Making Carbon a Commodity:
The Potential of Carbon Capture RD&D

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Abstract

This report examines the potential for market-driven deployment of carbon capture, utilization and storage (CCUS) technologies for coal and natural gas power plants. In particular, it examines how reducing the cost of carbon capture via a rigorous research, development and deployment (RD&D) program can enable new coal and natural gas power projects with carbon capture for enhanced oil recovery (EOR), and quantifies the resulting economic and employment benefits to the United States.

Under evaluated scenarios, an accelerated RD&D program enables market-driven deployment of ***62 to 87 GW*** *with carbon capture technologies without any additional environmental regulations or mandates. By 2040, power-sector carbon capture can enable over* ***920 million barrels of additional domestic oil production each year****,* ***with the increased oil activity supporting up to 780,000 jobs*** *and a* ***$190 billion*** *increase in gross domestic product (GDP). Lower-cost power produced via the RD&D effort reduced the national retail cost of electricity up to 2.0% by 2040, which is expected to* ***increase GDP an approximate $55 billion*** *and create* **another 380,000 jobs** *economy-wide. Projections vary based on key input assumptions, such as power demand growth and fuel prices.*

Analyses were conducted by three groups: (1) An evaluation of carbon-utilization potential in five major EOR regions by Advanced Resources International, Inc. (ARI); (2) Simulations of the U.S. electricity sector by NERA Economic Consulting (NERA) using their N_{ew}ERA Electricity Sector Model (N_{ew}ERA)*; and (3) Preparation of this report, coordination of the ARI and NERA work-streams and calculation of the macroeconomic benefits associated with lower-cost electricity by L.D. Carter.*

Executive Summary

Carbon capture refers to a suite of technologies that can produce concentrated streams of carbon dioxide from human operations, such as power plants and industrial sources. While federal investments in carbon capture have largely been based on its potential application as an emission control technology, captured carbon dioxide is also a desired commodity in the oil industry for use in enhanced oil recovery (EOR).

EOR, the process of injecting carbon dioxide underground in oil fields to boost production, has been conducted in the United States for nearly half a century. Conventional oil production is a relatively inefficient process, typically leaving behind two-thirds of the original oil in the ground after concluding operations.[1] An additional 10 to 20% can be extracted by injecting carbon dioxide to increase reservoir pressure, decrease oil viscosity, and develop miscibility between the injected carbon dioxide and reservoir oil.

Viewed through this lens, the U.S. power sector's annual production of over 1,500 million tons of carbon dioxide represents a potentially prolific economic opportunity: carbon dioxide can be captured from power plants and sold for oil production.[2] Many U.S. industrial facilities, such as Oklahoma's Enid Fertilizer facility and Wyoming's Shute Creek natural gas processing facility, have been capturing and selling carbon dioxide for several decades, and more recently, Texas's Port Arthur hydrogen plant has provided carbon dioxide for EOR operations. Similar levels of deployment in the power sector have not materialized largely because it is more expensive than industrial-sector capture, requiring additional purification steps. Yet, recent developments suggest market-driven carbon capture at power plants could be on the horizon.

In April 2017, the first large-scale U.S. carbon capture facility at a coal power plant opened in Texas[3]. Nearly one year later, a separate project testing an entirely new way to create electricity from natural gas while capturing carbon at potentially lower cost began its first stage of pilot testing.[4]

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[1] Over 400 billion barrels of oil remain in already discovered U.S. oil fields following conventional (non-EOR) recovery.

[2] In 2017, CO_2 emissions from coal-fired power plants totaled 1239 million metric tonnes and emissions from natural gas-fired power plants totaled 495 million tonnes. Energy Information Administration, *Annual Energy Outlook 2018 with Projections to 2050*, at tbl.8 (Feb. 6, 2018) (*EIA AEO 2018*), https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf.

[3] *See* NRG, Petra Nova, Carbon Capture and the Future of Coal Power, https://www.nrg.com/case-studies/petra-nova.html (last visited July 19, 2018). While the project has been a successful, first-of-its-kind demonstration, it required robust federal investments and unique public-private sector financing solutions in order to be launched. Recognizing the challenges facing early deployments of carbon capture projects, federal policy efforts today are focused on offsetting the costs of carbon capture through federal incentives and targeted RD&D investments.

[4] Press Release, PR Newswire, *NET Power Achieves Major Milestone for Carbon Capture with Demonstration Plant First Fire* (May 30, 2018), https://www.bizjournals.com/sanantonio/prnewswire/press_releases/Texas/2018/05/30/CL09548.

Our analysis finds that these recent developments could be the beginnings of a carbon capture revolution, culminating in **17 to 87 GW** of coal and natural gas power with carbon capture technologies in operation by 2040 without any additional environmental regulations or mandates.

Maximum deployment occurs in scenarios that simulate an aggressive public-private RD&D effort to lower carbon capture technology costs over 20 years. Under an aggressive RD&D program, **62 to 87 GW with carbon capture** were projected to be in operation by 2040, resulting in[5]:

- **up to a 40% increase in domestic coal production for power** from 2020 to 2040;
- **100 to 923 million barrels** of additional domestic oil produced annually by 2040 and up to 2,300 million metric tons of carbon dioxide captured from power plants to enable the growth;
- **270,000 to 780,000 new jobs** and a **$70 billion to $190 billion increase in GDP** associated with EOR field operations by 2040;
- Aggressive RD&D reduced the national retail cost of electricity **1.1 to 2.0% by 2040**, which on its own is forecasted to increase annual GDP by an additional **$30 to $55 billion** and create **210,000 to 380,000 more jobs** over a baseline RD&D case.

As this analysis modeled only market-driven opportunities, carbon capture power projects in all modeled scenarios were built only when it was the lowest cost option and associated EOR region(s) did not exceed production and carbon-storage limits. High rates of economic growth and high oil prices were other factors that resulted in more robust carbon capture deployment.

With less aggressive rates of RD&D, the analysis estimated significantly less deployment under all scenarios in 2040. With higher technology costs, the study estimated an approximate two-thirds reduction in new coal and natural gas with carbon capture and a comparative decline in associated benefits.

The study analyzed market-driven benefits, and did not model any future scenario where carbon dioxide is regulated or a carbon tax is imposed. The potential market-driven benefits estimated in this study from accelerated RD&D for use in EOR understate the benefits that could result from a scenario of accelerated RD&D under a potential climate regulation scenario. Under such a scenario, broader deployment of carbon capture would likely result from achieving the lower-cost carbon capture technology objectives through an aggressive RD&D program envisioned in this analysis and the *2018 CURC-EPRI Fossil Energy Technology Roadmap* (*2018 CURC-EPRI Roadmap*), resulting in cost-minimizing carbon capture deployment in regions beyond the results of this study.

Enhanced oil recovery has significant environmental co-benefits when EOR production displaces a barrel of oil produced with conventional methods today. Based on an analysis by the International Energy Agency, the carbon footprint of a barrel of oil produced with EOR is 37% smaller than a

[5] Results are reported in ranges because multiple scenarios were evaluated, such as different oil prices and economic growth. A qualitative description of key assumptions in the modeled scenarios is provided in the methodology section of the main report.

barrel produced with conventional methods.[6] The benefits would be even larger if higher carbon intensity oil is displaced.[7]

These benefits will not be realized on their own. Although the power-sector modeling analysis shows that a rapid reduction in carbon capture costs can lead to theoretical market deployment for EOR, translating these benefits into the real-world depends strongly on:

- **A public-private partnership across the entire RD&D cycle.** Dedicated public-private partnerships are needed across the development cycle, from bench-scale research to commercial projects. The large capital requirements and first-of-a-kind risks associated with transformative carbon capture projects make it uniquely challenging for the highly regulated power-sector industry to invest in the initial wave of projects. On first-of-a-kind commercial projects in particular, where new technologies have not been previously demonstrated, warranties and other forms of insurance are difficult to procure in the marketplace without initial government support. Bipartisan legislation authorizing public-private partnerships across the entire RD&D spectrum has been introduced in both the House and Senate that would accomplish this.[8]

- **An aggressive commitment to the carbon capture and power systems program**. By 2035, the U.S. Department of Energy (DOE) aims for a new coal plant with carbon capture to cost 40% less than it would cost to build a plant using today's technology.[9] While the DOE's Carbon Capture & Power Systems[10] budget in support of this goal has been steadily climbing, annual funding levels remain, on average, 45% below recommended levels by the power-sector and associated industries. Echoing previous reports from the National Coal Council,[11] the Carbon Utilization Research Council (CURC) and the Electric Power Research Institute (EPRI)[12], funding for basic research, large-scale pilots, and commercial-scale demonstrations is needed. The most recent industry report recommends a **$760 million** average annual budget for the equivalent activities in the DOE Carbon Capture & Power

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[6] *See* Clean Air Task Force, *The Emission Reduction Benefits of Carbon Capture Utilization and Storage using CO2 Enhanced Oil Recovery*, http://www.catf.us/resources/factsheets/files/CO2_EOR_Life_Cycle_Analysis.pdf.
[7] *See* Oil-Climate Index, *Total Estimated GHG Emissions and Production Volumes for 75 OCI Test Oils*, http://oci.carnegieendowment.org/#total-emissions?ratioSelect=perBarrel.
[8] H.R. 5745 (Fossil Energy Research and Development Act of 2018), S. 1460 (Energy and Natural Resources Act of 2017); and S. 2803 (Fossil Energy Utilization, Enhancement, and Leadership Act of 2018).
[9] Clean Coal Research Program, U.S. Department of Energy, *Carbon Technology Program Plan* (Jan. 2013), https://www.netl.doe.gov/File%20Library/Research/Coal/carbon%20capture/Program-Plan-Carbon-Capture-2013.pdf.
[10] Includes Fossil Energy's Coal CCS & Power Systems program.
[11] *See* National Coal Council, *Fossil Forward: Revitalizing CCS Bringing Scale and Speed to CCS Deployment*, at tbl. C.6. Cost Breakdown of Surviving CCPI 3 Projects (Jan. 2015), http://www.nationalcoalcouncil.org/studies/2015/Fossil-Forward-Revitalizing-CCS-NCC-Approved-Study-old.pdf.
[12] Coal Utilization Research Council and the Electric Power Research Institute, *The CURC-EPRI Advanced Coal Technology Roadmap* (July 2015), http://media.wix.com/ugd/80262f_ada0552d0f0c47aa873df273154a4993.pdf (2015 CURC-EPRI Advanced Coal Technology Roadmap).

Systems RD&D program through 2035, including significantly more funding in the next decade needed for commercial-scale demonstrations.[13] Technologies should be tested on natural gas as well as the three major U.S. coal types to benefit the existing coal and natural gas fleets, maximize domestic natural resources, and accelerate the development of advanced new power cycles. After increasing levels to this amount, the DOE annual Fossil Energy RD&D budget would still be less than current allocations to the DOE's renewable energy equivalent.

- **Streamlined rules and regulations.** Certain environmental regulations discourage industry's adoption of carbon capture technologies. Interstate and intrastate carbon dioxide pipeline permitting processes have been identified as potential barriers. Congress has signaled it will tackle these issues, such as through the USE IT Act sponsored by Senators Barrasso (R-WY), Capito (R-WV), Heitkamp (D-ND), and Whitehouse (D-RI) that would make large carbon dioxide pipeline projects eligible for a streamlined permitting process.[14] Another issue to be tackled is the subsurface reporting and regulatory requirements for EOR projects that capture carbon dioxide from power plants for use in their operations for compliance with the Clean Air Act, relevant state-based regulations, and potentially, the Section 45Q tax credit. Some entities within the EOR industry have stated they will not enter into commercial offtake agreements for captured power-sector carbon dioxide with owners and operators because of potentially significant cost, liability, and legal issues associated with these reporting requirements. These policies should be re-evaluated to address these challenges and encourage the utilization of power-sector carbon dioxide in EOR operations.

- **Internal Revenue Service (IRS) interpretation of the revamped carbon capture tax credit**. In 2018, Congress enacted sweeping reforms to the Section 45Q tax credit for the capture and storage of carbon dioxide in secure geologic storage. Section 45Q provides separate credit levels for EOR and pure sequestration projects. Included among the recent changes: the credit level for EOR projects is to increase from $10 to $35 per metric ton of carbon dioxide stored and a total cap on credits was replaced with a January 2024 commence-construction deadline. IRS interpretation of the new language, e.g., what it means to "commence construction" on a carbon capture project, will have a significant influence on short- and medium-term development and important project finance decisions. Early clarification of these critical ambiguities will facilitate carbon capture project development utilizing this credit.

Carbon capture is a confluence of heavy manufacturing, specialized chemical engineering, and integration with complex power systems. Building Petra Nova, the first large-scale carbon capture power project in the United States, was the culmination of over two decades of joint research and

[13] *See 2018 CURC-EPRI Roadmap*.
[14] Press Release, U.S. Senate Committee on Environment and Public Works, *Barrasso: USE IT Act is Important Bipartisan Legislation to Promote Carbon Capture Research and Development* (Apr. 11, 2018), https://www.epw.senate.gov/public/index.cfm/2018/4/barrasso-use-it-act-is-important-bipartisan-legislation-to-promote-carbon capture-research-and-development.

was ultimately financed by the private sector along with both the U.S. and Japanese governments. Achieving the vision outlined in this report is contingent on a federal commitment to support a steady public-private partnership in advancing power generation technologies equipped with carbon capture. Continued RD&D in carbon capture and EOR technologies are investments in our nation's long-term economic and energy security.

Released with this study is the *2018 CURC-EPRI Roadmap*, a technical report that describes enabling technology pathways and resources needed to achieve the cost reductions envisioned in this study.

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1. Introduction

Purpose and scope

This report examines how an aggressive public-private RD&D fossil-energy program impacts market-driven deployment of U.S power sector carbon capture projects for EOR and the resulting domestic macroeconomic benefits under eight different scenarios. The analysis is not intended to predict the future, or even a most likely future, but rather to track carbon capture deployment across explicitly defined scenarios. Key variables that differ by scenario include economic and electricity demand growth, fossil fuel prices, a capital charge "adder" used in the National Energy Modeling System (NEMS) model, and most prominently, carbon capture costs associated with different levels of RD&D ambition.[15]

As explained below, this study does not assume any national carbon dioxide regulations, but instead focuses on deployment of capture driven by a steady stream of revenues from selling carbon dioxide to EOR projects. EOR is an established commercial technology that utilizes carbon dioxide to extract significantly greater production from some oil fields than traditional primary and secondary production techniques alone. Results are reported for the period 2020 through 2040, although the modeling extended well beyond 2040 to ensure that generating units capturing carbon dioxide have adequate lifetime access to oil fields and EOR for utilization and incidental long-term storage. The study understates the potential benefits of RD&D due to the exclusive application of carbon capture for EOR. Broader application to coal-bed methane, non-geologic utilization, and carbon sequestration could lead to additional benefits.

Background

EOR, the process of injecting carbon dioxide underground in oil fields to boost productivity, has been conducted in the United States for nearly 50 years. EOR generates a significant proportion of U.S. oil production. An estimated 300 hundred thousand barrels of oil are produced per day with carbon dioxide EOR, approximately 3% of U.S. oil production in 2017.[16]

Conventional oil production is a relatively inefficient process, typically leaving behind 50 to 70% of the original oil in the ground after concluding operations. EOR has been proven to extract an additional 10 to 20% of the original oil in place by using carbon dioxide to decrease oil viscosity and develop miscibility between the injected carbon dioxide and the reservoir oil. Under industry best-practices, the carbon dioxide used in the process remains trapped and stored in the reservoir,

[15] The scenarios and a description of each variable is described in more detail on page 13
[16] *See* Advanced Resources International, *CO2-EOR Set for Growth as New CO2 Supplies Emerge* (April 2014), http://www.adv-res.com/pdf/CO2-EOR-set-for-growth-as-new-CO2-supplies-emerge.pdf.

producing a more environmentally friendly barrel of oil.[17] In the oil sector, carbon dioxide is a valued and useful commodity with a strong market demand.

The main constraint on future development of EOR projects is access to low-cost sources of carbon dioxide. Oil companies have traditionally received carbon dioxide from two sources: either mineable sources of naturally occurring carbon dioxide underground, or industrial facilities such as ethanol and natural gas processing plants that produce relatively pure streams of carbon dioxide.

