculate detailed breakdowns of capital and operating costs of CO_2 pipelines in two scenarios prepared for the Work Group.[25]

22 Environment and Climate Change Canada (2017), *Clean Fuel Standard: Discussion Paper* Available at: https://www.ec.gc.ca/lcpe-cepa/default.asp?lang=En&n=D7C913BB-1 [Accessed July 14, 2017].

23 Dickinson C (2016) *2016 Top Markets Report: Renewable Fuels* (International Trade Association).

24 Timothy Grant & David Morgan, National Energy Technology Laboratory. *FE/NETL CO_2 Transport Cost Model.* DOE/NETL-2014/1667. July 11, 2014.

25 Martin Dubois, Dane McFarlane and Tandis Bidgoli, CO_2 Pipeline Cost Analysis Utilizing and Modified FE/NETL Cost Model Tool, poster presented at the Carbon Storage and Oil and Natural Gas Technologies Review Meeting, Pittsburgh PA, August 3, 2017.

The NETL model calculates costs by pipeline segment based on inputs such as pipeline length, annual CO_2 volume, input/outlet pressure, capacity factor, and number of booster pumps. Model output includes capital costs for materials, labor, right-of-way negotiations, CO_2 surge tanks, pipeline control systems, and pumps. Operational costs include pipeline O&M, equipment and pumps, and electricity costs for pumps, by segment. The GPI/IHR study team mapped several pipeline network scenarios in ESRI's ArcGIS to determine the route, length, and volume of each segment of the network.[26] Ethanol plants ranged in size from 40 to 350 MGY, with many plants operating at around 100-110 MGY. Network design considered the location of large plants (at least 100 MGY and greater) for primary hubs or trunk line route, with smaller plants clustered along feeder lines into the trunk line.

Segment properties were entered into the modified NETL model to calculate costs for each segment. Additional pipeline assumptions included a +10 percent scaling factor to account for route right-of-way issues, a pressure drop from 2000 psi to 1400 psi (field delivery at 1400 psi), and booster stations distributed evenly throughout each segment. Ethanol CO_2 production was set at 90 percent of plant potential based on nameplate ethanol production volumes derived from Energy Information Agency (EIA) tables.[27] Resulting cost estimates were in line with a CO_2-EOR industry rule of thumb of about $100,000 per inch-mile (within ±10 percent variation for individual segments, and less than ± 3 percent for networks).

Estimating the capital and operating costs for CO_2 capture, compression, and dehydration (CCD) from fermenters in an ethanol plant is problematic because of the paucity of publicly available data. There are currently only three commercial-scale ethanol plant operations that process and deliver CO_2 via pipelines for injection into geologic targets, two for EOR and the other for saline storage, and capital expenditures (CapEX) and operating expenses (OpEX) are not publicly available for the three privately operated facilities. For this study, we relied on CapEX estimates from two DOE-funded projects[28,29] and data sourced from a publicly available presentation[30] covering a third DOE-funded project, augmented and adjusted by input from trusted sources with direct project experience. A simple linear regression equation was derived by cross-plotting CapEX estimates and ethanol plant size in MGY for the three examples:

CapEx ($Million) = 0.15*Plant Size [million gallons per year (MGY)] + 9

Capital costs for 55 and 200 MGY plants are estimated at $17 and $39 million respectively. On a cost per daily-MT of CO_2 basis, costs are approximately $43,000 and $26,000 per daily-MT, respectively, for 400 MT per day (55 MGY) and 1480 MT per day (200 MGY). Operating expense for capture, compression, and dehydration from ethanol plants in this study is $8.58 per MT processed. Operating costs are derived from the two DOE final reports24,25 and are applied in a linear fashion for all CO_2 volumes. By far, the largest contributor to OpEx is energy costs, which are directly proportional to CO_2 volumes compressed. There would be economies of scale for larger-sized plants but these savings could not be quantified from the data available. Both CapEx and OpEx for capture, compression, and dehydration operations deserve significant additional study and refinement, but are considered adequate for this study.

For financing purposes, the CO_2 capture equipment and pipelines are modeled as 22-year long projects with a two-year construction phase and 20 years of operation and amortization. Two financing scenarios were modeled, one for gathering 4.3 million MT per year of CO_2 from 15 ethanol plants, and the other for 9.85 million MT per year from 34 plants, each with two different return on investment (ROI) rates: 10 percent and 15 percent.

26 Environmental Systems Research Institute (ESRI). *ArcGIS Desktop: Release 10.5*. Redlands, CA. 2017.

27 US Dept. of Energy, Energy Information Administration, 2017, Ethanol Plans (EIA-819M Monthly Oxygenate Report, March 27, 2017.

28 Integrated Mid-Continent Carbon Capture, Sequestration & Enhanced Oil Recovery Project, final report for DOE Project # DE-FE-0001942, August 31, 2010.

29 Integrated Carbon capture and Storage for North Dakota Ethanol Production, final report for DOE Project # DE-F0024233, May 31, 2017.

30 Ray McKaskle, Trimeric Corporation, Insights into Costs of CCS gained from the IBDP, 2016 Midwest Carbon Sequestration Science Conference, May 17, 2016.