To date, nine large carbon capture projects to capture manmade carbon dioxide in the United States have been developed for EOR (Figure 1-1). Only one project, the Petra Nova facility in Texas, has been installed at a power plant. Within the first ten months, the project increased oil production in a local oil field by 1,300%[18]. Although the project was a technical success, being built on time and on budget, the recent decline in oil prices has challenged project developers in identifying a second project. DOE modeling suggests that the recent changes to the Section 45Q tax credit could deploy nearly 50 GW of carbon capture projects by 2040 when combined with aggressive RD&D.[19]

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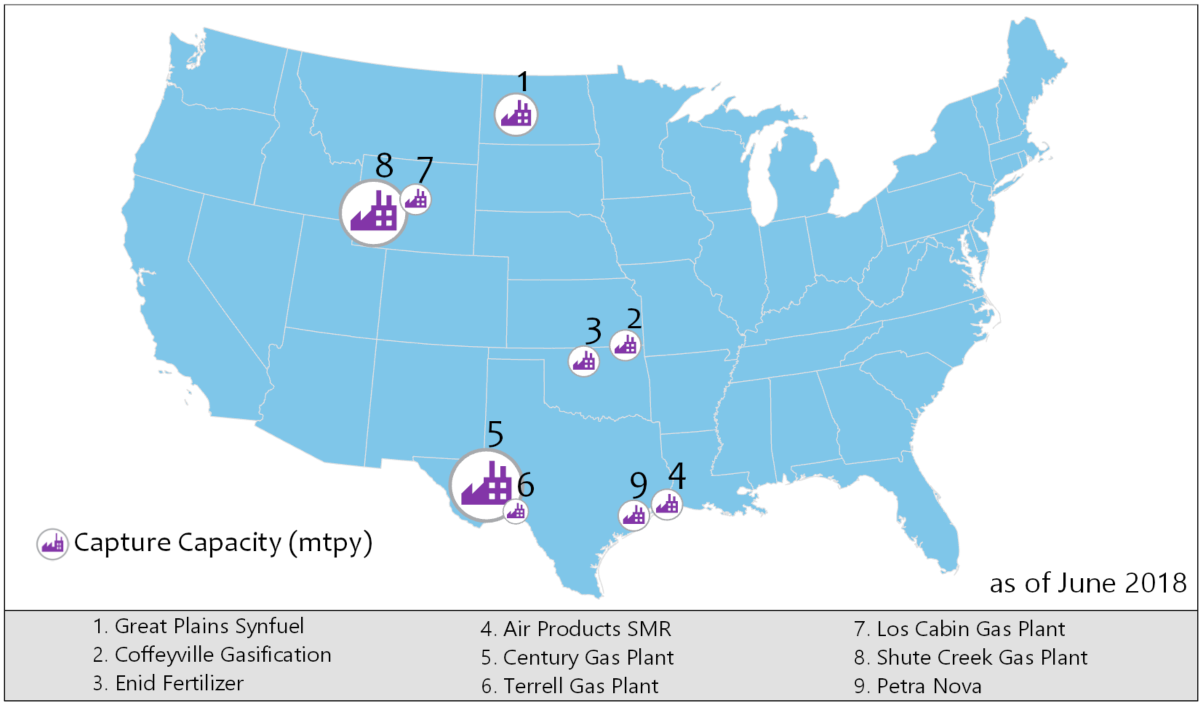
[17] *See* International Energy Agency, *Storing Carbon Dioxide through Enhanced Oil Recovery: Combining EOR with CO2 Storage (EOR+) for Profit* (2015), https://www.iea.org/publications/insights/insightpublications/Storing_CO2_through_Enhanced_Oil_Recovery.pdf.

[18] *See* NRG, Petra Nova, Carbon Capture and the Future of Coal Power, https://www.nrg.com/case-studies/petra-nova.html (last visited July 19, 2018).

[19] *See* U.S. Department of Energy, *Carbon Capture, Utilization, and Storage: Climate Change, Economic Competitiveness, and Energy Security* (Aug. 2016), https://www.energy.gov/sites/prod/files/2016/09/f33/DOE%20-%20Carbon%20Capture%20Utilization%20and%20Storage_2016-09-07.pdf.

Figure 1-1. Map of Large U.S. Carbon-Capture Projects for EOR[20]



Projecting additional declines in carbon capture costs in line with DOE's long-term goals, market-driven carbon capture at power plants for EOR can be a reality. The primary economic driver for such deployment is use of carbon dioxide for EOR, so profitability primarily depends on balancing of the additional cost incurred for capture and transport of carbon dioxide against the revenues generated from electricity sales and carbon dioxide sales to EOR projects. Other factors influencing the competitiveness of carbon capture systems include the perception of regulatory risk associated with new, unconstrained fossil-fueled power plants, and the future prices of fuels and competing non-fossil generation technologies.

In addition to the clear economic benefits, carbon capture with EOR has clear environmental benefits. Based on an International Energy Agency analysis, it is estimated the average carbon footprint of a barrel of oil produced with EOR has a 37% lower carbon footprint than a barrel of oil produced with traditional techniques[21], and others have found CO_2-EOR is carbon neutral in certain

[20] *Based on data from* Global CCS Institute, http://www.globalccsinstitute.com/projects (last visited July 20, 2018). Large is defined as having at least 0.5 million ton per year capacity.
[21] *See* International Energy Agency, *Storing Carbon Dioxide through Enhanced Oil Recovery: Combining EOR with CO2 Storage (EOR+) for Profit* (2015), https://www.iea.org/publications/insights/insightpublications/Storing_CO2_through_Enhanced_Oil_Recovery.pdf.

cases.[22] A 2017 National Resources Defense Council report finds that the amount of leakage necessary to make the typical EOR project a carbon-positive is "a very remote possibility."[23] In the oil sector, companies pay for carbon dioxide and have a strong incentive to ensure injected carbon dioxide remains in the subsurface.

Analysis associated with broader emissions reductions from non-EOR applications are outside of the scope of this study. Consequently, geologic storage in saline formations was not considered. Other carbon dioxide-utilization opportunities, such as conversion of carbon dioxide to fuels or materials, were also beyond the scope of this analysis. While these opportunities were not considered for this study, RD&D efforts focused on commercial-scale saline sequestration and carbon dioxide conversion are recommended in the *2018 CURC-EPRI Roadmap*. With the new Section 45Q tax credits available for saline sequestration and carbon dioxide-conversion technologies, undertaking such efforts will result in technology improvements and associated cost reductions for carbon capture in the power sector and may add to the overall benefits projected in this study, including enabling further deployments of carbon capture in regions of the country not captured by the study.

[22] *See* Energy Procedia, *CO_2 Utilization from "Next Generation" CO_2 Enhanced Oil Recovery Technology* (2013), https://www.elsevier.com/__data/assets/pdf_file/0005/97025/CO2-Utilization-from-Next-Generation-CO2-Enhanced-Oil.pdf

[23] National Resources Defense Council, *Strengthening the Regulation of Enhanced Oil Recovery to Align It With the Objectives of Geologic Carbon Dioxide Sequestration*, at 45 (Nov. 2017), https://www.nrdc.org/sites/default/files/regulation-eor-carbon-dioxide-sequestration-report.pdf.

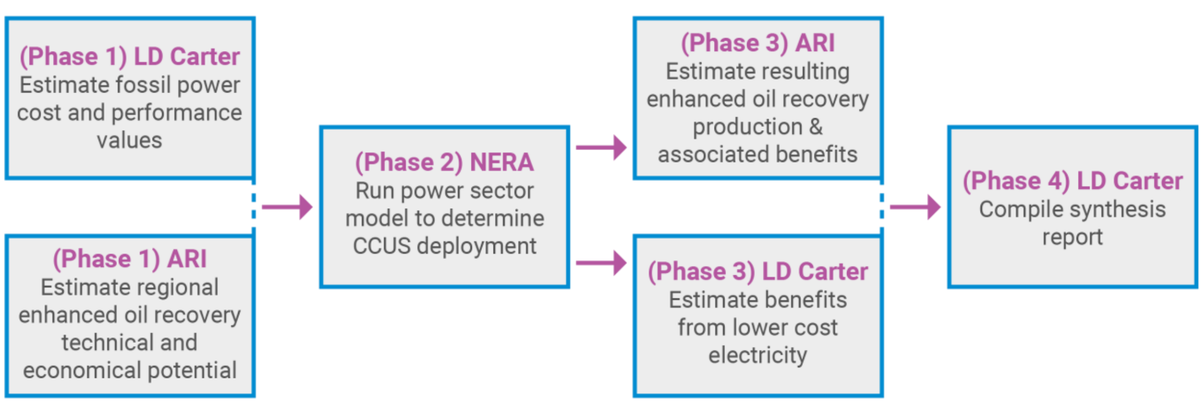
2. Methodology

The study was divided into four main phases (Figure 2-1), conducted by three different analytics groups:

1. **Advanced Resources International, Inc.** provided the study's main EOR assumptions and analyses, e.g., regional productivity and associated job creation benefits. ARI is an international expert on topics of worldwide unconventional gas resources, EOR and carbon dioxide storage dating back to research projects with the DOE in 1980.
2. **NERA Economic Consulting** modified and applied their N_{ew}ERA electricity sector model to simulate the U.S. power sector and volumes of carbon dioxide captured for EOR. Their N_{ew}ERA electricity model is an electricity long-term dispatch and resource planning model available in the consulting space and has been extensively used to evaluate a range of electricity sector policies.
3. **L.D. Carter** coordinated the analysis and estimated the macroeconomic benefits associated with meeting the DOE's long-term carbon capture RD&D program goals. Mr. Carter is an independent energy consultant with prior experience modeling fossil power systems at the National Energy Technology Laboratory (NETL) and systems analysis at CURC.

The reader should note the differences in precision across the phases of the analysis. NERA's power-sector model is a high-resolution power-sector model, explicitly and simultaneously solving for the least cost solution under a multitude of constraints over the study period. Similarly, ARI's EOR production estimates are based on its model tuned with data from U.S. EOR operations. In contrast, the associated macroeconomic benefits were estimated using macroeconomic multipliers previously used in the literature and industry analyses.

Figure 2-1. Main Phases Throughout the Study

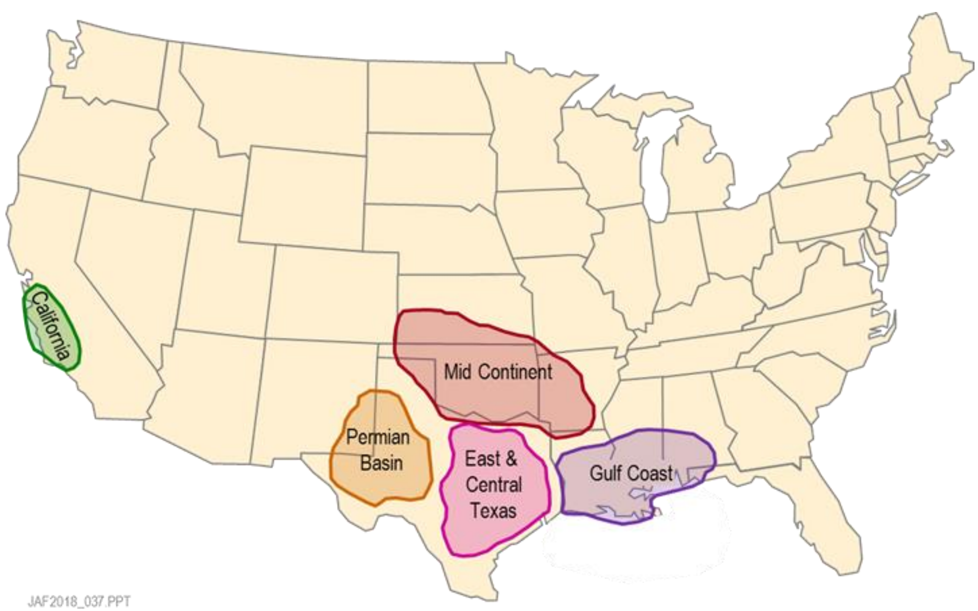


EOR Modeling

In 2004, the DOE sponsored ARI to conduct a series of ten "basin reports" that quantified the potential for increased domestic oil production and carbon dioxide storage using EOR techniques. In subsequent years, ARI conducted periodic updates to their initial reports, reflecting improved data and oil production techniques.[24] The techniques and technologies used in EOR continue to evolve, and the industry is producing more oil for each unit of carbon dioxide injected.[25]

For this study, ARI refreshed its basin reports across the five EOR regions evaluated by this study (Figure 2-2), providing upper bounds on the amount of CO_2-EOR production and volumes of carbon dioxide injection that could occur in each region.

Figure 2-2. EOR Regions Evaluated



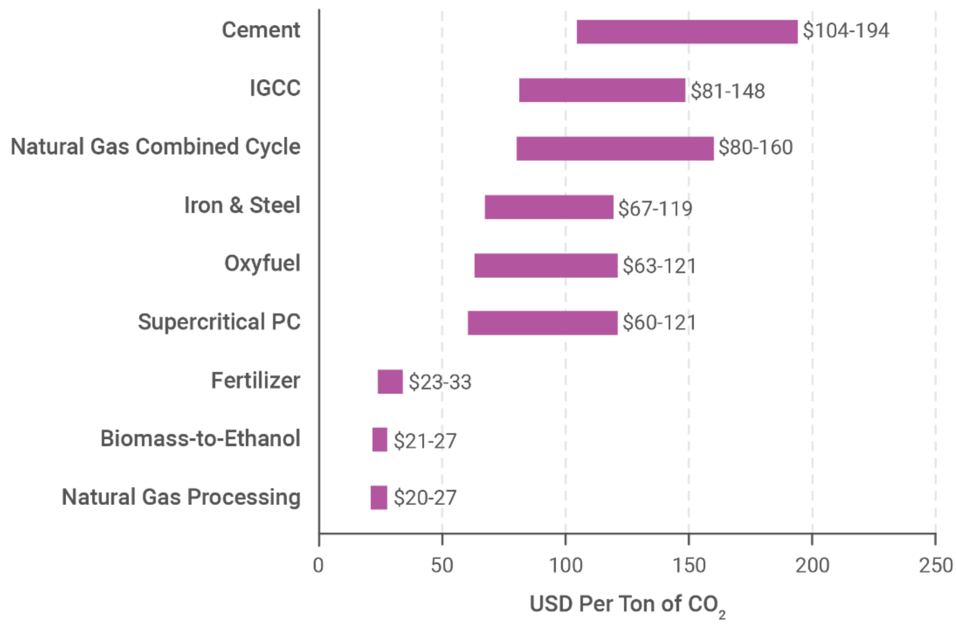
Source: Advanced Resources International

Other regions, such as the Rocky Mountain Corridor from Colorado up through Montana and in Wyoming, North Dakota, and Ohio, also hold significant potential for EOR spurring carbon capture. The relatively flat demand growth in these regions, combined with lower-cost carbon dioxide from natural domes or industrial sources (Figure 2-3) of carbon dioxide, are outside the scope of this

[24] *See* National Energy Technology Laboratory, U.S. Department of Energy, *Storing CO2 With Enhanced Oil Recovery* (Feb. 2008), http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/08-AFC-8/applicant/Tech_Studies_CO2_EOR/NETL%20Storing%20CO2%20with%20EOR.pdf.
[25] *See* National Energy Technology Laboratory, U.S. Department of Energy, *Improving Domestic Energy Security and Lowering CO_2 Emissions with "Next Generation" CO_2 Enhanced Oil Recovery (CO_2-EOR)* (June 20, 2011), http://www.midwesterngovernors.org/documents/NETL_DOE_Report.pdf.

study. There is also less publicly available source material identifying target oil-fields and the economics of EOR in these regions, which also limited opportunities for significant power plant CCUS penetration over the study period, making the more well-identified EOR regions in Figure 2-3 more economic for purposes of the study.   Nevertheless, these areas offer attractive opportunities to utilize carbon dioxide captured from power plants or other sources to boost production from stranded oil assets. Further market-driven development in these areas would add to the macroeconomic benefits projected by this analysis.

Figure 2-3. Estimated and Measured First-of-a-Kind Carbon Capture Applied to Different Plants[26]



Source: Adapted from the Global CCS Institute, 2017. EFI 2018.

ARI estimated that the ultimate economically viable application of carbon dioxide for EOR in the five regions examined is on the order of 31 billion tons of carbon dioxide to produce 66 billion barrels of oil. Appendix A-2 & A-3 show the expected potential of EOR regions at $75 and $100 per barrel of oil. These total capacities include adjustments to reflect storage available to power plant capture projects, and exclude volumes likely to be met by lower cost non-power plant sources of carbon dioxide. Available EOR resources included ROZ formations in 12 counties in Texas (Appendix A- 1), and ARI reported these formations as part of the total resources for the Permian

[26] Energy Futures Initiative Policy Paper, *Advancing Large Scale Carbon Management: Expansion of the 45Q Tax Credit*, at 13 (May 2018), https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5b0604f30e2e7287abb8f3c1/1527121150675/45Q_EFI_5.23.18.pdf. Note that these costs reflect a range of costs for new technologies that are projected to have improved and lower costs of capture, but have yet to be tested or demonstrated in commercial practice.

region. In addition to absolute carbon dioxide storage limits in each reservoir, time-based injection limits were applied to model "ramp-up" times experienced in EOR projects.

Power Sector Modeling

The second activity was conducted by NERA, which relied on its N_{ew}ERA electricity sector model to project sources of future electricity production, including fossil-fueled units with and without carbon capture. A description of the modeled scenarios is presented in the next section of this report. The scenarios are "paired" to contrast a future with and without a vigorous domestic RD&D program for advanced carbon capture power systems.

N_{ew}ERA is a linear programming dispatch and long-term capacity planning model for the U.S. electricity sector. The model contains information on 16 classes of generating units, including renewables, in 63 U.S. regions, and is generally calibrated to the Energy Information Administration's (EIA) *EIA AEO 2018*. The model uses data from other sources including the Environmental Protection Agency (EPA), North American Electric Reliability Corporation, National Renewable Energy Laboratory, and proprietary data sources.

N_{ew}ERA solves for the least cost combination of technologies that satisfies future electricity demand requirements, while meeting other constraints such as reserve capacity requirements, fuel availability, renewable portfolio standards (RPS), and emission regulations. The model assumes "perfect foresight" and minimizes the present value of costs over the entire forecast period.

ARI ensured the levels of captured carbon dioxide from the NERA analyses did not exceed temporal or volumetric EOR constraints by EOR region. For several EOR regions, projected levels of carbon capture by NERA's electricity model exceeded the carbon storage capacity of the closest EOR region. When this primary EOR region reached its maximum capacity, the model evaluated the opportunity of transporting the carbon dioxide to the second best option (oil fields in the Permian), which holds the greatest storage potential of the five regions.

Carbon-Capture Deployment Economics

In traditional power sector models, a power plant would only choose to install carbon capture to comply with policy regulations. For those modeling exercises, carbon capture is strictly an environmental compliance technology resulting in significant cost increases and declines in saleable power. In this analysis, carbon capture is a market-driven decision because the costs can be offset with carbon dioxide sales for EOR, and the recently enacted Section 45Q tax credits if operational prior to 2025 and 2030, for retrofits and greenfield units with carbon capture, respectively. The study did not assume any additional incentives or environmental regulations beyond the policies already in place.

a) *The Market Value of Carbon Dioxide in EOR*

The market value of carbon dioxide for EOR is highly correlated to the price of oil. When the price of oil is high, the willingness to pay for carbon dioxide increases because it is an input for oil extraction. When the price of oil is low, the market value drops. Based on guidance from ARI, the market price of carbon dioxide ($/metric ton) was modeled at 38.6% the price of oil ($/bbl) for prices under $100 per barrel and slightly less for prices over $100 per barrel. For example, for a future crude oil price of $100 per barrel, the delivered carbon dioxide would have a value of $38.60 per metric ton.

Figure 2-4. Estimated Sale Price of Captured carbon dioxide for EOR

CO_2 EOR Value ($/metric ton) = CO_2 value ($/mcf) x 19.3 (mcf/metric ton)

- When oil prices were less than $100 per barrel:
  CO_2 value ($/mcf CO_2) = 2% * Crude Oil Price ($/bbl)
- When oil prices were greater than $100 per barrel:
  CO_2 value ($/mcf CO_2) = (2%*100) + [(Oil price -100)*1%]
- 1 metric ton of CO_2 at 70º F & 1 Atmosphere = 19.3 mcf volume

Based on the oil price trajectory in the *EIA AEO 2018* Reference Case, the value of carbon dioxide for EOR increased from $26 per metric ton in 2020 to around $40 per metric ton by mid-century.

b) *The Section 45Q Tax Credit*

The market value could also be supplemented with the recently amended Section 45Q tax credit for carbon capture projects. The Section 45Q tax credit provides up to a $35 tax credit for each metric ton of carbon dioxide stored underground during EOR for a project's first twelve years of commercial operation (Appendix A- 2).

Although the total credit levels are set, key implementation details on the recent changes have not been determined by the IRS. One of the main considerations IRS has yet to rule on is the "commence construction" language. In order to qualify for the credit, projects must commence construction by January 1, 2024. It is unclear if the IRS will adopt an approach similar to the wind production tax credit where commence construction could be based on initial capital outlay, or another approach.

For the purposes of this study, a power plant's eligibility for the credit was based on the year it entered into service, rather than the currently ambiguous "commence construction" date. Using historical construction times as a proxy, greenfield carbon capture units that come online by 2030 and retrofit fossil units operating by 2025 could claim the new Section 45Q incentives. The credit was treated as added revenue for power plants with carbon capture, improving their economics and dispatching order for their first twelve years of operation.

Carbon Capture Costs

Baseline cost and performance values for large carbon capture systems were derived from DOE and NETL reports,[27] [28] and EIA techniques used in its *EIA AEO 2018*[29] as interpreted by L.D. Carter. Current coal and natural gas technologies were modeled based on values reported in NETL's Baseline Bituminous reports. Future coal power system costs and performance figures were estimated using DOE's long-term cost reduction goals for coal technologies and are consistent with the *2018 CURC-EPRI Roadmap*. Projected cost-reduction goals for natural gas-fueled technologies were based on the professional judgment of CURC members, as no published studies that project this information was found.

The "base" carbon capture costs improve over today's levels, though at a much lower rate. Generally, the cost of carbon capture in the base RD&D scenario trails the costs in the aggressive RD&D scenario by about 15 years as a proxy for a continuation of current funding levels.

a) *New Power Plants With Carbon Capture*

Table 2-1 shows cost-and-performance values for coal and natural gas-fueled technologies with and without carbon capture, for scenarios that assumed a robust RD&D program for these technologies. Additional details on capture costs are included in Appendix B.[30] These costs are estimated based on the projected results of the RD&D program outlined in the *2018 CURC-EPRI Roadmap*. The *2018 CURC-EPRI Roadmap* identifies multiple technology pathways to achieve these cost goals, which will largely be achieved through the development of new power cycles.

Table 2-1. Estimated 2035 Cost and Performance Values for New Natural Gas and Coal Power Plants[31]

	Accelerated RD&D				Business-as-usual RD&D			
	Unconstrained coal	Coal with capture	Unconstrained natural gas	Natural gas with capture	Unconstrained coal	Coal with capture	Unconstrained natural gas	Natural gas with capture
Capital cost ($/kW)	2,124	3,265	699	1,260	2,259	3,816	750	1,512
Fixed O&M ($/kW-yr)	70.92	101.23	24.67	40.06	75.44	118.31	26.45	48.08
Variable O&M ($/MWh)	8.98	13.00	1.62	3.24	9.55	15.20	1.74	3.89

[27] National Energy Technology Laboratory, U.S. Department of Energy, *Cost and Performance Baseline for Fossil Energy Plants, Vol. 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Rev. 3* (July 6, 2015), https://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Rev3Vol1aPC_NGCC_final.pdf.

[28] Clean Coal Research Program, U.S. Department of Energy, *Carbon Technology Program Plan* (Jan. 2013), https://www.netl.doe.gov/File%20Library/Research/Coal/carbon%20capture/Program-Plan-Carbon-Capture-2013.pdf.

[29] Energy Information Administration, *Electricity Market Module* (Apr. 2018) (documentation *EIA AEO 2018*, and related reports), https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.

[30] All cost and benefits values in the report are reported in 2017 dollars.

[31] Natural gas power plants based on a 500MW system. Coal power plants based on a 550MW system.

	Accelerated RD&D				Business-as-usual RD&D			
	Unconstrained coal	Coal with capture	Unconstrained natural gas	Natural gas with capture	Unconstrained coal	Coal with capture	Unconstrained natural gas	Natural gas with capture
HHV (Btu/kWh)	7,524	8,579	5,555	6,130	7,900	9,608	5,877	6,661
Emissions (Ton carbon dioxide /MWh)[32]	0.70	0.08	0.30	0.03	0.73	0.09	0.32	0.04

NERA applied CURC's cost and performance values to power plants of all sizes because the model requires maximum flexibility in capacity decisions. Cost and performance improvements were also applied to fossil-power units without carbon capture because many of the technologies are crosscutting, such as materials and sensors (Appendix Table B- 6 & Table B- 8).

b) *Carbon Capture Retrofits at Existing Power Plants*

Post-combustion carbon capture retrofits on coal power plants were available in NERA's model, with cost-and-performance figures based on a 2016 NETL analysis.[33] Under that analysis, the capture system was powered by a co-located natural gas combustion turbine so the performance of the host coal unit would be unaffected. Unlike greenfield units, the assumed cost of retrofits did not decrease over time due to resource constraints. Retrofits were restricted to coal units that met the following criteria: (1) the host coal unit had a capacity greater than 500 MW, (2) came online on or after 1980, (3) has both flue gas desulfurization and selective catalytic reduction controls, and (4) is located in the same state or two states away from one of the five EOR evaluated regions (Figure 2-2). States were made eligible for power sector carbon capture projects, based on their proximity to five EOR regions (Figure 2-5). After filtering the existing coal fleet through the eligible criteria list, 38 units were determined eligible. Three of those units are either already retired now or will be retiring this year; one unit already had the Petra Nova carbon capture retrofit; and seven units were assumed ineligible based on other geographic constraints.

c) *Pipeline Construction Costs*

Pipeline construction costs were estimated by combining ARI's market expertise with a pipeline model developed by NETL.[34] The modeled cost for delivering carbon dioxide by pipeline was a function of the length and diameter of the pipeline. Length was based on a power plant's proximity,

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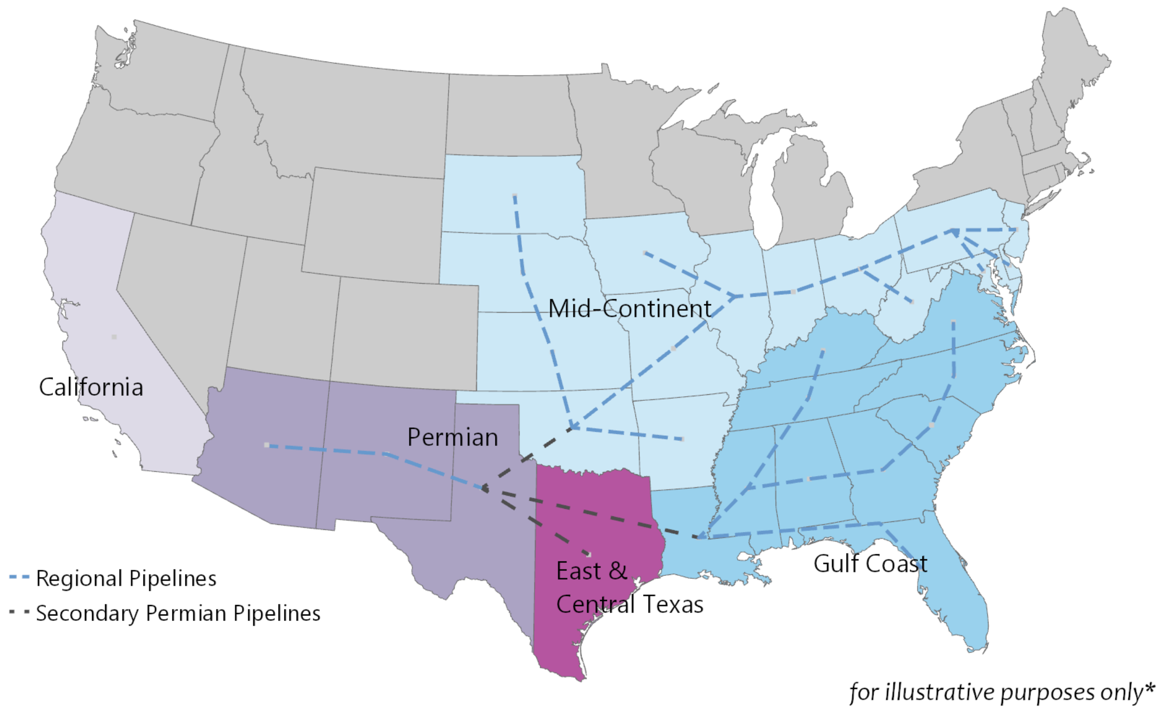
[32] The 90% capture rate is not a technical limit, but was selected because it is a benchmark frequently used by the DOE to evaluate and compare different capture technologies and the only publicly available cost data is from DOE and assumes 90% capture rates.
[33] *See* Jeffrey W. Hoffman, *et al.*, *Derate Mitigation Options for Pulverized Coal Power Plant Carbon Capture Retrofits* (Nov. 2016), https://reader.elsevier.com/reader/sd/818C153E0FDDF27AA5E97A9A79EFA4FD23BC3D1C79411EF090E8CBE05FA2F971D5F676968D91412ACBB22C3003184987.
[34] National Energy Technology Laboratory, U.S. Department of Energy, *FE/NETL CO_2 Transport Cost Model: Description and User's Manual* (July 2014), https://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/co2-transp-cost-model-desc-user-man-v1-2014-07-11.pdf.

represented by its state, to the nearest of the five EOR regions. Diameter was based on the approximate volume needs. Trunk lines, large pipelines which aggregate and ship carbon dioxide from multiple projects, were modeled from distant states. Figure 2-5 illustrates a representative pipeline network connecting source states with the five respective EOR regions.

Figure 2-5. Visual Representation of the Maximum Pipeline Network Used to Estimate CO_2 Transportation Costs[35]



Appendix A- 1 shows the primary and secondary costs of carbon dioxide pipeline transport by state. A higher secondary cost was provided in the case the primary region was overloaded. In all cases, the secondary option was the cost of transporting the carbon dioxide to the Permian region.

Scenarios

NERA evaluated eight scenarios defining different possible future paths for the U.S. electricity sector. These scenarios were structured around different assumptions regarding economic growth, electricity demand, energy prices, and a capital charge adder.

Each pair of four basic scenarios included a scenario that assumed the absence of reduced carbon capture costs based on base RD&D, and a scenario with identical assumptions but including an

[35] Interstate pipeline costs were estimated as a function of distance from the destination EOR basin. The depicted pipeline route in the Figure 2-2 was created for illustrative purposes.

aggressive RD&D program postulated to lead to lower capture costs. This study design allowed a general assessment of the role aggressive RD&D could play in economically driven deployment of carbon capture technology over time, under a range of market conditions. Table 2-2 summarizes the eight scenarios.

Table 2-2. Scenarios Simulated by NERA Model[36]

Scenario	Economic Growth	Oil and Natural Gas Prices	Electricity Demand	Capture Costs	Capital Charge Adder
1a	High	High(+)	High	RD&D	Y
1b	High	High(+)	High	Base	Y
2a	High	High(+)	High	RD&D	N
2b	High	High(+)	High	Base	N
3a	Base(-)	High	Low	RD&D	Y
3b	Base(-)	High	Low	Base	Y
4a	Base	Base	Base	RD&D	Y
4b	Base	Base	Base	Base	Y

Note that Scenarios 1a, 1b, 2a, and 2b reflect higher economic growth and electricity demand, which lead to higher energy prices than other scenarios. Scenarios 3a, 3b, 4a, and 4b are defined by assumptions regarding lower economic growth and electricity demand, which lead to lower energy prices. Scenarios ending in "a" assume an aggressive level of fossil-energy RD&D activity, which effectively lowers the cost of new generating units with and without carbon capture. All "b" scenarios are paired with an "a" scenario to evaluate the impact of an aggressive RD&D program on carbon capture deployment.

While these scenarios are only projections of what the future could hold, the higher electricity demand projections may not be consistent with how a power generator is projecting their own demand needs in the future. Demand increases being forecasted today are likely to occur under scenarios in which electrification of transportation and industry is projected to have high penetrations, which will spur growth in electric load. For example, EPRI modeled impacts of electrification on electricity demand in a recent report assessing U.S. electrification and estimated a 52% electric load increase by 2050 in its most aggressive scenario.[37] Generators also have different predictions of fuel prices than those projected in this study.

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[36] Base (-) was lower than the other Base growth due to higher energy prices. Similarly High (+) energy prices were adjusted slightly upwards to account for higher economic growth.

[37] Electric Power Research Institute, *U.S. National Electrification Assessment* (Apr. 2018), http://mydocs.epri.com/docs/PublicMeetingMaterials/ee/000000003002013582.pdf.

Capital Charge Adder

Emulating EIA's NEMS, a "capital charge adder" was factored into the analysis.[38] The EIA uses a 3 percentage point upward adjustment in the cost of capital for coal capacity additions and retrofits as a surrogate for a direct emission charge fee. EIA judged this charge to be "roughly equivalent . . . to about $15 per ton of carbon dioxide."[39] This analysis followed the approach and applied a cost of capital adder equivalent to $15 per metric ton of carbon dioxide (in 2017 $s).

Unlike the EIA, this study applied the adder to all new baseload fossil-fueled generation options (both coal and natural gas-fueled systems) without carbon capture systems. New power systems employing carbon capture technology were assumed to have eliminated regulatory risks and financial institution preferences, and were assigned no adder. Although natural gas projects have not faced the same levels of financial scrutiny as coal projects, the World Bank recently signaled its intent to strictly curtail the financing of upstream oil and natural gas plants[40] as it already has on coal power plants on the basis of carbon emissions.[41]

The adder has no direct impact on dispatch decisions of existing coal or natural gas units. The intent of the adder is to simulate financing unabated fossil units and the risk of a new, unabated unit becoming subject to carbon emission regulation during its useful life. For example, Duke Energy reports in its *2017 Climate Report to Shareholders*:

> *Since 2010, Duke Energy has included a price on carbon dioxide emissions in our IRP planning process to account for the potential regulation of carbon dioxide emissions. Incorporating a price on carbon dioxide emissions in the IRP allows us to evaluate existing resources and future resource needs against potential climate change policy risk in the absence of policy certainty.*[42]

Many entities use a range of adders to evaluate investment options under different assumptions. As of 2015, 28 states required U.S. electricity generating utilities operating in their state to prepare formal planning documents, called Integrated Resource Plans (IRPs), evaluating generation options over a planning horizon, typically the next 20 years. A review of seven of these IRPs, covering utilities operating in 21 states, found that all but one included a carbon price in evaluating future build and retirement decisions. All but two used multiple carbon price assumptions, with the lower

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[38] The incorporation of the capital charge adder is not an endorsement by any of the sponsors for its use in utility decision making and/or federal policy.
[39] Memorandum from Coal and Uranium Analysis Team to John Conti, Assistant Administrator for Energy Analysis, and Alan Beamon, Director, Office of Electricity, Coal, Nuclear, and Renewables Analysis, *AEO2014 Coal Working Group Meeting I Summary*, at 2 (July 22, 2013), https://www.eia.gov/outlooks/aeo/workinggroup/coal/pdf/meeting-summary07222013.pdf.
[40] Reuters, *World Bank to Cease Financing Upstream Oil and Gas After 2019* (Dec. 12, 2017), https://www.reuters.com/article/us-climatechange-summit-worldbank/world-bank-to-cease-financing-upstream-oil-and-gas-after-2019-idUSKBN1E61L.
[41] Anna Yukhananov, Valerie Volcovici, Reuters, *World Bank to Limit Financing of Coal-fired Plants* (July 16, 2013), https://www.reuters.com/article/us-worldbank-climate-coal-idUSBRE96F19U20130716.
[42] Duke Energy, *2017 Climate Report to Shareholders* at 5 (2017), https://www.duke-energy.com/_/media/pdfs/our-company/shareholder-climate-report.pdf.

or base case value averaging about $17 per metric ton of carbon dioxide in 2020 to 2025, and increasing over time.[43] Outside of the power sector, ExxonMobil has also publicly stated that it "has included a proxy price on carbon in its business planning since 2007. . . . This proxy cost, which in some regions may approach $80 per ton, seeks to reflect all types of actions and policies that governments may take."[44]

Energy Prices and GDP Forecasts

In general, the NERA model is closely calibrated to assumptions and projections used in *EIA AEO 2018*. Certain scenarios in this study contained assumptions that departed from EIA's approach. Higher growth scenarios were provided by the sponsors as part of the scenario definitions. For example, *EIA AEO 2018* assumed a relatively narrow range of economic growth (2.1 to 2.6% per year growth in GDP), whereas this study's range spanned 2% per year to an upper limit of about 3.5% per year. Corresponding electricity demand assumptions, driven primarily by a broader range of future GDP growth, were similarly more expansive than EIA's.

NERA incorporated both EIA's "Reference" and "Low Oil & Gas Resource" cases in its analysis. NERA's energy price projections tracked EIA's, but adjusted prices upwards in the cases of much higher rates of economic growth to reflect increased demands (Appendix B- 2 & Table B- 3). A sensitivity analysis of oil and gas prices below EIA's Reference case was outside the scope of this analysis. Under lower oil prices, it is expected that the economic case for carbon capture would decrease because carbon dioxide prices are determined by the price of oil.

Power Plant Retirements

Nuclear power plants were assumed to gradually phase out over the next few decades, with each plant retiring due to market pressures or sixty years from their original commencement date.[45] Sixty years was chosen because that is consistent with a one-time Nuclear Regulatory Commission (NRC) extension. Approximately two-thirds of U.S. nuclear units were over 45 years of age in 2018, and would be at least 67 years of age in 2040.[46] Lastly, hydropower capacity was assumed to be preserved throughout the study's lifetime.

Existing coal and natural gas power plants were assumed to have no additional regulatory forcing policies that impacted their operations , and could therefore continue to operate (typically at very low cost) as long as they were part of the mix of resources that could produce the lowest cost power to the grid. Other costs, such as required upgrades associated with New Source Review, were

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[43] Carbon Utilization Research Council, *Analysis of Options for Funding Large Pilot Scale Testing of Advanced Fossil-Based Power Generation Technologies With Carbon Capture and Storage* (Mar. 21, 2016), http://media.wix.com/ugd/80262f_2949eafbd03847619b8c02754de116fe.pdf.
[44] Ken Cohen, *ExxonMobil, Paris, and Carbon Policy*, ExxonMobil Perspectives (May 6, 2015), http://www.exxonmobilperspectives.com/2015/05/06/exxonmobil-paris-and-carbon-policy/.
[45] For example, *EIA AEO 2018* projected 99 GW of nuclear power in 2017, declining to 83 GW in 2040 and 79 GW in 2050.
[46] Energy Information Administration, Spent Nuclear Fuel, tbl.2 Nuclear power plant data as of June 30, 2013 (rev. February 2016), https://www.eia.gov/nuclear/spent_fuel/ussnftab2.php (last visited July 20, 2018).

also outside the study's scope. Both the EPA and Congress are taking active steps to modify the current law, because it has been widely documented to discourage modernization, e.g., efficiency and environmental control projects.

Additional information on assumptions used in the power sector analysis is included in Appendix B.

Financial Incentives and Policy Drivers

This analysis did not assume the use of any new financial incentive or regulatory requirements for low carbon-emission technologies, including renewable energy, nuclear power, or fossil-fueled systems with carbon capture. The major incentives provided under existing law, including state RPS and the Section 45Q carbon-storage incentives, were incorporated in all scenarios. Based on the current administration's clear intent to repeal the Clean Power Plan, it was not modeled in this analysis. Enacted state-based efforts, e.g., the Regional Greenhouse Gas Initiative and California's cap-and-trade system, however, are included.

Macroeconomic Benefits

Macroeconomic impacts of an activity include the direct effects of the activity on its primary business purpose (e.g., producing electricity, oil, etc.), as well as indirect effects on other activities supporting that primary purpose (e.g., increased mining, chemical production) and related induced activities supporting these activities (e.g., provision of housing, transportation, food to employees engaged in the direct and indirect activities). In this study, the macroeconomic drivers are the impacts of the lower price of electricity from more affordable fossil-power technologies, and the displacement of imported oil with increased domestic oil production via EOR.

Macroeconomic Benefits from EOR

After defining the volumes of additional oil production and capacity for carbon storage in each of the five regions, ARI also evaluated the macroeconomic benefits of increased domestic oil production related to EOR.

Increased domestic oil production via power plant based CO_2-EOR can enhance the nation's GDP, reduce the U.S. balance of payments deficit, provide energy security benefits, and create jobs. Of these benefits, ARI examined the GDP benefits related to increased oil production such as the direct value of the oil produced, the indirect value provided by those manufacturers and service industries that support EOR activity, and those economic activities such as housing, transportation, and food services that support workers engaged in direct and indirect activities. Projected macroeconomic benefits were based on the Bureau of Economic Analysis RIMS II model.[47]

[47] The calculations were made using final demand multipliers for the Oil and Gas Industry (Industry 211000). These input-output multipliers were applied on a regional basis to capture the contribution of CO_2-EOR in each of the five regions assessed by the Advanced Resources International study.

Macroeconomic Benefits of Lower-cost Electricity

A price change in electric power can have broad impacts that ripple through the U.S. economy. Since electric power is a basic input in the U.S. economy, even a small decrease can have a significant benefit. A 2014 Management Information Services, Inc. (MISI) report, written for the American Coalition for Clean Coal Electricity, compared lowering energy costs to the effect of a tax cut by "putting more money in the hands of consumers and businesses."[48]

The magnitude of lower-cost electricity benefits on the larger economy were estimated, referencing prior studies and modeling tools. These factors were then applied to the difference in NERA's reported retail electricity rates between the aggressive RD&D scenarios and their corresponding base RD&D scenarios (Table 3-1). For purposes of this paper, an elasticity factor of -0.1% was used for both GDP and employment impacts of a change in U.S. electricity prices.

Lower Cost Electricity Impact on GDP

The MISI paper defined price elasticity as the percent change in GDP for a given one percent change in the price of an energy commodity, such as oil or electricity. After a literature review, it estimated elasticity factors of about: "-0.17 for oil, -0.13 for electricity, -0.14 for energy."[49] In its own analysis, MISI used a conservative electricity price elasticity factor of -0.10.[50]

Lower Cost Electricity Impact on Jobs

A 2010 working paper by the National Bureau of Economic Research (NBER) considered the relationship between electricity prices associated with possible climate change mitigation programs and employment. "The main finding is that employment rates are weakly related to electricity prices with implied cross elasticity of full-time equivalent (FTE) employment with respect to electricity prices ranging from -0.16% to -0.10%."[51]

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[48] Management Information Services, Inc., for the American Coalition for Clean Coal Electricity, *The Social Costs of Carbon? No the Social Benefits of Carbon*, at 77 (Jan. 2014), https://www.eenews.net/assets/2014/01/22/document_pm_03.pdf.
[49] Ibid. at 74.
[50] Stated differently, a 10% increase in electricity prices could be expected to cause a 1% decrease in GDP.
[51] Olivier Deschenes, National Bureau of Economic Research, *Climate Policy and Labor Markets*, at Abstract (June 2010), http://www.nber.org/papers/w16111.

3. Results

Two variables dominated the deployment of power-sector carbon capture: energy prices and the existence of a vigorous RD&D program. A graphical overview of generation mixes across all scenarios is provided in Figure 3-1.

Oil and Natural Gas Prices

Forecasts were sensitive to the price of fuels, especially oil and natural gas. The impact of energy prices was examined by varying the escalation rate of fossil fuel and crude oil prices: Scenarios 4a and 4b are driven largely by the assumption that natural gas prices will escalate at 1% per year between 2020 and 2040, Scenarios 3a and 3b at 2% per year, and Scenarios 1a, 1b, 2a, and 2b assume a 3% per year increase. As a result, Scenario 1a (aggressive RD&D, high economic growth, high oil and gas prices) and Scenario 4b (base RD&D, base economic growth, base oil and gas prices) tend to bracket the modeling projections and are presented below to display overarching generation trends. Using Scenarios 1a and 4b as bookends, the minimum level of coal and natural gas carbon capture was forecasted to be 3% of the U.S. grid mix and the maximum level was 12% in 2040. For comparative reference, all the solar panels in the country generated 1.3% of U.S. electricity in 2017.[52]

For the six scenarios with "High" or "High(+)"energy prices, coal dominates carbon capture deployment through the study period, and for the two scenarios with lower ("Base") energy prices, natural gas dominates carbon capture deployment.

Under Scenario 1a, significant deployment of new carbon capture-equipped coal units begins in the period of 2025 to 2030, and accelerates after 2030. Under the lower fuel prices assumed in Scenario 4b, similar but delayed deployment of new natural gas-fueled units equipped with carbon capture was forecasted.

Aggressive RD&D

In viewing Figure 3-1, recall that the scenarios are "paired" (with and without RD&D leading to lower carbon capture costs).[53] A general trend found for these paired scenarios is that carbon capture deployment is approximately two to three times as large for a given simulation year after 2030 with an assumed rigorous carbon capture RD&D program, compared to the same year with less intense RD&D (Table C- 3, Table C- 6).[54] In all scenarios, new fossil-power plants were built without carbon capture ranging from 70 to 271 GW by 2040 (Table C- 2, Table C- 5). Existing coal

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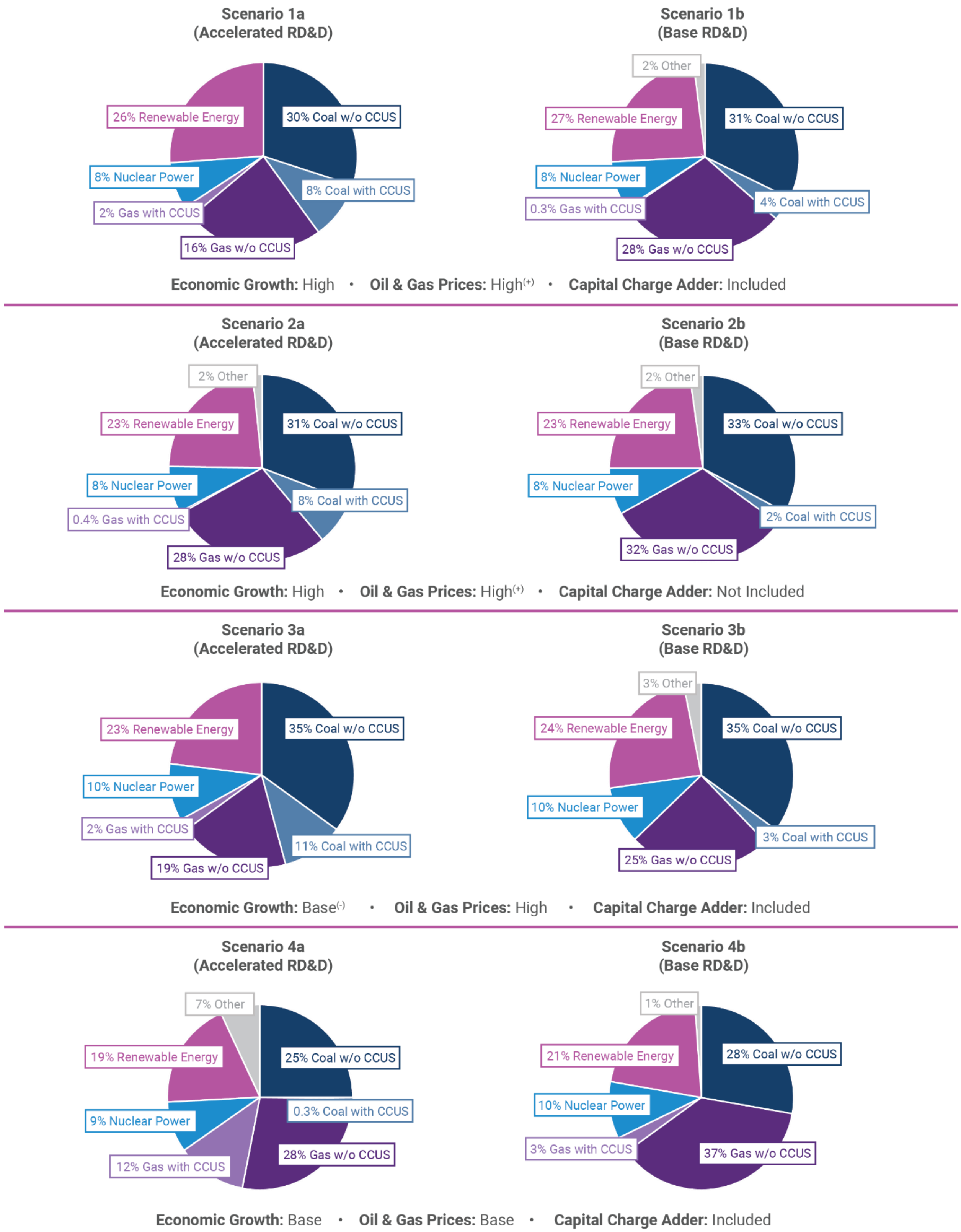
[52] Energy Information Administration, Electricity Data Browser, https://www.eia.gov/electricity/data/browser/ (last visited July 20, 2018).
[53] Scenarios 1 & 2 constitute such a pair, as do Scenarios 3 & 4, 5 & 6, and 7 & 8.
[54] This relationship holds for "With RD&D" scenarios in which the deployment of capacity exceeds about 20 GW for a given fuel.

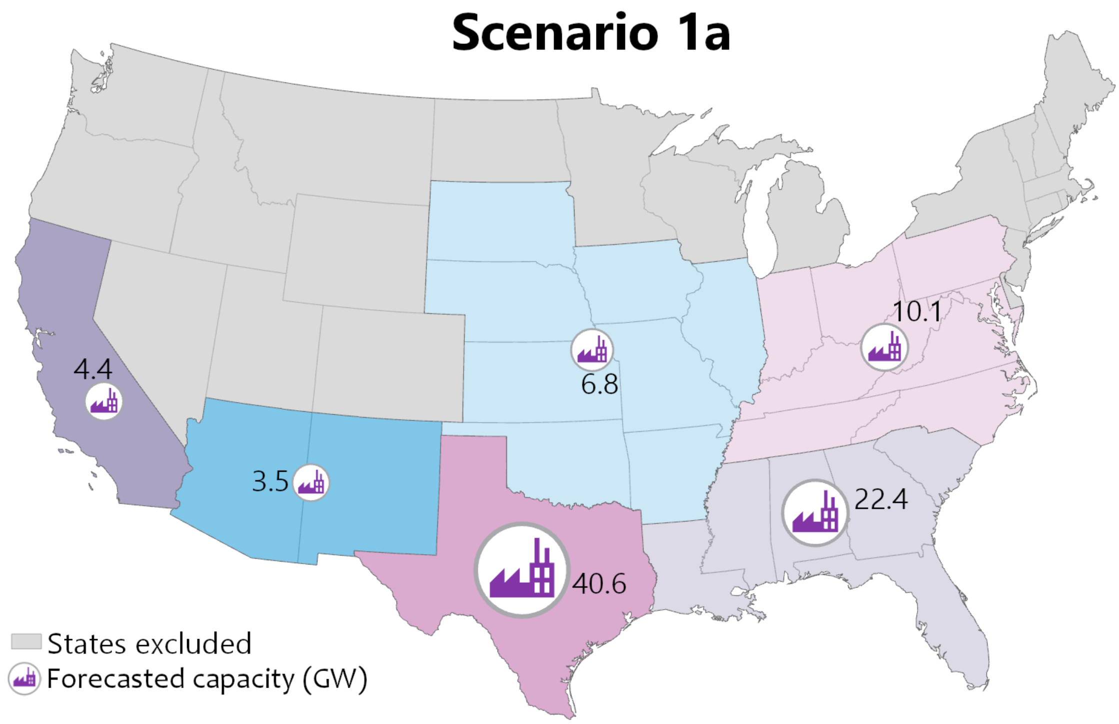
and natural gas generation remain in all scenarios through the forecasted study period with minimal retirements (Table C- 1, Table C- 4).

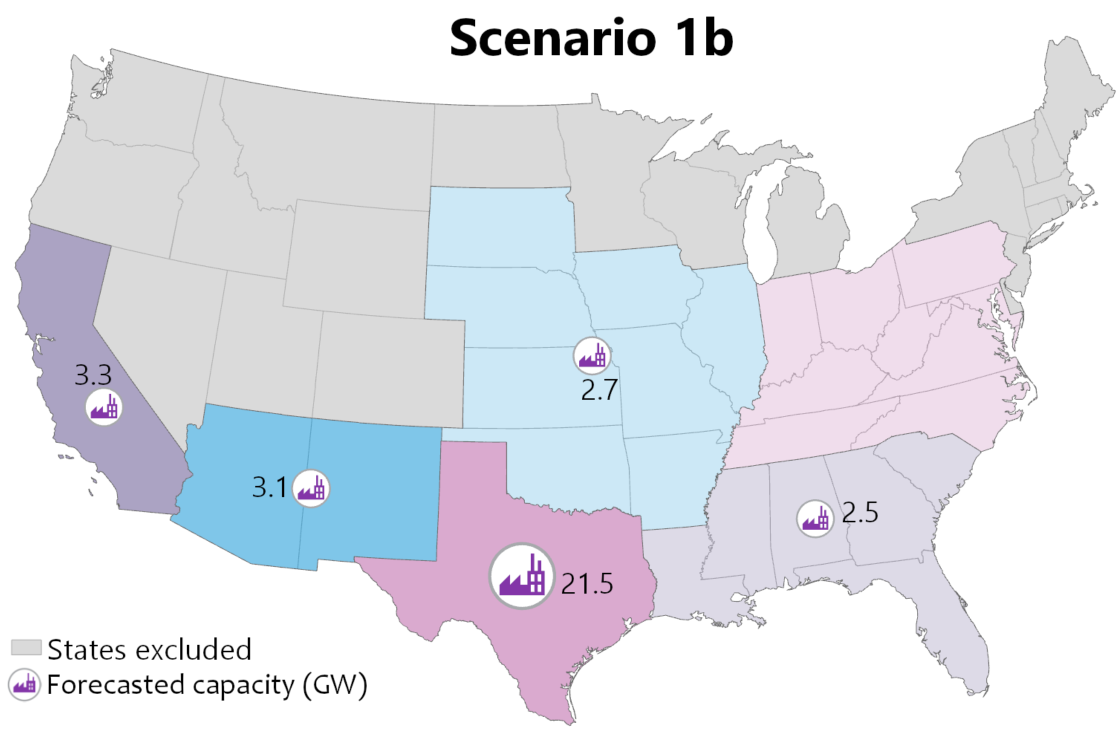
Figure 3-1. Forecasts of U.S. Power Sector in 2040

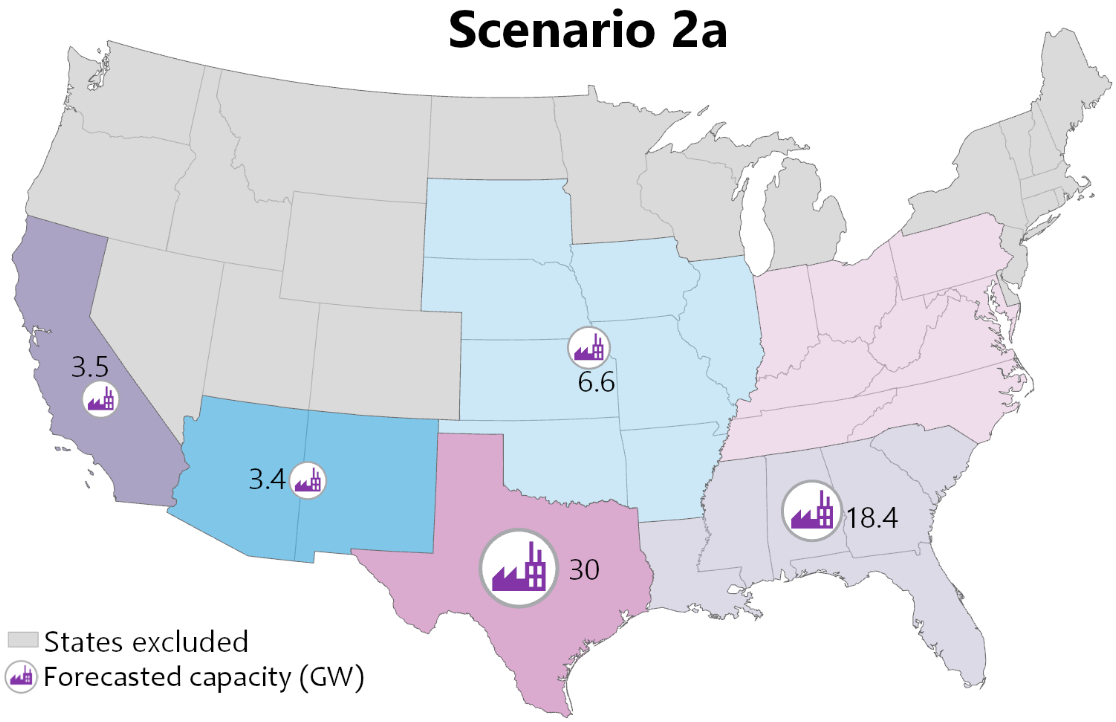


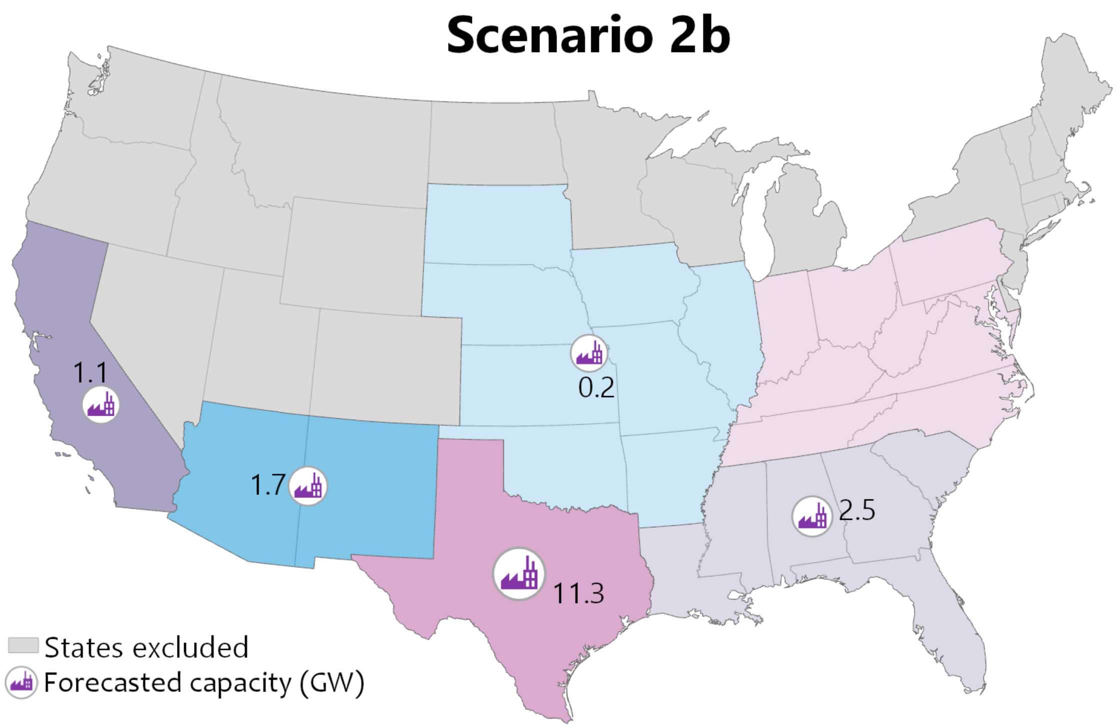
The following maps in Figure 3-2 display carbon capture forecasted deployment by region in 2040.

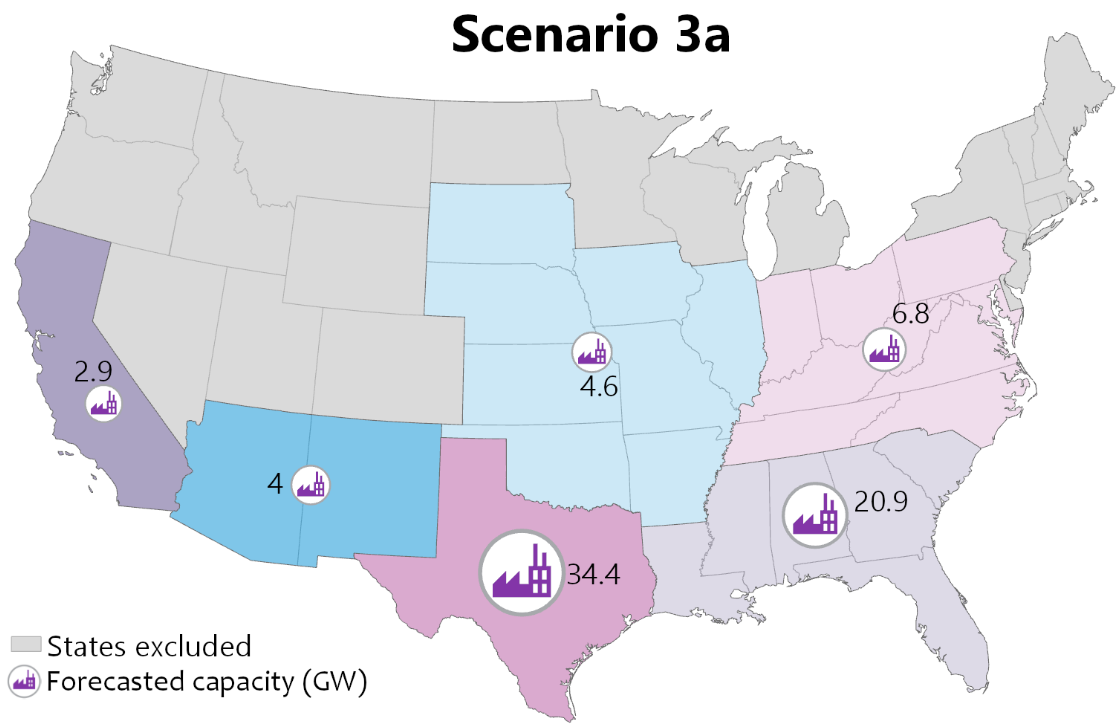
Figure 3-2. Projected Regional Carbon Capture Capacity by 2040 (GW)

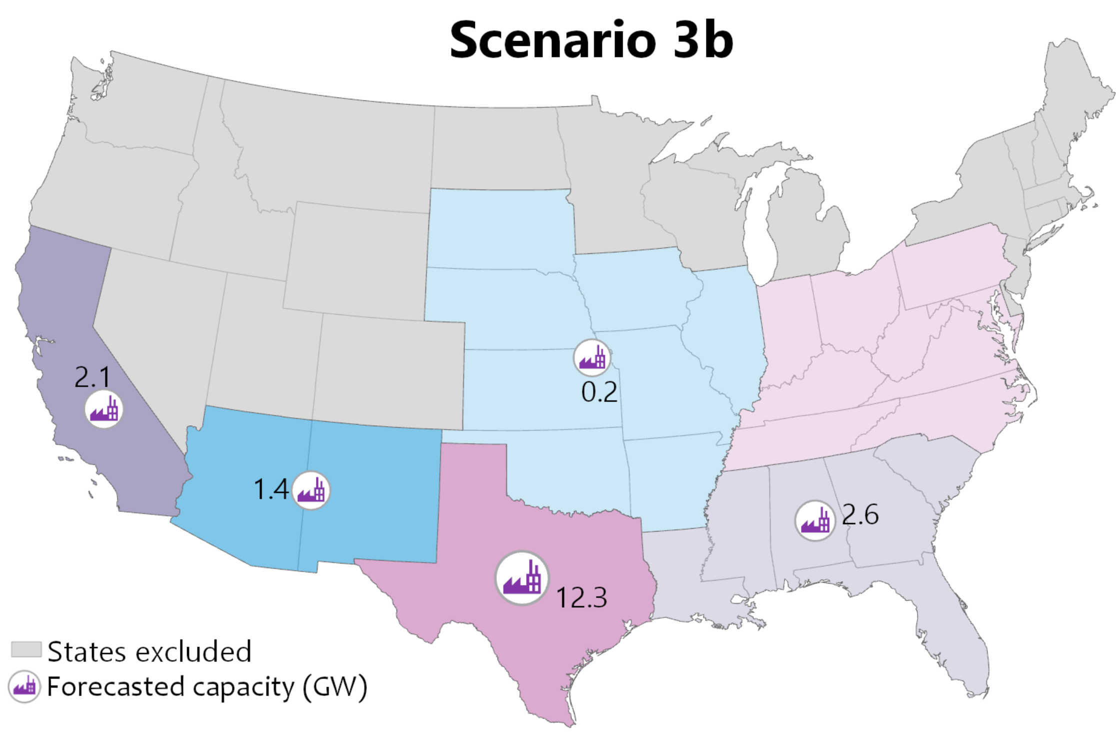




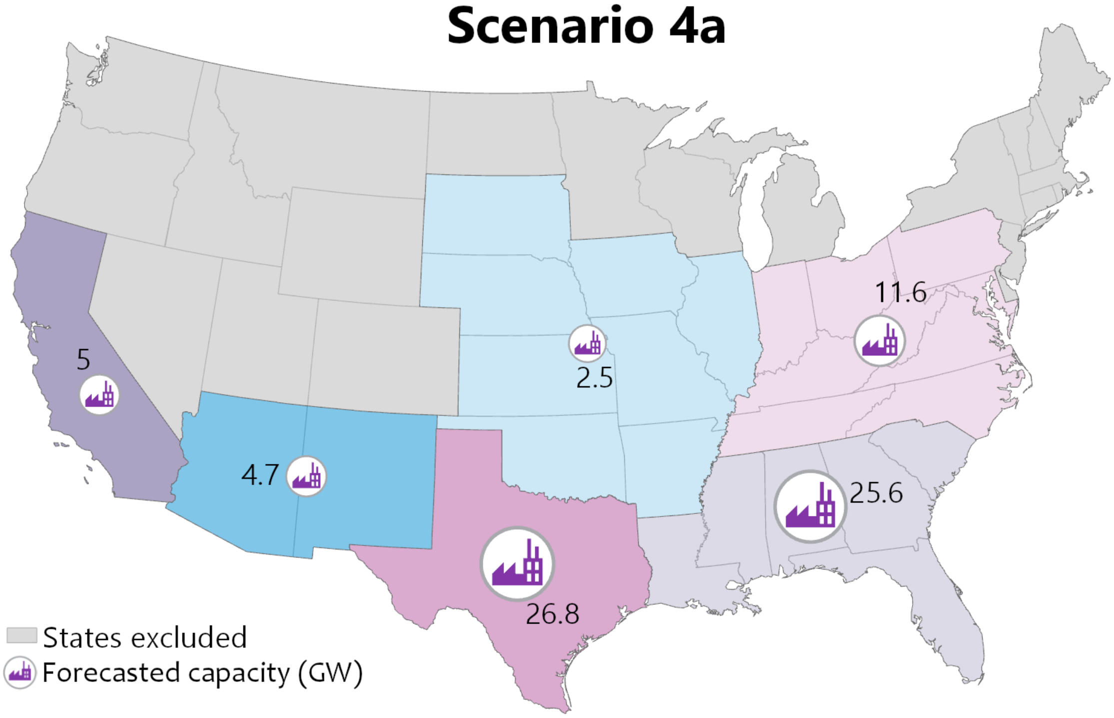

Scenario 2a
3.5
3.4
6.6
30
18.4
States excluded
Forecasted capacity (GW)


Scenario 2b
1.1
1.7
0.2
11.3
2.5
States excluded
Forecasted capacity (GW)

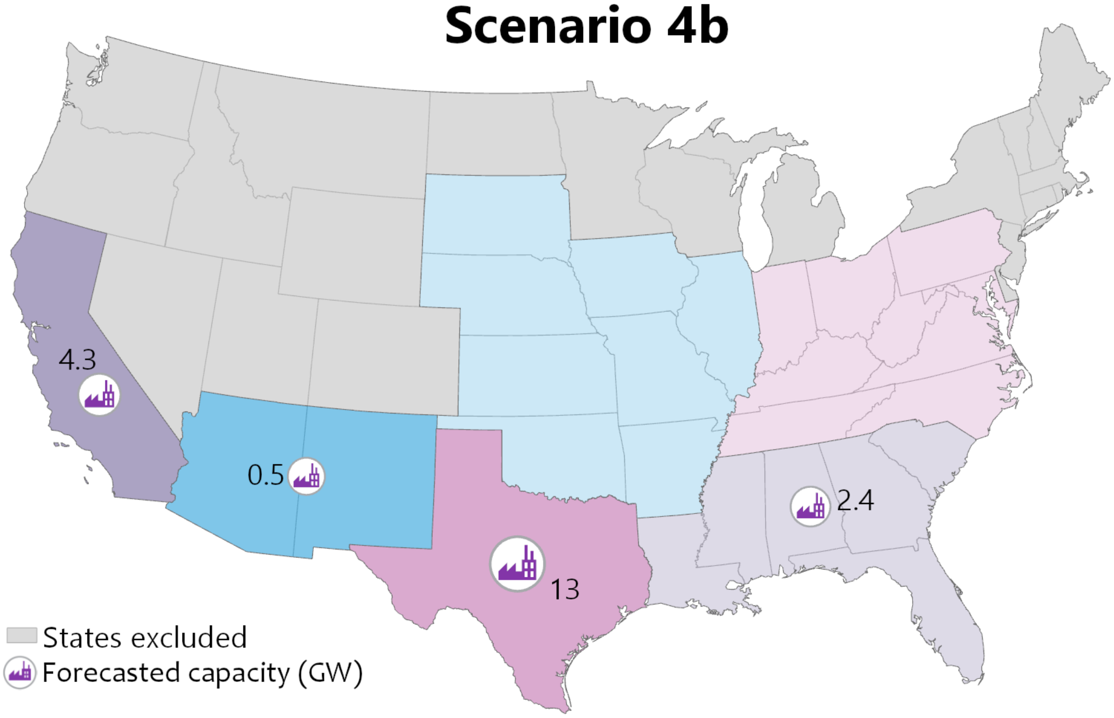

Scenario 3a
2.9
4
34.4
4.6
6.8
20.9
States excluded
Forecasted capacity (GW)


Scenario 3b
2.1
1.4
12.3
0.2
2.6
States excluded
Forecasted capacity (GW)

Scenario 4a



Scenario 4b



Macroeconomic Benefits Analyses

Electricity Price Projections

In addition to deployment, the price of electricity primarily depended on the future prices of natural gas and oil prices and the existence of an aggressive RD&D program. With lower fuel and crude oil prices (Scenarios 3a to 4b), resulting electricity prices are lower than those with higher fuel and crude oil prices (Scenarios 1a to 2b). Table 3-1 shows retail electricity prices resulting under the eight modeled scenarios.

Table 3-1. Projected National Blended Retail Rates by Scenario (¢/kWh)

Scenario	2040 National Retail Rate (¢/kWh)
1a	11.26
1b	11.44
% change (1a & 1b)	**-1.6%**
2a	10.99
2b	11.14
% change (2a & 2b)	**-1.4%**
3a	11.47
3b	11.70
% change (3a & 3b)	**-2.0%**
4a	10.46
4b	10.57
% change (4a & 4b)	**-1.1%**

EOR projections

The macroeconomic benefits flowing from increased domestic EOR was projected by ARI, using a methodology that applied BEA RIMS II multipliers to gross EOR oil revenues for a given scenario (Table 3-2). Summary tables reporting additional benefits, e.g. royalties and tax revenues, are shown in Table D- 3. Under Scenario 1a, for example, the gross revenue from producing a projected 923 million barrels of oil per year in 2040 with gross revenues of approximately $90B.

Table 3-2. Annual EOR Benefits Realized in 2040

	Benefits		
Scenario	**Incremental Oil Production (MM barrels per year)**	**Federal Income Tax Revenue ($MM per year)**	**Total Gross Revenue ($MM per year)**
1a	923	4,962	89,837
1b	449	2,877	44,496
2a	713	4,055	69,917
2b	239	1,449	23,651
3a	791	4,218	76,497
3b	245	1,398	23,936
4a	369	2,312	31,697
4b	104	718	8,996

Using the RIMS II model, this activity is expected to generate over 466,000 direct jobs and 313,000 indirect jobs for a total of 780,000 jobs related to EOR that year. The actual macroeconomic benefit related to EOR is higher, estimated at $190 billion across the five EOR regions in 2040 (Table 3-3). Note that these are nominal benefits and should be distinguished from the "incremental" benefits from an aggressive RD&D program, as discussed further in the following section.

Macroeconomic Benefits of RD&D

The total incremental macroeconomic benefit of an aggressive RD&D program are those directly attributable to a rigorous RD&D program. Incremental benefits were calculated by summing the nominal benefits from reduced electricity prices and increased EOR production for each scenario, then taking the difference between "paired" scenarios, which contain identical assumptions except the presence or absence of an aggressive RD&D program.

For example, the difference between Scenarios 1a and 1b was $140 billion and 694,000 jobs by 2040 (Table 3-3). Additional results from the ARI analysis can be found in Appendix D.

Table 3-3. The Annual Incremental Benefits of Aggressive RD&D by Paired Scenario (2040)[55]

Scenarios	EOR-based Benefits		Electricity-based Benefits		Total Benefits	
	GDP ($B)	*Jobs[56]*	*GDP($B)*	*Jobs[57]*	*GDP($B)*	*Jobs*
1a	190	780,000	-	-	-	-
1b	95	390,000	-	-	-	-
Difference (1a&1b)	**95**	**390,000**	**44**	**300,000**	**140**	**690,000**
2a	147	610,000	-	-	-	-
2b	50	200,000	-	-	-	-
Difference (2a&2b)	**97**	**410,000**	**38**	**260,000**	**135**	**670,000**
3a	162	660,000	-	-	-	-
3b	51	200,000	-	-	-	-
Difference (3a&3b)	**111**	**460,000**	**55**	**380,000**	**166**	**840,000**
4a	66	270,000	-	-	-	-
4b	19	80,000	-	-	-	-
Difference (4a&4b)	**47**	**190,000**	**30**	**210,000**	**77**	**400,000**

Other benefits

Power Plant Construction Jobs

The 600 MW Turk Coal Plant built in 2010 created 1,400 jobs at peak construction and 110 for continuous operation and maintenance, including skilled welders, crane operators, and chemical engineers. Applying these ratios to the additional fossil capacity additions from RD&D yields 4,400 to 6,400 continuous O&M jobs and up to 82,000 construction jobs related to fossil-power capacity additions by 2040, due to accelerated deployment of 24 to 35 GW of new fossil generating capacity with and without carbon capture by 2040 (Table 3-4).

[55] The macroeconomic benefits of lower electricity prices were calculated on a comparative basis, so individual values cannot be calculated.
[56] Rounded to the nearest 10,000.
[57] Rounded to the nearest 10,000.

Table 3-4. Total New Fossil Generation Capacity With and Without Carbon Capture (GW)

	2020	2025	2030	2035	2040
1a	26	26	75	152	229
1b	26	26	58	115	198
Difference (1a&1b)	**0**	**0**	**17**	**37**	**31**
2a	30	42	124	220	312
2b	33	39	91	181	288
Difference (2a&2b)	**-3**	**3**	**33**	**39**	**24**
3a	26	26	51	88	144
3b	26	27	46	65	109
Difference (5&6)	**0**	**-1**	**5**	**23**	**35**
4a	26	27	56	112	166
4b	26	27	42	75	140
Difference (4a&4b)	**0**	**0**	**14**	**37**	**26**

Coal Production

The projected increases in oil field jobs are also supplemented by coal mining jobs. The NERA model is able to report coal production for power production and found it could increase by 40% by 2040 from forecasted 2020 levels (Table 3-5). These figures only represent the volumes of steam coal produced for power production. Metallurgical coal used in industrial processes, such as steelmaking, are not included.

Table 3-5. Modeled Coal Production for Power in 2020 & 2040

	National Coal Production for Power (million short tons)	
Scenario	**2020**	**2040**
1a	785	1089
1b	789	998
2a	776	1069
2b	775	991
3a	785	1036
3b	788	914
4a	672	648
4b	676	671

Capital Charge Adder

Scenarios 2a and 2b were run to examine the impact of the capital charge adder. They include identical assumptions as Scenarios 1a and 1b, with the exception of the adder. Substantial deployment of carbon capture was seen with the adder. In Scenario 2a, roughly 8% of the U.S. grid was forecasted to be powered by a fossil-power plant with carbon capture by 2040. New coal power plants without carbon capture, also beneficiaries of the fossil energy RD&D program, were forecasted in the 2035 timeframe in Scenario 2a.

4. Discussion

Our results indicate a significant amount of fossil-fueled power technologies equipped with carbon dioxide capture can be deployed *by market-driven decisions* under a broad range of assumptions. Deployment under these future scenarios all began in the 2025 to 2030 time period and accelerate thereafter. Scenarios featuring an aggressive RD&D program generally had two to three times the deployment of carbon capture-equipped technologies in 2040 than scenarios of a baseline lacking such an aggressive RD&D program.

Many readers may be surprised by the proposition that power plants with carbon capture can be less costly than those without. Of course, that is not exactly the hypothesis tested by this analysis. This analysis compared the cost and revenues associated with unabated fossil energy generators to the cost and revenues associated with carbon capture equipped fossil units receiving a revenue stream for captured carbon dioxide used by EOR projects.[58] The analysis found that future EOR revenues, and potentially tax benefits associated with Section 45Q, could drive carbon capture development in many regions. Under a broad range of assumptions for future energy prices, economic growth, and perceived regulatory risks associated with carbon emissions, a significant amount of power generation with carbon capture can be deployed, with the majority of the growth occurring in the mid to late 2030s.

<u>Finding #1: Fossil Energy RD&D Investments Generate National Benefits</u>

The forecasted futures are heavily contingent on increasing the commitment and impact of public-private RD&D. Even the scenarios with "base" RD&D modeled in our analyses should not be taken for granted, as capital and operational costs for power plants with capture systems declined in both cases. For example, coal capital costs fell 13% by 2040, and natural gas capital costs by 22% (Table B- 7 and Table B- 9).

Bringing transformative technologies from the laboratory to the market requires a sustained commitment across the technology development chain. Achieving the *2018 CURC-EPRI Roadmap* technology goals will benefit both new carbon capture plants, as well as improve the performance of existing facilities through improved materials, sensors, and automation. Skilled jobs would be needed for the construction of new power plants, increased mining activity, and to support additional oil field productivity.

Furthermore, demonstrating advanced technologies across the main coal types in the United States would support domestic energy security and international export opportunities. The main coal

[58] This study was not intended to simulate the first- and second-of-a-kind commercial demonstration units. Such units tend to build their business case around expected profits from subsequent commercial deployment of the successfully demonstrated technology. Such considerations are highly case specific and are beyond the scope of this analysis.

types in the United States are representative of coal compositions found across the world.[59] Validating the concepts in the United States would increase market confidence to facilitate technology and export opportunities abroad.

Finding #2: Carbon Capture Can Benefit Both Coal and Natural Gas Systems

Recent natural gas power plant capacity additions have been driven by low fuel prices, in concert with perceived regulatory risks and the ability of natural gas to balance increasing levels of intermittent renewable generation on the grid. Decisions are highly influenced by natural gas costs because fuel costs constitute a large portion of the total cost of electricity from natural gas-fueled power plants, versus a relatively small portion of the cost of electricity from coal-fueled power plants.

Across the scenarios examined, the decision to build coal or natural gas, with or without capture, will largely depend on future energy prices, with the most significant factor being the price of oil and natural gas. With low-cost oil and natural gas, natural gas-fueled units (with and without carbon capture) were built. In scenarios with higher oil and natural gas prices, coal-fueled generation primarily with carbon capture dominated new capacity. Our model assumed perfect foresight of future natural gas and oil prices, but in the real world, decision-makers have no such luxury. Recognizing the volatile nature of natural gas and oil prices, the study finds that continued investment in both coal and natural gas systems is a prudent decision to provide power generators with maximum choices for the next generation of plants.

Finding #3: Market-driven Retrofits Constrained by the Fully Depreciated Existing Fleet

Despite including retrofits as an option, the study did not project any retrofit applications of carbon capture technology. The primary reason was that existing coal units are projected to be profitable in the scenarios, with low operating costs, and adding carbon capture did not improve their economics of the 38 coal power plants determined to be eligible for EOR in the analysis. They were assumed to continue to operate at lower costs without a retrofit than with a retrofit, given that they were fully amortized throughout most of projection period, and no additional regulations requiring additional capital investment would occur. The costs of compliance with additional environmental regulations – such as New Source Review or the Clean Power Plan – were not included in the analysis. New Source Review, a regulation designed to improve air quality, can paradoxically discourage investments in new and existing power plants that improve environmental performance. New Source Review was has been identified as one of the top obstacles for prospective carbon capture retrofit projects: the developers of Petra Nova opted to spend nearly

[59] *See* BP, *BP Statistical Review of World Energy: Coal* (June 2017), https://www.bp.com/content/dam/bp/en/corporate/pdf/energy-economics/statistical-review-2017/bp-statistical-review-of-world-energy-2017-coal.pdf.

$100 million on a sister natural gas combustion turbine to avoid the possibility of triggering it.[60] A bill sponsored by Rep. Griffith (H.R. 3127), amends the Clean Air Act to fix existing New Source Review issues and encourage more market-driven investments into existing fossil-power plants. Additional federal incentives were not factored into the analysis (e.g., private activity bonds and master limited partnerships), which could act to further lower the cost of capital needed for retrofits and greenfield facilities. Based on these assumptions, existing coal plants were more profitable operating as originally designed than by investing in a carbon capture system.

In the future, coal power plants may choose to install carbon capture systems for reasons not evaluated in this analysis, e.g., to sell carbon dioxide to EOR regions not covered in this study, monetize state or federal CCUS incentives, or comply with future carbon regulations. There are some retrofit coal plant projects in project development that are outside the scope of this study, and likewise, would add to the national macroeconomic benefits identified in this study.[61] Moreover, retrofit applications of new carbon capture technologies could serve to accelerate commercial-scale demonstration and deployment of new post-combustion technologies. In addition, this analysis did not evaluate retrofit applications to natural gas systems. The DOE and the *2018 CURC-EPRI Roadmap* have identified that coal post-combustion capture RD&D is highly applicable to natural gas applications.[62] A future analysis could evaluate the market potential of retrofit systems on the existing natural gas fleet.

Most states that were excluded from the analysis with high EOR potential, such as Wyoming and North Dakota, were forecasted to have no new fossil energy power plants built during the study period. The runs forecasted existing generation and imports from other states could satisfy future power demand, and that the demand for EOR opportunities in those states would be satisfied from lower-cost carbon dioxide supplied by nearby industrial operations (which were also not covered in the study).

Finding #4: Supply and Demand-side Forces Will Influence the Demand for New Capacity

Actual levels of carbon capture deployment will be sensitive to future electricity supply and demand, unrelated to carbon capture technology.

Power demand growth in the United States has slowed to a crawl. As noted in the DOE's *Staff Report to the Secretary on Electricity Markets and Reliability*, demand growth is "averaging 1.0 percent

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[60] *See* NRG Energy, Inc. Written Testimony of David Greeson, Vice President, Development, NRG Energy, Inc. (Sept. 13, 2017), https://www.epw.senate.gov/public/_cache/files/c/c/cc38b124-4842-4794-b883-21e1cd08f2c2/AA4D18981D364A7D686D95523F8EB5FD.greeson-testimony-09.13.2017.pdf.
[61] *See* Jessica Holdman, *Companies Kick Off Carbon Capture Project in North Dakota*, Bismarck Tribune (Oct. 5, 2017), https://bismarcktribune.com/business/local/companies-kick-off-carbon-capture-project-in-north-dakota/article_cce0a445-91ea-52f9-9802-52db30b9c265.html.
[62] *See* U.S. Department of Energy, *Carbon Capture Opportunities for Natural Gas Fired Power Systems* https://www.energy.gov/sites/prod/files/2017/01/f34/Carbon%20Capture%20Opportunities%20for%20Natural%20Gas%20Fired%20Power%20Systems_0.pdf (last visited July 20, 2018).

annually from 2000 to 2008, to remaining roughly flat since then."[63] This analysis modeled an uptick to 1.4% in annual power demand to reflect the growing economy, a renewed focus on growing a more energy-intensive manufacturing sector, and trend toward vehicle electrification. This estimate is consistent with the EPRI's *U.S. National Electrification Assessment*, which forecasts a high-end estimate of 1.2% growth through mid-century.[64] Predictably, the future market for new fossil-energy technologies is sensitive to these assumptions. Deployment was significantly more sensitive to demand growth in the base RD&D scenarios (33 GW in scenario 1b vs. 18 GW in scenario 3b) than the accelerated RD&D scenarios (87 GW in scenario 1a vs. 74 GW in scenario 3a).

On the supply side, the operating decisions of existing nuclear and coal plants will be key determinants of the future CCUS market. Cumulatively, they comprise over 200 GW of base-load generating capacity operating at high-capacity factors. Although the existing nuclear fleet faces both regulatory and economic pressures,[65] some states have provided out-of-market credits to keep their existing fleets in operation.[66,67] A few nuclear power plants are attempting to get a second extension from the NRC to operate for 80 years.[68] The analysis resulted in 40 GW decline of nuclear power plants by 2040 across all scenarios (Table C- 7). If fewer retirements occur, the market for greenfield fossil units with carbon capture would likely fall. Conversely, our analysis found very few existing coal units likely to retire. If this projection was incorrect, the demand for new carbon capture-enabled units would increase.

The constant flux in state and federal power market rules make it increasingly difficult to project market conditions of the power sector, and by extension, its composition by mid-century. Ohio is considering its own nuclear incentives, and other states will surely join them. Decisions from the Federal Energy Regulatory Commission (FERC), will also play a role. Last month, FERC rejected capacity-market reforms within PJM Interconnection, L.L.C. (PJM), the nation's largest competitive wholesale energy market. In its place, FERC ordered PJM to add out-of-market support to its

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[63] *See* U.S. Department of Energy, *Staff Report to the Secretary on Electricity Markets and Reliability*, at 13 (Aug. 2017), https://www.energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf.

[64] Electric Power Research Institute, *U.S. National Electrification Assessment*, at 40 (Apr. 2018), http://mydocs.epri.com/docs/PublicMeetingMaterials/ee/000000003002013582.pdf.

[65] Jim Polson, *More Than Half of America's Nuclear Reactors Are Losing Money*, Bloomberg (June 14, 2017), https://www.bloomberg.com/news/articles/2017-06-14/half-of-america-s-nuclear-power-plants-seen-as-money-losers.

[66] *See* Peter Maloney, *New Jersey Gov. Murphy Signs Bills Creating Zero Emission Credits for Nuclear*, UtilityDive (May 24, 2018), https://www.utilitydive.com/news/new-jersey-gov-murphy-signs-bills-creating-zero-emission-credits-for-nucle/524238/.

[67] *See* Robert Walton, *Updated: New York PSC Approves 50% Clean Energy Standard, Nuclear Subsidies*, UtilityDive (Aug. 1, 2016), https://www.utilitydive.com/news/updated-new-york-psc-approves-50-clean-energy-standard-nuclear-subsidies/423635/.

[68] *See* Nuclear Engineering International, *Surry to Seek 80-year Operation* (Mar. 30, 2016), http://www.neimagazine.com/features/featuresurry-to-seek-80-year-operation-4849335/.

capacity market bids or allow generators to opt-out of the capacity market.[69] Final implementation of these rules, as well as state actions, will have lasting and profound repercussions on both existing and new power plants.

Finding #5: Close Proximity to EOR Regions Enables Market-driven Deployment

EOR is the most immediate and high-value market for power-sector carbon projects, due to the oil industry's unique ability to offtake and pay a premium for large volumes of carbon dioxide.[70] Yet utilization opportunities beyond EOR that apply to a wider set of EOR regions and saline storage fields are available. Enhanced coal bed methane recovery (CBM) uses the general concept of EOR in oil plays and applies it to extract additional natural gas from coal seams. The DOE estimates over 30 years of U.S. power sector carbon emissions could be stored in this process from Appalachia to the Powder River Basin.[71][72] Non-geologic utilization, carbon sequestration with the Section 45Q tax credits, and combinations of the different utilization opportunities likely hold additional opportunities and regional benefits beyond this study's projections.

Building a pipeline from a carbon capture project to a destination EOR field is a non-trivial cost. In this analysis, carbon capture projects in states far away from an established EOR field paid more than five times for transportation than an identical project in the same state as an EOR region to reach those same fields. Thus, the model generally projected new carbon capture projects in states nearby the established EOR basins, especially those with high levels of future power demand growth (e.g., Texas and California).

Finding #6: Carbon Dioxide Pipelines Enable Distant States to Tap Into the EOR Market

Deployment of these advanced fossil-energy power systems tended to be regional, and related to a power plant's proximity to an EOR production region. Across the scenarios, states as far as Iowa and Florida were assessed for the viability to capture and sell carbon dioxide first within their region and subsequently to other regions or the Permian basin. These costs, although simplified in the model, show that long-distance transmission of carbon dioxide should be scoped out in more detail. The USE IT Act – a bipartisan bill supported by Senators Barrasso (R-WY), Capito (R-WV), Whitehouse (D-NJ), and Heitkamp (D-ND) – is one such measure. It would open high-value carbon dioxide pipelines for FAST Act eligibility,[73] which establishes a coordinated federal permitting process directed by the executive branch's Council on Environmental Quality. The forecasts in the

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[69] *See Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236 (2018), https://www.ferc.gov/CalendarFiles/20180629212349-EL16-49-000.pdf.
[70] *See* National Coal Council, *CO_2 Building Blocks: Assessing CO_2 Utilization Options* (Aug. 30, 2016), http://www.nationalcoalcouncil.org/studies/2016/NCC-CO2-Building-Block-FINAL-Report.pdf.
[71] John Litynski, *et al.*, *Using CO_2 for Enhanced Coalbed Methane Recovery and Storage*, CBM Review (June 2014), https://www.netl.doe.gov/File%20Library/Research/Carbon-Storage/Project-Portfolio/CBM-June-2014.pdf.
[72] Energy Information Administration, *Map of Coalbed Methane Fields*, Lower 48 States (Apr. 8, 2009), https://www.eia.gov/oil_gas/rpd/coalbed_gas.pdf.
[73] *See* Fixing America's Surface Transportation Act, Pub. L. No. 114-94 (2015) (FAST Act), https://www.fhwa.dot.gov/fastact/summary.cfm.

analysis would require a substantial increase in carbon dioxide pipelines. Similar to other pipelines, obtaining the appropriate permits and permission from existing landowners can be a significant challenge. In the 82-mile Petra Nova pipeline, the developers had to individually negotiate with several dozen property owners.[74] Additional clearances would be needed to cross environmentally sensitive areas or federal lands.

[74] *See* U.S. Department of Energy, W.A. Parish Post-Combustion CO2 Capture and Sequestration Project, DOE/EIS-0473, Final Environmental Impact Statement, https://www.energy.gov/sites/prod/files/EIS-0473-FEIS-Vol_I-2013_1.pdf.

5. Conclusion

Carbon dioxide, currently being treated as a waste stream, could be turned into a valuable commodity. When the sales of carbon dioxide and associated tax credits were factored into dispatch decisions, low-cost carbon capture technologies reduced power costs, as well as significantly increased domestic oil production.

The current market environment of low oil and power prices is not conducive for vibrant carbon capture development. Globally, only one-tenth of one percent of recent public-private clean energy investment has supported carbon capture and utilization.[75] Yet, increasing electricity demand (e.g., a growing economy, a revitalized manufacturing sector, and increased vehicle and industry electrification, etc.), rising oil prices, and declining carbon capture costs create favorable conditions ripe for future deployment. Both coal and natural gas-fueled systems equipped with carbon capture were amenable to commercial deployment, although the relative magnitude of each varied by scenario.

The steady commitment to the technology has established the United States as a global leader on carbon capture and is recognized in international forums such as the Carbon Sequestration Leadership Forum, Mission Innovation, and the Clean Energy Ministerial. Continued support for advanced fossil-energy technologies is an investment in our nation's long-term economic and energy security.

[75] *See* International Energy Agency, *Five Ways to Unlock CCS Investment,* http://www.iea.org/media/topics/ccs/5KeysUnlockCCS.PDF (last visited July 20, 2018).

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Appendix A. EOR Inputs and Assumptions

Table A- 1. CO_2 Transportation Cost by Source State and EOR Destination

Source State	Primary Destination	Primary Transport Cost ($ per metric ton)	Secondary Destination	Secondary Transport Cost ($ per metric ton)
CA	CA	2.7	N/A	N/A
East TX	East & Central TX	2.7	N/A	N/A
FL	Gulf	6.4	Permian	14
LA	Gulf	6.4	N/A	N/A
MS	Gulf	6.4	Permian	14
AR	Mid-Con	10.6	Permian	14.5
IA	Mid-Con	10.6	Permian	14.5
KS	Mid-Con	10.6	N/A	N/A
MO	Mid-Con	10.6	N/A	N/A
NM	Permian	2.7	N/A	N/A
West TX	Permian	2.7	N/A	N/A
East TX	Permian	5.4	N/A	N/A
AL	Permian	14	N/A	N/A
GA	Permian	14	N/A	N/A
KY	Permian	14	N/A	N/A
IL	Permian	14.5	N/A	N/A
IN	Permian	14.5	N/A	N/A

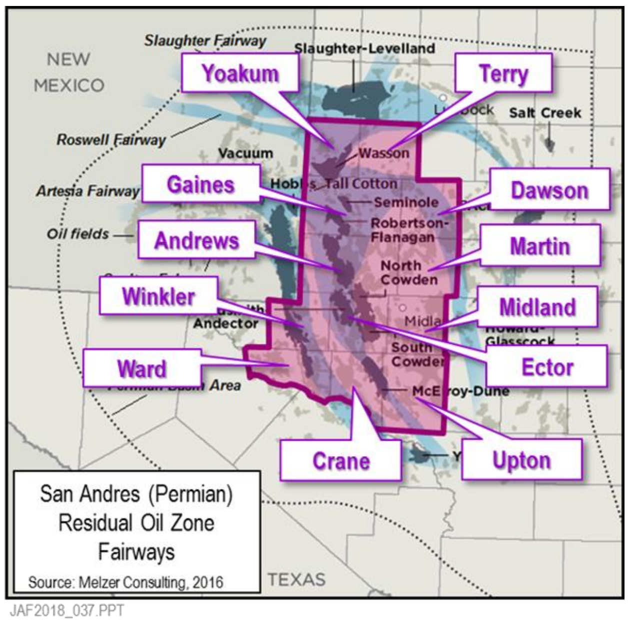
The cost for delivering carbon dioxide by pipeline is primarily a function of the length and diameter of the pipeline. Pipeline delivery costs in this analysis were determined by combining ARI's experience in this market with a pipeline model developed by NETL.

Where a state has two entries, the higher value reflects the cost of transport to a secondary region after the lowest cost region's storage capacity is exceeded. For example, power plants in Florida are projected to transport carbon dioxide to the Gulf EOR region for $6.40 per metric ton, until the EOR storage capacity of the Gulf is fully exploited. Thereafter, additional carbon capture projects at Florida power plants would transport captured carbon dioxide to the Permian region in Texas at a higher cost of $14.00 per metric ton.

Table A- 2. Nominal Value of Section 45Q Credits by Year

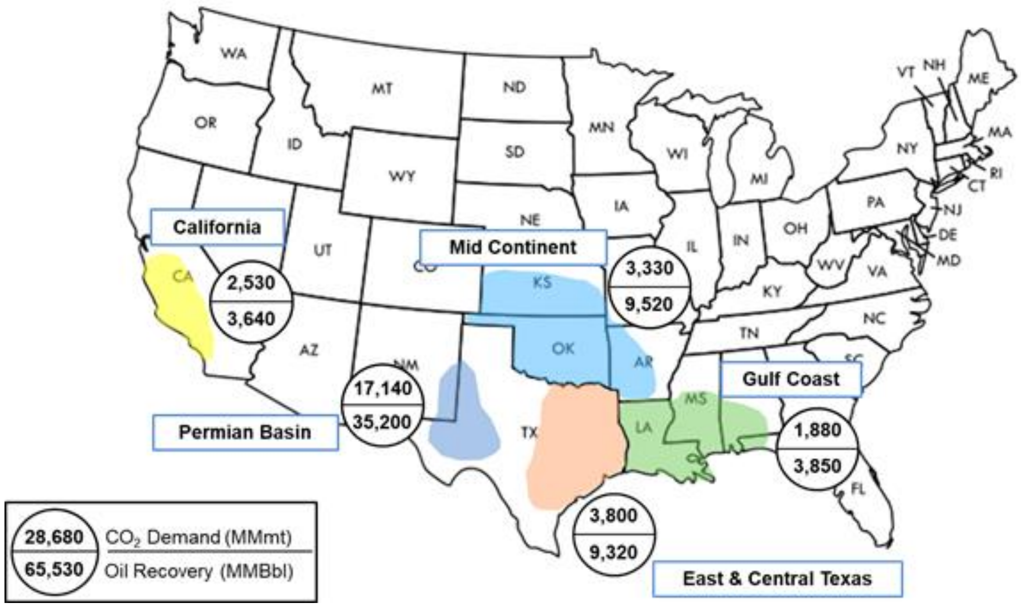
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026 to 2042
Credit ($)	12.83	15.29	17.76	20.22	22.68	25.15	27.61	30.07	32.54	35.00

Figure A- 1. Texas Counties in the Residual Oil Zone



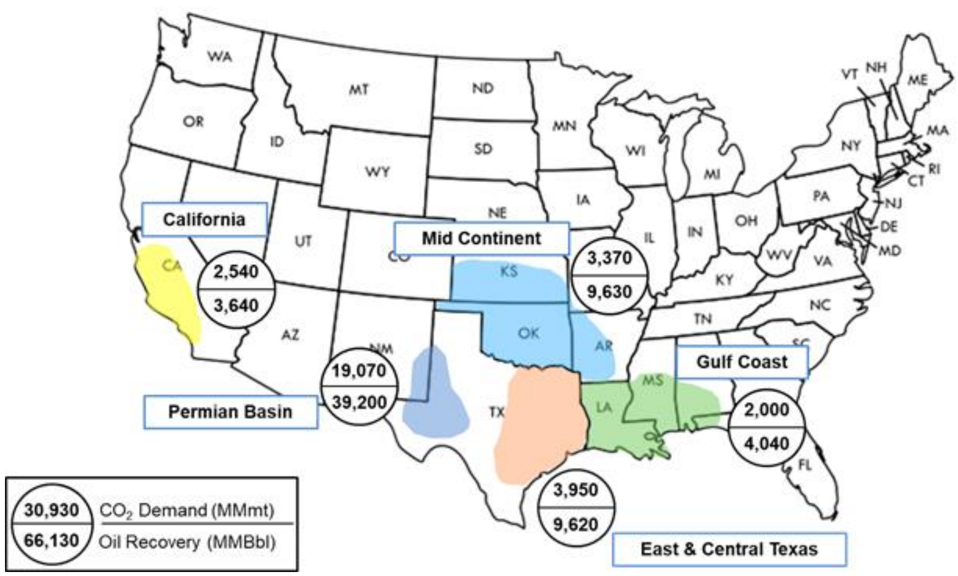
Source: Advanced Resources International

Figure A- 2. Ultimate Economically Viable CO_2 Demand and EOR at $75 Per Barrel



Source: Advanced Resources International

Figure A- 3. Ultimate Economically Viable CO_2 Demand and EOR at $100 Per Barrel



Source: Advanced Resources International

Appendix B. Power-sector Model Inputs

Table B- 1. Descriptions of Scenarios by Variable

	Variables				
Scenario	Economic Growth	Oil & Gas Prices	Electricity Demand	Capture Costs	Capital Charge Adder
#1a	High	High(+)	High	RD&D	Y
#1b	High	High(+)	High	Base	Y
#2a	High	High(+)	High	RD&D	N
#2b	High	High(+)	High	Base	N
#3a	Base(-)	High	Base(-)	RD&D	Y
#3b	Base(-)	High	Base(-)	Base	Y
#4a	Base	Base	Base	RD&D	Y
#4b	Base	Base	Base	Base	Y

"Base" energy prices, growth and electricity demand reflect *EIA AEO 2018* Reference case (0.60% per year electricity demand growth).

"Base(-)" economic growth reflects *EIA AEO 2018* Low Oil & Gas (LO&G) Resource and Technology case; electricity demand growth is 0.56% per year.

"High" economic growth assumes about 3.5% per year GDP growth between 2020 and 2040; electricity demand growth is 1.4% per year for 2020-2040.

Table B- 2. Henry Hub Natural Gas Prices by Case ($/MMBtu)

	2020	2025	2030	2035	2040
Base	$3.60	$4.00	$4.20	$4.20	$4.40
High	$5.00	$6.40	$6.80	$7.10	$7.50
High(+)	$5.00	$6.70	$7.10	$7.40	$8.70

Table B- 3. Crude Oil Prices by Case ($/MMBtu)

	2020	2025	2030	2035	2040
Base	$65.80	$81.10	$87.60	$93.50	$99.40
High	$69.10	$88.90	$96.90	$105.40	$111.60
High(+)	$69.10	$89.40	$98.10	$105.90	$114.40

Table B- 4. Pipeline carbon dioxide Offtake Prices by Case ($/MMBtu)

	2020	2025	2030	2035	2040
Base	$25.65	$31.62	$34.17	$36.48	$38.78
High	$26.93	$34.67	$37.78	$40.05	$41.25
High(+)	$26.96	$34.88	$38.25	$40.14	$41.81

Table B- 5. U.S. Electricity Demand (Generation) by Case (TWh)

	2020	2025	2030	2035	2040
Base	3,824	3,924	4,032	4,135	4,272
Base(-)	3,806	3,886	3,986	4,083	4,217
High	3,815	4,035	4,362	4,711	5,136

Base Cost and Performance Assumptions for Fossil-Fired Electricity Generating Units

Table B- 6. Coal Without Carbon Capture, Base Case

	2020	2025	2030	2035	2040
Capital ($/kW)	$2,361	$2,328	$2,296	$2,259	$2,157
Fixed O&M ($/kW-yr)	$78.85	$77.76	$76.66	$75.44	$72.02
Variable O&M ($/MWh)	$9.99	$9.85	$9.71	$9.55	$9.12
HHV (Btu/kWh)	8,379	8,151	7,923	7,809	7,695

Table B- 7. Coal With Carbon Capture, Base Case

	2020	2025	2030	2035	2040
Capital ($/kW)	$4,081	$4,024	$3,968	$3,816	$3,550
Fixed O&M ($/kW-yr)	$126.53	$124.78	$123.02	$118.31	$110.08
Variable O&M ($/MWh)	$16.25	$16.03	$15.80	$15.20	$14.14
HHV (Btu/kWh)	10,508	10,079	9,651	9,436	9,222

Table B- 8. Natural Gas Without Carbon Capture, Base Case

	2020	2025	2030	2035	2040
Capital ($/kW)	$789	$778	$767	$750	$710
Fixed O&M ($/kW-yr)	$27.84	$27.45	$27.07	$26.45	$25.06
Variable O&M ($/MWh)	$1.83	$1.81	$1.78	$1.74	$1.65
HHV (Btu/kWh)	6,629	6,271	5,913	5,734	5,555

Table B- 9. Natural Gas With Carbon Capture, Base Case

	2020	2025	2030	2035	2040
Capital ($/kW)	$1,699	$1,675	$1,652	$1,512	$1,325
Fixed O&M ($/kW-yr)	$54.03	$53.28	$52.52	$48.08	$42.14
Variable O&M ($/MWh)	$4.37	$4.31	$4.25	$3.89	$3.41
HHV (Btu/kWh)	7,466	7,083	6,699	6,508	6,316

Accelerated RD&D Cost and Performance Assumptions for Fossil-Fired Electricity Generating Units

Table B- 10. Coal Without Carbon Capture, Aggressive RD&D

	2020	2025	2030	2035	2040
Capital ($/kW)	$2,361	$2,259	$2,157	$2,124	$2,091
Fixed O&M ($/kW-yr)	$78.85	$75.44	$72.02	$70.92	$69.83
Variable O&M ($/MWh)	$9.99	$9.55	$9.12	$8.98	$8.84
HHV (Btu/kWh)	8,379	8,037	7,695	7,524	7,353

Table B- 11. Coal With Carbon Capture, Aggressive RD&D

	2020	2025	2030	2035	2040
Capital ($/kW)	$4,081	$3,816	$3,550	$3,265	$2,979
Fixed O&M ($/kW-yr)	$126.53	$118.31	$110.08	$101.23	$92.37
Variable O&M ($/MWh)	$16.25	$15.20	$14.14	$13.00	$11.87
HHV (Btu/kWh)	10,508	9,865	9,222	8,579	7,935

Table B- 12. Natural Gas Without Carbon Capture, Aggressive RD&D

	2020	2025	2030	2035	2040
Capital ($/kW)	$789	$750	$710	$699	$688
Fixed O&M ($/kW-yr)	$27.84	$26.45	$25.06	$24.67	$24.28
Variable O&M ($/MWh)	$1.83	$1.74	$1.65	$1.62	$1.60
HHV (Btu/kWh)	6,629	6,092	5,555	5,555	5,555

Table B- 13. Natural Gas With Carbon Capture, Aggressive RD&D

	2020	2025	2030	2035	2040
Capital ($/kW)	$1,699	$1,512	$1,325	$1,260	$1,194
Fixed O&M ($/kW-yr)	$54.03	$48.08	$42.14	$40.06	$37.97
Variable O&M ($/MWh)	$4.37	$3.89	$3.41	$3.24	$3.07
HHV (Btu/kWh)	7,466	6,891	6,316	6,130	5,943

Carbon Capture Retrofit Cost and Performance Assumptions for Coal-Fired Electricity Generating Units

Table B- 14. Retrofit of Coal With Carbon Capture Across All Scenarios

	Value	Description
Capital ($/kW)	900 - 1700	Economies of scale were assumed, with larger coal units being able to achieve lower costs on a $/kW basis.
Fixed O&M ($/kW-yr)	7 - 13	Economies of scale were assumed, with larger coal units being able to achieve lower costs on a $/kW-yr basis.
Heat Rate Penalty (%)	1.3 - 7.3	A lower pre-retrofit heat rate was assumed to generate a larger heat rate penalty.
CO_2 Reduction from Unconstrained Unit (%)	45 - 76	Capture rate is a flat 90%. These values are the net carbon dioxide reductions inclusive of carbon dioxide increase from the natural gas combustion turbine that is used to power the retrofit.

Cost and Performance Assumptions for Onshore Wind and Solar PV

Table B- 15. Onshore Wind and Solar PV Costs

	Capital Costs (2017$/kW)		Fixed O&M (2017$/kW-year)	
Year	**Onshore Wind**	**Solar PV**	**Onshore Wind**	**Solar PV**
2020	$1,870	$2,091	$51.29	$8.13
2025	$1,810	$2,024	$51.29	$8.13
2030	$1,810	$1,984	$51.29	$8.13
2035	$1,809	$1,814	$51.29	$8.13
2040	$1,807	$1,697	$51.29	$8.13

Capital costs are before the production tax credit or investment tax credit are applied, and are based on the Energy Information Administration's, *Annual Energy Outlook 2017 with Projections to 2050* (Jan. 5, 2017) (EIA AEO 2017), and reflect cost for a "generic region" – cost in any given region is based on EIA AEO 2017 regional adjustment factors. Fixed operating and maintenance (FOM) costs are constant across all years for a given region (also based on EIA AEO 2017) and reflect cost for a "generic region" – cost in any given region is based on EIA AEO 2017regional adjustment factors.

Table B- 16. Regional Annual Capacity Factors for Onshore Wind and Solar PV

	Capacity Factor (%)	
	Onshore Wind	**Solar PV**
Min	36.5	17.2
Med	36.8	19.9
Max	49.4	26.7

Capacity factors are constant across all years for a given region (based on EPA assumptions).

Appendix C. Power-sector Model Results

Table C- 1. Capacity of Existing Coal Without Carbon Capture by Scenario (GW)

	Scenarios							
Year	#1a	#1b	#2a	#2b	#3a	#3b	#4a	#4b
2020	235	236	228	232	228	229	208	209
2025	235	236	228	232	228	229	206	208
2030	235	236	228	232	228	229	205	207
2035	234	236	227	232	227	229	192	205
2040	234	236	227	231	227	228	184	193

Table C- 2. Capacity of New Coal Without Carbon Capture by Scenario (GW)

	Scenarios							
Year	#1a	#1b	#2a	#2b	#3a	#3b	#4a	#4b
2020	0	0	0	0	0	0	0	0
2025	0	0	1	1	0	0	0	0
2030	0	0	4	3	0	0	0	0
2035	1	0	11	9	0	0	0	0
2040	1	1	19	21	0	0	0	0

Table C- 3. Capacity of New Coal With Carbon Capture by Scenario (GW)

	Scenarios							
Year	#1a	#1b	#2a	#2b	#3a	#3b	#4a	#4b
2020	0	0	0	0	0	0	0	0
2025	0	0	0	1	0	1	0	0
2030	17	17	17	17	17	17	2	0
2035	32	17	17	17	23	17	2	0
2040	74	31	59	17	65	17	2	0

Table C- 4. Capacity of Existing Natural Gas Combined Cycle Without Carbon Capture by Scenario (GW)

	Scenarios							
Year	#1a	#1b	#2a	#2b	#3a	#3b	#4a	#4b
2020	234	234	234	234	233	233	235	235
2025	234	234	234	234	233	233	234	234
2030	234	234	234	234	233	233	234	234
2035	234	234	234	234	233	233	234	234
2040	234	234	233	234	231	233	234	234

Table C- 5. Capacity of New Natural Gas Without Carbon Capture by Scenario (GW)

	Scenarios							
Year	#1a	#1b	#2a	#2b	#3a	#3b	#4a	#4b
2020	26	26	30	33	26	26	26	26
2025	26	26	41	37	26	26	26	26
2030	55	41	100	71	32	28	36	32
2035	116	98	189	155	62	47	76	65
2040	141	164	231	250	70	91	88	120

Table C- 6. Capacity of New Natural Gas With Carbon Capture by Scenario (GW)

	Scenarios							
Year	#1a	#1b	#2a	#2b	#3a	#3b	#4a	#4b
2020	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	1	1
2030	3	0	3	0	2	1	18	10
2035	3	0	3	0	3	1	34	10
2040	13	2	3	0	9	1	76	20

Table C- 7. Capacity of Nuclear by Scenario (GW)

	Scenarios							
Year	#1a	#1b	#2a	#2b	#3a	#3b	#4a	#4b
2020	96	96	96	96	96	96	96	96
2025	95	95	95	95	95	95	95	95
2030	94	94	94	94	94	94	94	94
2035	73	73	73	73	73	73	73	73
2040	56	56	56	56	56	56	56	56

Table C- 8. Capacity of Hydropower by Scenario (GW)

	Scenarios							
Year	#1a	#1b	#2a	#2b	#3a	#3b	#4a	#4b
2020	77	77	77	77	77	77	77	77
2025	77	77	77	77	77	77	77	77
2030	77	77	77	77	77	77	77	77
2035	77	77	77	77	77	77	77	77
2040	77	77	77	77	77	77	77	77

Table C- 9. Capacity of Solar by Scenario (GW)

	Scenarios							
Year	#1a	#1b	#2a	#2b	#3a	#3b	#4a	#4b
2020	41	41	42	44	39	39	30	30
2025	42	42	43	44	39	40	30	30
2030	43	44	43	45	40	40	30	30
2035	80	97	56	62	41	42	31	31
2040	163	179	140	144	79	83	47	48

Table C- 10. Capacity of Onshore Wind by Scenario (GW)

	Scenarios							
Year	#1a	#1b	#2a	#2b	#3a	#3b	#4a	#4b
2020	25	26	24	25	23	23	15	15
2025	25	26	24	25	23	23	15	15
2030	29	29	29	30	24	24	15	15
2035	29	32	29	30	26	27	16	16
2040	46	58	36	37	27	30	17	17

Table C- 11. Coal Production for Electricity Generation (million metric tons)

	Scenarios							
Year	#1a	#1b	#2a	#2b	#3a	#3b	#4a	#4b
2020	794	797	783	782	791	795	676	680
2025	880	886	857	873	851	856	701	706
2030	945	964	919	949	912	922	701	711
2035	992	966	926	965	940	938	671	704
2040	1,109	1,020	1,085	1,006	1,049	928	653	676

Table C- 12. U.S. Generation Mix in 2040 By Scenario

Assumptions						Results							
Scenario #	GDP & Power Demand Growth	Oil & Gas Price	R&D Rate	Capital Charge Adder		Scenario #	Coal w. no CCS (%)	Coal w. CCS (%)	Gas w. no CCS (%)	Gas w. CCS (%)	Nuclear Power (%)	Renewable Energy (%)
#1a	Hi	Hi$^{(+)}$	Hi	Y	→	1	30	10	24	2	8	26
#1b	Hi	Hi$^{(+)}$	Ref	Y		2	31	4	28	<1%	8	27
#2a	Hi	Hi$^{(+)}$	Hi	N	→	3	31	8	28	<1%	8	23
#2b	Hi	Hi$^{(+)}$	Ref	N		4	33	2	32	0	8	23
#3a	Ref$^{(-)}$	Hi	Ref$^{(-)}$	Y	→	5	35	11	19	2	10	23
#3b	Ref$^{(-)}$	Hi	Ref$^{(-)}$	Y		6	35	3	25	<1%	10	24
#4a	Ref	Ref	Hi	Y		7	25	<1%	28	12	9	19
#4b	Ref	Ref	Ref	Y		8	28	<1%	37	3	10	21

Appendix D. EOR Model Results

Table D- 1. Cumulative EOR Benefits (2028-2040)

	Benefits			
Scenario	Jobs created (job years)	GDP Benefits ($MM)	Total Gross Revenue ($MM)	Oil production (MM barrels)
#1a	4,126,038	$ 1,009,732	$ 475,561	5250
#1b	2,449,405	$ 607,078	$ 286,095	3219
#2a	2,885,499	$ 710,251	$ 336,346	3751
#2b	2,083,857	$ 519,702	$ 245,315	2800
#3a	3,253,378	$ 800,439	$ 377,903	4245
#3b	2,061,628	$ 514,082	$ 242,715	2806
#4a	1,466,115	$ 361,592	$ 172,582	2161
#4b	491,395	$ 121,960	$ 58,507	741

Table D- 2. Annual EOR Benefits Realized in 2040

	Benefits			
Scenario	Jobs created (job years)	GDP Benefits ($MM)	Total Gross Revenue ($MM)	Oil production (MM barrels)
#1a	779,900	$ 190,176	$ 89,837	923
#1b	387,700	$ 94,802	$ 44,496	449
#2a	608,400	$ 147,031	$ 69,917	713
#2b	201,000	$ 50,132	$ 23,651	239
#3a	660,000	$ 161,686	$ 76,497	791
#3b	203,400	$ 50,724	$ 23,936	245
#4a	267,600	$ 65,852	$ 31,697	369
#4b	76,200	$ 18,973	$ 8,996	104

Table D- 3. Tax Benefits of EOR Realized in 2040

	Receipts (MM USD)			
Scenario	**Severance Tax**	**Ad Valorem Tax**	**State Income Tax**	**Federal Income Tax**
#1a	2004	1965	596	4962
#1b	772	876	321	2877
#2a	1801	1575	541	4005
#2b	553	527	153	1449
#3a	1853	1757	482	4218
#3b	556	526	159	1398
#4a	1124	804	382	382
#4b	207	167	125	125